141 FERC ¶ 61,048
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

Southwest Power Pool, Inc. — Docket Nos. ER12-1179-000, ER12-1179-001

ORDER CONDITIONALLY ACCEPTING TARIFF REVISIONS
TO ESTABLISH ENERGY MARKETS

(Issued October 18, 2012)

Paragraph Numbers

1. In this order, the Commission conditionally accepts for filing,[1] subject to further modifications, a proposal filed on February 29, 2012, as amended on May 15, 2012, by

[1] SPP proposal's eTariff designations appear at Appendix A, with Tariff designations for SPP's February 29, 2012 proposed revisions at Appendix A.1 and Tariff designations for SPP's May 15, 2012 amendment at Appendix A.2.

Southwest Power Pool Inc. (SPP) to revise its Open Access Transmission Tariff (Tariff) to implement its Integrated Marketplace.[2] Significant components of the Integrated Marketplace are a market-based congestion management program and energy markets, including day-ahead and real-time energy and operating reserve markets with locational marginal pricing, allocation of auction revenue rights (ARR) and a market for the auction of transmission congestion rights (TCR), virtual transactions, and a revised market power mitigation plan. SPP requests a March 1, 2014 effective date for the implementation of the Integrated Marketplace. This order accepts SPP's proposal subject to SPP submitting compliance filings to revise the proposed Tariff to transition from its current Energy Imbalance Service (EIS) Market to the Integrated Marketplace. We note that SPP proposes to submit plans necessary for the commencement of the new market, including Readiness and Reversion Plans, and a Readiness Certification. This order is conditioned upon SPP filing the proposed plans. These subsequent filings are to be submitted within the timeframe specified herein to ensure a timely start for the Integrated Marketplace.[3] This order also requires SPP to file an informational report 15 months after market start-up that evaluates the effectiveness of the Integrated Marketplace.

2. In prior market design orders, the Commission has acknowledged the importance of explicit market rules in the design of organized wholesale markets, and has contrasted such well-designed markets to instances where flaws in both market designs and market rules have undermined the reliability and stability of market operations. Given our experience now with several markets, and because we recognize the importance of acting in a timely manner to ensure that a well-designed market will be in place at the proposed effective date, we accept the filing subject to conditions.

3. For the purpose of readying the new market with constructs necessary for a successful start, at this time we are conditioning our approval of SPP's proposal and directing certain necessary changes in SPP's proposal. Some of these changes have been sought by commenters and agreed to by SPP in subsequent comments, such as the establishment of long-term financial transmission rights. Others are changes that we find are necessary for the successful functioning of the market, including tariff revisions to provide more comprehensive market power mitigation provisions and scarcity pricing provisions. Some revisions included herein are mandated by previously-issued Commission orders, such as Order No. 719 (Demand Response),[4] Order No. 755

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[2] The Integrated Marketplace filing was made pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d (2006).

[3] *See* P 506 of this order for a listing of expected future filings.

[4] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A,

(continued…)

(Frequency Regulations Compensation)[5] and Order No. 741 (Credit Policy).[6] We also establish reporting requirements for the purpose of providing SPP, the Commission and interested parties information to evaluate the initial year of the Integrated Marketplace operations.

I. Background

A. History of SPP

4. On February 10, 2004, the Commission conditionally granted SPP's application for recognition as a regional transmission organization (RTO) subject to SPP making tariff, organizational and other changes prior to qualifying for RTO status.[7]

5. On October 1, 2004, when acting on SPP's compliance filing, the Commission found that SPP's proposal to become an RTO satisfied the requirements of Order No. 2000,[8] and thus granted SPP's RTO status.[9]

FERC Stats. & Regs. ¶ 31,292 (2009), *order denying reh'g*. Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[5] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012).

[6] *Credit Reforms in Organized Wholesale Electric Markets*, Order No. 741, FERC Stats. & Regs. ¶ 31,317 (2010), *order on reh'g*, Order No. 741-A, FERC Stats. & Regs. ¶ 31,320, *reh'g denied*, Order No. 741-B, 135 FERC ¶ 61,242 (2011). SPP states that the Commission conditionally accepted SPP's June 30, 2011 filing to comply with Order No. 741. *See Southwest Power Pool, Inc.*, 136 FERC ¶ 61,189 (2011).

[7] *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 2, *order on reh'g*, 109 FERC ¶ 61,010 (2004).

[8] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000),

aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[9] *Southwest Power Pool*, 109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005).

6. In an order dated March 20, 2006, the Commission rejected, in part, and conditionally accepted and suspended, in part, SPP's revised filing to establish an EIS market and market monitoring and mitigation plan subject to further Commission orders.[10]

7. On January 26, 2007, the Commission accepted SPP's certification that it was ready to start the EIS market on February 1, 2007.[11] In its filing, SPP stated that upon the successful implementation of the EIS market, the SPP Strategic Planning Committee determined that it was important to assess opportunities for future market development. Following that recommendation, SPP created the Cost Benefit Task Force, with representatives and members from the Regional State Committee (RSC) that was tasked with working with a third-party consultant to develop a cost-benefit analysis. SPP contracted with Ventyx to analyze the costs and benefits of four options for SPP future market design.[12] Ventyx recommended in 2009 that SPP institute a market design combining a day-ahead market with unit commitment and a co-optimized energy and ancillary services markets as quickly as possible because of the estimated net benefits that would average approximately $100 million per year.[13]

B. Integrated Marketplace Filing

8. As proposed, the Integrated Marketplace includes day-ahead and real-time energy and operating reserve markets and TCR markets aimed at maximizing the cost-effective utilization of energy resources and the regional transmission system. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to achieve lowest-cost resource utilization.

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[10] *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (SPP EIS Market Order), *order on reh'g*, 116 FERC ¶ 61,289 (2006) (SPP EIS Market Rehearing Order).

[11] *Southwest Power Pool, Inc.*, 118 FERC ¶ 61,055 (2007), *reh'g denied*, 120 FERC ¶ 61,018 (2007).

[12] Ventyx performed the cost benefit analysis using the PROMOD IV market simulation application to calculate the adjusted production cost to quantify the benefits. Ventyx consulted with SPP and Market Participants to determine the costs of implementing the market designs options being studied.

[13] Exh. No. SPP-1 at 7. *See also* Exh. No. SPP-2 at 64 (Ventyx, SPP Cost Benefit Study for Future Market Design at 56). However, SPP notes that the study has been updated with an assumption of low gas prices and the estimated net benefit drops to $45 million per year. Exh. No. SPP-1 at 8.

9. SPP states that it reviewed the Commission-approved market designs of other RTOs with its stakeholders to identify effective market designs and avoid the problems that other RTOs encountered in designing their markets. SPP maintains that to the extent possible, SPP and its stakeholders incorporated the major features used successfully in the four eastern RTOs – Midwest Independent Transmission System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO) and ISO New England (ISO-NE). From these markets, SPP modeled many of its market components, including centralized security-constrained economic dispatch, Locational Marginal Prices (LMP), operating reserve markets and market power mitigation based on conduct and impact thresholds. SPP states that, where necessary, SPP modified aspects of its proposal in consultation with its stakeholders to address regional differences and SPP stakeholder needs.

10. SPP proposes a series of revisions to its Tariff and Membership Agreement to implement the Integrated Marketplace. SPP proposes to replace Attachment AE, Energy Imbalance Service Market, in its entirety with Attachment AE, Integrated Marketplace, and retain all of the other sections of its Tariff including schedules and attachments, revising them as necessary to implement the Integrated Marketplace.[14] Specifically, SPP proposes revisions throughout the common service provisions and main provisions of the Tariff governing point-to-point transmission service and network integration transmission service. SPP also proposes revisions to Schedules 1 through 9, and Schedule 11 to reflect the implementation of the Integrated Marketplace. SPP proposes revisions to several Tariff Attachments to conform to the Integrated Marketplace design, including revisions to the attachments pertaining to SPP's credit policy (Attachment X), market monitoring (Attachment AF) and mitigation (Attachment AG). SPP also proposes substantial revisions to attachments involving redispatch procedures and associated costs (Attachment K) and loss compensation (Attachment M) as many of the provisions in these attachments have been rendered unnecessary by the revisions to Attachment AE for the Integrated Marketplace. Finally, SPP proposes to delete the form of service agreement for loss compensation service (Attachment N) as it is no longer needed given the move to a marginal loss compensation method, the extensive revisions to Attachment M, and the implementation of the Integrated Marketplace. SPP states that it will make additional filings before its requested effective date of March 1, 2014 to address additional issues not addressed in the instant submittal. SPP states that it will submit filings to further comply with Order Nos. 741, 745 and 755, to provide the final agreement to consolidate the Balancing Authority Areas, to establish a Readiness Plan

[14] *See* SPP, OATT, Pt. V, Attachment AE (MPL), Attachment AE Integrated Marketplace (0.0.0). In this order, we will refer to the proposed tariff revisions as SPP Tariff, Proposed Attachment [x], and the existing tariff as SPP Tariff, Attachment [x].

and Reversion Plan and to certify the market and consolidation of Balancing Authority Areas is ready to commence March 1, 2014.

11. On May 15, 2012, SPP filed an amendment to revise its February 29, 2012 proposed Tariff revisions in which SPP proposes major changes to its mitigation measures. The filing also contained proposed Tariff changes that SPP characterizes as addressing miscellaneous clean-up or inconsistencies in various parts of the Tariff that were identified after it submitted the February 29 filing.

12. SPP requests an effective date of March 1, 2014 for the Tariff revisions proposed in the amendment, consistent with SPP's Tariff revisions proposed in the February 29, 2012 filing and with the anticipated launch date of the Integrated Marketplace. SPP requests a waiver of the Commission's notice requirements,[15] to allow SPP to submit these Tariff revisions to the Commission more than 120 days prior to the requested effective date. SPP states that a waiver will enable the Commission to issue an order approving SPP's Integrated Marketplace market design proposal with sufficient time for SPP to complete its development of the Integrated Marketplace market design in a timely and cost-effective fashion and for SPP Members to obtain any necessary state regulatory approvals to participate in the Integrated Marketplace.

II. Notice and Pleadings

13. Notice of the SPP filing was published in the *Federal Register*, 77 Fed. Reg. 14,357 (2012), with interventions and protests due on or before March 30, 2012. On March 28, 2012, Basin and Heartland filed a request to extend the deadline for comments to April 13, 2012. On March 29, 2012, the Commission granted an extension until April 6, 2012. On May 15, 2012, SPP filed an answer to the protests (SPP May 15 Answer). It also filed an amendment to its original filing. Notice of the amendment was published in the *Federal Register*, 77 Fed. Reg. 30,519 (2012), with interventions and protests due on or before June 6, 2012. The parties listed in Appendix B filed interventions, protests, and comments, as detailed below. Acronyms and short forms used for party names throughout the order can also be found in Appendix B. Answers to the SPP May 15 Answer were filed by Western, OPPD, E.ON, MRES and Heartland, NPPD, BP Wind Energy, TDU Intervenors, MISO, and Calpine. On June 26, 2012, SPP submitted another answer (SPP June 26 Answer) responding to the answers filed by other parties. In response, OPPD and E.ON submitted answers on July 9, 2012 and July 11, 2012, respectively. On October 11, 2012, MISO filed amended comments which the Commission is treating as an answer.

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[15] 18 C.F.R. § 35.3 (2012).

III. Discussion

A. Procedural Issues

14. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the notices of intervention and the timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R § 385.214(d) (2012), we will also grant the late-filed motions to intervene of Sunflower Electric Power Corporation and Mid-Kansas Electric Company LLC and MISO given these parties' interests in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

15. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2012), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We accept the answers filed because they have provided information that has assisted us in our decision-making process.

16. We find good cause to grant SPP's request for waiver of the 120-day notice requirement in section 35.3 of the Commission's regulations.[16] It is reasonable for SPP to file the proposal early to permit the Commission sufficient time to address the filing so that SPP may complete the remaining work required for commencement of the new market.

B. Overall Proposal

1. SPP Proposal

17. As proposed, the SPP Integrated Marketplace includes market-design components that are similar to ones previously approved by the Commission and implemented in other RTO/ISO markets. Specifically, the proposal includes the following major market-design components:

(1) Day-ahead energy and operating reserve market, which includes a day-ahead market obligation and virtual bidding proposal;[17]

(2) Day-ahead and intra-day Reliability Unit Commitment (RUC) processes;

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[16] 18 C.F.R. § 35.3 (2012).

[17] SPP's filing also addresses some of SPP's Order No. 719 and 719-A compliance requirements including the submission of a scarcity pricing proposal.

(3) Real-time balancing market, which will replace the current EIS market;[18]

(4) Price-based co-optimized energy and operating reserve procurement;

(5) Market-based congestion management process including a market for TCRs and allocation of ARRs;[19]

(6) Consolidation of 16 current Balancing Authority Areas in the SPP footprint into a single Balancing Authority Area operated by SPP;[20]

(7) Multi-Day Reliability Assessment performed prior to the day-ahead market to manage the commitment of long-start resources; and

(8) Market monitoring and mitigation with an Internal Market Monitor.

18. According to SPP, the day-ahead and real-time energy and operating reserve markets and TCR markets are intended to maximize the cost-effective utilization of energy resources and the regional transmission system. In the Integrated Marketplace, SPP will function as the Reliability Coordinator, Balancing Authority Area, Transmission Service Provider, Planning Coordinator, Reserve Sharing Group Administrator, Interchange Authority, and Market Operator.

2. Comments and Protests

19. AWEA states that energy and operating reserve markets are beneficial because they provide a uniform price signal for all system users, incentivize resources to offer their services, and guarantee the lowest cost provision of those services. AWEA notes that studies have documented that markets that dispatch generation and allow transmission scheduling at frequent time intervals—as SPP does with its proposed five-

[18] A real-time balancing market sets market prices in five-minute intervals based on the resource offers into the market.

[19] The term "congestion management" refers to a process that properly recognizes the physical limitations of the existing transmission grid and, based on those limitations, adjusts the production of various generation and demand resources. SPP does not submit a long-term financial transmission rights proposal.

[20] SPP does not provide specific details about the consolidation process but we expect SPP to provide such details when it makes a specific filing with the Commission to consolidate its Balancing Authority Areas.

minute interval—are particularly beneficial, as they provide market signals for generators to change their output in response to fluctuations in supply and demand, reducing the need for expensive operating reserves.[21]

20. EPSA strongly supports the creation of the Integrated Marketplace in SPP, noting that it has long advocated for competitive electricity markets and the evolution of wholesale electricity markets.[22] EPSA states it is a strong advocate of organized electricity markets and supports SPP's efforts to implement a Day 2 market featuring independent unit commitment, transparent commodity pricing, consolidated Balancing Authority Areas, and a market for ancillary service products.

21. DC Energy generally supports SPP's Integrated Marketplace proposal and appreciates SPP's efforts to develop this market, further emphasizing that it does not wish to impede implementation of the proposal. DC Energy states that it wants SPP's Integrated Marketplace to be a "best in class" market and points out several issues it believes SPP should address to achieve this goal.[23] Similarly, TDU Intervenors approve of the Integrated Marketplace's incorporation of many best practices from other RTO and ISO energy markets.

22. NPPD expresses its support of SPP's efforts to develop day-ahead and real-time energy markets, an operating reserve market, and TCRs. NPPD asserts a properly structured energy market should strive to maximize the cost-effective use of resources while respecting long-term contractual obligations and addressing transitional cost impacts.

23. Calpine appreciates SPP's efforts to develop and implement its market reforms and generally supports the structure of the Integrated Marketplace. In particular, Calpine supports SPP's decision to consolidate its 16 Balancing Authority Areas into a single Balancing Authority Area and to implement transparent TCR, ancillary service and day-ahead energy markets.[24]

[21] AWEA Protest at 3-4 (citing Enernex, "Final Report Avista Corporation Wind Integration Study," March 2007; and R. Wiser and M. Bolinger, "2010 Wind Technologies Market Report," June 2011 at 69-70).

[22] EPSA Protest at 4.

[23] DC Energy Protest at 1, 18-19.

[24] Calpine Protest at 1, 3-4.

24. APPA is concerned how SPP's market design might continue to develop after approval of the Integrated Marketplace. APPA notes that other RTOs began with similar Day 2 market designs and later added locational capacity markets. APPA states that the development of locational capacity markets in the other RTOs may put pressure on SPP to implement a locational capacity market in the future. APPA states that it does not want the right of its members to self-supply their own load curtailed by subsequent locational capacity markets as happened in other RTOs.

25. Acciona is in general agreement with and supportive of SPP's goal of forming the Integrated Marketplace, as well as a number of measures in the filing, including the consolidation of various Balancing Authority Areas. ECRNA agrees that the consolidation of Balancing Authority Areas will be beneficial for the grid and for customers, and notes that it appreciates the significant efforts of SPP and regional stakeholders to arrive at the Integrated Marketplace design.

26. Cooperatives participated in the development process as SPP Members, and generally support implementation of the proposed Integrated Marketplace. Xcel also participated in the SPP stakeholder process, and generally supports the SPP proposal.

27. Texas Cooperatives state that the SPP proposal represents a significant step forward for customers within the SPP region. They note that for load-serving entities like themselves that are also generation owners and developers, the proposal will provide an easily accessible market for selling excess energy. Accordingly, they recommend that the Commission accept the proposal. Texas Cooperatives urge quick approval, as SPP's proposal is based on well-established markets in other RTOs, as well as a lengthy stakeholder process. Texas Cooperatives note that any delay would add to uncertainty in the market, especially as relates to Entergy Corporation's decision to join MISO rather than SPP.

28. TDU Intervenors state that they are pleased that the Integrated Marketplace proposal incorporates best practices from other RTOs' energy markets. However, they argue that a number of features, as noted in the detailed discussion sections below, must be added or modified to make the proposal just and reasonable.

29. TradeWind states that it generally supports SPP's efforts. It notes that a properly crafted Integrated Marketplace will facilitate the market and provide far-reaching benefits for customers. However, TradeWind argues that market flaws in the proposal will restrain the cost-effective use of resources, and place certain SPP customers at a disadvantage.[25]

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[25] TradeWind's key concern is with the proposal to exclude certain firm transmission service arrangements from the ARR allocation, which is discussed below.

3. **Commission Determination**

30. The Commission commends the efforts by SPP and its stakeholders over the past few years to design the Integrated Marketplace proposal. We find that the proposed Integrated Marketplace features result in significant enhancements to how energy and operating reserves are provided throughout the SPP region.[26] We further find that the Integrated Marketplace will result in substantial benefits to stakeholders and customers throughout the region. As discussed throughout the body of this order, we conditionally accept the Integrated Marketplace proposal, subject to conditions and further orders.[27]

31. Among notable system enhancements proposed in the Integrated Marketplace are the energy and operating reserve markets, which will ensure efficient price signals for system users, while providing appropriate incentives for resources to offer their services.

32. In addition to the economic benefits, we find that the proposed Day 2 market will deliver significant qualitative benefits. For example, the use of the security constrained economic commitment by SPP in its Day 2 market will clearly improve the efficiency of the day-ahead market clearing, assist in market power mitigation and may also improve the incentive to participate in the market.[28] Additionally, the RUC rules and procedures will enhance reliability and promote the efficiency of the reliability commitment.[29] SPP's proposed Day 2 market, as modified, utilizes LMP with marginal losses and marginal cost of congestion, which will reflect the true value of additional delivered energy;[30] thereby providing an efficient price signal for bilateral contracts. Moreover, the market-based provision of operating reserves and the consolidation of Balancing

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[26] For example, SPP is modifying the responsibilities of parties under the NERC functional model, with SPP adopting the responsibilities that other RTOs have adopted.

[27] Further, while we understand that the proposal is still being refined by SPP and the stakeholders, we are not making a finding on any aspect of the Integrated Marketplace not before us in this proceeding. We do not address APPA's concerns regarding a locational capacity market because SPP has not proposed such a feature as part of the Integrated Marketplace and thus this issue is outside the scope of the proceeding.

[28] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,145, at P 66 (2003).

[29] *Id*. P 88.

[30] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 409-411 (2004) (MISO TEMT II Order).

Authority Areas will facilitate the integration of the significant amount of wind-powered Variable Energy Resources (VERs) expected for the SPP region. Finally, the proposed monitoring and mitigation plans, as conditioned herein, will discourage anti-competitive behavior in the monitored Day 2 market. For these reasons, we find that SPP's Integrated Marketplace is just and reasonable, as modified, consistent with the conditions discussed below.

C. Day-Ahead Market and Real-Time Balancing Market

33. As noted above, a key element of SPP's Integrated Marketplace proposal is the creation of a day-ahead market in conjunction with a real-time balancing market, designed to optimize resources and lower total production costs for the SPP footprint. In this order, we approve the general framework proposed by SPP. However, there are many specific issues related to the operation and design of the day-ahead market and the real-time balancing market that we address below.

1. Must-Offer Requirement

a. SPP Proposal

34. SPP's proposed Integrated Marketplace includes a limited, flexible must-offer requirement for Market Participants in the day-ahead market and a full must-offer requirement in the RUC and real-time balancing market. SPP explains that the must-offer requirement is intended to ensure that sufficient resources are available to serve load and provide operating reserves. SPP states that stakeholders discussed this aspect of the Integrated Marketplace design extensively and considered several different approaches, including approaches used in other RTOs. Ultimately, SPP states, stakeholders settled on a solution believed to meet SPP's regional needs.

35. Under the proposal, in the day-ahead market, each load-serving Market Participant is required to offer sufficient resources to cover its expected daily peak load for the operating day (as estimated by the Market Participant) plus operating reserve obligations (as estimated by SPP) to the extent that its resources are available. Load-serving Market Participants may choose the resources they offer into the market, so long as they offer as much as their expected load plus operating reserve obligations.[31] SPP's proposed must-offer requirement for the RUC process and real-time balancing market requires all resources to offer to the extent that their resources are available.

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[31] Market Participants that are not load-serving entities have no must-offer requirement in the day-ahead market.

36. SPP states that the must-offer obligation is tied to expected load because all load within the SPP market area is subject to retail regulation, which includes a must-serve obligation. SPP states that the day-ahead market is a financially-binding market, within which load participation is voluntary, and that the day-ahead market is more economic in nature than the reliability-focused RUC process. SPP contends that these day-ahead market features support the proposed limited and flexible must-offer requirement.[32] SPP explains that the RUC and real-time must-offer requirements are intended to ensure that load and operating reserve requirements can be met throughout the operating day, absent a capacity shortage, thereby reducing the opportunity for Market Participants to engage in physical withholding.[33]

37. SPP asserts that its proposed day-ahead must-offer requirement provides significant flexibility for load-serving Market Participants. While other RTO markets have imposed a day-ahead must-offer requirement on all of a load-serving entity's resources (e.g., all designated capacity resources),[34] SPP states that its day-ahead must-offer requirement for load-serving Market Participants is flexible and not resource-specific. SPP explains that, consequently, this market design feature allows Market Participants considerable flexibility to choose from which resources to offer in the day-ahead market to fulfill their load and reserve obligations.

b. <u>Protests</u>

38. Calpine, EPSA, TDU Intervenors, and Xcel request that the Commission require SPP to modify its proposed day-ahead must-offer requirement to conform more closely to day-ahead must-offer requirements in other RTOs and ISOs.[35] EPSA argues that SPP's day-ahead must offer requirement should follow the requirement in other proven markets, unless SPP can offer substantial support for a different approach.[36] These commenters request varying degrees of expansion of the day-ahead must-offer requirement. Calpine and EPSA assert that the day-ahead must-offer requirement should obligate all load-serving Market Participants to offer into the day-ahead market all available resources that

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[32] SPP Transmittal at 22.

[33] *Id*.

[34] *Id*. (citing Midwest Indep. Transmission Sys. Operator, Inc., FERC Electric Tariff, section 39.1.1A.a).

[35] *See* Calpine Protest at 4; EPSA Protest at 6; TDU Intervenors Protest at 34; Xcel Protest at 6.

[36] EPSA Protest at 6.

have been committed to serve load-serving Market Participant capacity obligations.[37] Xcel suggests expanding the day-ahead must-offer requirement to all Network Resources and also questions why SPP has exempted Market Participants that do not serve load from day-ahead must-offer requirements.[38]

39. Xcel protests SPP's day-ahead must-offer requirement, asserting that the cost-benefit analyses used to justify the new market assumed all dispatchable resources would be available for SPP commitment and dispatch. Xcel contends that because Network Resources have an obligation to serve load in SPP, since transmission service is provided on the assumption that those resources are available, it would be inconsistent to build a day-ahead market that does not require such resources or offers.[39] Calpine asserts that the must-offer requirement should be revised so that load-serving Market Participants must offer in the day-ahead market all resources that have been committed to serve load and that are available. Calpine states that such a requirement would limit a load-serving Market Participant's discretion to withhold resources and would work with SPP Criteria section 2.2, which requires load-serving Market Participants to procure adequate capacity in advance to satisfy their annual System Capacity Responsibility obligations.[40] EPSA agrees and adds that this requirement would also result in more effective market operations in the operating day and would ensure adequate liquidity in the day-ahead market.[41]

40. Xcel, Calpine, and EPSA contend that the proposed day-ahead must-offer requirement could distort price signals and adversely affect the market. Calpine and EPSA assert that the proposal allows load-serving Market Participants substantial leeway to withhold significant amounts of energy from the day-ahead market by underestimating their expected loads. They argue that this could distort the day-ahead dispatch and lead to more out-of-merit RUC commitments, inefficient unit commitment, and higher costs.

[37] Calpine Protest at 5-6; *see also* Calpine Answer at 4 (clarifying that Calpine is recommending the requirement that all resources that have been identified by a load-serving entity as being used to meet its capacity obligations, whether such resources are in the load-serving entity's rate-base or are paid to serve the load-serving entity's load under bilateral contracts, would be subject to a must-offer requirement); EPSA Protest at 6.

[38] Xcel Protest at 6-7.

[39] *Id*. at 7.

[40] Calpine Protest at 5-6 (citing SPP Criteria sections 2.2 and 2.1-2.4.2).

[41] EPSA Protest at 6.

EPSA argues that a well-functioning market should have accurate price convergence between the day-ahead and real-time periods, which is facilitated by requiring all resources obligated to serve load through load-serving entity ownership or contract to offer into the day-ahead market.[42]

41. Calpine argues that disparity between the day-ahead and real-time prices could cause real-time reliability and operational problems.[43] EPSA also raises reliability concerns, noting that SPP's proposal lacks specific rules requiring load-serving Market Participants to align their demand with adequate supply. EPSA asserts that, without such rules, load-serving Market Participants may lack sufficient oversight from an independent market operator responsible for maintaining system reliability. EPSA states that the load-serving Market Participant's day-ahead must-offer is imprecise because the Market Participant can vary it from day to day, and the must-offer may be insufficient to support the actual load of the load-serving Market Participant.[44] Xcel argues that there is no process to verify that offered resources are actually deliverable to the load for which the resources are being offered to cover, nor is there any identification of a range of acceptable load forecasting error before the Market Participant is deemed non-compliant with the day-ahead must-offer requirement.[45]

42. TDU Intervenors maintain that SPP's preference for a resource-flexible must-offer condition in its day-ahead market cannot be accommodated at the cost of an unduly thin day-ahead market that would produce unjust and unreasonable rates. TDU Intervenors assert that the Commission has no basis to find that competition in the Integrated Marketplace day-ahead market will be sufficiently robust with the proposed limits on the must-offer requirement, especially when significant resources are out of service. TDU Intervenors argue that SPP bears the burden of proof that its day-ahead market will function competitively despite the limited nature of its must-offer requirement, and that if it cannot so demonstrate, the Commission must require SPP to expand the must-offer requirement.[46]

43. TDU Intervenors argue that because the day-ahead energy market has more installed capacity than needed to meet peak loads, Market Participants may choose not to

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[42] Xcel Protest at 6-7; Calpine Protest at 5; EPSA Protest at 7.

[43] Calpine Protest at 5.

[44] EPSA Protest at 5.

[45] Xcel Protest at 7.

[46] TDU Intervenors Protest at 34-36.

offer a substantial portion of the region's resource fleet into the day-ahead market and instead may offer for the first time for any given operating day during the RUC process. In the RUC process, the selection of the next day's physical generation fleet only considers start-up and no-load costs and takes no account of energy costs. TDU Intervenors argue that by the time Market Participants are obliged to submit a resource's energy offer, they will have gained substantial information about that operating period's system conditions (e.g., transmission constraints and other sellers' resource availabilities) through the RUC process, which will allow them to raise their offers in the RUC and the real-time market to the highest price allowed under mitigation (rather than bidding competitively).[47] EPSA argues that because load-serving Market Participants may decide how they will cover load and reserves for the next day, this discretion creates uncertainty and makes it difficult for SPP's Market Monitor or independent monitors to oversee the process day to day.[48]

44. TDU Intervenors assert that if Market Participants are not offering their lower cost resources into the day-ahead market, SPP will have to commit resources eligible to receive make whole payments more frequently, resulting in additional make whole payments, which would be an artificial and unjustified cost. Further, TDU Intervenors expect that if substantial day-ahead make-whole payments result, fewer Market Participants may choose to bid their loads into that market, and financial traders may be disinclined to participate. TDU Intervenors assert that this would reduce the billing determinants over which make-whole payments are spread, further deterring participation and potentially debilitating the day-ahead market. [49]

c. Answers

45. In its answer, SPP argues that criticisms of its limited day-ahead must-offer requirement ignore Commission precedent, which disfavors broad must-offer requirements in day-ahead markets, absent a resource adequacy mechanism or other capacity payment. SPP maintains that there are market incentives for Market Participants to use accurate estimates when calculating resource capacity that they will offer into the day-ahead market. For example, SPP asserts that a load-serving Market Participant that underestimates its load will be subject to RUC make whole payment charges, potentially higher real-time LMPs, and congestion costs to serve its remaining load in real-time.

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[47] *Id*. at 44-46.

[48] EPSA Protest at 5.

[49] TDU Intervenors Protest at 35-36.

46. In their answers, both TDU Intervenors and Calpine note that load-serving Market Participants in SPP are already subject to resource adequacy obligations.[50] Accordingly, TDU Intervenors argue that this makes it appropriate for the Commission to require that SPP load-serving Market Participants offer resources used to fulfill these obligations in the day-ahead market. TDU Intervenors point out that the SPP region remains dominated by vertically-integrated utilities under traditional state regulatory regimens and that many—if not the majority—of resources receive the same implicit capacity payments described in Commission precedent cited by SPP. Both Calpine and TDU Intervenors question why it is necessary to give Market Participants flexibility to choose which resources to offer when capacity obligations already exist in SPP.[51]

47. Cooperatives characterize as irrelevant arguments that the proposed day-ahead must-offer requirement differs from those in other RTOs and ISOs, asserting that there is no requirement that all market designs be identical. Further, the Cooperatives argue that the Commission has supported RTO and ISO efforts to tailor proposals to meet regional needs, emphasizing that SPP's day-ahead must-offer requirement is a region-specific proposal developed through the stakeholder process.[52] Cooperatives also dispute arguments that load-serving Market Participants may game the market by under-forecasting load in the day-ahead market, contending that such claims are speculative and without support. Cooperatives assert that if the Commission has concerns regarding potential gaming, and SPP lacks authority under the Tariff and Market Protocols to require modifications of day-ahead load projections, then the proper remedy would be to amend the Tariff or the Market Protocols to give SPP that authority.[53]

48. Cooperatives also question protestors' assertions that requiring all resources to offer into the day-ahead market will improve price convergence between day-ahead and real-time prices.[54] Cooperatives posit that if load-serving Market Participants are required to offer all of their generation into the day-ahead market while merchant

[50] Under the SPP Criteria for the existing EIS market, load-serving SPP members are required to maintain a minimum capacity margin of 12 percent (13.6 percent reserve margin), which is believed to be adequate to cover a 90/10 weather scenario.

[51] Calpine Answer at 5; TDU Intervenors Answer at 19.

[52] Cooperatives Answer at 3.

[53] *Id*. at 4.

[54] Cooperatives point out that this argument is unrelated to reliability concerns, noting that SPP already proposes requiring Market Participants to offer all available units for both RUC and real-time market purposes. *Id*.

generation is exempt, LMPs may increase because older units owned by load-serving Market Participants would set the day-ahead market LMP, allowing merchant generation the opportunity to use this information to optimize their offer curves in the real-time market. Cooperatives argue that, although the result would be price convergence, the day-ahead market LMP would be artificially inflated due to merchant generation bidding up real-time market prices.[55]

49. Additionally, Cooperatives stress that a more important issue is whether SPP should compel Market Participants to undertake the costs and risks of offering resources they built or purchased for the purpose of serving their members' retail loads into the day-ahead market for the benefit of other Market Participants. Cooperatives offer specific examples of generating units constructed and owned by Golden Spread that they claim would face negative economic impacts if SPP's day-ahead must-offer requirement is expanded.[56] Cooperatives also assert that an expansion of the day-ahead must-offer requirement raises concerns for non-profit load-serving Market Participants. Cooperatives argue that a must-offer requirement for all load-serving Market Participant generation effectively converts these Market Participants—including non-profits—into merchant generators. Cooperatives contend that this would force some load-serving Market Participants to assume greater levels of risk, and in the case of non-profits, raises tax issues related to the percentage of income derived from non-member sales. Cooperatives also question whether the Commission has the authority to require non-profit load-serving Market Participants, such as Golden Spread, to become merchant generators and make sales into RTO and ISO markets beyond their members' needs. Cooperatives assert that if the Commission expands the day-ahead must-offer

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[55] *Id*. at 7.

[56] Cooperatives point to a Golden Spread quick start gas-fueled generating facility called Antelope Station. Cooperatives argue that if Golden Spread were compelled to offer Antelope Station into the day-ahead market, the basic business purpose for constructing the unit would be undermined. Cooperatives also point to several Golden Spread combustion turbine peaking facilities, which, Cooperatives explain, Golden Spread needs to cover load requirements during a limited number of hours each year. Cooperatives state that, during periods when Golden Spread does not need capacity from these units, it may sell this capacity in a bilateral transaction to a third party, and appropriate arrangements are made to supply fuel. If the day-ahead must-offer requirement is expanded, Cooperatives question whether load-serving Market Participants that have units without a firm gas supply would need to arrange and pay for a contingent supply of gas or whether they should run the risk of these units being called upon and penalized if they cannot obtain gas. *Id*. at 5-6.

requirement, the requirement should apply to both load-serving Market Participants and merchant generators.[57]

d. Commission Determination

50. We accept SPP's proposed must-offer requirement for the RUC process and real-time market, described in section 2.11.2 of Attachment AE. We find that requiring Market Participants to offer all of their uncommitted resources as part of the real-time market will ensure reliable operations. We conditionally accept SPP's proposed day-ahead must-offer requirement, subject to the following compliance requirements discussed below. We recognize that the proposal for a day-ahead must-offer requirement for the Integrated Marketplace resulted from a deliberative stakeholder process that attempted to balance multiple goals, such as system reliability and flexibility for Market Participants. We find that SPP's proposal strikes a reasonable balance between providing Market Participants flexible offer requirements and ensuring that Market Participants offer sufficient resources to meet their load obligations. At this time, we are not persuaded by commenters that argue the day-ahead must-offer requirement should be expanded. However, as discussed below, we will require SPP to monitor the effect that the limited day-ahead must-offer requirement proposed herein has on market outcomes and file with the Commission an assessment of market performance after the first year of operations. Accordingly, we conditionally accept SPP's limited day-ahead must-offer requirement in section 2.11.1 of Attachment AE, subject to SPP filing the Tariff changes discussed below in a compliance filing due 90 days after the issuance of this order and the required informational report 15 months following commencement of the Integrated Marketplace reflecting a full 12 months of data.[58]

51. The Commission has not required, and indeed has rejected in some instances, a day-ahead must-offer requirement in other RTOs and ISOs absent a capacity payment.[59] Unlike some other RTOs and ISOs, SPP has not proposed a capacity market that would

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[57] *Id*. at 3, 7.

[58] This report due 15 months following commencement of market operations is for informational purposes only and will not be formally noticed or acted upon by the Commission.

[59] For example, in addressing MISO's proposal to impose penalties for physical withholding in its day-ahead market, the Commission rejected the application of penalties for physical withholding in the day-ahead market and found that, absent a MISO-imposed resource adequacy requirement or state obligation, generators should not be required to bid into the day-ahead market. *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,280, at P 96 (2003) (MISO Market Mitigation Order).

compensate resource owners for offering capacity into the day-ahead market and also lacks other alternative mechanisms (e.g., state resource requirement) that could require Market Participants to offer capacity resources into the day-ahead market. Accordingly, we find that it is just and reasonable for SPP's day-ahead must-offer requirement not to apply to Market Participants that do not serve load. We believe that the proposal's requirement for load-serving Market Participants to offer their expected load in the day-ahead market is just and reasonable because it requires load-serving Market Participants to commit capacity to serve their load needs. We believe that it is reasonable to require load-serving Market Participants in the day-ahead market to offer sufficient capacity to serve their load. Thus, we will accept the must-offer requirement as proposed.

52. We will not require a more comprehensive day-ahead must-offer requirement (e.g., one that applies to all Network Resources) for load-serving Market Participants, as requested by several protesting parties. We note that in 2004, the Commission considered a proposal in which MISO submitted a day-ahead must-offer requirement under which Network Resources were required to submit a self-schedule or offer in the day-ahead market, unless the resources were unavailable due to an outage. The Commission expressed reservations about this proposal because there was no corresponding capacity product or payment. However, the Commission ultimately accepted MISO's proposal upon finding that: (1) states and regional reliability organizations had mechanisms in place to ensure fixed-cost recovery for Network Resources; and (2) MISO's proposal was an interim measure that would be replaced upon completion and approval of a permanent resource adequacy mechanism that included an installed capacity component.[60] Thus, the Commission accepted MISO's proposed day-ahead must-offer requirement for Network Resources based on these interrelated contingencies, including the development of a more robust resource adequacy mechanism. This situation is not analogous to the situation in SPP at this time, and SPP has not proposed developing an enhanced resource adequacy construct as part of its Integrated Marketplace.

53. We acknowledge the concerns of some protestors that SPP's limited day-ahead must-offer requirement could lead to artificially high real-time prices and contribute to price divergence between the day-ahead and real-time markets. However, we believe that the incorporation of virtual trading as part of the Integrated Marketplace design should drive convergence between day-ahead and real-time prices, despite the limitations SPP has proposed on the day-ahead must-offer requirement. Moreover, we will require SPP and its Market Monitor to file an informational report 15 months following commencement of the Integrated Marketplace, reflecting a full 12 months of data, to

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[60] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at PP 409-411 (2004).

discuss the effects of the must-offer condition on the extent of price divergence between its day-ahead and real-time balancing markets. The informational report should specifically evaluate whether the day-ahead must-offer requirement has contributed to any observed divergence during the first year of operations of the Integrated Marketplace.

54. In response to protestors' gaming and market manipulation concerns, we find that load-serving Market Participants will have an incentive to estimate their load properly in order to avoid being assessed RUC make whole payment charges. However, this incentive may not be sufficient. Therefore, we require SPP in a compliance filing due 90 days after the issuance of this order to revise its Tariff to create a process by which SPP or its Market Monitor will: (1) verify that Market Participants have not exceeded a pre-determined acceptable load forecasting error[61] and (2) establish non-compliance penalties if Market Participants' estimations exceed the acceptable range of load forecasting error.

55. We do not believe the proposal will encourage physical withholding, as argued by protesters. Nevertheless, we require SPP in a compliance filing due 90 days after the issuance of this order to provide in its Tariff that the Market Monitor will monitor for manipulative behavior associated with such offers. Such monitoring would include, but not be limited to, load-serving Market Participants engaging in manipulative behavior executed by purposeful underestimation of their peak loads. We also direct that SPP revise its Tariff to provide that the Market Monitor monitor for (and report to the Commission's Office of Enforcement) any locational problems, such as deliverability issues, that develop that are associated with load-serving Market Participants' offers in the day-ahead market. The Tariff must also be revised to provide that if the Market Monitor suspects there is a concerted effort to limit offers in the day-ahead market in order to raise the prices in the real-time market, the Market Monitor must report this to the Commission's Office of Enforcement. Similarly, the Tariff must impose on SPP's Market Monitor the obligation to monitor for and report to the Office of Enforcement the effects of any such failure to offer upon make whole payments. Further, the Tariff must require that the Market Monitor report to the Office of Enforcement price or make whole payment manipulation resulting from the failure to offer if it has credible information to believe that a market violation has occurred. Additionally, in a compliance filing due 90 days after the issuance of this order, we will require SPP to clarify how it will ensure

[61] This verification should compare a load-serving Market Participant's actual operating daily peak load to that Market Participant's peak load estimate. In developing this process, SPP will also need to propose and justify an acceptable range of forecasting error (e.g., a certain deviation, expressed as a percentage, above or below the actual operating daily peak load value that SPP deems acceptable).

that offered resources are deliverable to the load they were offered to cover and to modify its Tariff, if necessary, to reflect verification of deliverability.[62]

56. We will also require SPP's Market Monitor to report on any observed potential manipulative practices relating to the day-ahead market during the first year of market operations, in a separate, non-public section of SPP's informational report on the must-offer condition that is due 15 months after the commencement of the Integrated Marketplace, reflecting a full 12 months of data. We will also require SPP and/or its Market Monitor to address, in the aforementioned informational report, the effects of the proposed day-ahead must-offer upon uplift charges. The report must also discuss any trends of declining participation in the day-ahead market associated with any such increases in uplift charges.[63]

57. Finally, we do not believe that there is evidence at this time to indicate that the Integrated Marketplace will result in substantially fewer benefits because of the limited day-ahead must offer obligation. We recognize that proposals filed with the Commission will deviate, to some extent, from assumptions used in a cost-benefit analysis issued before a proposal is finalized, and these deviations do not render the study useless. We note, for example, that the future market design case most similar to the current proposal (Change Case IIA) in the cost-benefit analysis assumed that the new market would begin operations in 2011. Moreover, we note that our approval of the Integrated Marketplace proposal is not based on any specific cost-benefit amount. A cost-benefit analysis is largely a tool for stakeholders to evaluate different market designs and to determine their interest in moving forward with a market proposal.

2. <u>Demand Response Resources</u>

a. <u>General Demand Response Provisions</u>

i. <u>SPP Filing</u>

58. SPP states that it has adopted several provisions to facilitate demand response resource participation in the Integrated Marketplace, as required by Order No. 719. SPP asserts that these new terms will offer substantially greater opportunities for demand response resource participation than currently exists in the EIS market. SPP states that it will treat demand response resources like all other resources, with minor differences

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[62] For example, SPP could specify in the Tariff that each load-serving Market Participant must ensure deliverability to its own load.

[63] To clarify, SPP's discussion on uplift charges relating to its day-ahead must-offer requirement should be included in the publicly-available portion of its report.

attributable to the nature of demand response resources.[64] SPP explains it will commit and dispatch demand response resources in economic merit in place of more expensive generation resources. SPP also states that demand response resources are eligible to set prices in both the day-ahead and real-time markets, if they are dispatchable. Moreover, according to SPP, demand response may be offered to supply both energy and operating reserves or just operating reserves, to the extent the demand response resource qualifies to provide operating reserves. SPP also states that it has modeled its Integrated Marketplace demand response provisions on existing provisions previously accepted by the Commission for its EIS market.[65] SPP proposes two new categories of demand response resources: (1) dispatchable demand response resources, which are resources associated with a controllable load or behind-the-meter generation that are dispatchable on a five-minute basis,[66] and (2) block demand response resources, which are resources that are not dispatchable within the hour and can only be committed in hourly blocks, but are eligible to clear spinning reserves, if qualified.[67]

ii. <u>Protests</u>

59. Protests to specific aspects of SPP's demand response proposal are addressed below.

iii. <u>Commission Determination</u>

60. We conditionally accept SPP's demand response provisions in proposed Attachment AE, contingent on SPP (1) modifying or clarifying certain aspects of its proposal, as discussed below, and (2) modifying its proposal to conform to the Commission's directives in the October 18, 2012 order in SPP's ongoing Order No. 719 compliance proceeding, as discussed in more detail below.[68] We find that SPP's demand

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[64] SPP Transmittal at 30 (citing, *e.g.*, SPP Tariff, Proposed Attachment AE section 4.1.2.1(l) ("A Dispatchable Demand Response Resource is modeled in the Commercial Model the same as any other Resource, except that the Settlement Location associated with the Dispatchable Demand Response Resource must contain the Price Node associated with the Demand Response Load.")).

[65] *Id*. at 30-31.

[66] *Id*. at 31 (citing SPP Tariff, Proposed Attachment AE section 1.1 Definitions D).

[67] *Id*. (citing SPP Tariff, Proposed Attachment AE sections 1.1 Definitions B).

[68] *Southwest Power Pool, Inc.*, 141 FERC ¶ 61,047 (2012) (2012 SPP Order 719 Compliance Order).

response proposal is similar in most respects to demand response provisions currently applicable in SPP's EIS market or proposed in SPP's ongoing Order No. 719 compliance proceeding. We also accept the new categories of dispatchable and block demand response resources, as well as provisions allowing demand response resources to supply operating reserves, if qualified. We agree with SPP that these provisions should broaden opportunities for demand response resource participation in the Integrated Marketplace. We discuss aggregation requirements, settlement, and pricing node issues relating to Aggregators of Retail Customers (ARC) below.

61. Additionally, in the 2012 SPP Order 719 Compliance Order, the Commission required SPP to use a term more inclusive than "controllable load" (i.e., one that includes demand response facilitated by behind-the-meter generation) in part (f) of the definition of "Market Participant" in the Tariff, specifically in the phrase "technically qualified to offer controllable load into the EIS Market."[69] We require SPP to replace the term "controllable load" with "Demand Response Load" [70] in part (f) of the definition of "Market Participant" in a compliance filing due 90 days after the issuance of this order.[71]

62. We note that, in addition to ongoing compliance with Order No. 719, SPP also submitted a compliance filing on May 2, 2012 in response to the Commission's January 19, 2012 order rejecting SPP's initial Order No. 745 compliance filing.[72] Further directives in this compliance proceeding will necessitate revisions to proposed Attachment AE in the Integrated Marketplace relating to demand response compensation (through development and use of a net benefits test) and cost allocation. Additionally, further modifications to SPP's demand response measurement and verification provisions may also result from this compliance proceeding. We direct SPP to submit a subsequent filing to incorporate any Tariff revisions for the Integrated Marketplace required by its ongoing Order No. 745 compliance proceeding within 30 days of the final order accepting provisions for its EIS market.

[69] *Id*. at P 53. We note that in SPP's Integrated Marketplace proposal, this phrase in part (f) of the definition of "Market Participant" reads "technically qualified to offer controllable load into the Energy and Operating Reserve Markets."

[70] SPP proposes the following definition for "Demand Response Load" in Attachment AE, section 1.1, Definitions D: A registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider.

[71] In its February 29, 2012 filing, SPP proposes replacing the term "Controllable Load" with "Demand Response Load."

[72] *Southwest Power Pool, Inc.*, 138 FERC ¶ 61,041 (2012).

b. Demand Response Registration Provisions

i. SPP Filing

63. SPP states that proposed section 2.2 of Attachment AE governs the Market Participant application and asset process, which requires Market Participants to register all resources and loads, including load associated with demand response, except for demand response facilitated by behind-the-meter generation that is less than 10 MW. As part of these requirements, in proposed section 2.2(2) of Attachment AE, Market Participants must register all resources and load with SPP in accordance with the registration process specified in the Market Protocols. Section 2.2(2) also provides that non-conforming load[73] and demand response load may only be associated with a single price node.

64. SPP states that it has adopted specific registration provisions for demand response resources in proposed section 2.2(8) of Attachment AE. SPP explains that Market Participants that wish to offer controllable load as a demand response resource in the Integrated Marketplace must submit an application and register like any other resource. These Market Participants must also include certification that participation of their demand response resources in the energy and operating reserve markets is not precluded by the laws of the relevant electric retail regulatory authority. SPP asserts that this registration requirement is compliant with Order No. 719[74] and is consistent with language previously accepted by the Commission.[75] Additionally, SPP states that it has adopted language consistent with the ARC requirements set forth in Order No. 719-A.[76]

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[73] SPP proposes the following definition for "Non-Conforming Load" in Attachment AE, section 1.1, Definitions N: Load that is process driven that does not follow a predictable pattern.

[74] SPP Transmittal at 41 (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 49 n.78, P 158).

[75] *Id.* at 41-42, (citing *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,011, at PP 30, 77 (2011) (2011 SPP 719 Compliance Order)).

[76] In Order No. 719-A, the Commission required RTOs and ISOs to accept offers from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than four million MWh in the previous fiscal year, unless the relevant electric retail regulatory authority prohibits such customers' demand response to be offered into the organized wholesale market; and (2) the customers of utilities that distributed four million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be offered

(continued…)

65. SPP states that it has also adopted additional registration requirements for dispatchable demand response resources in proposed section 2.6 of Attachment AE and block demand response resources in proposed section 2.7 of Attachment AE. According to SPP, these additional registration requirements will enable SPP to identify the demand response load meter data submittal location and settlement location associated with each demand response resource. SPP explains that these provisions require SPP to notify the applicable retail provider and relevant electric retail regulatory authority of a demand response resource's registration and expected megawatt level of participation in the energy and operating reserve markets, in accordance with the requirement in Order No. 719-A.[77]

ii. Commission Determination

66. We conditionally accept SPP's registration requirements for demand response resources, contingent on the following requirements. We require SPP to explain why, in proposed section 2.2(6) of Attachment AE, it excludes demand response resources less than 10 MW whose demand response is facilitated by behind-the-meter generation from registering in the Integrated Marketplace. We require SPP to modify section 2.2(8) of Attachment AE to remove the term "controllable load" and replace it with the term "Demand Response Load." We require SPP to provide this modification in a compliance filing due 90 days after the issuance of this order. We also conditionally accept SPP's registration requirements for demand response resources in proposed section 2.2 of Attachment AE subject to additional compliance requirements relating to the single pricing node limitation in section 2.2(2), as it relates to ARCs, which we address in our discussion of ARC participation in the Integrated Marketplace below. We also discuss additional ARC registration requirements in that section.

67. We conditionally accept the registration requirements for dispatchable and block demand response resources in sections 2.6 and 2.7 of proposed Attachment AE, contingent on SPP submitting a compliance filing due 90 days after the issuance of this order. The compliance filing must clarify why SPP uses the terms "Dispatchable Controllable Load Settlement Location" in section 2.6 and "Block Controllable Load Settlement Location" in section 2.7. We find that use of the term controllable load may not be as inclusive as SPP intends (i.e., the term implies the exclusion of demand response facilitated by behind-the-meter generation).

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into the organized wholesale market. Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at PP 60, 65-67.

[77] SPP Transmittal at 34-35 (citing Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 69).

c. Demand Response Measurement and Verification

i. SPP Filing

68. SPP states that it has established two methods for measuring and verifying the output of demand response resources, as well as determining baselines, in its Integrated Marketplace: (1) the calculated resource production option (Calculated Option); and (2) the submitted resource production option (Submitted Option). SPP explains that these methods are similar to the calculated real-time response methodology (Calculated Methodology) and the submitted real-time response methodology (Submitted Methodology) that SPP submitted in its May 19, 2010 Order No. 719 compliance filing, which the Commission conditionally accepted subject to additional compliance, in an order issued on October 4, 2011.[78] SPP notes that it subsequently received permission from the Commission to delay implementation of these methodologies until the launch of its Integrated Marketplace.[79]

69. SPP explains that under the Calculated Option, which is available to both dispatchable and block demand response resources,[80] SPP will calculate a resource's output as the difference between: (1) the lesser of (a) the real-time consumption of the demand response load associated with the demand response resource in the dispatch interval immediately preceding initial deployment of the demand response resource, or (b) the hourly baseline (calculated in section 4.1.2.1(3) of proposed Attachment AE); and (2) the actual value of the associated demand response load received via telemetering (during the dispatch interval).[81] SPP states that the Calculated Option requires a Market Participant to submit an hourly baseline for its demand response load, indicating the level of energy consumption expected at the location if the demand response resource is not

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[78] SPP Transmittal at 31-32 (citing 2011 SPP 719 Compliance Order, 137 FERC ¶ 61,011).

[79] *Southwest Power Pool, Inc.*, Notice of Extension of Time, Docket No. ER09-1050-001, *et al*. (November 30, 2011). We note that, with the granting of this extension of time, previously proposed Tariff language describing SPP's demand response measurement and verification methodologies in the context of the EIS market will not become effective, although SPP's ongoing Order No. 719 compliance proceeding will aid in refining demand response measurement and verification methodologies proposed in this proceeding.

[80] SPP Transmittal at 32 (citing SPP Tariff, Proposed Attachment AE sections 4.1.2.1(1) and 4.1.2.1(2)).

[81] *Id*. (citing SPP Tariff, Proposed Attachment AE section 4.1.2.1(1)(b)).

dispatched.[82] SPP reserves the right to adjust the baseline if previous submitted baselines deviated from the actual metered load in periods when the demand response resource was not dispatched.[83]

70. SPP explains that under the Submitted Option, the Market Participant will calculate and submit demand response resource output via telemetering.[84] SPP proposes limiting the Submitted Option: (1) to demand response resources that use strictly behind-the-meter generation to facilitate their demand response; and (2) to Market Participants that are offering the demand response resource under a retail tariff provision that includes real-time measurement and verification terms. SPP reiterates that the purpose of the Submitted Option is to provide a streamlined alternative for participation by demand response resources that are capable of providing real-time measurement and verification, thus eliminating the need for SPP to calculate a baseline and conduct after-the-fact measurement and verification.[85] SPP explains that for both demand response resources utilizing behind-the-meter generation with sufficient net-metering (i.e., with separate metering on both the load and generator) and demand response resources calculating baselines and conducting measurement and verification as governed by a retail tariff, SPP may reasonably rely on the demand response output values provided by the Market Participant. Therefore, SPP asserts, it does not need to utilize the Calculated Option for these resources.[86]

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[82] *Id.* (citing SPP Tariff, Proposed Attachment AE section 4.1.2.1(3)).

[83] *Id.* (citing SPP Tariff, Proposed Attachment AE section 4.1.2.1(3)(b)). Section 4.1.2.1(3)(b) of proposed Attachment AE specifies that if there have been deviations in hourly integrated metered load from the hourly baseline during periods when the resource was not dispatched, SPP will adjust the baseline prior to the calculation of the demand response load. Section 4.1.2.1(3)(b) also stipulates that if the average of the hourly deviation between integrated metered load and submitted hourly baselines for the hours in the last 30 calendar days when the resource was not dispatched is more than five percent below the hourly baseline, the hourly baseline will be adjusted by the average deviations. Section 4.1.2.1(3)(b) further provides that SPP will perform this assessment each day and notify the Market Participant of any adjustments.

[84] *Id.* (citing SPP Tariff, Proposed Attachment AE section 4.1.2.1(1)(a)).

[85] *Id.* at 33 (citing SPP December 5, 2011 Filing in Docket No. ER12-550-000 at 18 (December 2011 Filing)).

[86] *Id.* at 32-33.

71. SPP notes that, in its December 2011 Filing, it provided much of the same explanations regarding its Calculated Methodology and Submitted Methodology (in the context of its EIS market). SPP states that it is proposing these methodologies here subject to the Commission's ruling on the December 2011 Filing.[87]

ii. Commission Determination

72. We conditionally accept SPP's demand response measurement and verification methodologies, subject to additional compliance relating to directives in the 2011 and 2012 SPP 719 Compliance Orders. Because the Commission granted SPP's request to delay implementation of its demand response baseline calculation and measurement and verification methodologies until launch of the Integrated Marketplace, the Commission did not rule on various modifications suggested by SPP in the December 2011 Filing (which SPP submitted to comply with the directives in the 2011 SPP 719 Compliance Order). Instead, the Commission stated that it would rule on the actual, submitted Tariff language in SPP's Integrated Marketplace proceeding.[88] Below are descriptions of compliance requirements in the 2011 SPP 719 Compliance Order and an assessment of SPP's compliance with these directives in its Integrated Marketplace proposal. We also describe additional compliance requirements in the 2012 SPP 719 Compliance Order that may affect measurement and verification provisions in the Integrated Marketplace.

73. In the 2011 SPP 719 Compliance Order, the Commission required SPP to specify in its Tariff how baselines are developed for the Calculated Methodology (in its EIS market).[89] In the 2012 SPP 719 Compliance Order, the Commission expressed satisfaction with SPP's commitment to include language in its Integrated Marketplace filing to clarify how Market Participants will develop and calculate hourly baselines.[90] SPP does so by providing that Market Participants base their baselines on the average of the hourly integrated controllable load for the same hours in the last 30 calendar days when the resource was not dispatched, adjusted by the Market Participant as necessary. SPP included this language in proposed section 4.1.2.1(3)(a) of Attachment AE in its Integrated Marketplace proposal. We will conditionally accept this language, subject to SPP substituting the term "Demand Response Load" for the term "Controllable Load," in a compliance filing due 90 days after the issuance of this order.

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[87] *Id.* at 33 (citing December 2011 Filing at 17-19).

[88] 2012 SPP 719 Compliance Order, 141 FERC ¶ 61,047 at PP 23, 25.

[89] 2011 SPP 719 Compliance Order, 137 FERC ¶ 61,011 at P 67.

[90] 2012 SPP 719 Compliance Order, 141 FERC ¶ 61,047 at P 23.

74. In the 2011 SPP 719 Compliance Order, the Commission required SPP to modify proposed section 1.2.2(l) of Attachment AE (for the EIS market) to remove the certification requirement for the Calculated Methodology, in which SPP had required Market Participants (including ARCs) desiring to offer controllable load in the form of a demand response resource to provide certification that their resource is not precluded by the laws of the relevant electric retail regulatory authority.[91] SPP does not include this certification requirement in section 2.6 of proposed Attachment AE in its Integrated Marketplace proposal. Thus, we find SPP has satisfied this compliance directive. Further, in the 2011 SPP 719 Compliance Order, the Commission required SPP to define in its Tariff the term Inter Control Center Communication Protocol (ICCP), used in the description of the Submitted and Calculated Methodologies.[92] In its Integrated Marketplace proposal, SPP replaces the term "ICCP" with the more general term "telemetering." We will accept this change for the Integrated Marketplace.

75. In the 2011 SPP 719 Compliance Order, the Commission required SPP to clarify the size of the demand reduction that is eligible for settlement, as provided in section 1.2.9.3 of Attachment AE (for the EIS market). The Commission found that this section did not address a potential circumstance wherein SPP asks for a level of demand reduction and the controllable load provides demand response in excess of the requested level.[93] In its December 2011 Filing, SPP stated it planned to revise section 1.2.9.3 of Attachment AE to state that, in the case where the controllable load's demand reduction is in excess of the dispatch instruction, the resource's production value will equal the value requested in the dispatch instruction.[94] However, in its Integrated Marketplace filing, SPP proposes not to include Tariff language giving rise to the need for these revisions and thus is not proposing additional Tariff language.[95] We find that SPP's removal of this language complies with this compliance directive.[96]

[91] 2011 SPP 719 Compliance Order, 137 FERC ¶ 61,011 at P 69.

[92] *Id*. P 72.

[93] *Id*. P 70.

[94] December 2011 Filing at 21-22.

[95] SPP Transmittal at 36.

[96] We note that SPP has included demand response resources as sub-categories when describing uninstructed resource deviations in sections 6.4.1(2)(b) and 6.4.1(2)(c) of proposed Attachment AE.

76. In the 2012 SPP 719 Compliance Order, the Commission required SPP to submit an additional compliance filing within 60 days after issuance of that order. We note that the Commission required SPP to provide additional clarifications, explanations, and modifications regarding its measurement and verification methodologies—particularly for the Submitted Methodology/Option—in this compliance filing.[97] Further, we note SPP's commitment to file any proposed Tariff revisions applicable to the Integrated Marketplace required by its ongoing Order No. 719 compliance proceeding. Should the Commission require additional Tariff changes in that proceeding, we direct SPP to make a subsequent filing within 30 days after a final order in that proceeding proposing Tariff language applicable to the Integrated Marketplace.

d. Technical Requirements, Bidding Parameters, and Information Sharing

i. SPP Filing

77. SPP asserts that its proposed Tariff revisions comply with technical requirements, bidding parameters, and information sharing directives in Order Nos. 719 and 719-A. SPP states that it has adopted Tariff language addressing the bidding parameters for all resources, including demand response resources, which require the resource to specify—among other things—the duration, frequency, and amount of its offer in both the day-ahead and real-time markets for both energy and operating reserves, which SPP notes will limit its dispatch of such resources to the specified parameters.[98] SPP states that demand response resources must submit the real-time value of their demand response load to SPP via telemetering that meets technical requirements set forth in SPP's Market Protocols.[99]

ii. Commission Determination

78. We will accept SPP's proposed bidding parameters for demand response resources in section 4.1(9) of proposed Attachment AE, as these parameters are applicable to all resources. We will conditionally accept sections 4.1.2.1(1) and 4.1.2.1(2) of proposed Attachment AE. Both of these sections state that a dispatchable/block demand response resource is modeled in the commercial model the same as any other resource, except that the settlement location associated with the dispatchable/block demand response resource

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[97] 2012 SPP 719 Compliance Order, 141 FERC ¶ 61,047 at PP 19-22.

[98] SPP Transmittal at 34 (citing SPP Tariff, Proposed Attachment AE section 4.1(9)).

[99] *Id*. (citing SPP Tariff, Proposed Attachment AE sections 4.1.2.1(1) and 4.1.2.1(2)).

must contain the price node associated with the demand response load. We note that this language may be affected by our determination regarding settlement and pricing node issues relating to ARCs, which we discuss below.

79. We find SPP compliant with Order No. 719-A compliance directives relating to technical requirements and information sharing, except for a remaining compliance requirement specified in the 2012 SPP 719 Compliance Order. The Commission required SPP to provide additional explanation on the verification procedures it has in place or is developing to verify the production quantity of demand response provided by an ARC, in a compliance filing due 60 days after the issuance of the 2012 SPP 719 Compliance Order.[100] We will evaluate compliance with this remaining Order No. 719-A directive once SPP submits this compliance filing.

e. ARC Participation in the Integrated Marketplace

i. SPP Filing

80. SPP states that it has adopted Tariff provisions to permit ARC participation in the Integrated Marketplace. SPP explains that proposed section 2.8(1) of Attachment AE provides that ARCs may offer either block or dispatchable demand response resources and must comply with all registration and other requirements applicable to other resources. SPP also notes that proposed section 2.8(2) of Attachment AE includes the Order No. 719-A requirement that distinguishes ARC eligibility to participate in wholesale demand response programs by the size of the distribution utility that serves the customer. SPP states that it has also adopted additional registration requirements for ARCs in proposed section 2.2(9) of Attachment AE, consistent with the registration provisions for its EIS market accepted by the Commission as compliant with Order No. 719.[101] SPP notes that it has also included a clarification to its ARC registration provisions, as required by the Commission in the 2011 SPP 719 Compliance Order.[102]

ii. Protests

81. NPPD supports the aggregation of demand response resources to the maximum extent practicable as a means of encouraging the expansion of demand response resource participation in the SPP region. NPPD seeks clarification that provisions allowing for the

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[100] 2012 SPP 719 Compliance Order, 141 FERC ¶ 61,047 at P 66.

[101] SPP Transmittal at 35 (citing 2011 SPP 719 Compliance Order, 137 FERC ¶ 61,011 at P 32).

[102] *Id*. (citing 2011 SPP 719 Compliance Order, 137 FERC ¶ 61,011 at P 78).

aggregation of retail demand response customers also apply to wholesale customers. NPPD also expresses concern that SPP has placed undue limitations on the geographic area within which ARCs can effectively aggregate, pointing to SPP's policy restricting ARC aggregation behind a single pricing node. NPPD notes that, typically, a pricing node is associated with load behind a single substation. NPPD asserts this limitation may prevent the aggregation of retail customers in neighboring towns because they are covered by separate nodes. By contrast, NPPD explains, MISO permits aggregation of demand response resources over an entire local Balancing Authority Area. NPPD supports aggregation within a local balancing area and alleges that SPP has provided no explanation for its single pricing node limitation.[103]

82. APPA notes that its SPP members have raised concerns regarding limitations on the use of demand response resources in SPP.[104]

iii. Commission Determination

83. We conditionally accept SPP's provisions for ARCs, subject to the conditions discussed herein. We agree with NPPD that SPP has not shown its aggregation requirements for ARCs to be just and reasonable. However, the Commission is addressing this issue in SPP's ongoing Order No. 719 compliance proceeding. In the 2012 SPP 719 Compliance Order, the Commission found that SPP had not provided sufficient justification to demonstrate that its "electrically equivalent point" aggregation

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[103] NPPD Protest at 7, 25-27.

[104] APPA Protest at 5.

requirement was just and reasonable.[105] The Commission expressed concern that this requirement could unnecessarily restrict the ability of ARCs to effectively and efficiently aggregate demand response for participation in the SPP marketplace. The Commission also noted that most RTOs and ISOs effectively manage localized congestion while allowing ARCs to aggregate smaller retail customers into a demand response resource on a sub-regional basis, such as within a local Balancing Authority Area, transmission zone, or load zone.[106] The Commission required SPP to include, in a compliance filing due 60 days after the issuance of the 2012 SPP 719 Compliance Order, a discussion of: (1) whether software or modeling limitations necessitated that aggregations be at an electrically equivalent point in the EIS market; (2) whether SPP had considered alternative ARC aggregation requirements that permit aggregation on a sub-regional level while allowing SPP to manage localized congestion; (3) whether SPP considered a broader aggregation requirement feasible for its EIS market and for the Integrated Marketplace; and (4) whether SPP intended to broaden its aggregation requirements in the Integrated Marketplace and, if so, a timeline for their implementation. The Commission also required SPP to explain, in the compliance filing due 60 days after the issuance of the 2012 SPP 719 Compliance Order, the continued necessity of the aggregation requirement that an ARC resource have a single retail provider.[107] Our acceptance of SPP's ARC provisions for its Integrated Marketplace, then, is contingent on the outcome of this Order No. 719 compliance proceeding.

84. We also conditionally accept SPP's ARC proposal contingent upon SPP addressing how the requirement in section 2.2(2) of proposed Attachment AE, which specifies that demand response load may only be associated with a single price node,[108] may be impacted by broadening ARC aggregation requirements to allow for aggregation at the sub-regional level. We also agree with NPPD that SPP has provided little explanation for its single price node limitation and will require SPP to provide further clarification on this proposal. Additionally, consistent with NPPD's request, we will

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[105] We note that, for the Integrated Marketplace, section 2.8(2)(a) of proposed Attachment AE contains the ARC aggregation requirement that end-use customers aggregated into a single demand response resource be located at the same electrically equivalent withdrawal point.

[106] 2012 SPP 719 Compliance Order, 141 FERC ¶ 61,047 at P 45.

[107] *Id*. PP 45-46.

[108] A price node, or PNode, is associated with a single node in the Commercial Model that has a one-to-one relationship to an electrical node where LMPs are calculated. SPP Tariff, Proposed Attachment AE section 1.1 Definitions P.

require SPP to clarify whether provisions allowing for the aggregation of retail demand response customers also apply to wholesale customers (i.e., the aggregation of smaller, wholesale demand response resources into larger demand response resources). We require SPP to provide these clarifications and explanations in a compliance filing due 90 days after the issuance of this order. We also require SPP to modify sections 2.2(2) and 2.2(3) of proposed Attachment AE, as well as related provisions in sections 4.1.2.1(1) and 4.1.2.1(2) of Attachment AE, if SPP believes ARC-specific modifications are necessary, based on the outcome of its ongoing Order No. 719 compliance proceeding.

3. Variable Energy Resources

a. SPP Proposal

85. SPP proposes to define two types of Variable Energy Resources (VERs): dispatchable VERs, which are capable of being incrementally dispatched by SPP, and non-dispatchable VERs, which are not capable of doing so.[109] SPP proposes to require all wind-powered VERs with an interconnection agreement executed after May 21, 2011 to register as dispatchable VERs.[110] SPP's proposed rules also allow VERs with fuel sources other than wind the option to register as dispatchable VERs, if the VER is capable of being dispatched by SPP. However, SPP proposes to require all other VERs (i.e., wind-powered VERs with an interconnection agreement executed on or before May 21, 2011) to register as non-dispatchable VERs.[111] SPP contends that the Commission previously accepted similar registration requirements for wind-powered VERs in MISO.[112]

86. SPP proposes to apply the same offer parameters for VERs and other resource types, with several exceptions. For a non-dispatchable VER, its energy offer curve "shall not apply" and it will receive dispatch instructions equal to its actual output at the start of

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[109] SPP Tariff, Proposed Attachment AE sections 1.1.D, 1.1.N.

[110] Mr. Dillon maintains that this requirement is consistent with the Commission's directives in Docket No. ER11-3154-000. Exh. No. SPP-3 at 36. *See also Southwest Power Pool*, *Inc.*, 135 FERC ¶ 61,148, at P 13 (2011).

[111] SPP Tariff, Proposed Attachment AE section 2.2(10).

[112] SPP Transmittal at 41 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 134 FERC ¶ 61,141, at PP 33-43 (MISO DIR Order), *reh'g denied*, 136 FERC ¶ 61,100 (2011)).

the Dispatch Interval in the real-time market.[113] SPP argues that these requirements reflect the non-dispatchable nature of these VERs and, therefore, are appropriate.[114] For a dispatchable VER, SPP proposes the following requirements regarding its ramp rates, minimum operating limits, maximum operating limits, and setpoint instructions:[115]

> (1) In the real-time balancing market, when SPP issues a Dispatch Instruction to reduce output, the dispatchable VER's setpoint instruction will be the sum of the VER's Dispatch Instruction and any regulation-down deployment.[116]
>
> (2) If the dispatchable VER's maximum capability is under 200 MW, its ramp rate cannot exceed eight MW/min. If the dispatchable VER's maximum capability is greater than 200 MW, its ramp rate cannot exceed four percent of its maximum capability.
>
> (3) The dispatchable VER's minimum operating limit must be zero.
>
> (4) In the day-ahead market and RUC process, SPP will calculate the dispatchable VER's maximum operating limits as the lesser of the maximum operating limit submitted by the VER or SPP's output forecast for the VER. In the real-time balancing market, when SPP issues a dispatch instruction to increase output after issuing a dispatch instruction in the previous interval to reduce output, the dispatchable VER's maximum operating limit will be the lesser of (a) SPP's output forecast for the VER, or (b) the sum of five times the VER's ramp rate and the Dispatch Instruction issued in the previous interval.[117]

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[113] SPP Tariff, Proposed Attachment AE section 4.1.2.5.

[114] SPP Transmittal at 43.

[115] SPP Tariff, Proposed Attachment AE section 4.1.2.4.

[116] SPP's proposed Tariff revisions state that this requirement applies even if the resource owner has indicated that the resource is not dispatchable.

[117] SPP's proposed Tariff revisions state that in all other real-time dispatch intervals, a dispatchable VER's maximum output limit will be the VER's actual output at the start of the Dispatch Interval.

Mr. Dillon states that the offer requirements for dispatchable VERs are necessary because of their unique operating characteristics. He also notes that the proposed modeling procedures for VERs are similar to those adopted in MISO.[118]

b. Protests

87. Acciona, AWEA, BP Wind Energy, and E.ON protest SPP's proposed treatment of dispatchable and non-dispatchable VERs.

88. In order to ensure that dispatchable VERs are treated similarly to other dispatchable resources and are not unduly disadvantaged, E.ON argues that the Commission should require SPP to adopt several features available to Dispatchable Intermittent Resources in MISO. In particular, E.ON recommends that the Commission direct SPP to allow dispatchable VERs to submit, every five minutes in real-time, energy offers that include forecasted maximum operating limits and update these forecasted maximum operating limits 10 minutes prior to each five-minute Dispatch Interval. E.ON contends that these requirements are used in MISO and would allow wind resources in SPP to update their offers as close to real-time as possible so that they can forecast their expected fuel input (i.e., wind) with greater accuracy. Therefore, SPP will be able to maximize the efficiency of its markets. E.ON also states that not to allow updating so close to real-time would be unduly discriminatory and preferential, because SPP proposes to charge VERs for Uninstructed Resource Deviation (URD). While non-variable dispatchable resources can control their fuel input and, thus, their energy output, to minimize URD charges, E.ON points out that VERs cannot and, thus, should be permitted to update their offers as close to real-time as possible to minimize exposure to URD charges.[119]

89. AWEA, BP Wind Energy, and E.ON oppose the proposed ramp rate limits for dispatchable VERs. They contend that the limits are unduly discriminatory, as they do not apply to other resource types, and will impede the ability of dispatchable VERs to follow price signals and compete with other resources.[120] E.ON argues that the ramp rate limits will adversely affect dispatchable VERs' compensation by, for example, hindering their ability to offer their full capacity to the market or to curtail its production in response to severely negative prices. To avoid being susceptible to severely negative prices, E.ON asserts that dispatchable VERs may be disinclined to offer their full ramp capability to SPP. E.ON states that rather than imposing arbitrary ramp rate limits, SPP

[118] SPP Transmittal, Exh. No. SPP-3 at 38.

[119] E.ON Protest at 3-4.

[120] AWEA Protest at 9-10; BP Wind Energy Protest at 12-13; E.ON Protest at 7-9.

should use wind resources' unique ability to ramp up or down their entire capacity within minutes to provide operational efficiencies for SPP's customers.[121] BP Wind Energy expresses similar concerns regarding dispatchable VERs' ability to respond to severely negative prices, and it adds that SPP has not explained the proposed ramp rate limits.[122]

90. AWEA and BP Wind Energy argue that SPP's proposed maximum operating limit requirements for dispatchable VERs should apply in the RUC process but not the day-ahead market. According to AWEA, it is appropriate to use SPP's forecast for reliability purposes, but doing so in the day-ahead market will limit dispatchable VERs' ability to submit their own output forecasts and use advanced forecasting methods. AWEA adds that this approach would be consistent with SPP's Market Protocols for the Integrated Marketplace. In addition, AWEA argues that SPP should give wind resources the option of submitting their own output forecasts, as forecasts can significantly impact unit commitment, dispatch, and settlement.[123] BP Wind Energy contends that the Tariff's reference to the day-ahead market with regard to the maximum operating limit requirements was inadvertent because the Market Protocols refer only to SPP's RUC processes. However, if it was not an inadvertent reference, BP Wind Energy argues that SPP has failed to support this position. BP Wind Energy does not object to the use of SPP's forecast for the RUC processes, which ensure system reliability; but BP Wind Energy does object to its use in the day-ahead market, because this is a purely financial market that does not consider reliability needs. BP Wind Energy contends that using SPP's forecasts in the day-ahead market will constrain dispatchable VERs' ability to offer energy at economic levels and to manage their exposure to RUC make-whole payment costs, which are allocated, in part, based on deviations between day-ahead and real-time quantities. BP Wind Energy adds that if it is necessary to limit day-ahead offers due to reliability considerations, then the proposed maximum operating limit requirements should apply to all resources, rather than only dispatchable VERs.[124]

91. E.ON argues that SPP's proposed maximum operating limit requirements for dispatchable VERs should apply only under discrete circumstances that are specified in the Tariff. E.ON argues that SPP has not explained why SPP's forecast should be used in lieu of offer information submitted by dispatchable VERs and expresses concern that VERs are at risk if their maximum operating limits are inaccurate, e.g., via the assessment of URD charges. E.ON maintains that since dispatchable VERs are included

[121] E.ON Protest at 7-9.

[122] BP Wind Energy Protest at 12-13.

[123] AWEA Protest at 8-9.

[124] BP Wind Protest at 10-12.

in the intra-day RUC process, SPP should have the ability to impose a maximum operating limit. However, E.ON recommends that the Commission require SPP to revise its tariff so that SPP may impose maximum operating limits only when: (1) a dispatchable VER fails to provide a maximum operating limit; (2) the maximum operating limit is more than 30 minutes old; or (3) the maximum operating limit exceeds the physical limit of the resource. Noting that these conditions were accepted by the Commission for Dispatchable Intermittent Resources in MISO,[125] E.ON maintains that these conditions should also apply in SPP. E.ON also notes that the Commission required MISO to explain its methodology for determining default forecast maximum limits for Dispatchable Intermittent Resources and address whether those resources may choose to rely on MISO's default forecast maximum limit rather than their own limits, e.g., to avoid developing an independent forecasting methodology.[126] Likewise, E.ON states that the Commission should require the same of SPP because SPP's forecasts have a direct impact on rates.[127]

92. AWEA cautions against unduly burdensome meteorological data reporting requirements. AWEA recommends that only data that will cost-effectively improve wind energy forecasts be required.[128]

93. E.ON also submits that dispatchable VERs should be allowed to provide operating reserves. Acknowledging that the Commission did not require such of MISO in the MISO DIR Order due to a lack of experience modeling and dispatching Dispatchable Intermittent Resources, E.ON notes that the Commission required MISO to study the issue and submit an annual compliance filing addressing whether those resources could reliably provide operating reserves.[129] E.ON requests that the Commission apply a similar directive in SPP for Dispatchable VERs, noting that SPP will have two additional years of experience with dispatchable resources prior to the launch of the Integrated Marketplace. E.ON recommends that the Commission require SPP to file with the Commission compliance filings 12 months and six months prior to market start-up, demonstrating why dispatchable VERs should not be permitted to offer operating reserves based on the most up-to-date industry information. If at market start-up it is

[125] E.ON Protest at 5-6 (citing MISO DIR Order, 134 FERC ¶ 61,141 at PP 4, 54, 55).

[126] *Id*. at 6 (citing MISO DIR Order, 134 FERC ¶ 61,141 at P 65).

[127] *Id*. at 6-7.

[128] AWEA Protest at 11.

[129] E.ON Protest at 9-10 (citing MISO DIR Order, 134 FERC ¶ 61,141 at P 107).

found that dispatchable VERs are still not allowed to offer operating reserves, E.ON requests that SPP be required to submit compliance filings on at least an annual basis demonstrating the justness and reasonableness of this exclusion.[130]

94. Finally, Acciona believes that SPP should clarify that when SPP calculates VER output for settlement purposes, VERs' auxiliary power may be netted against their gross output. Acciona argues that this would be similar to practices in MISO, CAISO, and PJM.[131]

c. Answers

95. In its May 15 Answer, SPP replies that its VER proposal is designed to balance the need to ensure continued operational reliability with the facilitation of VER participation.[132] SPP maintains that its experience shows that persistence forecasting[133] is more accurate than short-term interval forecasting and asserts that E.ON's request to instead allow a dispatchable VER to submit its own forecasts on a rolling basis is unnecessary and will not improve market efficiency.[134]

96. Regarding ramp rate limitations for dispatchable VERs, SPP states that because a VER is, by definition, variable, its ramp rate is not guaranteed. Therefore, if a VER fails to respond fully to a dispatch instruction due to the variable nature of the VER, the real-time balancing market solution will assume VER output that does not exist, leading to a shortage that will drive up prices for other Market Participants. Limiting the ramping of a VER to allow for a gradual reload over several five-minute Dispatch Intervals after it has responded to a dispatch instruction will help to avoid price spikes and reduce the need to use reserves, according to SPP.[135]

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[130] *Id*. at 10.

[131] Acciona Protest at 10.

[132] SPP May 15 Answer at 40.

[133] Persistence forecasting is forecasting that assumes the current value will be the same at a future point in time (e.g. 15 minutes-ahead, hour-ahead, etc). *See* National Renewable Energy Laboratory, Survey of Variable Generation Forecasting in the West, August 2011 – June 2012, (Apr. 2012) *available at* http://www.nrel.gov/docs/fy12osti/54457.pdf.

[134] SPP May 15 Answer at 41.

[135] *Id*. at 42.

97. Regarding maximum operating limits for dispatchable VERs, SPP argues that relying on its own forecasts, rather than those submitted by VER owners, will reduce opportunities for gaming, which could affect pricing across the SPP footprint. Further, SPP contends that using a single forecasting methodology would be more consistent than relying on multiple forecasting methodologies adopted by VER owners. SPP states that it is not unjust and unreasonable for SPP to use its own forecast when other RTOs accept VER-submitted forecasts. SPP also argues that it would be duplicative and burdensome to require SPP to rely on VER-submitted output forecasts because SPP will still need to perform its own VER forecasting. If the Commission requires SPP to accept self-supplied output forecasts, SPP states that it would need to develop software capable of utilizing and analyzing the submitted forecasts and comparing them to SPP's forecasts.

98. In response to SPP's May 15 Answer, E.ON reiterates its request that SPP allow dispatchable VERs to update their forecasts on a rolling basis. E.ON argues that SPP has not supported that persistence forecasting is more accurate and reliable than short-term interval forecasting. E.ON also states that SPP's use of persistence forecasting raises further questions, including: (1) whether SPP will use persistence forecasts to update VER offers for settlement purposes, and if so, how SPP will conduct settlements; and (2) whether dispatchable VERs may update their energy offers close to real-time, consistent with other dispatchable resources and, if not, what will happen if SPP's persistence forecast is incorrect, including whether dispatchable VERs will be made whole for foregone sales and whether SPP will adjust any URD charges. E.ON does not necessarily oppose the use of persistence forecasting, but maintains that, until these issues are addressed, SPP should rely on forecast information submitted by dispatchable VERs and allow updates on a rolling basis close to real-time.[136]

99. E.ON contends that SPP has not shown that significant price spikes and increased use of spinning reserves will occur if a dispatchable VER is allowed to ramp up or down consistent with its physical capabilities. E.ON asserts that SPP will not have the data necessary to make such a showing until after the Integrated Marketplace is implemented. According to E.ON, SPP should initially allow dispatchable VERs to ramp up and down to their fullest capability and submit a future filing if, based on its operational experience, SPP believes that ramp rate limits are necessary.[137]

100. With regard to maximum operating limit requirements for dispatchable VERs, E.ON argues that, in its May 15 Answer, SPP appears to state that it will use its forecasts *in lieu of* VER-submitted forecasts, which is inconsistent with proposed Tariff language

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[136] E.ON May 30 Answer at 2-4.

[137] *Id*. at 6-7.

indicating that SPP would use the *lesser of* the two forecasts. E.ON contends that it is not clear whether this change was intentional and, in any case, is unsupported.[138] Further, E.ON states that mitigation of potential gaming through the substitution of SPP's forecasts is not reasonable because the market monitoring unit can investigate any possibility of gaming, consistent with the treatment of other dispatchable resources. E.ON also argues that SPP has not explained how use of its own forecasts would eliminate withholding or undue influence on market prices. E.ON reiterates that SPP should use the maximum operating limit submitted by VERs, except in certain circumstances, as dispatchable VERs risk URD charges if their forecast is inaccurate.[139]

101. In a second answer, filed June 26, 2012, SPP argues that E.ON's various objections do not directly address the justness and reasonableness of the SPP proposal and should be dealt with through the stakeholder process as potential future market enhancements.[140] SPP responds to E.ON's questions regarding persistence forecasting. First, SPP states that it will use persistence forecasting for a dispatchable VER when there is no congestion in the real-time market, consistent with its existing practices. SPP explains that it will use a market participant's offer to determine whether a resource may be economically and reliably dispatched down due to a congestion event and, once a congestion event has been solved, SPP will use its VER forecast in order to ramp the unit up to the pre-congestion state. Once the resource is completely released, SPP states that it will resume persistence forecasting.[141]

102. Second, SPP explains that all resources may submit status and offer updates up to 30 minutes prior to the top of the hour and may modify non-price operating parameters anytime within the hour. SPP states that there should not be any implications if a dispatchable VER's forecast is more accurate during a Dispatch Interval because it will not be used in the real-time market solution (i.e., SPP will use persistence forecasting or, when releasing a resource from a curtailment, SPP's forecast). SPP adds that persistence forecasting is accurate and widely used in other markets.[142]

103. Third, in response to E.ON's questioning how SPP will make a dispatchable VER whole due to the use of a persistence forecast that is lower than the resource's self-

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[138] *Id*. at 4.

[139] *Id*. at 5-6.

[140] SPP June 26 Answer at 14.

[141] *Id*. at 15-16.

[142] *Id*. at 16.

generated forecast, SPP states that it settles only on metered output and SPP's persistence forecast and argues that using the market participant's forecast would invite gaming and introduce inconsistencies due to the difference in forecasting methods employed by dispatchable VERs. Finally, regarding the impact persistence forecasting will have on URD charges, SPP believes that the flexibility afforded all resources in submitting Ramp-Rate Up, Ramp-Rate Down parameters, and turn-around ramp rate factors, as well as the tolerance band built into the URD calculation, provide sufficient opportunity for a resource to minimize its exposure to URD charges. SPP states that when dispatchable VERs' maximum operating limits are set using persistence forecasting (i.e., the four-second setpoint instruction echoes the previous four-second actual output), any risk of URD charges are virtually eliminated.[143]

104. In response to E.ON's claim that SPP has not made a sufficient showing that the proposed ramp rate limits for dispatchable VERs are just and reasonable, SPP clarifies that the ramp rate limits would apply only during intervals when the resource is being released from a previously curtailed value. SPP states that at all other times, dispatchable VERs could ramp up or down to their fullest capability. SPP argues that the ramp rate limits when dispatchable VERs are being released from a previously curtailed value is necessary and just and reasonable. SPP uses an example to illustrate. According to SPP, in the case where a dispatchable VER has been curtailed due to a transmission constraint, if that constraint is solved by the market, though not physically relieved, and the dispatchable VER immediately ramps to its previous output level (or higher) in the following five-minute dispatch period, the solution algorithm will violate the transmission limit again. According to SPP, this will occur continuously and raise market prices, unless SPP is allowed to limit ramping "for wind-powered" dispatchable VERs in such cases.[144]

105. SPP states that E.ON's concerns over maximum operating limit requirements for dispatchable VERs are misplaced. SPP contends that it has not changed its position on this issue, and that the proposed "lesser of" calculation will be used in the day-ahead market-clearing process, the day-ahead RUC, the Intra-Day RUC, and when a dispatchable VER has been previously dispatched down due to congestion and is now being economically released from that curtailment in the real-time market. SPP states that at all other times (i.e., in the real-time market, when the resource is not being

[143] *Id*. at 17.

[144] *Id*. at 19-21.

released from a curtailment), dispatchable VERs can set their own maximum operating limit in its resource offer.[145]

106. In E.ON's July 11 answer, E.ON argues that, contrary to SPP's statements, its concerns are germane to SPP's proposal and the burden falls upon SPP to justify its proposal before market start-up.[146] E.ON understands that SPP's use of persistence forecasting for dispatchable VERs will not impede their ability to update their maximum operating limits up to 10-minutes prior to each Dispatch Interval. E.ON states that if the Commission accepts as just and reasonable SPP's proposal to use persistence forecasting, the Commission should require that the limited instances when it may be used should be outlined in the Tariff.[147]

107. Regarding SPP's proposed ramp rates limits for dispatchable VERs, E.ON contends that even if these limits only apply when dispatchable VERs are being released from curtailment, SPP has still not shown the limits to be just and reasonable and not unduly discriminatory or preferential. E.ON argues that SPP can control how resources are dispatched after a congestion event so as to avoid the creation of another congestion event while allowing a resource to ramp as much as possible. For this reason, E.ON argues that there is no need to impose on one class of resources an arbitrary ramp rate limit.[148]

d. <u>Commission Determination</u>

108. We find that, subject to conditions, SPP's dispatchable VER proposal will improve the efficiency of SPP's real-time energy market and reliability function by reducing SPP's need to manually curtail VERs. We note that in its June 26 Answer, SPP provides several important clarifications regarding its real-time dispatchable VER proposal, including the applicability of its proposed ramp rate limits and maximum operating limit requirements, as well as its use of persistence forecasting. In light of these clarifications, we conditionally accept SPP's proposed treatment of VERs, subject to the compliance requirements discussed below.

109. In its June 26 Answer, SPP explains that it will use persistence forecasting in the real-time market for dispatchable VERs when congestion is not active during a five-

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[145] *Id*. at 18-19.

[146] E.ON July 11 Answer at 2-3.

[147] *Id*. at 3.

[148] *Id*. at 4-5.

minute Dispatch Interval (i.e., when its proposed ramp rate limits and maximum operating limit requirements do not apply).[149] We find that SPP's proposed use of persistence forecasting for dispatchable VERs is just and reasonable. As SPP explains, its persistence forecasting proposal is consistent with its existing practices and virtually eliminates any risk that a dispatchable VER will be assessed URD charges because four-second setpoint instructions will merely echo the VER's actual output during the previous four seconds. We disagree with E.ON's argument that SPP should permit dispatchable VERs to update their offers up to 10-minutes prior to each five-minute Dispatch Interval. SPP states in its June 26 Answer that dispatchable VERs may update their status and offers up to 30 minutes prior to the top of the hour and may modify non-price related operating parameters anytime within the hour.[150] SPP explains that it intends to use persistence forecasting for dispatchable VERs unless a congestion event occurs. We are not persuaded that dispatchable VERs need to update their status and offers on a more frequent basis for the limited purpose of determining whether a resource may be economically and reliably dispatched down due to a congestion event. However, we agree with E.ON that the SPP Tariff should clearly state the circumstances in which SPP will use persistence forecasting.

110. We also find that the SPP Tariff should describe VER settlements in greater detail, such as including a provision to provide that a dispatchable VER's settlements will be based on metered data. Also, with regard to settlements, it is unclear whether SPP will permit auxiliary power netting.[151] Accordingly, we will require SPP to submit, in a compliance filing due 90 days after the issuance of this order, Tariff revisions to specify when SPP will use persistence forecasting, a market participant's offers, and/or SPP's forecast and how VERs will be settled in SPP's markets, including whether it permits auxiliary power netting, consistent with SPP's June 26 Answer. In its compliance filing, SPP should either justify its proposed Tariff language providing that the proposed setpoint instruction requirements for dispatchable VERs should apply, if the resource owner has indicated that the resource is not dispatchable, or SPP should submit Tariff revisions to remove this language. In addition, we will require SPP to submit a discussion of the accuracy of its persistence forecasting for VERs based on a full 12 months of data in an informational report due 15 months following commencement of the Integrated Marketplace.

[149] SPP June 26 Answer at 15.

[150] *Id*. at 16.

[151] *Id*. at 17; Acciona Protest at 10.

111. Regarding SPP's proposed ramp rate limits, in its June 26 Answer, SPP clarifies that the ramp rate restrictions for a dispatchable VER will apply only during intervals following a previous instruction from SPP to curtail output, and "[f]or all other periods, the D[ispatchable] VER may operate to the full extent its output allows."[152] As SPP explains, requiring a dispatchable VER to ramp up gradually when being released from a previously-curtailed value lessens the possibility of price spikes and reduces the need to call on reserves.[153] Moreover, as SPP notes, unlike other generation resources whose ramp rates are fixed by the mechanical and operational characteristics of the resources, VERs have a variable ramp rate. Therefore, because of the variable nature of ramp rates for VERs and because SPP will apply its ramp rate restrictions only in limited circumstances, we find that SPP's proposal to restrict dispatchable VERs' output following a curtailment event to be just and reasonable. Because the ramp rate restrictions will apply in these limited circumstances, we disagree with protesters' argument that they would unnecessarily expose dispatchable VERs to severely negative prices or provide a disincentive for those resources to offer their full ramp capability. However, we will require SPP to submit a discussion of the effects of its substitution of SPP's output forecast for the maximum operating limit submitted for a dispatchable VER based on a full 12 months of data in an informational report due 15 months following commencement of the Integrated Marketplace.

112. Further, we are concerned that SPP's proposed Tariff revisions to section 4.1.2.4 do not reflect the clarification that SPP provided in its June 26 Answer, i.e., that the proposed ramp rate restrictions will apply only during intervals following a previous curtailment instruction.[154] Similarly, SPP's proposed ramp rate restrictions apply to only those dispatchable VERs with a maximum capability "less than" or "greater than" 200 MWs but do not address resources with a maximum capability equal to 200 MWs.[155] Therefore, we will require SPP to submit, in a compliance filing due 90 days after the issuance of this order, Tariff revisions to: (1) specify when the proposed ramp rate

[152] SPP June 26 Answer at 19-20.

[153] SPP explains, for example, that if a dispatchable VER immediately ramps up to its full output following a curtailment instruction due to congestion, the market solution again will violate the transmission constraint. SPP states that this will occur continuously unless SPP is allowed to ease the ramping of dispatchable VERs over several five-minute intervals following curtailments. *Id.* at 20.

[154] *Id.* at 19-20.

[155] SPP Tariff, Proposed Attachment AE, section 4.1.2.4.

restrictions will apply, consistent with its June 26 Answer; and (2) provide ramp rate requirements for a dispatchable VER with a maximum capability "equal to" 200 MWs.

113. With regard to its proposed maximum operating limit restrictions for dispatchable VERs in the real-time market, SPP's proposed Tariff revisions provide that they will apply only when SPP is ramping a resource up following instructions to reduce output during a congestion event.[156] As these restrictions will apply only in those limited circumstances to help ensure system reliability, and SPP's output forecast is used only in the event that it is *less than* the maximum output limit submitted for the VER, it is unclear how any inaccuracies in SPP's forecast could expose the VER to adverse financial risks, as E.ON asserts. For example, if SPP's output forecast is used because it is lower than the maximum operating limit submitted by for the VER, then the VER should be able to meet SPP's forecast without incurring URD charges, regardless of whether SPP's output forecast was inaccurate. However, we agree with E.ON that it is appropriate to substitute SPP's output forecast for a dispatchable VER's maximum operating limit when the VER fails to provide that limit, fails to update that limit close to real-time, or submits a limit that exceeds the resource's physical operating limit. Accordingly, we will accept SPP's proposed maximum operating limit requirements for the real-time market and require SPP to submit, in a compliance filing due 90 days after the issuance of this order, tariff revisions to incorporate the instances noted above in which SPP's output forecast would be substituted for the maximum operating limit submitted for a dispatchable VER. We will also require SPP to submit a discussion of the effects of its ramp rate requirements for dispatchable VERs, including any adverse financial consequences for VERs, based on a full 12 months of data in an informational report due 15 months following commencement of the Integrated Marketplace.

114. We agree with AWEA and BP Wind Energy that while SPP's proposed maximum operating limit requirements for dispatchable VERs in the RUC process will help to ensure reliability, SPP has not shown that these requirements are just and reasonable when applied in the day-ahead market. Specifically, SPP has not demonstrated the need to override the offer information submitted by a dispatchable VER in the day-ahead market, nor has SPP responded to concerns that this may prevent that resource from taking advantage of advanced forecasting techniques or unfairly expose it to adverse financial risks (e.g., by preventing a resource from clearing the day-ahead market at its full as-offered capacity). We will require SPP to submit, in a compliance filing due 90 days after the issuance of this order, either: (1) a justification for SPP's proposed maximum operating limit requirements for dispatchable VERs in the day-ahead

[156] *Id.*

market;[157] or (2) Tariff revisions so that these requirements for dispatchable VERs do not apply in the day-ahead market.

115. We agree with E.ON that SPP should explain its methodology for determining SPP's output forecasts for dispatchable VERs, as these forecasted values may be used for a dispatchable VER's maximum operating limit and, therefore, could have rate implications. We agree in principle with AWEA's concern that meteorological data reporting be limited to data that is necessary for SPP to produce the specific power production forecasts it intends to produce. However, we find no reference to such data reporting requirements in SPP's proposal. Therefore, we require SPP to submit in a compliance filing due 90 days after the issuance of this order an explanation of: (1) its methodology for determining SPP's output forecasts for dispatchable VERs; and (2) any meteorological data that is required from the VERs and, if needed, corresponding Tariff revisions.

116. In response to E.ON's concerns that dispatchable VERs are not allowed to provide operating reserves, we will require SPP to clarify whether dispatchable VERs may provide operating reserves. We note that in proposed sections 2.10.1, 2.10.2, and 2.10.3 of Attachment AE there is no specific provision disqualifying dispatchable VERs from providing these services, nor can we find any other provision disqualifying these resources from providing these services. We require SPP to submit such clarification in a compliance filing due 90 days after the issuance of this order, including any corresponding Tariff revisions. If SPP intends not to allow dispatchable VERs to provide operating reserves, SPP must provide a justification for this restriction in the compliance filing referenced above.

117. In section 2.2(10) of Attachment AE, SPP proposes that "a wind-powered [VER] with an interconnection agreement executed after May 21, 2011 must register as a Dispatchable [VER]. [VER]s with fuel sources other than wind may optionally register as a Dispatchable [VER]. Otherwise, [VER]s must register as Non-Dispatchable [VER]s."[158] We are concerned that these registration requirements will prevent wind-powered VERs with interconnection agreements executed on or before May 21, 2011

[157] To the extent that there are concerns regarding potential gaming of maximum operating limits, SPP should address whether its market monitoring and mitigation measures could address any such gaming activities.

[158] *Id*. section 2.2(10). We note that May 21, 2011 is the effective date of revisions to SPP's *pro forma* Generator Interconnection Agreement requiring wind resources to be capable of reducing output in increments of 50 MW or less in five-minute intervals. *See Southwest Power Pool, Inc.*, 135 FERC ¶ 61,148.

from registering as dispatchable VERs, even if they are already "capable of being incrementally dispatched by the Transmission Provider," consistent with the definition of "Dispatchable Variable Energy Resource" in Attachment AE,[159] or are willing to satisfy this requirement (e.g., by installing additional equipment). We require SPP to submit in a compliance filing due 90 days after the issuance of this order, Tariff revisions to permit wind-powered VERs with interconnection agreements executed on or prior to May 21, 2011 to register as dispatchable VERs, if they satisfy the applicable requirements (e.g., are capable of being dispatched by SPP).

118. SPP also proposes to allow VERs with fuel sources other than wind to choose whether to register as non-dispatchable VERs or dispatchable VERs.[160] We are concerned that this could inappropriately allow dispatchable VERs to revert to non-dispatchable VER status. SPP proposes to differentiate between dispatchable VERs and non-dispatchable VERs based on their physical capabilities (i.e., whether they are "capable of being incrementally dispatched by the Transmission Provider"),[161] and a single unit cannot meet both definitions simultaneously. Once a resource qualifies as a dispatchable VER and, thus, is physically capable of being dispatched, it is not reasonable to allow that resource to switch back and forth. As the Commission previously explained in the MISO Dispatchable Intermittent Resources proceeding, "[s]uch switching would defeat the significant reliability and market transparency reasons for requiring Intermittent Resources to register as Dispatchable Intermittent Resources in the first place, as well as the efficiency gains associated with the requirement."[162] Accordingly, we require SPP to submit in a compliance filing due 90 days after the issuance of this order, Tariff revisions to section 2.2(10) providing that resources that have previously registered as dispatchable VERs may not later register as non-dispatchable VERs.

119. With regard to the treatment of non-dispatchable VERs, we note that the Commission conditionally accepted SPP's proposal to permit the systematic[163] and

[159] *Id*. sections 1.1.D, 1.1.N.

[160] *Id*. section 2.2(10).

[161] *Id*. section 1.1.D.

[162] *See* MISO DIR Order, 134 FERC ¶ 61,141 at PP 40-41.

[163] By using the term "systematic," SPP means that its market software tools will send instructions directing Non-Dispatchable Resources to curtail output, rather than sending instructions that merely reflect the resource's actual output and that do not contemplate or instruct that the resources change the amount of the output. *Southwest Power Pool, Inc.*, 140 FERC ¶ 61,225, at P 2, n.2 (2012).

automated curtailment of non-dispatchable resources,[164] including Qualifying Facilities, in SPP's EIS market.[165] Among other things, the Commission required SPP to address in a compliance filing how the treatment of non-dispatchable resources will work within the Integrated Marketplace.[166] In its Integrated Marketplace proposal, SPP does not fully explain the treatment of non-dispatchable VERs, including its curtailment procedures and whether it will continue to apply its systematic and automated processes. We will require SPP to submit, in a compliance filing due 90 days after the issuance of this order, an explanation of how non-dispatchable VERs will be treated in the Integrated Marketplace and, as needed, corresponding Tariff revisions.

120. Finally, in section 1.1 of Attachment AE, SPP proposes to define a "Variable Energy Resource" as "[a] Resource powered solely by wind, solar Energy, run-of-river hydro or other unpredictable fuel source that is beyond the control of the Resource operator."[167] Characterizing these fuel sources as "unpredictable" does not reflect that resource operators may develop forecasts that accurately predict the availability of these fuel sources, within a margin of error. Accordingly, we require SPP to submit revisions to this definition in a compliance filing due 90 days after the issuance of this order that characterizes the fuel source as variable.[168]

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[164] In Attachment AE of the Tariff, Section 1.1 – Definitions, SPP proposed to define a "Non-Dispatchable Resource" as "A Resource meeting any of the following conditions: (a) operating in Shut-down Mode; (b) operating in Start-up Mode; (c) operating in Test Mode; (d) operating under Exigent Conditions; (e) is an Intermittent Resource; or (f) is a Qualifying Facility." *Id.* n.3.

[165] *Id.*

[166] *Id.* P 59.

[167] SPP Tariff, Proposed Attachment AE, section 1.1.V.

[168] We note that the Commission previously defined a "VER" as:

> a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic facilities.

Integration of Variable Energy Resources, Order No. 764, 77 Fed. Reg. 41,481 (July 13, 2012), FERC Stats. & Regs. ¶ 31,331, at n.1 (2012) (citing *Integration of Variable*

(continued…)

4. Uninstructed Resource Deviation

a. SPP Proposal

121. In the current EIS market, a URD[169] charge is applied to resources that operate outside of a tolerance band equal to 10 percent of the resource's Maximum Capacity Operating Limit subject to a floor of five MW and ceiling of 25 MW. The URD charge is not imposed on intermittent resources in the EIS market.[170]

122. In the Integrated Marketplace, SPP proposes to calculate URD subject to a tolerance band, set as five percent of the resource's Maximum Emergency Capacity Operation Limit. The tolerance band will be subject to a floor of five MW and a ceiling of 20 MW.[171] SPP proposes to assess resources with a URD outside of the Operating Tolerance for RUC make whole payments and to assess a Regulation Deployment Failure Charge.[172] SPP proposes to calculate URD for VERs according to these URD provisions and to subject VERs to the same URD-related charges as other resources. SPP states that the calculation of URD and the associated charges provide a disincentive for resources to operate outside of their tolerance band, and this disincentive enhances the reliability of the Integrated Marketplace.

b. Protests

123. Protesters ask the Commission to reject SPP's proposed tolerance band definition. BP Wind Energy notes that MISO initially proposed a similar Operating Tolerance to the

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Energy Resources Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,664, at P 64 (2010)).

[169] SPP defines URD in the existing Tariff as the average MW amount of actual output in a dispatch interval above or below the resource's average set point instruction in the dispatch interval.

[170] *See* SPP Tariff, Attachment AE, section 4.1.e.

[171] SPP proposes several exemptions from the calculation of the URD; these include deviations caused solely by events or conditions beyond the control of the resource, an incident where the resource trips off-line, or where the resource is subject to manual dispatch or load deviations during a capacity shortage emergency.

[172] A resource with cleared Regulation Up, Regulation Down, or both will be assessed a Regulation Resource Deployment Failure Charge, in a dispatch interval, when the URD is outside of the resource's tolerance band.

one SPP proposes here, but revised it to eight percent of maximum capacity limit, with a maximum Operating Tolerance of 30 MW, upon determination that its original proposal was too restrictive. Additionally, BP Wind Energy and E.ON note that MISO does not impose charges associated with URD unless the deviations outside of the tolerance band exist over four consecutive five-minute dispatch intervals, which the Commission found to be important in accepting MISO's proposed charges. BP Wind Energy also states that SPP is unclear about which entity – SPP or the owner/operator of the resource itself – is responsible for setting the resource's Maximum Emergency Capacity Operating Limit. BP Wind Energy believes that SPP intended that responsibility to rest with the resource's owner/operator, rather than being separately set by SPP. However, to the extent SPP did intend to set that limit itself, BP Wind Energy argues the Commission should reject SPP's proposal.

124. E.ON argues that SPP has not supported its proposed tolerance band, especially as it pertains to VERs, given the wider variability of VERs. It notes that the Commission required MISO to perform an analysis of whether its eight percent tolerance band is appropriate for VERs based on its first year of operating experience.

c. Commission Determination

125. We conditionally accept SPP's URD proposal subject to the compliance requirements discussed below. We find that SPP's proposal to continue to impose URD charges upon units that operate outside of their tolerance band is just and reasonable. However, we find that SPP has not provided sufficient justification for the Commission to find the specifics of its proposed URD tolerance band to be just and reasonable.[173] We find that SPP has neither demonstrated that the proposed tolerance band is reasonable; nor has it made a sufficient showing that the tolerance band is reasonable with respect to the treatment of VERs,[174] whose output tends to fluctuate more than typical dispatchable resources. Thus, we find the URD tolerance band is unsupported and direct SPP to submit in a compliance filing due 90 days after the issuance of this order, justification to support its tolerance band proposal (or a less-restrictive version thereof). For example, we note that MISO's tolerance band proposal could serve as useful basis for SPP's revised proposal.[175]

[173] *See e.g.*, MISO DIR Order, 134 FERC ¶ 61,141.

[174] VERs are currently exempt from URD and associated charges under the EIS market.

[175] MISO DIR Order, 134 FERC ¶ 61,141.

126. SPP has not developed a separate penalty charge for URDs and has proposed to subject URDs to its RUC make whole payment cost allocation methodology. Thus, we will address issues relating to URD exemptions in section 6.4.1.1 of Attachment AE in our discussion of SPP's make whole payment proposal below.

127. In response to BP Wind Energy, we note that proposed section 2.11.2 of Attachment AE specifies that, for the RUC processes and real-time balancing market, a Market Participant must submit resource offers for all its resources and must include in its resource offers the full amount of available physical capacity, as reflected in the resource's submitted Maximum Normal Capacity Operating Limit and Maximum Emergency Capacity Operating Limit. This Tariff language provides that the owner/operator of the resource is responsible for setting the resource's Maximum Emergency Capacity Operating Limit in its submittal to SPP. Thus, we find that no further clarification is necessary.

5. Virtual Transactions

a. SPP Proposal

128. SPP states that the Integrated Marketplace will accommodate virtual transactions in the day-ahead market, wherein Market Participants will be permitted to submit virtual Energy Offers[176] to sell energy or virtual energy bids to purchase energy at any settlement location, including Market Hubs.[177] SPP notes that the Commission has previously found that virtual transactions benefit Market Participants by improving price convergence between day-ahead and real-time balancing markets.[178] SPP also states that virtual transactions are a common feature of the organized day-ahead markets of other RTOs. However, SPP proposes for the Integrated Marketplace to limit a Market Participant to a single offer or bid per hour at each settlement location for each asset owner it represents.[179] SPP contends that this difference between its proposal and other

[176] Virtual offers and bids are purely financial and not associated with any specific physical resource, but are eligible to set prices in the day-ahead market. Virtual transactions are reversed and liquidated in the real-time balancing market. Market participants may not submit virtual offers and bids for Operating Reserve.

[177] The SPP Tariff defines a Market Hub as a Settlement Location consisting of an aggregation of price nodes. SPP Tariff, Proposed Attachment AE, section 1.1 (Definition M).

[178] SPP Transmittal at 24 n.104 (citing *Ameren Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,121, at P 45 (2009), *order on reh'g*, 138 FERC ¶ 61,039 (2012)).

RTO practices is necessary to permit the day-ahead market software time to arrive at a feasible solution. SPP states that many virtual transactions introduce administrative and model solution problems due to the compressed timelines in which such numerous transactions must be processed. [180]

129. SPP states that it will assess a transaction fee called the Virtual Energy Transaction Fee on each virtual bid and virtual offer to cover administrative costs for the Integrated Marketplace.[181] SPP notes that it will use the revenues collected through the Virtual Energy Transaction Fee to reduce the budgeted expenses used to calculate the administrative fee charged under Schedule 1-A.[182]

b. Protests

130. DC Energy understands that the purpose of the Virtual Energy Transaction Fee is to recover the portion of administrative costs that are not currently covered under SPP's Schedule 1-A, which DC Energy finds appropriate. While DC Energy expects SPP's proposed rate to be modest and comparable to other RTO and ISO markets, DC Energy states that, absent more detail, it is difficult to determine whether the rate is just, reasonable, and not unduly discriminatory. DC Energy requests that the Commission direct SPP to complete the development of this rate as expeditiously as practicable and direct SPP to consider the impact of the fee on potential virtual participation levels.[183]

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[179] *See* SPP Tariff, Proposed Attachment AE, sections 4.2.1(3) and 4.3.2(3).

[180] Exh. No. SPP-3 at 23.

[181] SPP notes that it is still developing the rate for the Virtual Energy Transaction Fee, which SPP states it will submit to the Commission for approval in a subsequent filing. SPP Transmittal at 23 n.100.

[182] SPP explains that currently its administrative costs are recovered under Schedule 1-A of the Tariff, which imposes charges on point-to-point transmission service and network integration transmission service. However, because virtual transactions are financial-only transactions in the day-ahead market without any associated transmission service, SPP states that it must have a mechanism to recover costs from these transactions. *Id*. at 23.

[183] DC Energy Protest at 23-24.

c. Commission Determination

131. We conditionally accept SPP's virtual trading proposal subject to the following informational and compliance requirements. We find the inclusion of virtual trading within SPP's Integrated Marketplace design to be just and reasonable. As the Commission has previously found, virtual transactions provide important benefits to organized energy markets, such as improved convergence between day-ahead and real-time prices, improved market liquidity, and increased competition.[184] We note that SPP has taken a conservative approach to overseeing virtual trading activity in the Integrated Marketplace, particularly with regard to its proposal in sections 4.2.1 and 4.3.2 of Attachment AE to limit a Market Participant to a single virtual offer or bid per hour at each settlement location for each asset owner it represents. We find that SPP's conservative approach is reasonable at commencement of the Integrated Marketplace, as such a strategy provides a type of safety net at market launch to protect against unintended consequences and to allow Market Participants a transition period to gain experience in virtual trading in the Integrated Marketplace.[185] Additionally, we note that there is not a consistent approach to overseeing virtual transactions, and RTOs and ISOs have implemented a variety of measures, some similar to those proposed by SPP, to oversee virtual trading activity based on regional needs.[186] However, we believe it is necessary to require SPP to assess, based on actual market experience, whether its provisions overseeing virtual transactions have unnecessarily restricted virtual trading activity in its day-ahead market.

132. Accordingly, we conditionally accept SPP's virtual trading proposal contingent upon SPP reviewing its measures to overseeing virtual transactions and reporting on the state of virtual transaction activity in the Integrated Marketplace in its informational report to the Commission 15 months after market start-up reflecting 12 full months of

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[184] *See, e.g., ISO New England Inc.*, 110 FERC ¶ 61,250, at P 30 (2005).

[185] *See Cal. Indep. Sys. Operator Corp.,* 130 FERC ¶ 61,122, at P 55 (2010) ("We…recognize that at the start of convergence bidding, an additional safety net may be appropriate to prevent unforeseen and unintended market outcomes that might come about because Market Participants lack experience in the new convergence bidding market.").

[186] Additional measures used by other RTOs and ISOs to regulate virtual trading activity that SPP has proposed include: a fee to recover administrative costs, virtual trading market monitoring provisions, market power mitigation measures that allow the market operator to suspend a Market Participant's virtual trading activity for a certain period of time, and credit requirements for virtual traders.

data. We require SPP to report on: (1) whether it has experienced any administrative and model solution problems relating to virtual trading activity; (2) whether it finds that its provisions regulating virtual transactions have unnecessarily restricted virtual trading activity; and (3) whether a relaxation of virtual transaction limits, or other modification to a provision overseeing virtual trading activity, is warranted, based on its market experience.

133. We also conditionally accept SPP's virtual transaction proposal contingent upon SPP submitting and justifying its day-ahead Virtual Energy Transaction Fee, described in proposed section 8.5.17 of Attachment AE, in a section 205 filing. While we find it reasonable for SPP to assess an administrative fee on virtual transactions comparable to the tariff service administration fee assessed for transmission service in Schedule 1-A of the SPP tariff, we cannot determine the justness and reasonableness of the actual fee without having the rate — and cost causation support justifying that rate — before us.

6. Make Whole Payments

a. General Proposal

i. SPP Proposal

134. SPP proposes adopting make whole payments for SPP-committed resources that are unable to recover their costs. According to SPP's witness, Richard Dillon, the specific purpose of make whole payments is to keep resource owners indifferent to SPP's commitment decisions. To the extent that market revenues are insufficient, SPP proposes compensating resource owners for their commitment and incremental energy costs[187] for the period that SPP commits them in the day-ahead market, the day-ahead RUC, or intra-day RUC.[188]

135. SPP proposes a day-ahead make whole payment to be paid to an asset owner when the sum of a resource's costs[189] is greater than the day-ahead market revenues

[187] Commitment and incremental energy costs include start-up, no-load, energy offer curve, and operating reserve offer costs.

[188] SPP Transmittal at 26.

[189] Section 8.5.9(3) of proposed Attachment AE contains an extensive list of cost recovery rules that apply to each day-ahead make whole payment eligibility period. Section 8.5.9(4)(a) describes the costs that are accounted for in the calculation of the day-ahead make whole payment amount, which include start-up and no-load offers, energy costs associated with cleared energy offers, and operating reserve costs associated with cleared operating reserve offers.

received for that resource over the resource's day-ahead make whole payment eligibility period. The make whole payment is equal to the difference between costs and revenues.[190] SPP's proposed Tariff contains an equation for calculating the day-ahead make whole payment amount that would be paid to each asset owner for each eligible settlement location for a given eligibility period.[191]

136. To fund the day-ahead make whole payment, SPP proposes instituting a charge called the day-ahead make whole payment distribution amount,[192] which is an hourly charge to asset owners. This charge will be determined at each settlement location and is the product of the day-ahead make whole payment distribution rate[193] and quantity.[194]

137. SPP also proposes adopting a RUC make whole payment, which applies to resources committed in either the day-ahead or intra-day RUC.[195] SPP explains that this RUC make whole payment compensates resources committed by SPP after the close of the day-ahead market to the extent that real-time market revenues do not compensate the resource for its start-up, no-load, energy offer curve, and operating reserve offer costs[196] during the resource's RUC make whole payment eligibility period.[197] The Tariff

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[190] SPP Transmittal at 26; SPP Tariff, Proposed Attachment AE section 8.5.9(1).

[191] SPP Transmittal at 26 (citing SPP Tariff, Proposed Attachment AE section 8.5.9(4)).

[192] SPP Tariff, Proposed Attachment AE section 8.5.10.

[193] Section 8.5.10(1) of proposed Attachment AE describes the day-ahead make whole payment distribution rate as the sum of all make whole payments for the operating day for all asset owners divided by the sum of all asset owners' day-ahead make whole payment distribution quantities for all settlement locations for the operating day.

[194] Section 8.5.10(2) of proposed Attachment AE provides that an asset owner's day-ahead make whole payment distribution quantity at a settlement location for an hour is equal to that asset owner's net cleared energy withdrawals at the settlement location for that hour. The day-ahead make whole payment distribution rate provides a regional average of make whole payments for the operating day.

[195] SPP Tariff, Proposed Attachment AE section 8.6.5.

[196] Section 8.6.5(3) of proposed Attachment AE contains an extensive list of cost recovery rules that apply to each RUC make whole payment eligibility period.

[197] SPP Transmittal at 27; SPP Tariff, Proposed Attachment AE section 8.6.5(1).

provides an equation for calculating the RUC make whole payment amount that would be paid to each asset owner for each eligible settlement location for a given RUC make whole payment eligibility period.[198]

138. To fund the RUC make whole payment, SPP proposes instituting a charge called the RUC make whole payment distribution amount, which is a real-time market charge calculated at each settlement location for each asset owner for each hour and is the product of the asset owners' distribution volume[199] and a daily RUC make whole payment rate.[200] SPP states that it will assesses this charge on a cost-causation basis through calculation of certain load and resource deviations from the day-ahead market cleared amounts, operating parameter changes from those used in the day-ahead market, and deviations associated with not following dispatch instructions.[201]

139. SPP asserts that its make whole payment mechanism is similar to the mechanisms established in other RTOs,[202] except that SPP's make whole payment related to recovery of start-up offer costs is based on an eligibility period that may span two operating days,[203] rather than a daily or hourly period.[204] However, SPP argues that its

[198] SPP Transmittal at 27 (citing SPP Tariff, Proposed Attachment AE section 8.6.5(4)).

[199] Section 8.6.7 of Proposed Attachment AE describes the RUC make whole payment distribution charge. Section 8.6.7(2) of Proposed Attachment AE provides a detailed explanation of the values accounted for in determining an asset owner's RUC make whole payment distribution volume at a settlement location for an hour.

[200] Section 8.6.7(1) of Proposed Attachment AE provides that the RUC make whole payment rate is the sum of all make whole payments for the operating day (as calculated under section 8.6.5) divided by the sum of asset owners' RUC make whole payment distribution volumes for all settlement locations for the entire operating day. The RUC make whole payment distribution rate provides a regional average of make whole payments for the operating day.

[201] SPP Transmittal at 27.

[202] *Id*. at 27 (citing *ISO New England Inc.*, 138 FERC ¶ 61,042, at P 119 n.133 (2012); ISO New England Inc. Transmission, Markets, and Services Tariff, Market Rule 1, Appendix F section III.F.2.1.17; MISO Tariff sections 40.3.5 and 40.3.6; NYISO Market Services Tariff at Attachment J section 25.1; CAISO Fifth Replacement FERC Electric Tariff section 11.21.1).

[203] Section 8.5.9(2) of proposed Attachment AE specifies that a resource's day-ahead make whole payment eligibility period is equal to a resource's day-ahead

(continued…)

proposed eligibility period provides an incentive for Market Participants to allow SPP to optimize unit commitment decisions for the entire SPP Balancing Authority Area, as opposed to Market Participants self-committing their resources.[205]

ii. Protests

140. DC Energy alleges that SPP has not based its RUC make whole payment cost allocation methodology on cost causation principles. DC Energy argues that there are numerous circumstances necessitating make whole payments, and as such, a one-size-fits-all approach does not reflect cost causation. DC Energy asserts that RUC make whole payment costs should be allocated on the basis of the circumstances leading to unit commitment. DC Energy argues that, as is the case in other wholesale energy markets such as MISO, SPP system operators are aware of the circumstances leading to unit commitments and are able to make notations for when and why they commit units. DC Energy believes SPP could then use these notations to allocate costs in a manner more in keeping with cost causation principles.[206]

iii. Answer

141. SPP asserts that the granular cost-causation construct proposed by DC Energy is not realistic. According to SPP, allocating RUC make whole payment costs based on

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commitment period. However, for resources with an associated commitment period that begins in one operating day and ends in the next, two make whole payment eligibility periods are created. The first period begins in the first operating day in the hour that the day-ahead commitment period begins and ends in the last hour of the first operating day. The second period begins in the first hour of the next operating day and ends in the last hour of the day-ahead commitment period. Section 8.6.5(2) of proposed Attachment AE describes a resource's RUC make whole payment eligibility period, which is similar to the day-ahead make whole payment eligibility period, with the exception of references to commitment and de-commitment time frames.

[204] In his testimony, Mr. Dillon states that other markets typically limit the period in which start-up costs may be recovered to a single operating day. Mr. Dillon states, however, that in both instances (eligibility period in single operating day or eligibility period spanning two operating days), the inclusion of start-up costs for recovery is limited to the lesser of the resource's minimum run-time or 24 hours. Exh. No. SPP-3 at 25.

[205] SPP Transmittal at 27.

[206] DC Energy Protest at 4-6.

specific resource commitment decisions is both inconsistent with Commission precedent and impractical because a number of circumstances can lead to a commitment decision.[207]

iv. Commission Determination

142. We will conditionally accept SPP's overall make whole payment construct for market start, as amended, contingent on SPP modifying and clarifying certain aspects of its proposal, as discussed below. DC Energy alleges that the RUC make whole payment cost allocation methodology is not based upon on cost causation principles and that SPP's one-size-fits-all approach does not reflect cost causation. However, we agree with SPP that it is impractical to allocate RUC make whole payment costs based on the specific circumstances affecting resource commitment decisions at market start, as DC Energy proposes. The Commission has previously commented, "[i]t is well-established that the Commission is not required to allocate costs with exacting precision, nor are we obligated to reject any rate mechanism that tracks the cost causation principles less than perfectly."[208] However, we expect that as SPP gains market experience with its Integrated Marketplace, SPP will review and modify its RUC make whole payment cost allocation methodology, as necessary, based on market observations.

143. Additionally, to further SPP's evaluation and development of any necessary future modifications, we will require SPP to submit to the Commission an informational report due 15 months following commencement of the Integrated Marketplace that evaluates the performance of the make whole payment construct during the first year of market operations. This informational report should address the following issues: (1) whether SPP has found its make whole payment construct provides appropriate incentives to promote competitive markets; (2) whether the construct appropriately allocates the costs of make whole payments in a manner generally consistent with cost causation principles, based on SPP's observations on circumstances leading to the need for additional unit commitments in its Integrated Marketplace; (3) the impact of the two-day eligibility period upon these factors; and (4) the impact of virtual transactions on its make whole payment mechanismbased on its first year of operations. We also note that,

[207] SPP May 15 Answer at 47-48. SPP notes that its RUC make whole payment cost allocation methodology was the product of extensive stakeholder discussions and was ultimately approved with broad stakeholder support. SPP contends that none of the arguments advanced by DC Energy regarding the proposed RUC make whole payment cost allocation methodology were presented during the stakeholder vetting process.

[208] *Cal. Indep. Sys. Operator, Corp.*, 130 FERC ¶ 61,122, at P 131 (citing *Sithe/Independent Power Partners, L.P. v. FERC*, 285 F.3d. 1, 5 (D.C. Cir. 2002); *see also Midwest ISO Transmission Owners v. FERC*, 373 1361, 1369 (D.C. Cir. 2004)).

as SPP continues to gain experience with its Integrated Marketplace, it may propose additional revisions, as necessary, to improve its make whole payment mechanism. We find that this approach will promote the refinement of SPP's make whole payment construct as SPP gains market experience, while allowing for a basic mechanism to be in place at market launch that ensures that Market Participants remain indifferent to SPP's commitment decisions.[209]

144. Further, in order to minimize ambiguity in the Tariff, we will require SPP to modify its make whole payment provisions in sections 8.5.9 and 8.6.5 of Attachment AE to specify that only SPP-committed resources are eligible to receive make whole payments. We will require SPP to make these modifications in a compliance filing due 90 days after the issuance of this order.

145. With regard to SPP's proposed day-ahead make whole payment cost allocation methodology described in section 8.5.10 of Attachment AE, we find that it is inappropriate to allocate day-ahead make whole payment charges to resource offers and import interchange transaction bids.[210] The purpose of assessing a day-ahead make whole payment charge is to provide a means to compensate generators if purchases in the day-ahead market do not fully compensate those generators for their costs. Accordingly, we will require SPP to revise section 8.5.10(2) of Attachment AE to remove reference to resource offers and import interchange transactions bids in a compliance filing due 90 days after the issuance of this order. Also, we will require SPP to remove language from section 8.5.10(2) referring to positive net summing at a settlement location (i.e., this section should simply refer to the sum of cleared energy withdrawals at a settlement location) in a compliance filing due 90 days after the issuance of this order. Finally, we will require SPP to explain whether any additional revisions to its make whole payment methodologies are warranted based on the different characteristics (e.g., offer parameters) between block and dispatchable demand response resources and to propose Tariff revisions, if appropriate, in its compliance filing due 90 days after the issuance of this order.

[209] We note that this approach is compatible with DC Energy's sentiment that it does not oppose implementing SPP's current proposal on an interim basis, subject to certain modifications discussed in its protest, in order to avoid delaying market launch. *See* DC Energy Protest at 13.

[210] We address the treatment of virtual transactions in the day-ahead make whole payment cost allocation methodology later in this section.

b. Allocation of Make Whole Payment Costs to Virtual Transactions

i. SPP Proposal

146. With regard to day-ahead make whole payment cost allocation, section 8.5.10(2) of proposed Attachment AE specifies that an asset owner's net energy withdrawal at a settlement location is calculated as the positive net sum of cleared demand bids, resource offers, import interchange transaction bids, export interchange transaction bids, virtual energy bids, and virtual energy offers at that settlement location.[211] With regard to RUC make whole payment cost allocation, section 8.6.7(2)(a)[212] of proposed Attachment AE accounts for virtual transactions in one of the values used to calculate an asset owner's RUC make whole payment distribution volume at a settlement location for an hour.

147. SPP asserts that because virtual energy offers may displace physical offers in the day-ahead market, virtual offers create the need for the commitment of additional physical resources in the day-ahead market and RUC process. Thus, SPP concludes that Market Participants making virtual energy offers should contribute to funding make whole payments. SPP also asserts that virtual energy bids can increase the amount of physical supply that is necessary to clear the day-ahead market, which may result in resources being committed that require make whole payments. Thus, SPP contends that it is appropriate to include virtual transactions in the uplift associated with make whole payments.[213]

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[211] SPP notes that section 8.5.10(2) of proposed Attachment AE also specifies that an asset owner's day-ahead make whole payment distribution quantity, which is used to calculate the hourly charge to fund day-ahead make whole payments, is equal to that asset owner's net cleared energy withdrawals at a settlement location for an hour.

[212] Section 8.6.7(2)(a) of proposed Attachment AE states:

> The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, virtual transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load in excess of amounts cleared in the Day-Ahead Market.

[213] SPP Transmittal at 24 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 61,108, at PP 48-49 (rejecting MISO proposal to eliminate virtual supply

(continued…)

ii. Protests

148. DC Energy raises several issues with SPP's proposed RUC make whole payment cost allocation methodology relating to virtual transactions. DC Energy argues that virtual energy bids should not be allocated RUC make whole payment costs. Specifically, DC Energy contends that make whole payments should be allocated to virtual offers because virtual offers can cause the need for additional unit commitments. When additional units are committed, virtual offers can displace physical resources that SPP ultimately commits to meet forecasted load. However, DC Energy contends that day-ahead virtual bids cause additional resources to be committed in the day-ahead market, which decreases the number of units that SPP needs to commit and decreases the make whole payments associated with these units. Thus, DC Energy argues that it is unjust and unreasonable to allocate RUC make whole payment costs to virtual bids. It supports this argument by observing that other regional electric organizations, including MISO, CAISO and NYISO, do not allocate RUC make whole payments to virtual bids.[214]

149. Additionally, DC Energy contends that SPP's RUC make whole payment cost allocation methodology should distinguish between virtual transactions fixed at the close of the day-ahead market and other transactions. According to DC Energy, SPP will perform the day-ahead RUC process after posting the day-ahead market results. At that point, SPP should know the effect of all virtual offers and bids, as Market Participants cannot submit additional virtual transactions for the operating day. DC Energy asserts that any unit commitments and associated make whole payments attributable to virtual transactions can be made at this point.[215] DC Energy argues that because SPP should be aware of deviations associated with virtual transactions at the close of the day-ahead market, there is no need to allocate intra-day RUC make whole payments to virtual transactions.[216]

iii. Answer

150. SPP asserts that the Commission has recognized in other RTO and ISO proceedings that deviations or "uplift" charges are properly applied to virtual

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offers from the uplift mechanism used to fund resource make whole payments), *order on reh'g*, 117 FERC ¶ 61,113 (2006), *order on reh'g*, 118 FERC ¶ 61,212, *order on reh'g*, 121 FERC ¶ 61,131 (2007)).

[214] DC Energy Protest at 13-15.

[215] *Id*. at 6-7.

[216] *Id*. at 7-8.

transactions.[217] SPP explains that this is appropriate because, when a virtual sale or purchase is cleared in the day-ahead market and generation or load does not materialize in real time, costs are incurred by the market operator to reconcile any imbalances or deviations.[218] For example, SPP explains that the operator may, for example, incur costs associated with requesting resources in real-time to start-up, ramp-down, ramp-up, or extend run times on schedules that deviate from the schedules or levels cleared in the day-ahead market. Thus, SPP argues that there is ample support for assessing virtual transactions RUC make whole payment charges.[219]

iv. <u>Commission Determination</u>

151. We conditionally accept SPP's make whole payment provisions related to virtual transactions subject to a compliance filing, as discussed below. While we find that it is generally appropriate to assess make whole payment costs to virtual transactions, we find that it is inappropriate to assess day-ahead make whole payment charges to virtual energy offers. Moreover, we find that SPP has not provided adequate support to justify assessing virtual energy bids RUC make whole payment costs.

152. In the day-ahead context, virtual energy bids create the illusion that more supply is needed to meet demand (i.e., that more units need to be committed) to clear the day-ahead market, which contributes to higher day-ahead make whole payment costs. Thus, it is appropriate to allocate make whole payment costs to virtual energy bids in the day-ahead context. However, virtual energy offers increase the amount of supply in the day-ahead market, which lowers day-ahead make whole payment costs. Consequently, we do not find it appropriate to allocate day-ahead make whole payment costs to virtual energy offers based on the record before us. We will require SPP to modify its day-ahead make whole payment cost allocation methodology to limit virtual transaction cost allocation to virtual energy bids in a compliance filing due 90 days after the issuance of this order.

153. As both SPP and DC Energy point out, virtual energy offers may displace physical offers in the day-ahead market, which results in SPP needing to commit additional physical resources during the RUC process to meet forecasted load. Thus, we find it appropriate to allocate virtual energy offers RUC make whole payment costs.

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[217] SPP May 15 Answer at 46 (citing *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,244, at PP 2, 37 (2008); *Midwest Indep. Sys. Operator, Inc.*, 115 FERC ¶ 61,108, at PP 48-49, *order on reh'g*, 117 FERC ¶ 61,113 (2006)).

[218] SPP May 15 Answer at 46 (citing *DC Energy, LLC v. PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,165, at P 64 (2012)).

[219] *Id*. at 46.

However, as DC Energy explains in its protest, virtual energy bids may cause additional resources to be committed in the day-ahead market, which decreases the number of units that SPP needs to commit in the RUC process and thus decreases make whole payments associated with these units. Because SPP has not adequately supported this aspect of its proposal, we will require SPP either to modify its RUC make whole payment cost allocation methodology to limit cost allocation to virtual energy offers or to better justify why it proposes allocating RUC make whole payment costs to virtual energy bids in a compliance filing due 90 days after the issuance of this order.

154. We find that, at market start, it is not necessary for SPP to distinguish between the day-ahead RUC and intra-day RUC periods in its RUC make whole payment cost allocation methodology. As SPP gains more experience with its Integrated Marketplace and further refines its make whole payment provisions, we encourage SPP and its stakeholders to revisit whether a further distinction between day-ahead RUC and intra-day RUC periods is warranted, particularly for the purposes of assessing make whole payment costs to virtual energy offers (and possibly to virtual energy bids).

c. Netting Provisions

i. SPP Proposal

155. Proposed section 8.5.10(2) of Attachment AE provides that an asset owner's day-ahead make whole payment distribution quantity[220] at a settlement location for an hour is equal to an asset owner's net cleared energy withdrawals at that settlement location for that hour. An asset owner's net energy withdrawal at a settlement location is calculated as the positive net sum of cleared demand bids, resource offers, import interchange transaction bids, export interchange transaction bids, virtual energy bids, and virtual energy offers at a settlement location.

156. Proposed section 8.6.7(2) of Attachment AE provides that an asset owner's RUC make whole payment distribution volume[221] at a settlement location for an hour is equal to the sum of various calculated values, based primarily on deviations from the day-ahead market. One of these values, described in section 8.6.7(2)(a) of Attachment AE, is calculated as the absolute value of the sum of actual real-time settlement location

[220] The day-ahead make whole payment distribution quantity is a variable in the equation to assess an asset owner's hourly day-ahead make whole payment charge at each settlement location.

[221] The RUC make whole payment distribution volume is a variable in the equation to assess an asset owner's hourly RUC make whole payment charge at each settlement location.

deviations from day-ahead market cleared amounts for load, virtual transactions, and interchange transactions, except during any dispatch interval in which the transmission provider has declared an emergency condition.

ii. **Protests**

157. DC Energy argues that SPP's day-ahead make whole payment cost allocation methodology should incorporate netting provisions that take into account the net impact of all bids and offers. DC Energy argues that unit commitment processes do not commit resources on the basis of an individual Market Participant's position at a given settlement location. Instead, the unit commitment processes evaluate market capacity requirements on a much broader basis, taking into account the net impact of all bids and offers. DC Energy asserts that the lack of broader netting requirements in SPP's day-ahead make whole payment cost allocation methodology is unjust and unreasonable and requests that the Commission direct SPP to modify its proposal in accordance with cost causation principles.[222]

158. In contrast, TDU Intervenors argue that allowing Market Participants to combine diverse loads and resources at a single settlement location would have unintended consequences. TDU Intervenors contend that section 8.5.10 of proposed Attachment AE is ambiguous as to the circumstances where a Market Participant would be able to net its day-ahead loads and resources at a settlement location for purposes of determining its share of day-ahead make whole payment costs. TDU Intervenors assert that the Commission should not permit the type of widespread netting that the Commission previously rejected in a MISO proceeding involving the allocation of Revenue Sufficiency Guarantee costs. TDU Intervenors argue that the proposal rejected in the MISO proceeding is analogous to SPP's proposed make whole payments. According to TDU Intervenors, in the MISO proceeding, the Commission rejected arguments that would permit the netting of virtual offers and bids across the entire MISO footprint, thereby reducing a Market Participant's allocation of day-ahead Revenue Sufficiency Guarantee costs.[223] Accordingly, TDU Intervenors ask that the Commission require SPP to justify its proposal regarding the netting of loads and resources for purposes of determining load-ratio responsibility for allocating day-ahead make whole payment costs.[224]

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[222] DC Energy Protest at 18.

[223] TDU Intervenors Protest at 20-21 (citing *Ameren Services Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,121, at P 112 (2009)).

[224] *Id*. at 19-21.

159. DC Energy contends that SPP's RUC make whole payment cost allocation methodology should incorporate netting provisions because netting across a Market Participant's bids and offers appropriately reflects cost causation. DC Energy points to Commission precedent recognizing that netting of bids and offers, either on a locational or market-wide basis, is necessary for cost causation purposes, citing proceedings in CAISO and MISO.[225] DC Energy notes that in both CAISO and MISO, individual Market Participants may net their positive and negative deviations from their cleared day-ahead transactions, after which CAISO and MISO allocate the equivalent of the costs associated with make whole payments to Market Participants based upon the Market Participant's net position.[226] Accordingly, DC Energy recommends that SPP adopt either Market Participant-level netting and/or market-wide netting for RUC make whole payment cost allocation as the appropriate remedy for correcting the disparity between cost causation and cost allocation.[227]

iii. Answer

160. SPP argues that although it supports the netting of virtual transactions in its day-ahead make whole payment cost allocation methodology, it would be inappropriate to net virtual bids and offers on a system-wide basis. SPP contends that system-wide netting would require netting of physical load and generation on a system-wide basis. According to SPP, this approach would result in SPP lacking any basis to allocate day-ahead make whole payment costs because all transactions would effectively net to zero.[228]

161. SPP also responds to TDU Intervenors' protest, stating that TDU Intervenors' concerns are misplaced. According to SPP, Market Participants cannot net loads and resources when determining the cost allocation for make whole payments. SPP maintains that physical load and generation cannot be settled at a single location because settlement

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[225] DC Energy Protest at 9-11 (citing *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,039, at P 60 (2010); *Ameren Services Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,161, at P 116 (2008); *Ameren Services Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,121 at P 113; and MISO DIR Order, 136 FERC ¶ 61,100 at P 26).

[226] DC Energy notes that CAISO also accounts for market-wide netting prior to cost allocation, where CAISO looks at net deviations across all virtual Market Participants when assessing the share of committed volume and make whole payments driven by virtual transactions. *Id*. at 13.

[227] *Id*. at 9-13.

[228] SPP May 15 Answer at 51.

locations for load and resources are unique. Thus, because the allocation of make whole payments in the day-ahead market occurs at the settlement location level, a Market Participant cannot net load and resources at a settlement location. Despite this limitation, SPP states that netting between physical load and cleared virtual offers or bids or between generation and cleared virtual offers or bids may occur at a settlement location. SPP states that in this regard, SPP's proposal is consistent with the Commission's restrictions against widespread netting across an entire system.[229]

iv. **Commission Determination**

162. SPP and its stakeholders have proposed to allocate make whole payment costs to asset owners at the settlement location level. We find this settlement location focus to be just and reasonable at market start and will not require SPP to institute market-wide netting within its make whole payment cost allocation methodologies.[230] As SPP explains in its answers, this settlement location focus affects netting provisions in its make whole payment cost allocation methodologies. As communicated in the market registration provisions in section 2.2 of Attachment AE and in the definition of a Market Participant's meter settlement location, settlement locations for load and resources are unique. However, we will require SPP to clarify, in a compliance filing due 90 days after the issuance of this order, the statement in its June 26 Answer that load and generation can never be co-located. It remains unclear whether this statement is accurate in the case of a demand response resource whose demand response is facilitated by behind-the-meter generation. Further, we note that the benefits of virtual trading may not necessarily be limited to a single settlement location, and as SPP gains market experience, it may find that allocating make whole payment costs at the settlement location level may unduly burden virtual transactions with these costs. Accordingly, we will require SPP to address in its informational report to the Commission 15 months after market launch (reflecting 12 full months of data): (1) whether allocating make whole payment costs at the settlement location level has created any barriers to virtual trading; and (2) the ability of SPP to broaden netting of virtual transactions beyond a single settlement location for purposes of make whole payment cost allocation.

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[229] SPP June 26 Answer at 24.

[230] *Ameren Services Co. v. Midwest Indep. Transmission Sys. Oper., Inc.*, 127 FERC ¶ 61,121 at P 112.

d. Other Make Whole Payment Issues

i. SPP Proposal

163. SPP proposes to exempt resources from an allocation of RUC make whole payment costs if those same resources are exempt from URD.[231] Section 8.6.7(2)(h) includes the absolute value of a resource's URD in the calculation of an asset owner's RUC make whole payment distribution volume at a settlement location for an hour, if that resource operated outside of its operating tolerance and the resource has not been exempted from URD.

ii. Protests

164. DC Energy explains that, unlike the URD charges imposed upon resources that fail to follow SPP dispatch instructions, RUC make whole payment costs are not intended to function as a penalty for lack of performance. DC Energy considers it unnecessary to link the need to encourage Market Participants to be indifferent to a commitment decision with a Market Participant's failure to follow dispatch instructions. Accordingly, DC Energy asserts that, consistent with Commission precedent, SPP should allocate RUC make whole payment costs to resources irrespective of whether the resources are exempt from URD charges.[232]

165. E.ON requests that the Commission require SPP to amend its proposal to provide an exemption from URD when events arise that are beyond the control of a wind-powered VER. E.ON notes that the Commission required this in a MISO proceeding.[233]

166. DC Energy asserts that real-time import interchange transactions should not bear any share of RUC make whole payment costs. DC Energy argues that real-time import interchange transactions serve to augment the amount of generation that is available in the real-time market. DC Energy claims that these transactions do not drive the commitment of other resources that may require RUC make whole payments.[234]

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[231] Exemptions from URD are described in section 6.4.1.1 of proposed Attachment AE.

[232] DC Energy Protest at 8-9 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,184, at P 57 (2010) (MISO RSG Exemption Order)).

[233] E.ON Protest at 14-15 (citing MISO DIR Order, 134 FERC ¶ 61,141 at P 82, *reh'g denied*, 136 FERC ¶ 61,100).

[234] DC Energy Protest at 14.

167. E.ON requests that SPP clarify its statement that day-ahead make whole payments will be funded by cleared energy withdrawals.[235] E.ON understands this statement to mean that entities that take energy will fund these payments. Further, E.ON also requests that the Commission clarify that dispatchable VERs, in addition to being eligible to receive day-ahead and RUC make whole payments, may receive such payments under all conditions, comparable with other dispatchable resources.[236]

iii. Answer

168. SPP asserts that the proposed URD exemptions in its RUC make whole payment cost allocation methodology are reasonable. SPP argues that there are no explicit charges for URDs in its Integrated Marketplace proposal other than what is embedded in the RUC make whole payment charges. SPP states that if the Integrated Marketplace design had included such a charge and a resource had been exempt, the exemption would logically and necessarily continue with no additional charge applied.[237]

169. With regard to RUC make whole payment costs and real-time import interchange transactions, SPP states that DC Energy neglects the fact that such fixed transactions are not dispatchable. SPP argues that these transactions depress real-time prices which, in turn, depress revenues received by RUC-committed units. SPP asserts that, as a consequence, RUC make whole payment costs are potentially increased as a direct result of import interchange transactions and should therefore be allocated RUC make whole payment costs.[238]

iv. Commission Determination

170. We note that SPP's proposed exemptions for URDs in section 6.4.1.1 of Attachment AE are similar to exemptions in use for its current EIS market. However, not all of the exemptions appropriate for URD charges in the EIS market are necessarily appropriate for the allocation of RUC make whole payments in the Integrated Marketplace.[239] Thus, we will require SPP to provide appropriate justification for the

[235] E.ON Comments at 15 (citing SPP Transmittal at 26).

[236] *Id*.

[237] SPP May 15 Answer at 49.

[238] *Id*.

[239] *See* MISO RSG Exemption Order, 132 FERC ¶ 61,184 at P 57 ("The sole purpose of a penalty charge is to provide an incentive for market participants to perform in a certain manner. In contrast, the purpose of a settlement charge such as the Revenue

(continued…)

proposed URD exemptions in section 6.4.1.1 in a compliance filing due 90 days after the issuance of this order, subject to the following guidance and conditions. We note that we have previously addressed appropriate exemptions for MISO's real-time Revenue Sufficiency Guarantee charge, which recovers costs that are equivalent to SPP's RUC make whole payments. Consistent with that precedent, we find it reasonable to exempt resources deviating because they are following a specific instruction from SPP to maintain system reliability.[240] We also find it reasonable to not include a blanket exemption for VERs.[241] Also consistent with that precedent, we find that the exemption described in section 6.4.1.1(7) of Attachment AE[242] is overly broad and could be interpreted to encompass a number of deviations that cause RUC make whole payments that should not be exempted from the corresponding charges.[243] At the same time, we recognize that the proposed exemption includes deviations due to certain rare, abnormal operating conditions that should be exempted from allocation of RUC make whole payment costs, such as deviations caused solely by the failure of the SPP unit dispatch

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Sufficiency Guarantee charge is to charge market participants for the full cost of energy. Accordingly, it is appropriate to base the cost allocation of the Revenue Sufficiency Guarantee charge on whether the market participant contributed to the incurrence of these costs.").

[240] *Id*. P 110 ("Exempting resources from real-time Revenue Sufficiency Guarantee charges during such circumstances acknowledges that any deviations that occur result from instructions by the Midwest ISO rather than the behavior or discretion of the resources involved. We find that our application of cost causation principles in this instance would fail to recognize that this exemption will help to preserve system reliability by avoiding disincentives to obeying Midwest ISO instructions during emergencies and contingency reserve events.").

[241] *Id*. PP 88-89. We note that for its EIS market, SPP excluded intermittent resources from URD charges. SPP does not propose a similar blanket exemption for its Integrated Marketplace.

[242] Proposed section 6.4.1.1(7) of Attachment AE provides an opportunity for the Market Participant to demonstrate that a deviation was caused solely by events or conditions beyond its control, and without Market Participant fault or negligence of the Market Participant. The Market Participant must provide SPP with adequate documentation through the invoice dispute process in order for the Market Participant to be eligible to avoid being assessed an URD charge. Section 6.4.1.1(7) also specifies that SPP will determine through the dispute process whether such URD should be waived.

[243] MISO RSG Exemption Order, 132 FERC ¶ 61,184 at P 112.

system or other computer hardware or software systems,[244] or specific events or conditions beyond the resource's control. This provision also would afford SPP undue discretion. Therefore, we will require SPP to modify section 6.4.1.1(7) to clarify the events or circumstances that qualify for the exemption, and to provide appropriate justification for such exemptions.[245] We find that specifically delineating the types of events or circumstances that are beyond a Market Participant's control in the Tariff will address E.ON's concerns regarding wind-powered VERs. We will require SPP to make these modifications to 6.4.1.1(7) and supporting justifications in a compliance filing due 90 days after the issuance of this order.

171. With regard to real-time import interchange transactions, we agree with SPP and find it just and reasonable to allocate RUC make whole payment costs to import interchange transactions because these transactions can reduce real-time market revenues, which increase make whole payments. We note that this practice is not unprecedented. For example, MISO assesses Real-Time Revenue Sufficiency Guarantee charges to import schedules in its market.[246]

172. In response to E.ON's clarification request regarding whether day-ahead make whole payments will be funded by cleared energy withdrawals, consistent with our findings earlier in this section, we confirm that day-ahead make whole payments will be funded by cleared energy withdrawals. These include cleared demand bids, export interchange transaction bids, and virtual energy bids.

173. In response to E.ON's concerns regarding dispatchable VER eligibility to receive day-ahead and RUC make whole payments, we note that sections 8.5.9 and 8.6.5 of proposed Attachment AE do not single out dispatchable VERs or indicate that SPP intends to treat dispatchable VERs differently from other dispatchable resources. To the extent that E.ON's concerns relate to operating tolerances, ramp rate limitations, and other VER-related matters, we discuss these issues in more detail elsewhere in this order.

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[244] *Id*.

[245] MISO DIR Order, 134 FERC ¶ 61,141 at P 82.

[246] MISO Tariff, Module C sections 40.3.3.a.ii(5), 40.3.3.a.iii(5)(a), 40.3.3.vi(3), and 40.3.3.a.vii(5).

e. **Amendment to Make Whole Payment Proposal**

i. **SPP Amendment**

174. In its May 15 Amended Filing, SPP corrects a typographical error in section 8.6.7(2)(f) of Attachment AE to state that RUC make whole payment costs will be allocated to resources that self-commit after the close of the day-ahead market and then receive a dispatch instruction to their minimum (rather than maximum) operating limit.[247] SPP states that this change is consistent with language in the Market Protocols for the Integrated Marketplace.[248]

175. SPP also proposes a revision to section 8.6.5(4)(b) of Attachment AE to clarify that an asset owner's RUC make whole payment amount for each eligible resource will include any real-time regulation deployment adjustment amount for all hours in the RUC make whole payment eligibility period. SPP states that this change is consistent with language in its Market Protocols for the Integrated Marketplace.[249]

176. SPP also proposes two new URD exemptions and proposes to incorporate those URD exemptions as part of its RUC make whole payment cost allocation methodology. First, in revised section 6.4.1.1(8) of Attachment AE, SPP proposes an URD exemption if a resource has been issued a manual dispatch instruction to resolve a reliability issue. Second, in a new section 6.4.1.2, SPP proposes an URD exemption for certain load deviations.[250] SPP explains that these changes also necessitate a revision to the RUC make whole payment calculation in section 8.6.7(2) of Attachment AE to clarify (when calculating the asset owner's volume for make whole payment cost responsibility) that the emergency condition (from which deviations are not considered) is specifically related to a capacity shortage. SPP asserts these revisions are just and reasonable because they ensure compliance with Order No. 719, and because resources that are manually dispatched for reliability purposes should not be subject to URD-related charges.[251]

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[247] SPP Amendment at 10. BP Wind and AWEA both pointed out this discrepancy in their protests. BP Wind Protest at 14-15; AWEA Protest at 10.

[248] SPP Amendment at 10.

[249] *Id*.

[250] SPP notes that, consistent with the Commission's directive in Order No. 719, a load deviation during a capacity shortage emergency should be excluded from any deviation charges. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 111.

[251] SPP Amendment at 13.

ii. Commission Determination

177. We accept SPP's amendment correcting a typographical error in section 8.6.7(2)(f) of proposed Attachment AE. We find that this amendment satisfies AWEA and BP Wind's concerns and appropriately corrects the discrepancy between SPP's Tariff and Market Protocols. We also accept SPP's amendment to section 8.6.5(4)(b) of proposed Attachment AE. We find that this clarification provides more detail in the Tariff and ensures consistency between the Tariff and Market Protocols.

178. We accept the revision in the SPP Amendment to section 8.6.7(2) of proposed Attachment AE and the newly proposed section 6.4.1.2 to comply with the Commission's directive in Order No. 719. As the Commission stated in Order No. 719, RTOs and ISOs must eliminate deviation charges to buyers in the energy market for taking less energy in the real-time market than was scheduled in the day-ahead market during a real-time market period for which the RTO or ISO declares an operating reserve shortage.[252] Additionally, we also find reasonable the exemption from RUC make whole payments due to the new URD exemption in section 6.4.1.1(8) of Attachment AE that will apply when a resource has been issued a manual dispatch instruction for reliability purposes. We find that operating outside of the tolerance band due to a manual dispatch instruction for reliability purposes warrants an exemption from RUC make whole payments. We also note that this exemption applies to a system operator-instructed deviation.

f. Make Whole Payments for Local Reliability Issues

i. SPP Proposal

179. SPP proposes procedures that would allow local transmission operators to operate in emergency conditions on low voltage facilities and to communicate their actions to SPP as soon as possible, and proposes modifying the make whole payment charge to address local reliability issues. The SPP Filing did not include a mechanism for compensating resources that are committed by a local transmission operator or dispatched out-of-merit order by a local transmission operator. However, SPP addresses this issue in the SPP Amendment, which recognizes that emergency conditions may arise within the operating area of a local transmission operator that could involve elements not monitored by SPP and could involve out-of-merit commitment, de-commitment, or dispatch instructions to be issued to one or more resources. SPP states that, where time permits, local transmission operators must request that SPP issue any such changes in commitment of resources.[253] Under SPP's proposal, these resources would then receive

[252] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 111.

[253] SPP Tariff, Proposed Attachment AE, section 6.1.2(4).

make whole payments, which are allocated regionally, to compensate them for start-up costs and no-load requirements of the local resources that are not recovered by LMP.

ii. Protests

180. Protesting parties raise issues concerning make whole payments for resources that resolve local reliability issues. TDU Intervenors are unsure as to the meaning of "local reliability issue" because the term is not defined.

181. Westar takes issue with SPP's Amendment regarding local reliability issues, as emergency conditions arising within the local transmission operator's operating area could involve elements not monitored by SPP. Westar contends that local resource commitments on lower voltage systems should not be eligible for make whole payments allocated on a regional basis. Westar argues that these local resource commitments involve either sub-transmission issues or issues localized to a specific settlement area and that spreading costs for these commitments on a regional basis would create an unjust and unreasonable rate. Therefore, Westar argues that if SPP wants to make whole such local area reliability commitments, it should allocate these costs to the area that receives the benefits. Westar claims that allocating such costs on a regional basis provides no incentive for the applicable area to upgrade its local sub-transmission system. As further support, Westar states that MISO and PJM only provide make whole compensation to resources committed by the market operator or by the NERC Regional Reliability Coordinator. For these reasons, Westar asks the Commission to accept all of SPP's proposed tariff revisions except for those described above.[254]

iii. Answers

182. SPP clarifies by way of example that "local reliability issues" cannot be directly modeled in the market clearing software and occasionally require a system operator to instruct an otherwise uneconomical resource to operate at a certain level. SPP states that when the resource is asked to operate for several hours at a time or is regularly committed and/or dispatched to address a recurring voltage issue it could raise potential market power concerns. Thus, SPP argues its proposed mitigation measures are reasonable in instances where such local reliability issues present themselves.[255]

183. SPP argues that regional cost allocation for make whole payments to address local reliability issues is appropriate because emergency conditions, including those conditions on elements not monitored by SPP, affect deliverability of other resources that

[254] Westar Protest at 2-3.

[255] SPP May 15 Answer at 13.

may not be located in the same settlement area as where the emergency arises. SPP states that prompt and appropriate response to emergency conditions ensures reliability of the entire transmission system which benefits all users.[256]

iv. Commission Determination

184. The Commission conditionally accepts SPP's proposal to provide payments to resources on low voltage facilities that respond to local reliability issues. However, we agree with Westar that such payments should be allocated locally rather than regionally, consistent with cost causation.[257] SPP has not shown that a region-wide allocation is consistent with cost causation.

185. We direct SPP to change the make whole payment procedure to allocate these costs locally and explain which local entities will be allocated a share of the costs to address local reliability issues and how SPP determines the amount of costs.[258] Moreover, we note that SPP's proposal does not define the term "local reliability issues" and does not explain the process for determining when these manual commitments will be made in a non-discriminatory manner.[259] In order for resources that are committed by the local transmission owner to receive make whole payments we would expect the

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[256] SPP June 26 Answer at 21-22.

[257] We note that this finding is consistent with Commission precedent that supports the local allocation of local reliability costs. *See e.g., Midwest Indep. Transmission Sys. Operator, Inc*., 140 FERC ¶ 61,171, at P 78 (2012) (MISO RSG Order). (Commission agrees that local load is primary beneficiary of manual commitments to address local reliability). *See also PJM Interconnection, LLC*, 107 FERC ¶ 61,112. (Commission stated, "Further, consistent with our views regarding the negative implications of broadly spread uplift charges, the payment obligations resulting from the auction/[Request for Proposal] process should be allocated to the local area benefiting from the reliability improvement") and *PJM Interconnection, LLC,* 108 FERC ¶ 61,196 (2004) (Commission accepted a proposal to allocate locally the cost of synchronous condensers to address a local voltage problem on the Delmarva peninsula).

[258] We note that the Commission accepted in the MISO RSG Order, MISO's proposal to allocate the costs to the local Balancing Authority Area unless the costs were commercially significant in which case, the costs were allocated to those local Balancing Authority Areas affected by the local reliability issue as determined via a MISO study.

[259] We note that we also require SPP to define local reliability with respect to mitigation. SPP should take care to define local reliability separately for each of these applications, assuming there are any differences in the definitions needed.

manual commitment decision to be reviewed by SPP to ensure it was done in a non-discriminatory manner. Consequently, we also direct SPP to include in its Tariff all necessary defined terms, the description of the process to determine such commitments in a non-discriminatory manner,[260] and outline the study process to determine which local parties will be assessed the charge. SPP is directed to submit in a compliance filing due 90 days after the issuance of this order Tariff revisions that address all of these concerns.[261]

g. Out-of-Merit Energy

i. SPP Proposal

186. Under the Integrated Marketplace proposal, SPP or the transmission operator may issue out-of-merit energy dispatch directives to resolve emergency conditions.[262] If time permits, SPP will issue the out-of-merit energy directive, but if initial instructions are issued by the local transmission operator, the transmission operator will coordinate with SPP to ensure subsequent instructions are provided by SPP. SPP will instruct the on-line resources of the anticipated MW level at which the resource is expected to operate through the manual dispatch instructions. For the duration of the out-of-merit energy event, resources will receive setpoint instructions equal to the manual dispatch MW instructions. SPP will activate the appropriate constraint in the real-time market Security Constrained Economic Dispatch (SCED) within one hour of the manual reconfiguration, which will last until the SCED can resolve the constraint through the real-time market. SPP will notify Market Participants when the out-of-merit energy event has ended.

187. Each owner of a resource that receives an SPP manual dispatch instruction that creates a cost to the owner or that adversely affects the owner's day-ahead market position for energy or operating reserves will receive a payment. If the dispatch instruction to the resource is to increase production, and the resource's energy offer curve

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[260] The revisions should include criteria that will ensure the manual commitments are made consistently and in a non-discriminatory manner both by SPP and the transmission operators.

[261] We note that MISO's Commission-approved allocation of local reliability costs may serve as a reasonable basis for SPP's allocation of similar costs.

[262] *See* SPP Tariff, Proposed Attachment AE, sections 6.2.4 (Out-of-Merit Energy Dispatch) and 8.6.6 (Real-Time Out-of-Merit Amount).

is above the LMP, then the resource receives payment.[263] Similarly, if the dispatch instruction to the resource is to decrease production, and the resource's energy offer curve is below the LMP, then the resource will receive payment for the difference. In both cases, the resource is paid the difference in LMP and energy offer curve for the difference between the dispatch instruction and economic operating point.[264] The Tariff also provides for resources to receive compensation for manual dispatch instruction or de-commitment instructions for operating reserves equal to the difference of the amount of operating reserves subject to the out-of-merit energy instruction and the difference between the day-ahead market price and real-time market price.

ii. Commission Determination

188. We conditionally accept SPP's out-of-merit energy proposal, subject to SPP making a compliance filing due 90 days after the issuance of this order to cap the out-of-merit energy payments at the amount of the actual under-recovery. This revision is consistent with our determinations regarding SPP's out-of-merit energy dispatch compensation in the EIS market.[265]

189. A cap on out-of-merit energy payments is necessary because SPP's proposal could over-compensate generators that are subject to out-of-merit energy instructions requiring an increase in production. In the SPP OOME Order proceeding, SPP had proposed to compensate generators an amount equal to the difference in the energy offer curve and the market price,[266] which may be the same price for a portion of the energy offer curve.[267] The difference in the Locational Imbalance Price and energy offer curve at the out-of-merit energy setpoint instruction was then multiplied by the difference

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[263] The resource gets paid the difference in LMP and energy offer curve for the difference between the dispatch instruction and economic operating point.

[264] The economic operating point is the MW output where the resource's energy offer curve is equal to the real-time LMP.

[265] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,068 (2011) (SPP OOME Order).

[266] The market price in the EIS Market is the Locational Imbalance Price.

[267] For example, assuming an OOME redispatch instruction required a resource to increase production from 150 MW to 225 MW, the Locational Imbalance Price and energy offer curve may be the same from 150 MW to 200 MW (e.g., $60/MW), and the energy offer curve may increase to $70/MW for output above 200 MW and be different from the Locational Imbalance Price.

between the out-of-merit energy setpoint instruction in MW and the scheduled output.[268] The Commission determined that if the resource's energy offer curve was higher than the Locational Imbalance Price for any portion of the increase in output (or lower than the Locational Imbalance Price for any portion of the decrease in output) from a schedule, SPP could potentially compensate the resource at the offer curve for the entire deviation from the resource's schedule, which could result in an over-recovery. Thus, while the resource experienced an under-recovery of only $250, the resource would be paid $750.[269] The Commission required SPP to place a cap on the total payments equal to the amount of the under-recovery.

190. In the instant proceeding, SPP has not placed a cap on the total out-of-merit energy payments equal to the total under-recovery. We note that, for resources required to increase production to meet an out-of-merit energy setpoint instruction, SPP calculates the difference in price in the same manner it did in the SPP OOME Order proceeding. That is, SPP proposes to apply that difference between the LMP and the offer curve at the out-of-merit energy setpoint instruction to the difference in the out-of-merit energy setpoint instruction and the economic operating point, which is the output at which the energy offer curve is equal the LMP. Because the energy offer curve may be the same as the LMP over a range of MW output, we find that SPP may create the same over-recovery problems that existed in the SPP OOME Order. Thus, we find that without such a cap on the total out-of-merit energy payments equal to the total under-recovery, resources may over-recover the costs of meeting out-of-merit energy setpoint instructions. Accordingly, we will require SPP to submit, in the compliance filing due 90 days after the issuance of this order, a cap on out-of-merit energy payments equal to the actual under-recovery.

7. Market Registration and Market Hubs

a. SPP Filing

191. Proposed section 2.2 of Attachment AE governs the Market Participant application and asset process, which requires Market Participants to register all resources and load with SPP in accordance with the registration process specified in the Market Protocols. Section 2.2(3) of Attachment AE permits Market Participants to define a single

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[268] Using the same example, the resource would receive $750 for an OOME payment because the difference between the Locational Imbalance Price and energy offer curve at the OOME setpoint instruction equals $10 (i.e., $70/MW minus $60/MW) which is then multiplied by the amount of OOME redispatch of 75 MW (*i.e.*, 225 MW less 150 MW). SPP OOME Order, 137 FERC ¶ 61,068 at P 22.

[269] *Id*. P 23.

settlement location that aggregates multiple meter data submittal locations associated with their load assets.[270]

192. Section 3.1.1 of Attachment AE contains provisions regarding the establishment and modification of Market Hubs.[271] Section 3.1.1 provides that SPP shall maintain and facilitate the use of a Market Hub or Market Hubs for the day-ahead market and real-time markets and shall use the following criteria to establish Market Hubs: (1) each Market Hub shall contain a sufficient number of nodes to ensure that a Market Hub LMP can be calculated for that Market Hub at all times; (2) each Market Hub shall contain a sufficient number of nodes to ensure that the unavailability of, or an adjacent line outage to, any one node or set of nodes would have only a minor impact on the Market Hub LMP; (3) each Market Hub shall consist of nodes with a relatively high rate of service availability; and (4) each Market Hub shall consist of nodes among which transmission service is relatively unconstrained.

b. **Protests**

193. TDU Intervenors state that a bedrock premise of the Integrated Marketplace is that resources must be settled at individual physical locations and that — with limited exceptions — an asset owner's or Market Participant's physically diverse resources cannot be aggregated into a single settlement location, even though its diverse loads can be. While TDU Intervenors note that the language in section 2.2(3) allows diverse loads to be aggregated, TDU Intervenors contend that the proposed Tariff language and Market Protocols for the Integrated Marketplace should include provisions to prevent Market Participants from aggregating multiple resources into a single settlement location, either by themselves or combined with load meter data submittal locations.

194. TDU Intervenors also find that the new definition for "Market Hub" does not prevent SPP from creating a Market Hub that encompasses the combined loads and resources of large vertically-integrated utilities, which Market Participants could use as their settlement location. TDU Intervenors request that the Commission require SPP to include language in its Tariff explicitly limiting the aggregation of diverse loads and resources for settlement purposes.[272]

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[270] SPP Tariff, Proposed Attachment AE section 2.2(3).

[271] Attachment AE defines a Market Hub as a settlement location consisting of an aggregation of price nodes.

[272] TDU Intervenors Protest at 18-19.

c. Answers

195. SPP confirms its intention to restrict the aggregation of resources into a single settlement location in the same manner that it limits the aggregation of resources in SPP's EIS market. SPP states that to the extent the Commission believes that more explicit Tariff language is necessary to clarify that a single resource must be registered and settled at a single resource price node location, it will provide such language in a compliance filing.[273]

d. Commission Determination

196. We conditionally accept SPP's proposed registration requirements in section 2.2(3) of Attachment AE, contingent upon SPP making the following modification in a compliance filing due 90 days after the issuance of this order. In order to reduce any ambiguity in the Tariff, we require SPP to state explicitly in section 2.2(3) of Attachment AE that it will restrict the aggregation of resources into a single settlement location in the same manner that it limits the aggregation for resources in SPP's EIS market, as explained in its June 26 Answer.[274]

197. We also conditionally accept provisions regarding the establishment and modification of Market Hubs in section 3.1.1 of proposed Attachment AE, contingent on SPP modifying this section. This modification should be submitted in a compliance filing due 90 days after the issuance of this order, to specify that the transmission provider may not create a Market Hub that encompasses the combined loads and resources of a vertically-integrated utility. We find that this modification addresses TDU Intervenors' concerns and removes any ambiguity in the Tariff.

8. Revenue Neutrality Uplift

a. SPP Proposal

198. SPP proposes a Revenue Neutrality Uplift for the operating day to ensure that payments and receipts for each daily settlement interval equals zero. SPP states that it will retain a modified version of the Revenue Neutrality Uplift charge[275] that is currently

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[273] SPP June 26 Answer at 23.

[274] We note that further modifications to section 2.2(3) may be necessary based on the outcome of SPP's ongoing compliance with ARC aggregation requirements.

[275] The existing EIS market Revenue Neutrality Uplift assesses or distributes deficient or excessive revenues to Market Participants based on the absolute value of their total market activity. SPP Tariff, Attachment AE, section 5.6 (b).

effective for the EIS market. First, virtual transactions will be subject to Revenue Neutrality Uplift charges or credits. Second, the Revenue Neutrality Uplift rate for charges or credits will be calculated on a daily basis, rather than on an hourly basis. SPP explains that the first change simply reflects the introduction of virtual trading in the Integrated Marketplace. The second change is the result of stakeholder consensus to move to a more static, one-time, daily Revenue Neutrality Uplift calculation. SPP states that this change does not affect the overall amounts that are ultimately reflected in Revenue Neutrality Uplift charges or credits.[276]

199. In section 8.8 (Revenue Neutrality Uplift Distribution Amount) of the proposed Attachment AE, SPP indicates the Revenue Neutrality Uplift will be allocated on the basis of a distribution volume for a given Settlement Location for a given hour that is equal to:

(a) The absolute value of the minimum of:

(i) Actual metered generation in the hour; or
(ii) Scheduled Import Interchange Transactions in the hour; or
(iii) Cleared Virtual Energy Offers in the hour;

plus

(b) The absolute value of the maximum of:

(i) Actual metered load in the hour;
(ii) Scheduled Export Interchange Transactions in the hour; or
(iii) Cleared Virtual Energy Bids in the hour.[277]

b. Protests

200. DC Energy contends the proposed allocation of the Revenue Neutrality Uplift is unjust and unreasonable. It argues that under the proposed allocation process, a Market Participant with only metered generation at a given Settlement Location will be allocated a portion of the Revenue Neutrality Uplift on the basis of their metered generation. Similarly, DC Energy argues that another Market Participant with only a cleared virtual offer at a given Settlement Location will be allocated a portion of the Revenue Neutrality Uplift on the basis of their virtual offer. In contrast, any Market Participant with both

[276] SPP Transmittal at 46.

[277] SPP Tariff, Proposed Attachment AE, section 8.8(2).

metered generation and cleared virtual offers at a given Settlement Location will only be allocated a portion of the Revenue Neutrality Uplift on the basis of the lesser of its metered generation or its cleared virtual offer. As such, DC Energy asks the Commission to direct SPP to revise their Revenue Neutrality Uplift allocation process to operate in a more equitable manner.[278]

c. Answers

201. SPP submits that there is no inequity in its Revenue Neutrality Uplift allocation proposal because allocating Revenue Neutrality Uplift on the "lesser of" basis accounts for the fact that the Market Participant with the virtual offer actually showed up in the real-time balancing market with physical generation. SPP states that this approach avoids unfairly charging the Market Participant for both physical generation and virtual offers in the same transaction.[279]

d. Commission Determination

202. We conditionally accept SPP's proposal subject to a compliance filing due 90 days after the issuance of this order, as described below. The Revenue Neutrality Uplift provisions are designed to allocate excess revenues to Market Participants or surcharge deficient revenues from Market Participants in order for SPP to remain revenue neutral on a daily basis. The proposed Revenue Neutrality Uplift provisions provide that SPP will distribute or surcharge Market Participants a portion of the excess or deficient revenues based upon the Revenue Neutrality Uplift distribution volume as detailed above. The higher the distribution volume for a Market Participant, the greater the amount of distributed or surcharged revenues it will be allocated. Thus, the amount of the distribution volumes will determine the amount of SPP's excess revenues it receives or the amount of SPP's deficient revenues it must pay.

203. While SPP states that it is making only two changes to the Revenue Neutrality Uplift proposal from its current Revenue Neutrality Uplift mechanism, we note a third change. The existing EIS market Revenue Neutrality Uplift mechanism assesses or distributes deficient or excessive revenues to Market Participants based on the absolute value of their total market activity.[280] Under the instant proposal, SPP's Revenue Neutrality Uplift distribution volumes are based upon the "lesser of" three kinds of

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[278] DC Energy Protest at 17-18.

[279] SPP May 15 Answer at 50-51.

[280] In other words, the distribution volumes of the EIS market Revenue Neutrality Uplift are additive.

resource market activity plus the "greater of" three kinds of load-related market activity. Because SPP's proposal uses distribution volumes that reflect the "lesser of" or "greater of," SPP's proposal will not reflect all market activity that could lead to excessive or deficient revenues. For example, under the existing Revenue Neutrality Uplift mechanism the distribution volume of a Market Participant with a 50 MW export interchange, 75 MW of generation, and 25 MW of load at a settlement location, is based on the absolute value of its market activity, which in the example equals 150 MW. Under the proposed regime, the above Market Participant's distribution volume would be 100 MW. Thus, 50 MW of market activity is not reflected in the distribution volume. Further, SPP has not explained why it is favoring load over generation in basing the distribution volume on the "lesser of" resource market activity and "greater of" load market activity.

204. Moreover, SPP contends that it is reasonable to use distribution volumes with a "lesser of" basis because it accounts for the fact that the Market Participant with the virtual offer actually showed up in real-time with physical generation implying that the two are part of the same transaction. However, the definition of a cleared Virtual Energy Offer is "[a] proposal by a Market Participant to sell Energy at a specified price, Settlement Location and period of time in the day-ahead market that is not associated with a physical Resource."[281] Because a Virtual Energy Offer is defined as not being associated with a physical resource, the Commission disagrees with SPP's rationale that the Virtual Energy Offer and the actual metered generation represent the same transaction. A Market Participant could have both a cleared resource offer that leads to actual generation at the settlement location and a cleared virtual energy offer at that settlement location. Therefore, we agree with DC Energy that it is not equitable for SPP to use distribution volumes that treat these two separate transactions as though they were one transaction. Accordingly, we direct SPP to modify the Revenue Neutrality Uplift proposal to reflect the total market activity of a Market Participant that led to the excessive or deficient revenues in the compliance filing due 90 days after the issuance of this order.

9. Marginal Losses

a. SPP Proposal

205. In the Integrated Marketplace, SPP proposes to calculate losses using a marginal loss method rather than an average loss method. SPP explains that it selected the marginal loss method because it sends a more accurate price signal to Market Participants than an average losses mechanism, it lowers the overall production cost of electricity, and

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[281] SPP Tariff, Proposed Attachment AE, section 1.1.

it has been used in other organized markets.[282] SPP also explains that, because the marginal loss methodology will result in an over-collection of revenues, SPP proposes to provide refunds based on loss pools[283] using a proxy estimate of each Market Participant's contribution to the marginal loss surplus.[284] SPP argues that its proposed loss pool methodology is similar to MISO's marginal loss surplus distribution method, except that the loss pools proposed by SPP are more granular than those used by MISO, and will be based upon hourly transactional activity.[285]

b. <u>Protests</u>

206. NPPD argues that SPP's marginal loss refund mechanism proposal is excessively complicated. Additionally, NPPD contends that SPP's proposed methodology may not achieve SPP's stated objective of refunding the over-collection of transmission losses to market participants in proportion to their contribution to the marginal loss surplus. In support of its argument, NPPD references an SPP market monitor's comment that the refund calculation "may be unnecessarily complex."[286] NPPD adds that, absent experience with the calculation of actual incremental losses and related refunds, there is

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[282] SPP Transmittal at 24. SPP cites to the CAISO as an example of an RTO that applies the marginal loss methodology. *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 90-95 (2006).

[283] A Market Participant's loss pool is defined as the set of settlement locations at which the Market Participant has transactional activity.

[284] SPP Transmittal at 25. SPP explains that:

> [T]he net over-collection of the Marginal Loss Component of the LMP is distributed to Market Participants based on a proxy estimate of each Market Participant's contribution to the marginal loss surplus. The proxy contribution is determined for each settlement location included in the Market Participant's loss pool, but only at settlement locations where the total of all Resources, load, virtual transactions and Interchange Transactions at the settlement location results in a net withdrawal. The proxy is calculated based upon differences between the marginal loss component at each market participant loss pool withdrawal settlement location and its corresponding set of injection settlement locations.

[285] SPP Transmittal at 26 (citing Exh. No. SPP-3 at 21-22).

[286] NPPD Protest at 28 (quoting *Southwest Power Pool Integrated Marketplace Proposal,* prepared by Boston Pacific Company, Inc., December 30, 2010).

no way of knowing whether the refund mechanism will produce a more equitable distribution of the refund to each individual asset owner. [287]

207. NPPD also contends that SPP is wrong in claiming that its proposal is similar to the methodology used by MISO. NPPD argues that MISO proposed a transitional refund mechanism for a five year period to refund load-serving entities the difference between the marginal loss charge and the average losses on a Balancing Authority Area basis.[288] NPPD requests that the Commission establish a transitional refund mechanism, similar to the MISO mechanism, to mitigate the impact of the use of increased incremental loss factors as SPP and its stakeholders monitor the implementation of SPP's marginal loss methodology.[289]

c. <u>Answers</u>

208. SPP argues that NPPD incorrectly relies upon MISO's use of a transitional refund mechanism to support its argument that SPP should implement a similar transitional refund mechanism. SPP argues that the Commission expressly adopted certain transition procedures for MISO, based upon MISO's "unique features, such as the fact that [MISO] does not have prior experience operating as a single power pool and has only a short period of experience operating under a single reliability framework."[290] Further, the Commission noted that MISO and its customers lacked experience with LMP pricing.[291]

209. SPP notes that the Commission also cautioned that "such a refund measure could dampen the incentive to make efficient purchases in the spot market," and, therefore, the Commission directed MISO to adopt additional rules to encourage efficient activity in the spot market.[292] In contrast, SPP argues that its customers already have experience with locational pricing and a centralized real-time energy market, experience that did not exist in MISO when the Commission approved certain short-term transitional features such as the losses refund methodology. SPP asserts that because the "unique features" that

[287] NPPD Protest at 28.

[288] *Id*. (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 73).

[289] *Id*. at 29.

[290] SPP May 15 Answer (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 3).

[291] MISO TEMT II Order, 108 FERC ¶ 61,163 at P 72.

[292] *Id*. P 76.

existed in MISO do not exist in SPP, the transitional refund mechanism sought by NPPD is unnecessary and should be rejected.

d. <u>Commission Determination</u>

210. The Commission conditionally accepts SPP's proposed use of marginal losses subject to the compliance filing discussed below. The Commission agrees the use of the marginal loss method in calculating losses is a just and reasonable approach.[293] However, as described below, we find that SPP's proposal for refunding the marginal loss surpluses has not been shown to be just and reasonable and will require SPP either to provide supplemental information in support of its refund proposal, or submit an alternative proposal for refunding marginal loss surpluses.

211. SPP proposes to refund losses based on the positive difference between the weighted average marginal loss component at a Market Participant's injection and withdrawal settlement locations. SPP claims that, because its loss pool methodology adjustments for net sales and purchases from the market at the weighted average marginal loss component of all excess injections of all net sellers Market Participants will not receive refunds in direct proportion to the amount of marginal losses they pay. However, the Commission finds that load serving entities' withdrawals and injections may match closely (i.e., generation will approximately equal load), in which case such Market Participants will be receiving refunds in direct proportion to the amount of losses they pay. The marginal loss methodology over-collects losses and this over-collection of losses must be refunded in some manner. However, SPP's more granular loss pool methodology appears to be an impermissible direct refund[294] because it refunds surplus losses to individual Market Participants in proportion to their contribution to the

[293] *Midwest Indep. Sys. Operator* 102 FERC ¶ 61,196, at P 53 (2003); *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at PP 90-95; *Atlantic City Electric Co. v. PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,169 (2006).

[294] *Northeast Util. Serv. Co.*, 109 FERC ¶ 61,204, at P 21 (2004).

surplus.[295] The Commission has previously found a direct reimbursement to be inappropriate because it diminishes the price signal provided by marginal loss pricing.[296]

212. Moreover, while SPP asserts that its proposal will create an equitable refund distribution, it does not explain why its proposal is equitable, nor does it explain why its proposal is not a direct refund. Consequently, in a compliance filing due 90 days after the issuance of this order, the Commission directs SPP either to better explain and justify how its proposal will not result in a direct reimbursement to customers or, alternatively, SPP should submit a different proposal for refunding the marginal loss surpluses such as one similar to the MISO proposal which does not suffer from the same direct refund concern.

213. In addition, the Commission finds that SPP has demonstrated that a transitional refund period is not necessary for its proposal to be just and reasonable. While NPPD describes the unique circumstances that warranted a transition period in the MISO proceeding, SPP has demonstrated that the circumstances present in MISO are not present in SPP. For the Commission to find that a transition for SPP is warranted, based upon the MISO precedent, NPPD would have to explain why it would be adversely affected by the lack of a transitional refund period.[297] NPPD has not made that showing here.

[295] In contrast, MISO first calculates each Balancing Authority Area's share of the surplus and then allocates the Balancing Authority Area's share of the surplus to load within the Balancing Authority Area on a load ratio share basis. The Commission accepted MISO's methodology on a permanent basis in *Midwest Indep. Sys. Operator,* 131 FERC ¶ 61,185 (2010).

[296] *Northeast Util. Serv. Co.*, 109 FERC ¶ 61,204 at P 21 (finding that a direct reimbursement to customers of the amount of over-collection is inappropriate as it diminishes the price signal provided by marginal loss pricing).

[297] For example, the Commission noted in the MISO TEMT II Order that one market participant's request was based on the "15-20 percent of [its] annual energy requirements that is imported, the large proportion of joint ownership of baseload units that fall outside the control areas where load is located, and the heavy loading on transmission lines into and within [the Wisconsin-Upper Michigan System]."

10. Price Formation During Shortage Conditions

a. SPP Proposal

214. SPP states that a shortage of capacity or regulation capability for a reserve zone or region-wide will trigger scarcity pricing for the shortage. SPP explains that it will use demand curves to adjust market clearing prices and LMPs to reflect more accurately the value of energy during the shortage period. SPP states that it will increase operating reserve market clearing prices and energy LMPs to $1,100/MW[298] when operating reserve capacity is insufficient to meet the operating reserve requirements and when capacity is inadequate to meet energy requirements.[299]

215. During a shortage of regulation capacity (i.e., regulation-up or regulation-down), the market clearing price for capacity experiencing a shortage increases to $600/MW.[300] For example, during a shortage of regulation-up capability caused solely from the lack of available resources that have regulating capability necessary to meet the regulation-up requirements, the regulation-up market clearing price will increase to $600/MW. In this example, regulation-up capability shortages will have no additional impact to LMPs or market clearing prices for the other operating reserve products (i.e., LMPs during regulation-up capability shortages will not reflect the $600/MW regulation demand curve price).[301] Similarly, when there is insufficient regulation down capability caused solely by lack of available resources with the regulating capability to meet the regulation-down requirements, the regulation demand curve of $600/MW applies to the market clearing price for regulation-down with no additional impact on LMPs or market clearing prices for the other operating reserve products. However, during an excess generation emergency caused by the need to remove qualified resources from regulating in order to meet minimum energy requirements, SPP asserts that there will be an additional impact on LMPs. More specifically, SPP will reduce the LMP by the regulation demand curve

[298] SPP states that the operating reserve demand curve is the sum of the safety-net Energy Offer Cap (proposed as $1,000/MWh) and the contingency reserve Offer Cap (proposed at $100/MW) totaling $1,100/MWh as currently proposed.

[299] Exh. No. SPP-3 at 11.

[300] The regulation demand curve is the sum of the regulation Offer Cap (proposed at $500/MW) and the contingency reserve Offer Cap (proposed at $100/MW), totaling $600/MW as currently proposed.

[301] The operating reserve demand curve is not applied to LMPs for regulation-up capability shortages caused by the need to remove qualified resources from regulating in order to meet Energy requirements.

to provide the proper market incentive for both resources and load to respond to the excess generation emergency.[302]

216. SPP states that CAISO and NYISO use demand curves as part of their market designs to address shortage situations. Moreover, SPP asserts that its scarcity pricing proposal is consistent with Order No. 719,[303] which requires a pricing mechanism to encourage entry of demand response, generation resources, and other innovative solutions to resolve capacity shortages. According to SPP, in Order No. 719 the Commission found that demand curves constitute a reasonable pricing tool during times of shortages and identified six criteria to consider in a scarcity pricing mechanism.[304] SPP asserts that its proposal considers all of these criteria.[305] Moreover, SPP states that its co-optimization process is similar to the process used by other RTOs.[306]

b. <u>Commission Determination</u>

217. The Commission conditionally accepts SPP's proposed use of demand curves to reflect the value of energy during shortage conditions, subject to the compliance filing discussed below. Generally, the Commission finds that a demand curve for operating reserves is a reasonable way to institute shortage pricing. However, we find that in its transmittal letter[307] and in testimony by Mr. Dillon,[308] SPP fails to fully address each of

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[302] Exh. No. SPP-3 at 12.

[303] Order No. 719, 125 FERC ¶ 61,071 at P 165.

[304] SPP states that the six criteria of a pricing mechanism during shortages identified in Order No. 719 are: (1) improve reliability by reducing demand and increasing generation; (2) make it more worthwhile for customers to invest in demand response technologies; (3) encourage existing generation and demand response resources to continue to be relied upon; (4) facilitate entry of new generation and demand response resources; (5) ensure continued applicability of comparable treatment of and compensation to all resources; and (6) ensure that market power is mitigated and gaming behavior is deterred. SPP asserts that the demand curves, which are based on historical market data, are consistent with these criteria.

[305] Exh. No. SPP-3 at 14.

[306] Exh. No. SPP-3 at 18.

[307] SPP Transmittal at 44-45.

[308] *See* Dillon Testimony at 13-14.

the six criteria outlined in Order No. 719. Further, what explanation is provided relies entirely on existing rules and market conditions and does not demonstrate how SPP's proposed new demand curves for operating reserves, which will go into effect in the event of a shortage, are just and reasonable vis-à-vis the six criteria. Likewise, while SPP claims that its shortage pricing proposal is similar to that used in other RTOs, SPP fails to demonstrate how its proposal satisfies the six criteria. Thus, in a compliance filing due 90 days after the issuance of this order, SPP must address the six criteria from Order No. 719, individually, as they apply to what SPP proposes, not just to its existing rules. It also must address the inconsistencies between Mr. Dillon's testimony describing how the proposed pricing scheme works and what is described in the proposed Tariff as further described below.

218. The Commission also finds that SPP has not fully addressed how LMPs will be formed in the event of a shortage of necessary capacity to meet energy needs. While Mr. Dillon describes the effects of a shortage event on LMP, the Tariff sheets proposed by SPP fail to reflect this description. At proposed section 6.2.2.1(b) it states "[i]f there is a shortage of available capacity to meet energy requirements . . . LMPs [for energy] will be set . . . as specified in section 8.3.4.2 of this Attachment AE." But section 8.3.4.2 makes reference only to how a shortage condition will affect Market-Clearing Prices for operating reserves, regulation-up, and regulation-down. Therefore, SPP must describe the effects of a shortage event on LMP for energy.

219. Finally, Mr. Dillon describes shortage conditions as resulting in the energy LMPs and operating reserve, regulation-up, and regulation-down Market Clearing Prices increasing by the values specified in the Tariff.[309] Again, SPP has not included these descriptions in the proposed Tariff sheets. The proposed Tariff revisions imply that market clearing prices will be increased to the specified levels.[310] These two methods of calculating scarcity pricing will result in different prices but will also result in different incentives for Market Participants. Specifically, to add to the existing LMP or market clearing price a fixed amount, the scarcity price, can create incentives for resources not to follow dispatch instructions.[311] In a compliance filing due 90 days after issuance of this

[309] *Id*.

[310] *See, e.g.*, SPP Tariff, Proposed Attachment AE, section 8.3.4.2.

[311] *See* PJM June 18, 2010 proposed Order No. 719 compliance filing (Docket No. ER09-1063) at Attachment C, Affidavit of Paul M. Sotkiewicz, Ph.D. Dr. Sotkiewicz, Chief Economist at PJM, provided testimony on behalf of PJM for its proposed shortage pricing rules, including an example of how mis-specifying how prices are determined during a shortage condition can lead to inappropriate incentives for Market Participants.

order, this issue must be clarified and new Tariff sheets submitted describing how both LMPs and market clearing prices will be determined during shortage conditions.

11. Operating Reserves

a. SPP Proposal

220. SPP proposes to include the competitive procurement of operating reserves on a region-wide basis. Under SPP's proposal, Market Participants will offer to sell operating reserves in the day-ahead market and real-time balancing market to satisfy SPP's requirements. SPP states that the four operating reserve products for sale in its market are: regulation-up,[312] regulation-down,[313] spinning reserve,[314] and supplemental reserve.[315] SPP states that its proposal will co-optimize energy dispatch and operating

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[312] Regulation Up is defined as "[a]n Operating Reserve product procured by the Transmission Provider from resources that increase their Energy output in response to a Regulation Deployment Instruction from the Transmission Provider." SPP Tariff, Proposed Attachment AE section 1.1, Definitions R. Resources providing Regulation-Up must be capable of being deployed through Automatic Generation Control (AGC) equipment to automatically and continuously adjust resource output to balance supply and demand in near Real-Time and must be able to deploy the full amount of Regulation Up cleared within the Regulation Response Time, currently set at five minutes.

[313] Regulation Down is defined as "[a]n Operating Reserve product procured by the Transmission Provider from resources that reduce their Energy output in response to a Regulation Deployment instruction from the Transmission Provider." *Id.* Like Regulation Up, resources qualified to provide Regulation Down must be capable of being deployed automatically and continuously through AGC and must be able to deploy the full amount of Regulation Down cleared within the Regulation Response Time, currently set at five minutes.

[314] Spinning Reserve is defined as "[t]he portion of Contingency Reserve consisting of Resources synchronized to the system and fully available to serve load within the Contingency Reserve Deployment Period following a contingency event." *Id.* section 1.1, Definitions S. Spinning Reserve is provided by synchronized resources that can supply it within the Contingency Reserve Deployment Period (currently set at 10 minutes).

[315] Supplemental Reserve is defined as "[t]he portion of Operating Reserve consisting of on-line Resources or off-line Resources capable of being synchronized to the system that is fully available to serve load within the Contingency Reserve Deployment Period following a contingency event." *Id.* Like Spinning Reserve,

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reserve procurement, resulting in the lowest-cost mix of resources to clear in the day-ahead market and dispatch in the real-time balancing market.[316] The co-optimization process includes a product substitution logic that will allow use of available higher quality operating reserve products for lower quality operating reserve products if the substitution is more economic (i.e., regulation-up market clearing price greater than or equal to the spinning reserve market clearing price; spinning reserve market clearing price greater than or equal to supplemental reserve market clearing price). SPP states that the Integrated Marketplace will ensure procurement of sufficient operating reserves to satisfy region-wide reserve requirements at the lowest possible cost, while also ensuring that operating reserves will be deliverable to load given transmission system limitations.[317] It argues that competitive operating reserve procurement will also increase Market Participant access to operating reserves, improve regional supply and demand balancing, and facilitate VER integration.[318]

b. Commission Determination

221. The Commission conditionally accepts SPP's proposal concerning the procurement of spinning reserve, supplemental reserve, regulation-up, and regulation-down. We find that SPP's proposal for the procurement, settlement, and cost-recovery of spinning reserve and supplement reserve is just and reasonable as modified below. The method proposed by SPP to co-optimize on a five minute basis the procurement of these services is a just and reasonable way to procure the various energy and ancillary services products necessary for the reliable operation of the SPP market and is one the Commission has accepted in other markets.[319]

Supplemental Reserve must be able to provide it within the Contingency Reserve Deployment Period (currently set at 10 minutes).

[316] This new, area-wide procurement, deployment, and settlement of regulation reserves, spinning reserves, and supplemental reserves in the Operating Reserve market is further enhanced by the consolidation of Balancing Authority Areas, discussed more fully below.

[317] SPP states that it will need to file new proposed Tariff sheets to revise how it procures and compensates regulation-up and regulation-down (i.e., the service described in SPP's proposed Schedule 3). SPP Transmittal at 65.

[318] SPP Transmittal at 14.

[319] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008).

222. However, as SPP notes,[320] it will need to file new proposed tariff sheets to revise how it procures and compensates regulation-up and regulation-down (i.e., the service described in SPP's proposed Schedule 3). At the time of market start-up, SPP will be required to be in compliance with Order No. 755.[321] In order to ensure timely compliance with Order No. 755, we direct SPP to file with the Commission in a compliance filing due no later than June 30, 2013 a proposal for the procurement and compensation of resources providing regulation-up and regulation-down. This will allow sufficient time for the Commission to review the proposal, issue an order, and for SPP to integrate these changes into its new market design.

223. Additionally, certain qualifications for being a Regulation Qualified Resource, Regulation-Up Qualified Resource, and Regulation-Down Qualified Resource are found at proposed section 4.1(a) Offer Submittal, but not found at section 2.10.3 Regulation Qualified Resources, where standards for testing are found. Since the deployment, duration, and telemetry requirements[322] described in section 4.1(a) are central to achieving qualification as a Regulation Resource, SPP should include these standards in section 2.10.3 as well. Accordingly, we direct SPP to revise section 2.10.3 in a compliance filing due 90 days after the issuance of this order.

224. Finally, we note that the definitions of Regulation Up, Regulation Down, Spinning Reserve, and Supplemental Reserve may be more restrictive than intended, thereby eliminating certain resources from providing these services by definition rather than through qualification, and in contradiction of other sections of the proposed Tariff. For example, these definitions appear to limit the ability of demand response resources to provide the services even in instances where other proposed Tariff language would allow for the qualification of demand response resources to provide the services. Therefore, we will require SPP to propose new definitions that are appropriately inclusive in a compliance filing due 90 days after the issuance of this order.

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[320] SPP Transmittal at 65.

[321] Order No. 755, FERC Stats. & Regs. ¶ 31,324, *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123.

[322] A resource must be capable of deploying 100 percent of cleared Regulation Up and/or Regulation Down within the Regulation Response Time for a duration of 60 minutes and provide telemetered output data that meet the technical requirements specified in the Market Protocols.

12. Reserve Zones

a. SPP Proposal

225. SPP states that it will define potential reserve zones within the SPP Balancing Authority Area to ensure the deliverability of cleared operating reserves.[323] SPP explains that it also will conduct reserve zone studies on a semi-annual basis to identify areas where transmission constraints may either limit the deliverability into or out of the reserve zone. SPP notes that, as transmission system conditions change, it may add or reconfigure reserve zones as needed during its semi-annual study process. According to SPP, the reserve zone provisions are necessary as SPP consolidates 16 separate Balancing Authority Areas into one. Additionally, given transmission system and generator limitations, SPP contends that setting daily limits on operating reserve procurement in certain areas is necessary to ensure deliverability and reliable transmission system operation.[324] Finally, SPP notes that the Commission has accepted reserve zones in ISO-NE and MISO.[325]

b. Commission Determination

226. The Commission conditionally accepts subject to a compliance filing SPP's proposal to use reserve zones in the event the system operator needs to establish minimum or maximum levels of operating reserves must be procured from one sub-region of SPP. We agree with SPP that constraints can arise that lead to conditions where operating reserves cannot be delivered into or out of a particular area. In such cases, it is imperative that the zone have the necessary reserves available to maintain reliability.

227. However, while SPP notes that its proposal is similar to that approved for MISO, SPP fails to note the degree to which the Commission required MISO to include in its Tariff a detailed discussion of how the reserve zones would be determined and how often they would be studied.[326] SPP states only that it may add or reconfigure reserve zones as

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[323] SPP states that initially there will be six potential reserve zones.

[324] SPP Transmittal at 40.

[325] Dillon Testimony at 9-10.

[326] *Midwest Indep. Transmission Sys. Operator, Inc*, 119 FERC ¶ 61,311, at PP 90-91 (2007) (MISO Guidance Order). MISO includes in its Tariff detailed descriptions of how both Configuration and Requirements Studies will be carried out among other things (*see* MISO, FERC Electric Tariff, Module C, section 39.2.1A). Further, in the MISO Guidance Order, when directing MISO to include such detail in its Tariff, the Commission cited PJM's similarly detailed descriptions of its process to set

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needed during a semi-annual study process.[327] Therefore, we require SPP to submit in a compliance filing due 90 days after the issuance of this order new Tariff sheets specifying the types of studies that will be used to determine the reserve zone borders, the types of studies that will be used to determine reserve zone minimum and maximum requirements, and how these studies will be carried out, i.e., the studies discussed in proposed section 3.1.3(2) of Attachment AE. Included with this must be a proposal for ensuring Market Participants are appropriately notified of any changes in the Reserve Zones.

D. Market-Based Congestion Management

228. As part of its proposal, SPP states that it intends to implement ARRs and TCRs to assist Market Participants in managing the cost of congestion. Protesters raise several issues with SPP's congestion management proposals, which we address below.

1. Overall Congestion Management Proposal

a. SPP Proposal

229. SPP states that, in the Integrated Marketplace, all energy transactions are subject to congestion charges that are calculated using a Marginal Congestion Component of LMP (which is equal to zero if there is no congestion).[328] Two new mechanisms, ARRs[329] and TCRs,[330] are intended to provide Market Participants with financial tools to

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the regulation and synchronous reserve requirements for its reserve zones, and how the PJM manuals specify the standards and requirements for system operators in decision-making.

[327] *See* SPP Transmittal at 40; SPP Tariff, Proposed Attachment AE, section 3.1.3.

[328] SPP Transmittal at 18.

[329] An ARR can result in a credit or charge to the holder, based upon the TCR auction clearing price on the particular ARR path. SPP states that Eligible Entities may either self-convert awarded ARRs into TCRs or hold the ARR to receive a share of the revenue SPP collects from auction purchasers of TCRs.

[330] TCRs are financial instruments entitling the holder to a stream of revenues or charges based upon the difference between the hourly day-ahead market Marginal Congestion Component of LMP at the source settlement location and the hourly day-ahead market Marginal Congestion Component of LMP at the sink settlement location associated with the TCR. TCRs are obtained in the TCR auction, either through purchase or self-conversion of ARRs, or through secondary sales of TCRs.

protect themselves from these congestion costs and to allow them to sell their rights to others. In this way, Market Participants will be able to translate firm transmission service reservations into a product, i.e., a credit against daily congestion costs, either through a TCR or through payments received for the ARR.[331] Annually, SPP will verify the amount of firm transmission service for each customer, allocate ARRs to the firm transmission customers,[332] and hold TCR auctions to allow ARR holders to convert their ARRs into TCRs and to allow Market Participants an opportunity to buy and sell TCRs.[333] SPP also asserts that it will conduct monthly TCR auctions to allow Market Participants to convert ARRs to TCRs and to buy and sell TCRs. Additionally, SPP will conduct incremental ARR allocations to auction unused capacity after the annual auction if requested by an Eligible Entity,[334] conduct settlements for ARR allocation and TCR auction settlements, and operate TCR secondary markets.[335]

230. SPP explains that when congestion occurs, SPP collects congestion revenues that must be allocated in the settlement process. During this settlement process, SPP will complete daily TCR settlements using the Marginal Congestion Component of day-ahead market LMPs. If the congestion revenues SPP collects during an operating day are insufficient to fund the net congestion payments made to TCR holders, SPP states that it will assess a day-ahead market daily charge to all Market Participants holding TCRs for the operating day in the amount of the revenue shortage.[336]

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[331] SPP Transmittal at 16.

[332] SPP states that it allocates the nominated ARRs that are simultaneously feasible given SPP's transmission system.

[333] SPP proposes to release 100 percent of the capacity in June, ninety percent of the capacity for July through September, and sixty percent of the capacity for the rest of the year during the annual auction.

[334] Attachment AE defines an Eligible Entity as "[a] Transmission Customer or Market Participant having firm SPP Transmission Service or firm non-SPP transmission service (referred to as a "grandfathered agreement" or "GFA") into, out of, or within or through the SPP region."

[335] SPP Transmittal at 14.

[336] *Id*. at 19. To the extent that SPP collects revenues in excess of amounts needed to fund TCR payments fully, the excess revenue is carried forward for future use in monthly and annual TCR payback mechanisms to compensate Market Participants that are charged under the day-ahead market TCR uplift.

231. SPP's TCR proposal includes only TCR obligations and does not establish TCR options.[337] It contends that this approach is consistent with the approach taken at the commencement of other financial transmission rights markets.[338] SPP states that this approach reflects the consensus of SPP stakeholders, who concluded that the cost of including TCR options in the market design and the potential reduced availability of allocable TCRs outweighed any potential benefit of this design feature.[339]

b. Protests

232. DC Energy agrees with SPP that TCRs are the appropriate financial tool for managing congestion costs. DC Energy also contends that SPP's proposed reductions in the release of transmission capacity in the annual TCR auction should minimize potential underfunding issues.

233. TDU Intervenors, NPPD, and APPA express concern that SPP's proposal provides no assurance of a sufficient hedge to cover the firm transmission rights for load-serving entities.[340] NPPD asserts that it is located in a highly-congested interface between SPP and MISO. For this reason, it argues that the market clearing prices for resources that address this congestion can be negative, and it has no assurance that the congestion hedge can sufficiently cover its firm transmission rights. Absent the adoption of effective mitigation measures, NPPD contends that its participation in the Integrated Marketplace could be harmful to its publicly-owned interests and contrary to Nebraska state law.[341]

234. NPPD requests a five-year transition period to hold it financially harmless from extreme congestion arising from the start-up of a new market structure, and it notes that the Commission approved a transition period for the commencement of MISO's market. NPPD expects that the planned construction of the Nebraska-Sibley Priority Project will

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[337] A TCR obligation provides credits or imposes charges on the holder of a TCR obligation depending on whether the marginal congestion cost component of LMP is higher or lower at the sink than it is at the source. However, a TCR option provides credits, but does not impose any charges, when the marginal congestion cost component of LMP is higher at the sink than at the source.

[338] SPP Transmittal at 18 (citing MISO TEMT II Order, 108 FERC ¶ 61,163 at P 193).

[339] *Id.*

[340] TDU Intervenors Protest at 15; APPA Protest at 4; NPPD Protest at 5, 21.

[341] NPPD Protest at 5, 21.

address its concern about congestion flows, but it does not expect the project to be in service until at least 2017, three years after launch of the Integrated Marketplace.[342]

235. NPPD asserts that the Commission has previously required mitigation to hold parties financially harmless from extreme congestion arising from the launch of a new market structure. NPPD points to an analogous situation in MISO, in which the Commission found it appropriate to expand a congestion cost hedge mechanism to entities located in constrained load pockets for a five-year transition period.[343] While NPPD is not located in a load pocket, NPPD asserts similar transitional relief is appropriate. NPPD also points to Commission support for transitional mechanisms to address congestion cost exposure in ISO-NE[344] and PJM[345] proceedings. NPPD requests that the Commission direct SPP to develop such transitional tariff provisions.[346]

c. <u>Answers</u>

236. SPP argues that the Commission should not hold NPPD harmless from congestion charges, as doing so would undermine the price signals that LMP is designed to achieve. Further, SPP states that NPPD's reliance on Commission precedent is misplaced. SPP notes that in MISO, the Commission accepted a limited congestion cost protection mechanism for persistently congested areas with respect to transactions from external sources. But as SPP notes, NPPD concedes that it is not a MISO-type load pocket and that the congestion NPPD refers to does not affect transactions with sources external to SPP. Similarly, according to SPP, the Commission in PJM was concerned with establishing a new transitional hedging mechanism for a new transmission zone integrating into PJM. However, SPP explains that NPPD is not transitioning into an existing ARR/TCR market, but is similarly situated to all other SPP Market Participants. Additionally, SPP explains that in ISO-NE, the Commission did not mandate a new mechanism for mitigating the impact of congestion on LMP for certain customers; instead it declined to delay the implementation of the new market in ISO-NE pending resolution of identified transmission constraints. SPP states that the Commission also

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[342] *Id*. at 6.

[343] *Id*. at 22 (citing MISO TEMT II Order, 108 FERC ¶ 61,163).

[344] *Id*. at 23 (citing *New England Power Pool and ISO New England, Inc.*, 101 FERC ¶ 61,344, at P 36 (2002)).

[345] *Id*. at 23-24 (citing *PJM Interconnection, LLC*, 107 FERC ¶ 61,223, at P 45 (2004)).

[346] NPPD Protest at 6, 21-24.

suggested that ISO-NE consider adopting measures to moderate the financial impact of LMP "without blunting price signals," such as building a defined set of transmission upgrades . . . identified at the start of the implementation of LMP, and [assigning] a portion of the upgrade costs to other New England customers."[347] SPP states that the costs of the Nebraska City-Sibley Priority Project will be shared among other SPP customers through the SPP highway/byway cost allocation methodology and, consistent with this precedent, SPP argues the Commission should find that SPP has addressed NPPD's concerns.

d. **Commission Determination**

237. We conditionally accept SPP's market-based congestion management proposal, as modified below. SPP's proposal is similar to the market-based congestion management constructs successfully implemented by other RTOs.[348] SPP states that it will settle TCRs using the Marginal Congestion Component of the day-ahead LMP, similar to other markets.[349] SPP's proposal takes into account the system's expected usage and, in a security-constrained power flow, it allocates firm transmission rights in a simultaneously feasible manner, allows for congestion cost hedging, and recognizes the historical rights of firm transmission customers.[350] While the Commission expects SPP's market-based congestion management construct to provide significant benefits, protesters have raised concerns with some aspects of the proposal. The Commission conditions its finding that SPP's proposal is just and reasonable, subject to the modifications and clarifications discussed further below.

238. We deny NPPD's request for an expanded congestion cost hedge transition mechanism. While NPPD is correct that the Commission has allowed RTOs/ISOs

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[347] SPP May 15 Answer at 55 (citing *New England Power Pool and ISO New England, Inc.*, 101 FERC ¶ 61,344 at PP 35-36).

[348] *See, e.g.*, *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,276 (2003); MISO TEMT II Order, 108 FERC ¶ 61,163, *order on reh'g*, 109 FERC ¶ 61,157 (2004).

[349] *See, e.g.*, *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,279, at P 5 (2008); MISO Markets Settlement Business Practice Manual, 2.1.2 (effective October 1, 2011) (posted at https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=19181).

[350] Like other markets, SPP will use a simultaneous feasibility test to limit the amount of ARRs based upon the transmission system's capability. While loop flows will affect the amount of system capability available for ARR allocation in the simultaneous feasibility study, the Commission expects SPP and its neighbors to closely coordinate the management of congestion.

additional time to adjust to new markets, SPP's proposal is distinguishable from the cases that NPPD cites as SPP explains in its answer. Moreover, we find that SPP's proposal is just and reasonable without a transition period like that approved for MISO.[351] For instance, NPPD concedes that it is not a MISO-type load pocket.[352] Further, NPPD does not explain why a five year transition period is necessary when, according to NPPD, the Nebraska City-Sibley Priority Project will address its congestion concerns in three years. Finally, given the Commission's findings below strengthening the proposed mitigation plan and the burden that would be imposed on other customers to pay for an expanded congestion cost hedge transition period for NPPD, we find that such a transition period has not been shown to be just and reasonable.

239. However, we condition our acceptance of the market-based congestion management proposal on SPP making a compliance filing to provide specificity. Specifically, we direct SPP to include the following provisions in its Tariff: (1) a process for awarding ARRs for contracts that provide for the rollover of transmission agreements;[353] (2) a provision identifying how pseudo-tied resources and load will be treated with regard to ARR allocation; (3) a provision stating that the TCR auction is subject to review by the market monitor and mitigation, as needed; and (4) a process for handling two or more winning bids in case there is a tie. Additionally, we direct SPP to submit Tariff provisions explaining the process for awarding ARRs and TCRs between the start-up date of the market (March 1, 2014) and the start date for the annual TCR year (June 1, 2014). We direct SPP to file a compliance filing within 90 days after issuance of this order to incorporate these provisions into the SPP Tariff.

2. <u>Long-Term TCRs</u>

a. <u>Protests</u>

240. Because SPP's proposal does not address long term TCRs, NPPD, TDU Intervenors, and Texas Cooperatives express concern as to how SPP plans to comply with

[351] MISO TEMT II Order, 108 FERC ¶ 61,163 at PP 90-94.

[352] NPPD Protest at 22.

[353] We note that MISO's Tariff assumes the rollover will occur during the annual auction and allocates ARRs for the agreement for the entire year unless notified otherwise prior to the auction that the rollover will not occur. If MISO is notified after the auction that the agreement will not be rolled over, then MISO takes the ARRs back after the contract terminations. SPP's Tariff does not explain the process that it uses for these rollovers.

Order No. 681,[354] which requires SPP to provide long-term transmission congestion contracts.[355] According to NPPD and TDU Intervenors, SPP's proposal will establish an "organized electricity market"; thus, under Order No. 681, SPP must provide for long-term TCRs.[356] NPPD requests that the Commission immediately issue an interim order directing SPP to propose modifications to its Tariff necessary to comply with Order No. 681 prior to launch of the Integrated Marketplace.[357] TDU Intervenors state that the proposal must provide TCRs that are available for 10 years,[358] ensure coverage of the reasonable needs of load-serving entities,[359] and allow such rights to follow the load to another entity that acquires the service obligation.[360] Additionally, though the filing does not address this requirement, TDU Intervenors state that SPP must plan transmission to ensure that long-term rights are, and remain, feasible.[361]

241. TDU Intervenors and the Texas Cooperatives request that the Commission require SPP to file an Order No. 681 compliance filing to provide for long-term TCRs. Texas Cooperatives state that SPP should file the compliance filing before Integrated Marketplace commencement or within a reasonable time thereafter.[362]

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[354] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs ¶ 31,226, *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006).

[355] SPP refers to financial transmission rights as TCRs, and SPP's terminology will be used in this order.

[356] TDU Intervenors Protest at 10 (citing 16 U.S.C. § 824r(b)(4) (2006)); NPPD Protest at 30.

[357] NPPD Protest at 8, 29-31.

[358] TDU Intervenors Protest at 11 (citing 18 C.F.R. § 42.1(d)(4) (2012)).

[359] *Id*. (citing 18 C.F.R. § 42.1(d)(5) (2012)).

[360] *Id*. at 12 (citing 18 C.F.R. § 42.1(d)(6) (2012)).

[361] *Id*. (citing 16 U.S.C. § 824r(b)(4) (2006); Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 453).

[362] Texas Cooperatives Protest at 4-5.

b. Answers

242. SPP acknowledges that upon implementation of the Integrated Marketplace, SPP will be an "organized electricity market" subject to Order No. 681. Nonetheless, SPP states that its proposal currently provides for firm transmission rights through an annual verification and nomination process in which load-serving entities can obtain ARRs and TCRs to hedge their congestion costs in the first year of operations and each year thereafter. SPP explains that load-serving entities can use this annual process to hedge their firm long-term transmission arrangement until SPP supplements the proposal to develop long-term firm transmission rights.[363]

243. SPP states that development of a long-term firm transmission rights mechanism will require the input of stakeholders and the RSC, to whom SPP's by-laws provide the authority to allocate TCRs.[364] Given the time required to formulate such a mechanism, SPP asks the Commission to find that the proposal reasonably allows load-serving entities to hedge their congestion until SPP formulates a long-term firm transmission rights mechanism through the stakeholder process.[365]

244. TDU Intervenors argue that SPP's answer indicates SPP might not submit a compliance plan for several years. SPP answers that it will file its long-term firm transmission rights mechanism by the beginning of the second year of operations.[366]

c. Commission Determination

245. We agree with SPP that the proposal will enable load-serving entities to hedge their congestion costs for the first year of the Integrated Marketplace. We also agree that SPP's proposal serves as a reasonable interim congestion management mechanism until SPP files, and the Commission accepts, SPP's Order No. 681 compliance filing. All parties agree that the Integrated Marketplace will constitute an "organized electricity market" subject to Order No. 681's requirements. However, the parties disagree about

[363] SPP May 15 Answer at 20.

[364] SPP states that the ARR and TCR constructs were developed under the leadership of the RSC, with the principal design objective being to translate firm transmission service reservations into a product that allows the Market Participant to obtain a credit against daily congestion costs, either through a TCR or through payments received for the ARR.

[365] SPP May 15 Answer at 21.

[366] SPP June 26 Answer at 11.

when SPP must submit its filing. We find that the firm transmission customers are covered with an adequate congestion cost hedge for the first year. Thus, we will allow SPP to submit such a compliance filing after market start-up, so as not to delay the commencement of the market. Though SPP commits to file before the second year of market operations begins, in Order No. 681 the Commission found that such compliance filings could be reasonably made within a 180 day timeframe and filing a long-term firm transmission rights proposal 180 days after market start-up will enable the Commission to review the filing prior to the second year of market operations..[367] Accordingly, SPP must establish long-term firm transmission rights in a compliance filing due within 180 days after the commencement of the Integrated Marketplace.

3. Annual and Monthly ARR Allocation Process

a. SPP Proposal

246. SPP states that an Eligible Entity[368] can nominate candidate ARRs along specific transmission paths consistent with firm service. SPP will allocate the portion of these nominated ARRs that are simultaneously feasible. SPP notes that ARR allocation will occur annually during three rounds conducted each April and that additional monthly ARR allocations will be made as necessary to address new transmission service.[369] Eligible Entities will nominate candidate ARRs for transmission paths based upon their network integration transmission service, point-to-point transmission service, or grandfathered agreement (GFA). SPP explains that to nominate an ARR, the Eligible Entity's transmission service must span the entire month or seasonal period of the ARR nomination.

247. SPP states that it will verify an Eligible Entity's existing transmission service entitlements based upon the source, sink, and reservation capacity information on the SPP Open Access Same-Time Information System (OASIS). Once verified, the Eligible Entity can nominate candidate ARRs for the transmission paths associated with its transmission service. A network integration transmission service or GFA customer taking the equivalent of network integration transmission service may nominate candidate ARRs up to 103 percent of the average of the customer's three highest annual peak

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[367] Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 490.

[368] Section 1.1 of Attachment AE of the SPP Tariff defines Eligible Entity as "[a] Transmission Customer or Market Participant having firm SPP Transmission Service or firm non-SPP transmission service (referred to as a "grandfathered agreement" or "GFA") into, out of within or through the SPP region."

[369] SPP Transmittal at 15.

network loads since February 1, 2007. SPP states that this cap accommodates ARRs for all existing firm transmission service rights and accounts for load growth. For point-to-point and GFA customers taking the equivalent of firm point-to-point transmission service, ARR allocations are based on the customer's reservation capacity associated with the specific source and sink of the point-to-point or GFA transmission service.[370]

248. SPP explains that the proposed 14 nomination periods[371] reflect the significant changes to load, resource availability, and transmission outages that occur throughout the year. For example, SPP notes that agricultural needs double the load of certain Market Participants during certain months, which, coupled with transmission and resource facility outages, cause significant changes to transmission system flows during the year.[372]

249. SPP states it will base ARR allocations on historical firm transmission service. It explains that because the SPP region has no retail open-access, load-serving entities in SPP need sufficient transmission system access to fulfill their native load service obligations. Hence, SPP contends that its ARR proposal aligns ARR allocations with native load needs and growth by allocating ARRs based upon the firm network integration transmission service or point-to-point use of the transmission system.[373]

250. Pursuant to section 13.5 of SPP's existing Tariff, if a firm point-to-point transmission service request requires new upgrades, SPP will commence service prior to the completion of these upgrades, if SPP can address the constraint identified in system impact studies through redispatch, and if the customer is willing to pay redispatch costs. SPP proposes to revise section 13.5 to specify that any point-to-point transmission service requiring this redispatch will be ineligible for ARR allocation associated with such redispatch until the transmission facility additions have been made and redispatch is no longer required.

[370] *Id*.

[371] SPP explains that in a single round allocation process, ARRs will be awarded monthly for June, July, August, and September, and seasonally for Fall (October and November), Winter (December through March), and Spring (April and May), for both peak and off-peak periods.

[372] SPP Transmittal at 17.

[373] *Id*. at 16-17.

b. Protests

251. Because transmission capacity is finite, AWEA and BP Wind Energy contend that SPP should not over-allocate ARRs to any Market Participant.[374] AWEA claims that ARR eligibility for network integration transmission service customers, as described in the SPP proposal, "sets up a paradigm" whereby network integration transmission service customers' share of ARR nominations can increase steadily, a situation that would negatively affect the ability of point-to-point customers to obtain ARRs.[375] BP Wind Energy further contends that SPP has not justified basing the network nomination cap on peaks from as early as 2007. It argues that if SPP permits network customers to base their nominations on inflated load estimates while limiting point-to-point customers to their actual reserved capacity, the corresponding reductions in ARR allocations will fall disproportionately on point-to-point customers.[376] As a remedy to address this concern, AWEA recommends that SPP modify section 7.1.3 of its proposed Attachment AE to change "[o]ne hundred and three percent (103%) of the average of that customer's three highest annual peak Network Loads since February 1, 2007" so that it reads "[o]ne hundred and three percent (103%) of the average of that customer's three most recent annual peak Network Loads."[377] BP Wind Energy supports a similar revision to SPP's proposal, arguing that the revision would result in more reliable ARR allocation estimates for network customers and would ensure that point-to-point customers are not subjected to unnecessary ARR nomination reductions.[378]

252. KMEA states that several of its members were parties to recently expired bundled contracts, and, consequently, these members do not have the three years of transmission service to average as required by SPP's candidate ARR nomination procedures. KMEA requests that the Commission require SPP to use the members' three highest peak loads to nominate candidate ARRs and impute the transmission service data to the KMEA members rather than to the members' bundled supplier.[379]

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[374] AWEA Protest at 6-7; BP Wind Energy Protest at 9.

[375] AWEA Protest at 7; *see also* BP Wind Energy Protest at 9.

[376] BP Wind Energy Protest at 8-9.

[377] AWEA Protest at 6-7.

[378] BP Wind Energy Protest at 9-10.

[379] KMEA Protest at 2.

253. Several parties associated with the wind generation industry take issue with proposed revisions to section 13.5 of SPP's Tariff. TradeWind faults the proposal for exempting some firm point-to-point transactions from the ARR allocation. It states that under the proposal transmission customers taking firm point-to-point transmission service with a limited dispatch condition cannot nominate ARRs.[380] TradeWind argues that a customer paying for firm point-to-point service with a limited dispatch condition should get the same ARRs as other point-to-point transmission customers. TradeWind and BP Wind Energy also consider it discriminatory to treat point-to-point transmission customers dissimilarly simply because one customer has agreed to a limited redispatch obligation and another did not.[381] TradeWind also notes that network integration transmission service does not have this redispatch provision. Moreover, it contends that once the new market is in place, "redispatch" will be unnecessary, and SPP will replace it with a continuous dispatch determination to ensure the most economical facility usage and the necessary resource mix to complete transmission service transactions. Moreover, it states that redispatch for certain firm transmission arrangements may never be necessary because the study to determine redispatch assumes a 100 percent capacity factor when actual usage may be less.[382] AWEA echoes this argument.[383]

254. Both AWEA and BP Wind Energy consider section 13.5 of the proposed Tariff vague. According to AWEA, one interpretation of this provision makes firm point-to-point transmission customer that need new facilities ineligible for ARRs.[384] Another interpretation would allow ARRs to be granted unless the aggregate study indicates that redispatch may be necessary under the study scenarios. AWEA suggests that SPP delete the sentence from section 13.5 that reads "Firm Point-to-Point Transmission Service that is requested and that requires this redispatch shall be ineligible for the portion of the Auction Revenue Right . . . allocation associated with such redispatch until the transmission facility additions have been made and redispatch is no longer required."[385] If the Commission does not require SPP to delete this sentence, AWEA asks it to require

[380] TradeWind Protest at 4.

[381] BP Wind Energy Protest at 6.

[382] TradeWind Protest at 11.

[383] AWEA Protest at 5. AWEA adds that the new market construct proposed by SPP presents a mechanism for solving transmission constraints that occur and should result in less frequent need to resolve transmission constraints in the way SPP does today.

[384] AWEA Protest at 4; BP Wind Energy Protest at 5.

[385] AWEA Protest at 6 (citing SPP Tariff, Proposed Attachment AE, section 13.5).

SPP to modify the proposal to specify that the reduction in eligible ARRs is calculated based upon the number of hours that redispatch was required over the previous 12 months.[386]

255. BP Wind Energy suggests that the Commission direct SPP to adopt one of two methods to ensure that all firm point-to-point customers receive a reasonable ARR allocation. Under the first method, it suggests that SPP adopt a proposal under which firm point-to-point customers do not experience reduced ARR eligibility, and SPP separately computes redispatch costs arising under the transmission service agreement and bills the customer for them, if they arise. Alternatively, BP Wind Energy proposes that SPP could reduce customers' ARR allocation to account for the periods when redispatch is necessary. According to BP Wind Energy, under this approach, the adjustment could be based on the number of hours and volume of redispatch relief subject to redispatch payments over the previous 12 months resulting from the limited circumstances identified in a customer's transmission service agreement.[387] Finally, BP Wind Energy argues that the data on annual peak network load from as early as February 1, 2007 are not reliable in predicting current network loads and asks the Commission to require SPP to adopt a more reasonable means of calculating current network loads.[388]

256. TDU Intervenors argue that the proposal will not produce a meaningful hedge for system power purchasers. They state that these purchases often have the same firmness as the supplier's service to its own retail load.[389] TDU Intervenors concede that the ARR allocation process described in section 7.1.1(1)(a)(i) of Attachment AE would create a candidate ARR whose source may accurately reflect the diversity of the generating sources behind it.[390] However, they argue that the source of the candidate ARR must match up with the same resources used to calculate the LMP, including the congestion

[386] *Id.*

[387] BP Wind Energy Protest at 7.

[388] *Id.* at 6.

[389] TDU Intervenors Protest at 15 (citing SPP Tariff, Proposed Attachment AE, section 7.1.11(1)(a)(i)).

[390] SPP Tariff, Proposed Attachment AE section 7.1.1.(1)(a)(i) provides that if a transmission reservation with a source internal to SPP is not a specific resource, SPP will determine the load settlement location that most electrically corresponds to the source of the reservation. Thus, a system power sale would have a load settlement location as the source and a load settlement location as the sink.

component to which the purchaser would be exposed.[391] TDU Intervenors state that the only way to match the candidate ARRs with the source used to calculate the resource's LMP, including the congestion cost paid by the purchaser, is to create a Bilateral Settlement Schedule. When the parties to a bilateral agreement create a Bilateral Settlement Schedule, it would be "located" at the same load settlement location as the ARR source determined by SPP for the same system purchase under section 7.1.1(1)(a)(i). TDU Intervenors state that a candidate ARR would then provide an effective hedge against the congestion risk between the load settlement location representing the contract resource and the purchaser's own load settlement location.[392]

c. Answers

257. With respect to the allocation of ARRs to network integration transmission service customers, SPP states that the stakeholders considered other proposals (e.g., the most recent three years), but instead opted for a period of time that stakeholders consider to be a sufficient representative historical period. SPP states that the selection of February 1, 2007 as the start date for network integration transmission service customers to identify their three highest annual peak network load allows such customers to account for current system usage and load growth and for short-term load reductions experienced during the economic downturn.[393]

258. Responding to the concerns of KMEA, SPP states that in calculating peak load for purposes of determining ARR eligibility, SPP will adjust for load transfers among load-serving entities.

259. SPP argues that it is appropriate for its proposal to disallow firm point-to-point customers who require redispatch service from sharing in the ARR allocation, because redispatch service, by definition, is not provided using the path requested by the transmission customer. Instead, SPP argues, the pre-existence of transmission service commitments to other customers renders such paths unavailable for the customer receiving service subject to the redispatch conditions. Because ARR allocation is subject to simultaneous feasibility, SPP argues that allowing such customers to also nominate candidate ARRs over the same requested path would result in ARR over-allocation

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[391] TDU Intervenors Protest at 16. TDU Intervenors note that the source of this candidate ARR is a load settlement location and the sink is also a load settlement location and this approach is different because congestion is the difference between the LMPs at a resource settlement location and a load location.

[392] TDU Intervenors Protest at 16-17.

[393] SPP May 15 Answer at 34.

because more service "is being provided over that path (due to redispatch) than is actually physically feasible."[394] SPP also claims that it might be impossible to identify an ARR that accurately reflects the path for firm point-to-point service, as service subject to redispatch is provided through generation redispatch that occurs over paths other than the requested one.

260. In its answer, BP Wind Energy agrees that SPP cannot issue ARRs that exceed simultaneous feasibility. However, it disagrees that this fact provides a basis to deny any firm point-to-point customer a reasonable ARR allocation. It argues that those firm point-to-point customers affected by section 13.5 pay the full OATT rate and redispatch costs. Thus, BP Wind Energy considers it unjust, unreasonable, and unduly discriminatory to deny ARRs to such customers. It also argues that section 13.5 effectively requires firm point-to-point customers to not only pay for redispatch associated with the specific transmission constraints identified in these customers' transmission service agreements, but also for other redispatch costs arising in the SPP system from the combined impacts of all system users. Therefore, BP Wind Energy argues that SPP cannot reasonably make this change without providing such customers with the same opportunity to obtain congestion protections afforded to all customers paying the full Tariff rate.[395]

261. With regard to the use of a Bilateral Settlement Schedule in the hedging of a system power sale, SPP states that while a system sale purchaser might not have control over the seller's choices of which units to dispatch, the buyer can submit a Bilateral Settlement Schedule up to four days after the operating day for use in the initial settlement and up to 44 days following the operating day to be included in the final settlement. Thus, SPP claims the buyer could match and properly account for these types of hourly energy deliveries.[396]

d. <u>Commission Determination</u>

262. We conditionally accept SPP's proposal subject to a compliance filing due 90 days after the issuance of this order, as discussed below. With the modifications ordered below, we find that SPP's ARR allocation proposal is a just and reasonable and not unduly discriminatory approach for awarding ARRs. While SPP and stakeholders were able to resolve many of the concerns involving this potentially contentious issue, those remaining are addressed below.

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[394] *Id*. at 33.

[395] BP Wind Energy Answer at 4.

[396] SPP May 15 Answer at 38.

263. We find SPP has not demonstrated that its proposed method for approximating a network integration transmission service customer's load is just and reasonable. The Commission has typically required the allocation of hedging mechanisms, like ARRs, to reflect the realities of the system. For example, in CAISO, the Commission rejected an historical period that was too distant to account for recent changes in market circumstances and required CAISO to adopt a more recent historic period.[397] We find that SPP's proposal does not account for all the relevant circumstances surrounding the current system. For example, we note that the Nebraska utilities did not join SPP until 2009. For this reason, we find that allowing network integration transmission service customers to use the highest three annual peaks from 2007 would not be representative of the current system.

264. Further, as protesting parties note, if a network integration transmission service customer's load decreases in a given year, the ARR allocation proposal will allow for an even greater distortion of the realities of the system. Under this scenario, the proposal would over-allocate ARRs to such customers and under-allocate ARRs to other firm transmission customers. We find that SPP should file a revised proposal that would reflect system realities more accurately.[398] Moreover, we also note that the Commission has already determined that MISO's approach to allocating ARRs is reasonable. Therefore, we direct SPP to adopt the approach recommended by the protesters (i.e., 103 percent of the previous three years average annual peak network loads).[399]

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[397] *Cal. Indep. Trans. Sys. Operator, Inc.*, 120 FERC ¶ 61,023, at P 155 (2007). ("In general, the historical reference period chosen should be reasonably representative of the period during which the rates will be in effect."). *See also, e.g., Allegheny Elec. Coop. v. Niagara Mohawk Power Corp.*, 58 FERC ¶ 61,096, at 61,349 (1992); *Blue Ridge Power Agency*, 55 FERC ¶ 61,509, at 62,787 (1991).

[398] We note that MISO uses an ARR allocation that has been found to be just and reasonable and MISO's allocation could serve as a reasonable basis for SPP's revised proposal. Under MISO's Tariff, MISO allocates ARRs based on a calculation of the peak usage which uses the preceding three years' annual peak. Thus, MISO's approach appears to be the same except that it does not increase the preceding three year average by an extra three percent as recommended by protesters. *See* MISO Section, Section 1.497 "Peak Usage" definition and MISO Firm Transmission Right and ARR Business Practice Manual, at 3-15.

[399] Additionally, section 7.1.1(1)(a) states that the Transmission Provider will use the source, sink and transmission capacity from the OASIS "for each monthly and seasonal period for which ARRs are allocated" for network integration transmission service and point-to-point transmission service. However, under section 7.1.1(2)(a), for

(continued…)

265. Moreover, SPP provides no support for using an annual peak methodology in the ARR allocation process for all seasons or months of the year. As SPP notes, agricultural needs can double the load of certain Market Participants during certain months, which, coupled with transmission and resource facility outages, can cause significant changes to transmission system flows during the year. SPP's use of an annual peak methodology in the ARR allocation process may reasonably allocate ARRs during those months or seasons of the year when the annual peak reflects the realities of the system. However, SPP needs to show that an annual peak methodology would reasonably serve as the basis to allocate ARRs during those months or seasons of the year when load drops in half. Providing ARRs during the times of the year when load drops in half based on an annual peak methodology would allow these firm transmission customers to receive twice the number of ARRs required to provide a financial hedge of congestion costs, thereby, leaving other Market Participants with less ARRs. While the 14 nomination periods during the annual TCR auction would allow these firm transmission customers with significant swings in load to convert the ARRs to TCRs and sell the TCRs to others in the market, the 14 nomination periods do not address whether these firm transmission customers with significant swings in load should have received the ARRs in the first place. Thus, we require SPP to either support its use of an average peak methodology for allocating ARRs for the firm transmission customers with significant swings in load or propose refinements to the ARR allocation process to account for these significant monthly and seasonal differences.

266. We also direct SPP to clarify the Tariff to state explicitly that in calculating peak load for purposes of determining ARR eligibility, SPP will adjust for load transfers among load-serving entities, as SPP commits to doing in its answer.[400]

267. With respect to protestor concerns regarding ARR allocation to firm point-to-point transmission customers with redispatch obligations, we find that SPP's proposal, as modified, is just and reasonable. Point-to-point transmission customers with redispatch obligations under section 13.5 of the Tariff will receive planning redispatch service to allow them to get power to their loads before an otherwise necessary facility is in service. Such service allows for use of the grid even though transmission is likely unavailable for part of the year. The Commission has considered planning redispatch service to be a

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firm service under a GFA, the Transmission Provider will get information from OASIS. If SPP will use data "for each monthly and seasonal period for which ARRs are allocated" for GFAs as it does for other firm service, we direct SPP to include such language for GFAs in section 7.1.1.(2)(a) as it does for other firm service in section 7.1.1(1)(a).

[400] SPP May 15 Answer at 34.

complementary service to conditional firm service.[401] Because the nature of this service is conditional, protesting parties have not shown that customers making use of this conditional service to be similarly situated to other firm point-to-point transmission customers for whom SPP does not have a redispatch obligation. Therefore, whether they pay the same firm transmission rate as other firm point-to-point transmission customers, without redispatch obligations is not determinative of the ARR allocation amount they should receive.

268. However, we find that SPP's proposal does not provide benefits that accurately reflect the conditional nature of this service. As the Commission stated in Order No. 681, for a transmission right to be "firm," it must be firm in price and quantity.[402] Point-to-point transmission customers with redispatch obligations receive conditional service only when redispatch is required; at all other times, their service is firm. Accordingly, while we agree with SPP that such customers need not receive the same ARR allocation rights as other firm point-to-point transmission customers, SPP should allow for ARR allocation for those times when the redispatch obligation is not required. For example, if the redispatch obligation is for a particular season, SPP should provide ARRs for the other seasons. We direct SPP to modify section 13.5 to make clear that such firm point-to-point transmission customers with redispatch obligations will obtain ARR allocations except for those times of the year and for only those amounts of service that are subject to the redispatch obligation.

269. Additionally, we direct SPP to clarify the Tariff provisions to enhance transparency in the congestion management process. We direct SPP to submit in the required compliance filing the same process that is currently in the Market Protocols for reducing the number of nominated ARRs when not simultaneously feasible.[403] Further, in section 7.2.3 of Attachment AE of the Tariff, SPP's explanation of the ARR award process is much less informative than the corresponding discussion in the Market Protocols. Among other things, the Market Protocols discuss how parallel flows are treated and future adjustments that SPP will make to the model if the funding of ARRs is

[401] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 912, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[402] *Id*. P 170.

[403] Section 5.2.4 of the Market Protocols (Version 11.0) states that ARRs are reduced via the least squares method. We direct SPP to clarify the Tariff to state and explain this methodology.

below 90 percent or above 100 percent. Because these issues may affect the amount of ARRs a party will receive, the Commission directs SPP to include the language currently in the Market Protocols in the Tariff.[404]

270. We also accept SPP's proposal as it pertains to system power sales. As TDU Intervenors note, a Bilateral Settlement Schedule can be used to settle the congestion component of a system power sale. Further, as SPP notes, a Bilateral Settlement Schedule is sufficiently flexible enough to match and accurately account for these transactions. Because the Bilateral Settlement Schedule pertaining to future bilateral system power sale agreements may involve careful negotiations, we require SPP to provide an example in the Tariff of how a Bilateral Settlement Schedule can be used to settle a bilateral system power sale agreement. Such an example will facilitate transparency and ultimately reduce the likelihood of future disputes. As explained below in the section specifically addressing Bilateral Settlement Schedules, existing bilateral agreements, including existing system power sale bilateral agreements, are subject to a transition period that should address TDU Intervenors' concerns.

271. Finally, we direct SPP to explain in the required compliance filing whether SPP will reconfigure ARRs during annual and monthly TCR auctions to maximize value and whether it intends to impose counter-flow ARRs. If SPP will include this feature, it should clarify the Tariff to explain the process.

4. Incremental ARR Allocation Process

a. SPP Proposal

272. SPP states that, in a manner similar to the annual ARR verification and nomination process, it will verify an Eligible Entity's transmission service entitlements and the Eligible Entity may then nominate candidate monthly ARRs. Eligible Entities with new firm transmission service requests confirmed following completion of the annual TCR auction and prior to the next annual ARR allocation period may nominate incremental candidate ARRs associated with their transmission service for each remaining month in the current annual ARR allocation period for which the firm transmission service applies.[405] SPP will then analyze the simultaneous feasibility of the candidate ARRs

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[404] Additionally, we direct SPP to clarify the role the shadow price plays in the annual TCR awards in section 7.3.4.

[405] The monthly allocation also includes monthly firm transmission service verified during the annual verification process that did not span an entire season.

accounting for all previously awarded TCRs and all remaining ARRs not accounted for in the annual TCR auction in the model.[406]

b. Protests

273. TDU Intervenors argue that Market Participants with newly acquired reservations should not be the only entities eligible for incremental ARRs. TDU Intervenors state that if a Market Participant requests but is denied ARRs in the annual auction, then it should be able to seek incremental ARRs up to its nomination cap, given the statutory directive requiring recognition of its long-term rights.[407]

c. Answers

274. SPP takes issue with TDU Intervenors' request that SPP expand incremental ARR eligibility to any entity that unsuccessfully sought ARRs during the ARR allocation. It states that the purpose of the incremental ARR process is to provide an opportunity for customers whose transmission service has not been confirmed the same opportunity to nominate candidate ARRs. SPP argues that its proposal seeks to achieve this objective, not to provide unsuccessful annual ARR process customers a "second bite of the apple."[408] SPP also states that allowing additional participation in the incremental ARR process would add complexity to the process, requiring SPP to initiate the incremental process an entire month earlier than under the current construct.[409] SPP contends that TDU Intervenors did not identify any Commission precedent supporting their request.

275. In their answer, TDU Intervenors again state that all Market Participants that requested but did not receive full ARR allocation through the annual allocation must have at least an equal opportunity to hedge their congestion risk through incremental ARR allocation.[410]

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[406] SPP Transmittal at 16.

[407] TDU Intervenors Protest at 14.

[408] SPP May 15 Answer at 35.

[409] *Id.*

[410] TDU Intervenors Answer at 27.

d. **Commission Determination**

276. We conditionally accept SPP's incremental ARR proposal subject to a compliance filing, as discussed below. SPP's proposed incremental ARR allocation process does not specify the reason for the incremental capacity becoming available after the annual TCR auction. To the extent the new capacity on the system is available as a result of network additions built in response to a transmission service request, then SPP's proposal would be one way to allocate the ARRs for this incremental capacity to the new transmission service request.

277. However, to the extent incremental ARRs represent existing capacity on the transmission system including capacity expected to be added during the year (e.g., addition of regionally-allocated transmission facilities), we grant TDU Intervenors' request and direct SPP to modify its proposal to allow a load-serving entity to acquire incremental ARRs for this existing transmission capacity up to its nomination cap along with Market Participants with newly acquired reservations.[411]

278. Recently, the Commission issued an order granting a complaint against PJM regarding its process for allocating Residual ARRs.[412] In conducting the annual ARR allocation, PJM determined which transmission facilities to model as in-service and which facilities to model as out-of-service for the entire planning year. When a transmission facility was modeled as out-of-service for the entire planning year, and was subsequently made available for several months of the year, under its tariff, PJM did not allocate the ARRs associated with the available capacity to the historical ARR holder. Instead, it sold the additional Firm Transmission Rights[413] in a monthly auction process. The Commission determined that the PJM Tariff was unjust and unreasonable and unduly discriminatory because it failed to allocate the ARRs or the revenue associated with the Firm Transmission Rights resulting from the new capability to parties with historic rights over the paths.[414]

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[411] *See, e.g.*, MISO Tariff, Module C, section 43.7.3, which states that MISO does not guarantee that new transmission customers are entitled to the same level of Firm Transmission Rights as existing transmission customers.

[412] *FirstEnergy Solutions, Corp. v. PJM Interconnection, LLC*, 140 FERC ¶ 61,019 (2012) (FirstEnergy Complaint Order).

[413] In PJM, TCRs are referred to as Financial Transmission Rights.

[414] FirstEnergy Complaint Order, 140 FERC ¶ 61,019 at P 23.

279. As was the case with PJM, SPP proposes to allocate incremental ARRs to parties with new transmission reservations instead of allocating ARRs to parties with historic rights to the paths up to their nomination cap.[415] As noted above, the SPP Tariff is not clear on whether these incremental ARRs pertain to existing transmission capacity on the system or new transmission capacity on the system resulting from new transmission service requests. To the extent that it is the former, as indicated by the FirstEnergy Complaint Order, Commission precedent requires SPP to recognize the historic rights of parties when allocating ARRs up to their nomination cap.

280. The Commission understands that the SPP's TCR construct was developed under the leadership of the SPP RSC, which has authority to develop "the transition mechanism to be used to assure that existing firm customers receive [Financial Transmission Rights] equivalent to the customers' existing firm rights."[416] However, we find that allowing load-serving entities an opportunity to receive allocations of incremental ARRs will fulfill the RSC's obligation because existing firm customers will have an opportunity to receive ARR allocation up to a cap equal to their historic usage.

281. Thus, we direct SPP to clarify the Tariff in a compliance filing due 90 days after the issuance of this order, the incremental ARR process to allow parties with historical rights to the existing transmission system to obtain incremental ARRs for transmission capacity that comes available after the annual TCR auction. Moreover, we direct SPP to clarify the Tariff to explain the ARR allocation process when network upgrades are made to the transmission system,[417] and in particular when the network upgrade is not the result of a transmission service request.[418]

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[415] SPP states that parties with historical rights to the path can acquire TCRs in the market like everyone else. However, this would not provide load-serving entities that have not already received ARRs equal to their nomination cap a quantity of financial rights commensurate with their physical rights to access the transmission system.

[416] SPP Bylaws, section 7.2.

[417] *See, e.g.*, MISO Tariff, Module C, section 46, Network Upgrades, which allows Market Participants that fund Network Upgrades and elect not to receive credits, be deemed eligible by MISO to receive Firm Transmission Rights up to the incremental transmission capacity created by the upgrade.

[418] For example, the proposal does not state whether a sponsor to a transmission upgrade will receive an allocation of ARRs associated with that upgrade. Similarly, the proposal is not clear regarding whether the ARRs resulting from an increase in the transmission capability of the system due to network upgrades required to be built per the

(continued…)

5. TCR Auctions

a. SPP Proposal

282. SPP states that it will conduct an annual TCR auction and subsequent monthly auctions to maximize the total TCR auction value while "ensuring that the cleared TCRs are simultaneously feasible."[419] SPP explains during the annual TCR auction 100 percent of the transmission system capability will be made available for TCRs for the month of June, 90 percent of the transmission system capability will be made available for TCRs for the months of July, August, and September, and 60 percent of the transmission system capability will be made available for the subsequent Fall, Winter, and Spring seasons. SPP makes available for TCRs the remaining transmission system capability during the corresponding monthly and seasonal TCR auctions. SPP argues that releasing transmission capability in this manner should minimize the possibility of TCR underfunding issues caused by changes in transmission system topology after the annual TCR auction.[420] SPP further asserts that it will award simultaneously feasible TCRs based upon the TCR auction bid prices,[421] with self-converted TCRs given the highest priority in the simultaneous feasibility test.[422]

283. SPP also states that it will conduct subsequent monthly auctions for remaining transmission system capability not sold in the annual TCR auction. Like the annual TCR auction, SPP states that the objective of the monthly TCR auctions is to maximize the total TCR auction value while ensuring that cleared TCRs are simultaneously feasible. Self-converted TCRs will be given the highest priority subject to simultaneous feasibility.

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terms of an interconnection agreement would be made available to new customers with transmission requests.

[419] SPP Transmittal at 17. Any eligible Market Participant that meets the creditworthiness requirements in Attachment X of the Tariff can participate in the TCR auction.

[420] For example, releasing only 60 percent of capability in the annual auction will allow SPP to forecast the transmission system topology in the upcoming months more accurately, thus minimizing the chance that TCRs associated with the transmission system will be oversold (which would cause an underfunding issue).

[421] Auction Clearing Prices are calculated for each Settlement Location based on the Marginal Congestion Component formula.

[422] SPP Transmittal at 18.

According to SPP, Market Participants that obtained TCRs in the annual auction can also offer them for sale in the monthly TCR auctions.[423]

284. SPP asserts that the creation of a TCR market will not erode current customers' physical access to the transmission system because the physical rights can continue to be used and form the basis of the financial rights in the ARR allocation process. SPP also states that TCRs are settled independent of actual physical energy flow, so they protect Market Participants from paying congestion charges along a path whether or not their resources are committed in the day-ahead market. It argues that this feature facilitates optimal unit commitment by providing incentives for Market Participants to allow SPP to make commitment decisions on a regional basis in the day-ahead market, because they will not need to physically schedule their generation to their load to receive a congestion hedge. According to SPP, another benefit is that TCRs allow the transmission rights to be used by those entities that value them most. Additionally, SPP contends that increased competition in the TCR auction will lead to better prices for load-serving entities that choose to sell their TCRs.[424]

b. <u>Protests</u>

285. DC Energy observes that SPP's proposed use of two rounds in the monthly auctions should provide more liquidity. However, DC Energy asks the Commission to require SPP to introduce multi-period auctions into its TCR allocation process, a feature that DC Energy asserts is a natural extension of SPP's market design and is currently practiced in other RTO and ISO markets.[425] DC Energy explains that under a multi-period TCR auction, Market Participants can buy or sell TCRs for the next three months or next three quarters. DC Energy asserts that such a proposal allows Market Participants to manage their congestion costs to match the dynamics of their changing portfolios. DC Energy identifies other benefits of the proposal: (1) it provides flexibility; (2) it improves the liquidity of the TCR market and alleviates auction price volatility; (3) it provides Market Participants with the ability to make intra-year adjustments to reflect both changing load obligations and/or changing generation availability; (4) it provides a

[423] *Id*.

[424] *Id*. at 19.

[425] DC Energy states that PJM implemented its Balance of Planning Period auctions for financial transmission rights in June of 2006, ISO-NE plans to implement its Balance of Planning Period auctions in January 2013, and MISO has targeted the end of 2013 for implementing its Multi-Period Monthly Auctions. DC Energy also notes that stakeholders in ERCOT and NYISO are currently discussing the issue. DC Energy Protest at n.14.

better source of future price discovery to the benefit of all Market Participants; (5) it facilitates bilateral contracts due to increased hedging possibilities; and (6) it provides a means of liquidating a default position, which alleviates credit risk.[426]

286. DC Energy also argues that SPP's proposal artificially limits bids in the TCR auctions, which will result in unintended consequences. It states that sections 7.3.1 and 7.4.1 limit the number of TCR bids in the annual and monthly auctions to 2,000 per Market Participant and that SPP has provided no rationale for this limit. DC Energy claims that this limit does not consider the actual needs of the Market Participant and that MISO currently limits auction bids to 4,000 per Market Participant but that it intends to increase this limit. Moreover, DC Energy claims that PJM permits 10,000 bids per Market Participant. Based on these comparisons, DC Energy asks the Commission to reject SPP's proposed limit and to require SPP to increase its limit to account for Market Participant needs and other reasonable limiting factors. DC Energy also asks the Commission to require SPP to modify its definition of the bid limit so that only bids, and not bids *and* offers, will count for purposes of the bid limit.[427]

c. <u>Answers</u>

287. SPP asks the Commission to reject DC Energy's request that the Commission mandate that SPP incorporate multi-period auctions. According to SPP, no Commission precedent requires SPP to adopt features from other ISO markets.[428] SPP states that DC Energy's request is unsupported, and that DC Energy has not shown the proposal to be unjust and unreasonable without multi-period auctions.

288. SPP also requests that the Commission reject DC Energy's request to change the bid limit because the limit was proposed due to concerns over model performance and the desire to minimize potential logistical challenges that could delay market start-up. SPP states that it is amenable to re-visiting the bid limit if operational experience reveals no performance problems during testing and market trials.[429]

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[426] DC Energy also notes that this latter benefit provides a means of liquidating a default position for the remainder of a given auction cycle without the need to conduct SPP's proposed "specially scheduled auctions." DC Energy Protest at 21.

[427] DC Energy Protest at 16-17.

[428] SPP May 15 Answer at 36.

[429] *Id*. at 50.

d. Commission Determination

289. We conditionally accept SPP's TCR auction proposal subject to a compliance filings, as discussed below. We find the proposal is reasonable even though SPP is not offering to implement multi-period TCR auctions, as requested by DC Energy. The Commission has not mandated multi-period TCR auctions for market start-up and will not do so here. As DC Energy acknowledges, although other RTOs are considering multi-period TCR auctions, only one has implemented them to date.[430] DC Energy is free to raise this issue in the SPP stakeholder process.

290. We conditionally accept SPP's proposal to limit the bidding activity in TCR auctions as a reasonable start-up limit to ensure that the market commences operations effectively. Nonetheless, we find that SPP should consider the feasibility of raising the bid limit if operational experience reveals no performance problems. Increased bids can create a more liquid TCR market. Thus, we require SPP to submit a compliance filing 15 months following commencement of the Integrated Marketplace, either revising the Tariff to revise the bid limit to a level that is reasonable based on SPP's experience and market-size or providing justification for retaining the current level based upon its experience.[431]

291. Further, we agree with DC Energy that SPP has not explained whether its use of "bid" refers to both "Bid" and "Offer" as the term applies to the 2,000 TCR bid limit. For example, Attachment AE defines "Bid" as:

> [a] commitment to pay a specific maximum price for a quantity of Energy or Transmission Congestion Rights that includes a Demand Bid, a Virtual Energy Bid, an Export Interchange Transaction Bid, or a Transmission Congestion Right Bid, where such quantities may be submitted in 0.1 Megawatt increments.[432]

[430] PJM, Intra-PJM Tariffs, OATT, Attachment K, section 7 (0.0.0) (Financial Transmission Rights Auctions).

[431] While SPP has offered to make a filing after market trials, the Commission will not require it in order to ensure that the market commences on-time. Moreover, the Commission believes that having one year of experience will provide a reasonable basis on which to base a revised bid limit.

[432] Attachment AE, section 1.1, SPP defines Demand Bid, Virtual Energy Bid, and an Export Interchange Transaction Bid but SPP does not define TCR Bid which results in the definition of Bid as self-referential.

Attachment AE defines "Offer" as "[a] commitment to sell a quantity of Energy that includes a Resource Offer, a Virtual Energy Offer or an Import Interchange Transaction Offer where such quantities may be submitted in 0.1 MW increments."[433] While the definition of "Offer" does not refer to TCRs, section 7.4.1(3) of Attachment AE states that a Market Participant may not submit "more than a total of 2,000 TCR bids, Offers, and self-conversions." It is unclear why this section, which involves the monthly TCR auction, refers to "Offers" when the defined term does not appear to relate to TCRs at all. Moreover, the 2,000 bid limit appears to apply to bids, offers and self-conversions, and not just to bids and offers.[434] Given the confusion created by SPP's terminology, we direct SPP in a compliance filing due 90 days after the issuance of this order, to clearly define each term without any self-references to the term being defined and to clarify whether the 2,000 bid limit applies to Bids, Offers and/or self-conversions.[435]

292. Additionally, in the compliance filing due 90 days after the issuance of this order, we require SPP to support the proposed percentages used in making transmission capability available during the annual TCR auction. For example, SPP must support the use of 90 percent during July through September and 60 percent for the Fall, Winter and Spring seasons.

E. <u>Integration Issues</u>

293. As part of the move to an Integrated Marketplace, SPP must consider existing arrangements both within and outside of the SPP footprint. Issues requiring consideration include the treatment of GFAs and bilateral agreements, various seams issues, and the consolidation of existing Balancing Authority Areas into one Balancing Authority Area operated by SPP. We address these issues below.

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[433] *Id*.

[434] However, the Tariff provisions involving the Annual TCR auction only refer to bids with no mention of offers or self-conversions. We note that section 4.10.8.1(h) of the MISO Firm Transmission Right and ARR Business Practice Manuals (BPM-004-r9) applies the 4,000 limit to only bids and offers.

[435] The Commission also notes that SPP uses the term "self-conversion" in many places in Attachment AE but it also uses the term "direct conversion" (e.g., section 7.3). To the extent these terms are intended to refer to the same concept, the Commission directs SPP to use a common defined term.

1. Grandfathered Agreements

a. SPP Proposal

294. SPP explains that the Integrated Marketplace proposal accommodates existing GFAs within the new market design to the extent possible, rather than abrogating or modifying them.[436] Specifically, SPP proposes to accommodate existing GFAs by giving GFAs that involve firm transmission service reservation transactions the same ARR nomination rights as other firm transmission reservations. Further, Market Participants with GFAs will have the right to convert the ARR associated with their transmission service to a TCR in the TCR auction along with other Market Participants. SPP proposes that, absent agreement between the parties to the GFA as to which party is to receive the ARRs, the transmission owner that is a party to the GFA will receive the allocation of ARRs by default. Additionally, SPP notes that GFAs related to transactions through, into, or out of the SPP Balancing Authority Area will continue their current scheduling practices, which will accommodate these agreements within the rules and design of the Integrated Marketplace. Consequently, SPP states that in the Integrated Marketplace GFAs will not be subject to a "carve-out";[437] instead, they will be accorded treatment comparable to firm transmission service under the Tariff. SPP argues that its proposed treatment of GFAs will avoid problems experienced in other markets where the "carve-out" of GFAs resulted in revenue shortfalls to other TCR holders due to reduced allocations or funding.[438]

b. Protests

295. Protesting parties request that the Commission carve-out certain GFAs from the Integrated Marketplace. MRES and Heartland, joined by Basin, request a carve-out of their GFA No. 496.[439] NPPD requests a carve-out of 22 of its GFAs.[440] NPPD explains

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[436] Attachment W of the SPP Tariff identifies all the agreements for transmission service and/or other jurisdictional services that have been grandfathered in the SPP region.

[437] A physical "carve-out" of GFAs excludes those GFAs from the scheduling and settlement requirements of the market and those "carved-out" GFAs are financially exempt from many energy market charges (e.g., congestion charges and marginal losses).

[438] SPP Transmittal at 43 (citing Dillon Testimony, Exh. No. SPP-3 at 49-50).

[439] MRES and Heartland filed a joint protest regarding the treatment of their 1977 transmission service agreement, identified as GFA No. 496 on Attachment W of the SPP Tariff. MRES, Heartland and others created the Missouri Basin Power Project. Basin is the operator of the project and acts as agent in obtaining transmission service on behalf of

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that it has been able to place the balance of its 128 GFAs related to retail load and native wholesale load under the SPP Tariff.[441] Similarly, OPPD requests that the GFA status of its contracts in the EIS market continue into the Integrated Marketplace.[442]

296. NPPD, OPPD, Basin, and MRES and Heartland protest that SPP's proposal not to carve-out non-jurisdictional GFAs will result in an unlawful modification of these agreements.[443] Despite SPP's assurances that GFAs will be treated in the same manner as other firm transmission contracts with respect to ARR nomination rights, they contend that parties under GFAs that sell and purchase power may be required to pay congestion costs and marginal loss costs as part of their purchase prices in excess of the price and losses currently charged under such agreements for the same service.[444] Protesting parties assert that if these costs are assessed to parties under GFAs, then SPP's proposal will affect the previously negotiated bargain between the parties to the GFA. They argue that the impact of these costs will constitute a significant modification of the existing

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itself and five other consumer-owned entities including MRES and Heartland to transmit power under GFA No. 496 from the Laramie River Station (Laramie) in Wyoming to these six entities. MRES and Heartland request to incorporate by reference the arguments raised in the NPPD and Basin Electric filings concerning the GFAs. *See* MRES and Heartland Protest at 8. Subsequently, on July 11, 2012, MRES and Heartland filed a Conditional Withdrawal of Protest in response to the SPP June 26 Answer in which SPP indicated that service under their GFA No. 496 would not be affected by or subject to the terms of SPP's Integrated Marketplace. *See* MRES and Heartland Conditional Withdrawal at 5. MRES and Heartland's withdrawal is conditioned upon SPP submitting a filing indicating its concurrence with MRES and Heartland's understanding of SPP's treatment of GFA No. 496. To date, SPP has not submitted a response.

[440] NPPD argues that its request for a carve-out of some GFAs is limited in scope and, therefore, will not prevent SPP from implementing its new market. NPPD Protest at 4.

[441] *Id*. NPPD provides limited information about the 22 GFAs. On the basis of the information in the record, it appears that the 22 contracts involve approximately 2,000 MW in total.

[442] OPPD Protest at 3.

[443] APPA also protests that SPP has failed to carve-out the grandfathered contracts. APPA Protest at 4.

[444] NPPD Protest at 15; Basin Protest at 6.

GFAs. Alternatively, Basin requests that SPP provide assurance and specify the mechanisms that will prevent GFAs from being required to pay congestion costs and marginal loss costs as part of their purchase prices.[445]

297. Protesting parties argue that the Commission does not have jurisdiction under the FPA to modify or abrogate the terms of non-jurisdictional GFAs. In support, they state that the Commission required MISO to provide a carve-out of its non-jurisdictional GFAs when MISO commenced operation of a similar market, and the Commission's determination was upheld by the Court of Appeals.[446] However, NPPD asserts that its request for a carve-out of its GFAs is not based solely on its non-jurisdictional status, because the requested treatment is identical to the treatment the Commission has provided to jurisdictional GFAs.

298. NPPD and MRES and Heartland argue that when the Commission implemented major industry-wide reform of transmission service in Order No. 888,[447] the Commission did not order generic abrogation of existing contracts. Additionally, they contend that when the Commission later encouraged transmission owners to join RTOs in Order No. 2000,[448] the Commission allowed existing contracts to be reviewed on a regional basis in order to balance the respect for existing contractual arrangements against the need for uniform transmission pricing. NPPD and OPPD conclude that they reasonably

[445] Basin Protest at 6-7.

[446] Basin Protest at 5-6; OPPD Protest at 3; NPPD Protest at 10 (all citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004), *order on reh'g*, 111 FERC ¶ 61,042, *order on reh'g*, 112 FERC ¶ 61,311 (2005) (MISO GFA Order), *aff'd sub. nom. Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007)).

[447] NPPD Protest at 16-17; MRES and Heartland Protest at 10 (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) at 31,663-64, *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002)).

[448] NPPD Protest at 16; MRES and Heartland Protest at 10. (citing Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,205 ("[O]ur goal in reviewing existing transmission contracts . . . is to balance the desire to honor existing contractual arrangement with the need for a uniform approach for transmission pricing.")).

expected SPP to maintain the GFA status of their agreements in the Integrated Marketplace because such treatment is fully consistent with the Commission's treatment of GFAs in every other RTO energy market.[449]

299. MRES and Heartland argue that their GFA, which was negotiated in 1977, is unambiguous that the parties intended the financial terms of the agreement to last for the life of the contract.[450] MRES and Heartland contend that the Court in *Atlantic City Electric Co.*[451] limited the Commission's ability to modify contracts within the context of RTO reforms, holding that the *Mobile-Sierra* doctrine[452] requires that the Commission preserve the benefit of the bargain reached before market reform. MRES and Heartland comment that the Court reversed a Commission order that reformed a contract with a *Mobile-Sierra* clause where the Commission sought to eliminate multiple transmission charges. MRES and Heartland argue that the Court held that the Commission had not found that the public interest required the modification of the contracts.[453] Moreover, MRES and Heartland argue that even though their GFA does not include an explicit *Mobile-Sierra* clause, the protection of *Mobile-Sierra* doctrine applies to their GFA.[454] MRES and Heartland rely upon the holding in *Atlantic City Elec.* that even if a contract

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[449] NPPD Protest at 18-20 (citing *Pacific Gas and Electric Co*, 81 FERC ¶ 61,122 (1997), *Central Hudson Gas & Electric Corp*., 86 FERC ¶ 61,062 (1999), *New England Power Poo*l, 83 FERC ¶ 61,045 (1998), *Atlantic City Elec. Co. v. FERC*, 295 F.3d. 1 (D.C. Cir. 2002)); OPPD Protest at 3.

[450] MRES and Heartland Protest at 6.

[451] *Id*. at 11 (citing *Atlantic City Elec. Co., v. FERC*, 295 F.3d 1 (D.C. Cir. 2002) (*Atlantic City Elec.*)); *see also* NPPD Protest at 20.

[452] MRES and Heartland Protest at 6,11 (citing *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) (*Mobile*); *Federal Power Comm'n v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) (*Sierra*)). (Under the *Mobile-Sierra* "public interest" standard, the Commission must presume that rates set by power sales contracts that are freely negotiated at arm's length between willing buyers and sellers meet the statutory "just and reasonable" standard of review. This presumption may be overcome only if the Commission concludes that the underlying rate "adversely" affects the public interest. *Devon Power LLC*, 134 FERC ¶ 61,208, at P 10 (2011) (citing *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, Washington*, 554, U.S. 527, 530 (2008); *Sierra*, 330 U.S. at 355).

[453] *Id*. at 11 (citing *Atlantic City Elec.*, 295 F.3d at 1).

[454] *Id*. (citing *Atlantic City Elec.*, 295 F.3d at 1); *see also* NPPD Protest at 20.

does not include explicit *Mobile-Sierra* language, the *Mobile-Sierra* doctrine limits the Commission's authority to modify a contract. Therefore, MRES and Heartland argue that when a contract does not have a *Mobile-Sierra* clause, because the parties are non-jurisdictional and, at the time of the formation of the contract, the parties could not have anticipated Commission review, the Commission's ability to modify the contract is limited.[455] Finally, MRES and Heartland argue that preservation of their GFA is required by the U.S. Supreme Court's reaffirmation of the *Mobile-Sierra* doctrine in *Morgan Stanley v. P.U.D. No. 1 of Snohomish County* where the Court stated that "FERC may abrogate a valid contract only if it harms the public interest."[456] Relying upon this standard, MRES and Heartland conclude that SPP has not established in this proceeding that any harm to the public interest will result from a carve-out of its GFA.[457]

300. MRES and Heartland also dismiss as unpersuasive SPP's explanation that it is seeking to avoid a carve-out of GFAs because it could result in revenue shortfalls, as was experienced in other markets. MRES and Heartland argue that in the appeal of the MISO GFA Order, the court explained that unless the Commission could conclude that abrogation of the GFAs was necessary to protect the public interest, then "FERC had no choice but to carve-out [the] GFAs." The court reasoned that to find that the public interest required a modification of a contract, "FERC must make a finding that the existing rate might impair the financial ability of the public utility to continue its service, or that the rate would cast upon other consumers an excessive burden, or be unduly discriminatory, among other circumstances of unequivocal public necessity."[458]

301. Both NPPD and OPPD argue that SPP's failure to carve-out its wholesale GFAs is inconsistent with their membership agreements with SPP. NPPD and OPPD explain that when they joined SPP in 2008 and 2009 respectively, the Commission approved their membership agreement with SPP, which expressly defines GFAs as including existing contracts to serve retail and wholesale load. NPPD and OPPD also argue that their membership agreements require that new contracts that serve any retail or wholesale customers that have a right to service under state law and where service under the SPP

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[455] MRES and Heartland Protest at 11 (citing *Town of Norwood v. FERC*, 587 F. 2d 1306, 1312 (D.C. Cir. 1978)).

[456] *Id*. at 12 (quoting *Morgan Stanley v. P.U.D. No. 1 of Snohomish County*, 554 U.S. 527, at 548 (2008)).

[457] *Id*.

[458] *Id*. at 12-14 (quoting *Wisc. Public Power, Inc. v. FERC*, 496 F.3d at 271).

Tariff would not satisfy their obligations under state law should receive grandfathered status.[459]

c. Answers

302. In its May 15 Answer, SPP contends that nothing in its proposed accommodation of GFAs in the Integrated Marketplace will modify any term or condition of these existing agreements. Therefore, protesting parties' reliance upon the carve-out treatment of GFAs in MISO is inapposite to SPP's proposal. Moreover, SPP argues that the contentious issue in the MISO proceeding was the imposition of new centralized scheduling that resulted in modification of the MISO GFAs. SPP asserts that because its current EIS market uses centralized scheduling, there will be no new scheduling requirements in the Integrated Marketplace. SPP also notes that no protester argues that scheduling in the new market will modify their GFAs.[460]

303. SPP explains that the Integrated Marketplace will provide parties to GFAs with mechanisms to carve-out their GFAs, at least on a financial basis, without having to impose any special scheduling rules. SPP argues that this can be accomplished through a combined use of allocated ARRs converted to TCRs and the use of a Bilateral Settlement Schedule. Additionally, SPP asserts that GFAs are not mandated into the Integrated Marketplace because historically SPP has treated GFA load as effectively the load obligation of the transmission owner. In the Integrated Marketplace, SPP will allocate ARRs to the transmission owner for its GFA load, and corresponding charges will be assessed to the transmission owner for any congestion attributed to that load. SPP contends the parties to the GFAs will be responsible for determining how to resolve the rights and obligations under the provisions of the GFA in the context of the Integrated Marketplace.

304. SPP repeats its earlier comments that its proposed treatment of GFAs will avoid the revenue shortfalls to other TCR holders that can result from carve-outs. SPP continues that by avoiding the use of a carve-out, it avoids contentious cost allocations and congestion management issues that could undermine the overall integrity of the market design. However, SPP also comments that if the Commission determines that its proposed treatment of GFAs cannot be approved, then referral back to the SPP

[459] NPPD Protest at 11; OPPD Protest at 3. NPPD and OPPD note that the Commission also approved tariff revisions recognizing NPPD's membership as a non-jurisdictional public power agency. *See* SPP Tariff, lines 473, 479-606 of Attachment W.

[460] SPP May 15 Answer at 16.

stakeholders will be necessary so that it may consider how such a carve-out will be structured and to address the resultant allocation and funding issues.[461]

305. In reply to the SPP May 15 Answer, OPPD and NPPD re-assert their concerns that without a carve-out for certain GFAs in the new Integrated Marketplace, their GFAs will be abrogated.[462] Specifically, OPPD responds that even though it believes SPP's proposal to award ARRs and TCRs in place of firm service is an abrogation of customers' contractual rights, OPPD will voluntarily convert its grandfathered rights, as long as all of those rights are converted.[463] However, OPPD asserts that it will not receive an allocation of ARRs that it can convert to TCRs for certain GFAs because of SPP's new procedures for awarding ARRs that identify eight criteria for GFAs to qualify for ARR allocations. OPPD explains that, among other things, SPP requires a GFA to have a source and sink that map to a valid settlement location and a GFA must represent a full firm path.[464] OPPD states that the sink for some of its GFAs are former border points of SPP and are now internal points of SPP that are not settlement locations.[465] OPPD explains that when it joined SPP in 2008, SPP made changes to its firm transmission reservations that altered the reservation's source, sink, point of receipt and point of delivery. As a result, its GFAs now represents only partial path rights on the OPPD system.[466] Because these GFAs no longer qualify for ARR allocation, OPPD argues that it is unable to hedge congestion on the flowgates associated with service to the sink that are former border points of SPP. OPPD requests that the Commission clarify that OPPD's GFAs providing service to former SPP border points are to be reflected as settlement locations by SPP, which would allow OPPD to obtain ARRs and

[461] *Id*. at 17-18.

[462] OPPD May 25 Answer at 1; NPPD June 1 Answer at 2.

[463] OPPD May 25 Answer at 3.

[464] Alternatively, the GFA may be combined with supplemental GFAs or SPP transmission service that, collectively, represent a full firm path.

[465] Prior to joining SPP, OPPD had agreements for service to sinks located at its border with SPP. After joining SPP the sinks in these GFAs became points internal to SPP. These sink locations are not settlement locations under SPP's Integrated Marketplace.

[466] OPPD May 25 Answer at 4-5.

TCRs. Without this clarification, OPPD will not be able to obtain financial instruments that are intended to be equivalent to firm transmission service.[467]

306. NPPD responds that SPP is mischaracterizing the Commission's determination regarding the carve-out of the GFAs in the MISO energy market proceeding as being solely the result MISO's centralized scheduling protocols.[468] NPPD argues that the Court upheld the Commission's recognition that MISO's central scheduling was inextricably linked to congestion charges imposed on GFAs. NPPD asserts that, similar to the situation in MISO, SPP's Integrated Marketplace will impose upon GFAs congestion charges as well as marginal losses, and that these costs will constitute a significant change affecting the agreements.[469] Moreover, NPPD asserts that it is not requesting grandfathered treatment of GFAs for which NPPD is allowed under state law to pass such congestion charged and the related ARRs to the customers receiving service under the GFAs. NPPD asserts that without a carve-out of its remaining 22 GFAs, SPP's treatment of the GFAs will generate unnecessary conflicts under state law over the interpretation of contracts over which the Commission does not have jurisdiction.[470]

307. In the SPP June 26 Answer, SPP responds to OPPD regarding its border points. SPP states that OPPD is not entitled to schedule on its partial path unless there is a corresponding downstream reservation submitted with the upstream (partial path) reservation. Because OPPD is not entitled to schedule power on these former border points that are now internal SPP points, SPP argues that it cannot properly consider these points as valid settlement locations for allocating ARRs and TCRs. SPP asserts that OPPD's partial path reservations are more akin to conditional firm transmission reservations and are not entitled to congestion protection.[471]

308. In reply to the SPP June 26 Answer, OPPD argues that SPP agrees to calculate the financial value of partial path reservations that exit in the SPP footprint without requiring a corresponding pancaked transmission request, but it refuses to do so for partial path reservations to points internal to SPP. OPPD argues that SPP's refusal to recognize its

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[467] *Id*. at 5.

[468] NPPD June 1 Answer at 6-7 (citing MISO GFA Order, 108 FERC ¶ 61,236 at P 227).

[469] *Id*. at 3.

[470] *Id*. at 4-5.

[471] SPP June 26 Answer at 6.

partial path reservations will result in a significant financial impact on OPPD.[472] OPPD also explains that OPPD's transmission segments are valuable because they currently have the right to schedule physical flows of power across congested SPP flowgates. SPP proposes to collect congestion revenues associated with these physical rights through SPP's physical scheduling practices, using a centralized market dispatch across the affected congested flowgates. OPPD argues that SPP will be using OPPD's firm transmission rights across the affected flowgates to increase the allocation SPP can make to other SPP members, or to increase payments to all transmission congestion rights holders. However, OPPD argues that SPP is not proposing to return that revenue to OPPD ratepayers. Instead, SPP is requiring OPPD ratepayers to pay for firm transmission rights through affected GFAs and then donate the value of those rights to other SPP members.[473]

d. Commission Determination

309. The Commission conditionally accepts SPP's proposed treatment of GFAs, subject to a compliance filing discussed below. We find that SPP has constructed a well-reasoned proposal for treatment of those GFAs that are being integrated into the new market. In so doing, SPP has managed to address and largely resolve a very complex issue that has challenged other markets. However, in preparation for a successful launch of the Integrated Marketplace, we find that SPP needs to address all GFAs within the Integrated Marketplace construct. As explained below, we direct SPP to negotiate with protestors the resolution of the remaining GFAs whose integration into the new market has not been resolved and file an informational report with the Commission within 90 days of the issuance of this order on the status of such negotiations.

310. The Commission notes that both NPPD and OPPD have represented to the Commission that they seek to integrate into the market as many of their outstanding GFAs as possible. NPPD adds that it will communicate with the counterparties to each GFA to determine whether any of its 22 outstanding additional GFAs can be integrated into the SPP Integrated Marketplace.[474] OPPD also states that it will voluntarily convert its grandfathered rights so long as all of those rights are converted. OPPD contends that

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[472] OPPD also comments that the financial impact of SPP only calculating the value of the partial path reservation for sinks to SPP border will be exacerbated if Associated Electric Cooperative, Inc. becomes a transmission-owning member of SPP because the sinks at existing border points in other OPPD GFAs will become sinks at points internal to SPP.

[473] OPPD July 9 Answer at 4.

[474] NPPD June 1 Answer at 4.

GFAs can be integrated into the market if SPP establishes settlement locations in the market software to correspond to these delivery points. We direct SPP to negotiate in good faith to resolve the partial path issue so that OPPD can integrate these GFAs into the market.[475]

311. The negotiations to integrate the remaining GFAs whose integration into the new market has not been resolved are necessary because, based on the record in this proceeding, the new market is likely to create an overall environment that is significantly different from what existed when the parties negotiated the GFAs. The parties to the GFAs had physical transmission rights that likely allowed flexible schedules when they negotiated their GFAs, but under SPP's proposal the parties to these GFAs will have financial transmission rights and be subject to congestion costs with a hedge only to the extent they have TCRs and schedule consistent with those on a day-ahead basis. Additionally, although SPP states that the GFA contracts are subject to centralized scheduling in the EIS market and, therefore, there will be no change in scheduling requirements, SPP has not demonstrated that the GFAs currently are subject to day-ahead centralized scheduling as they would be in the Integrated Marketplace. Because it is necessary to schedule in the day-ahead market in order to hedge congestion costs, if the GFAs were to schedule in the real-time market as they currently do in the EIS market, the GFAs would be exposed to congestion costs without a hedge. Further, while the GFAs may receive a hedge for the new congestion costs through the allocation of ARRs, the parties to the GFAs might not receive an allocation of ARRs to fully hedge the congestion cost. Additionally, these GFAs would be exposed to marginal loss pricing, which may be different from the loss pricing provisions of the GFAs, exposing these GFAs to additional costs for losses.

312. SPP states that parties to GFAs have the financial instruments (i.e., ARRs converted to TCRs and Bilateral Settlement Schedules) to effectively carve-out their

[475] Alternatively, SPP can make other arrangements if such arrangements are mutually satisfactory to both SPP and OPPD, to integrate these GFAs into the market. For example, OPPD contends that SPP should calculate the financial value of the partial path reservation to internal points of SPP without requiring a corresponding pancaked transmission request. If such a calculation would facilitate the integration of the GFAs into the Integrated Marketplace and be administratively easier than establishing settlement locations, then SPP may pursue this alternative method of integrating the GFAs.

GFAs financially.[476] However, SPP does not explain how a Bilateral Settlement Schedule could effectively financially carve-out GFAs. Nonetheless, to the extent SPP is confident that these financial instruments are a way to preserve the existing bargain in the GFAs, the Commission encourages SPP to work to integrate these remaining GFAs into the market during the settlement discussions we order herein.

313. The situation here is similar to the situation in the MISO energy markets proceeding. There, the Commission encouraged the MISO parties with GFAs to settle their differences in order to facilitate integration of GFAs into the energy market. Of those GFAs that did not settle, the Commission carved-out GFA contracts that were not subject to modification under the just and reasonable standard of review because the GFAs would experience a change in terms (i.e., scheduling) and an increase in costs (e.g., unhedged congestion costs and marginal losses) that would effectively modify the contracts.

314. Similarly, if SPP's negotiations with protesting parties concerning the unresolved GFAs are not successful, a carve-out could be consistent with Commission precedent. In the MISO GFA Order the Commission determined that it had no authority to modify some of the GFAs that had a non-jurisdictional entity as the transmission owner, and directed MISO to carve them out.[477] The Commission's requirement that MISO carve-out these contracts was upheld by the U.S. Court of Appeals.[478]

315. We also note that following the MISO GFA Order, the Commission held in *Dairyland* that certain GFAs between a non-jurisdictional transmission-owning cooperative and its cooperative owner-members did not need to be carved-out from the MISO market because Dairyland was able to modify these contracts.[479] Thus, in certain circumstances, not all GFAs of a non-jurisdictional transmission-owning member merit a

[476] While the Commission addresses Bilateral Settlement Schedule below and finds that buyers of energy face undue risk, for these GFAs many are not power sales and those that are, the Commission does not have the contract to review to determine if the buyer faces undue risk.

[477] MISO GFA Order, 108 FERC ¶ 61,236 at P 150. The Commission also determined that contracts with a Mobile-Sierra "public interest" standard of review for modification and those contracts that were silent with respect to the standard for modification also were to be carved-out of the MISO energy market. *Id*. PP 141-149.

[478] *Wisconsin Public Power Inc. v. FERC*, 493 F.3d at 272.

[479] *Dairyland Power Coop. v. Midwest Indep. Transmission Sys. Oper.*, 129 FERC ¶ 61,221, *reh'g denied*, 131 FERC ¶ 61,163 (2010) (*Dairyland*).

carve-out as long as it can be shown that the non-jurisdictional transmission-owning member is able to modify the GFA. When SPP, NPPD and OPPD discuss integrating NPPD and OPPD's GFAs in the market, the parties should also examine the contracts to determine whether the NPPD or OPPD GFAs meet this policy for carve-outs. For example, based on the limited information NPPD provided concerning the 22 contracts for which it requested a carve-out, four of the NPPD contracts state that NPPD is both the buyer and the seller. It is unclear from the record why NPPD would be unable to modify these contracts if NPPD is both the buyer and seller under these contracts.

316. As to NPPD's request to carve-out future contracts entered into by NPPD that would be considered a violation of state law if they were integrated into the marketplace, the Commission believes the issue is beyond the scope of the proceeding.[480] Nonetheless, the Commission notes the definition of Grandfathered Agreement in the SPP Tariff states, in part:

> new contracts entered into by a Member which is a Nebraska public-power entity with any retail or wholesale electric utility customer that has a right under state law to obtain electric transmission service or energy service from such Member to the extent that provision of service under the Tariff would not satisfy such Member's obligation under state law.[481]

317. We direct SPP to begin settlement negotiations with protestors who are parties to GFAs whose integration into the new market has not been resolved. Also, we direct SPP to file an informational report due 90 days after the issuance of this order explaining the status of the negotiations and identifying the remaining GFAs that are not integrated into the market. After SPP files the report with the Commission, SPP may commence a stakeholder process to finalize the carve-out proposal for the GFAs that have not been integrated and which merit a carve out, as discussed above. SPP should file the GFA carve-out proposal with the Commission as soon as it is complete. Additionally, if SPP is in agreement with MRES and Heartland regarding the representations in the MRES and

[480] OPPD requested that the Commission recognize that under the provisions of its membership agreement with SPP, the Board of Directors must retain the authority to determine whether aspects of the proposal are violations of Nebraska law. While not specifically mentioning GFAs, the Commission nonetheless views OPPD's request as similar to the request made by NPPD that future contracts be grandfathered if integration in the market would be inconsistent with state law.

[481] Section 10 of the SPP Membership Agreement with NPPD, OPPD and other Nebraska Entities has similar language.

Heartland Conditional Withdrawal of Protest regarding GFA No. 496, SPP is directed to so inform the Commission.

2. **Bilateral Settlement Schedules**

a. **SPP Proposal**

318. SPP proposes to use bilateral settlement schedules[482] to address the issue of how to deal with bilateral agreements during market settlement. In an organized market, a seller gets paid for every injection at the generator bus and a buyer pays each time energy is withdrawn at the load location. Typically, the prices at the generator bus and load location will change based on variables including bids, offers and congestion. In order to establish a fixed price, buyers and sellers can enter into bilateral agreements, including long-term agreements that were signed prior to the implementation of the market and also future bilateral agreements after the market is formed. However, if the seller is paid for each injection and is paid by the buyer under the bilateral agreement, it will be paid twice. The reverse is true for buyers with bilateral agreements, who pay SPP for withdrawals of power and also have to pay under the bilateral agreement. To avoid the double charging, SPP proposes to use bilateral settlement schedules, which back out the market transaction from the settlement process for each product, leaving only the bilateral agreement transaction and any residual costs (e.g., congestion). The bilateral settlement schedule is purely a settlement activity and does not affect market clearing. Both parties must confirm the bilateral settlement schedule for it to be included in settlement unless the parties have agreed upon the use of the auto-approve option which would approve the bilateral settlement schedule when only one party submits the transaction information.

b. **Protests**

319. TDU Intervenors note that the Commission has previously recognized the need for day-ahead markets to accommodate existing bilateral power purchase and sale agreements in order to ensure that buyers under those contracts are not placed at risk. TDU Intervenors state that, when reviewing a new market proposal, two primary questions regarding bilateral agreements should be addressed: (1) how will the purchaser under a bilateral agreement avoid double payments for energy; and (2) how will congestion charges apply to the purchased power and can they be hedged? TDU Intervenors also ask more specific questions, including: (1) for purposes of assessing responsibility for congestion, what source settlement location will be used; (2) how will candidate ARRs for bilateral purchases be assigned; (3) to what extent are purchases of

[482] Attachment AE defines a Bilateral Settlement Schedule as “[a]n arrangement between two Market Participants for transfer of Energy or Operating Reserve obligations.”

power considered resources that can (and, if so, must) be offered into the market by the purchaser as resources independent from the generating units supporting the sales, which are offered into the market by the seller under the contract; (4) if power purchases are considered resources, how is the purchaser to offer them into the market without duplicating or conflicting with the seller's offers for the underlying generation; and (5) if a Market Participant is not able to offer its purchases into the market and thereby receive revenues for it, what is the mechanism by which the buyer is assured credit for the energy purchase? TDU Intervenors assert that these questions remain largely unanswered in SPP's proposal, noting that SPP limits any discussion to two pages of testimony regarding bilateral settlement schedules.[483]

320. TDU Intervenors state that they generally support the use of bilateral settlement schedules as one option to facilitate the continued use of existing bilateral arrangements, as well as future ones. However, TDU Intervenors argue that, under SPP's proposal, the purchaser under a bilateral agreement may be deprived of this option too easily. TDU Intervenors state that, as proposed, a bilateral settlement schedule cannot be established unless the seller agrees to terms with the buyer. TDU Intervenors assert that the seller—who may be a competitor with the buyer—can delay its agreement, insist on unreasonable terms, agree to reasonable terms contingent upon concessions, or simply refuse agreement. TDU Intervenors also point out that SPP's proposed Tariff language offers no recourse in these situations, including dispute resolution. TDU Intervenors also have questions regarding the validation process SPP will use to evaluate bilateral settlement schedules. Additionally, TDU Intervenors object to language in proposed section 8.2 of Attachment AE that permits the seller to terminate a bilateral settlement schedule at any time and also permits termination by SPP if it encounters recurring settlement disputes or if either party is in default. TDU Intervenors assert that these provisions constantly place the buyer at risk of losing the benefit of its bargain under the bilateral agreement. TDU Intervenors also contend that SPP has made no attempt to explain why these provisions are just and reasonable or what alternatives exist to a bilateral settlement schedule.[484]

321. Accordingly, TDU Intervenors request that the Commission require SPP to revise proposed section 8.2 of Attachment AE to ensure that a purchaser under a bilateral contract can obtain a bilateral settlement schedule under reasonable terms and conditions, even if the seller refuses to agree to it. TDU Intervenors also request that the Commission require SPP to specify that the bilateral settlement schedule cannot be terminated without the buyer's consent. If SPP insists on retaining its ability to terminate

[483] TDU Intervenors Protest at 21-23 (citing SPP Transmittal, Exh. No. SPP-3 at 50-51).

[484] *Id*. at 24-26.

the bilateral settlement schedule without buyer consent, TDU Intervenors request that Commission require SPP to state clearly the potential triggers for such termination, narrowly circumscribe them, and logically relate them to failure of the buyer to comply with the contract. Additionally, TDU Intervenors request that the Commission require SPP to specify that SPP must allow the buyer a reasonable opportunity for dispute resolution before terminating a bilateral settlement schedule.[485]

322. TDU Intervenors also assert that the bilateral settlement schedule should not be the sole means for handling bilateral arrangements, noting that there is diversity among power purchase arrangements. TDU Intervenors state that, where the contract is for the buyer's full requirements, the seller could register as the asset owner for the buyer's load. However, TDU Intervenors note that there is no indication that this is SPP's expectation, no requirement that a seller under a full-requirements contract take on this responsibility, and there is an opportunity for the seller to demand further concessions from the buyer to accept such an arrangement. For other types of contracts where the buyer is the Market Participant responsible for its load, TDU Intervenors posit that the buyer could offer, as a resource, the energy quantities it has the right to receive under the bilateral contract at a settlement location that corresponds to the delivery point stated in the contract, essentially buying back the energy at the buyer's load settlement location. However, TDU Intervenors believe it may be difficult or impossible for the buyer to do this under the proposed market rules, particularly if the energy sold under the contract is not from a single specific generator. TDU Intervenors posits that, in this context, it may be appropriate for the buyer to designate as the source for its resource the load settlement location that electrically corresponds to the fleet of resources used to supply the contract energy, which TDU Intervenors suggest reflects the contract service being provided. For a purchaser under a unit-specific purchase agreement, TDU Intervenors state its ability to offer energy in a given hour will depend on its dispatch and scheduling rights under the bilateral contract, and its posture may be similar to that of a co-owner of a jointly-owned unit. However, TDU Intervenors note, it is unclear whether the rules for jointly-owned units would apply in this context.[486]

c. <u>Answers</u>

323. SPP states in its May 15 Answer that a bilateral settlement schedule will accommodate a system sale where the seller controls which units will provide the power, because a bilateral settlement schedule can be submitted up to four days after the operating day and presumably the parties would match the bilateral settlement schedule

[485] *Id*. at 26-27.

[486] *Id*. at 27-29.

to the unit that actually provided the sale. SPP states that its tariff should not be changed to compel a seller to agree to a bilateral settlement schedule, because SPP does not know how that sort of tariff provision would be enforced. SPP states that it cannot act as a arbiter of the parties' rights that may arise under a bilateral agreement.[487] SPP also confirms that TDU Intervenors are correct in that the seller can register as the Asset Owner for the buyer's load to preserve the value of its full requirements agreements. SPP argues that a Bilateral Settlement Schedule will accommodate a system sale where the seller controls which units will provide the power, because a Bilateral Settlement Schedule can be submitted after the operating day and presumably the parties would match the Bilateral Settlement Schedule to the unit that actually provided the sale.

324. TDU Intervenors state in their answer that SPP does not provide sufficient protection to buyers, because buyers have to get the seller either to agree to register, as its own load asset, the load being served under the agreement or upon the terms of the bilateral settlement schedule.[488] TDU Intervenors state that if the seller does not agree to either of these, the buyer will receive no recognition of the energy it must purchase under the bilateral agreement, and it will be obligated to pay both the seller and SPP for the same energy.[489] TDU Intervenors state that it is not requesting SPP to change the tariff to compel a seller to agree to a bilateral settlement schedule, but rather it is requesting the Commission to deprive the seller and SPP of an unjustified veto of a reasonable bilateral settlement schedule or at least to require dispute resolution.[490] TDU Intervenors argue that SPP at a minimum should have a transition mechanism to preserve the benefit of existing bilateral agreements. For example, TDU Intervenors note that in MISO, the Commission required the seller in a system sale to be responsible for both the congestion

[487] SPP also clarifies that it can only tell parties the auto-approve option is no longer available when the parties' dispute over submittals of a bilateral settlement schedule with the auto-approve option.

[488] TDU Intervenors also state that being able to get a Bilateral Settlement Schedule with a load settlement location as its source is necessary to match the ARRs for a system power sale which will use a load settlement location as its source.

[489] Similarly, by not agreeing to a Bilateral Settlement Schedule or by terminating a Bilateral Settlement Schedule, TDU Intervenors state that the seller would get paid by both the buyer and SPP for the same energy.

[490] TDU Intervenors also claim that SPP, by introducing the proposed market, is not a bystander to the parties' bargain, but has an obligation to ensure that its Tariff does not disrupt existing contracts.

costs and holding the Firm Transmission Rights until such time as some alternative solution could be agreed upon by the contract parties.[491]

d. <u>Commission Determination</u>

325. The Commission conditionally accepts the proposed treatment of bilateral agreements. SPP has demonstrated that Bilateral Settlement Schedule will allow parties to a future bilateral agreement to reflect the agreement in the new market because the parties to the bilateral agreement can negotiate the terms, including the terms governing termination and dispute resolution, among themselves when they negotiate the terms of the future bilateral agreement. We find that SPP's proposal is a just and reasonable method of addressing the integration of future bilateral agreements into the market settlement process.

326. However, we note that TDU Intervenors have presented a valid concern with the treatment of existing bilateral agreements in the transition to the Integrated Marketplace. The parties to existing bilateral agreements have already negotiated the terms and rates of their agreement; a seller may have limited incentive to agree to a Bilateral Settlement Schedule absent additional consideration. Other options for reflecting existing bilateral agreements (such as the seller reporting the buyer's load as the seller's asset) also require the seller's consent. The Commission encourages parties to existing bilateral agreements to resolve any dispute as to how the existing bilateral agreement will be reflected in the market (*e.g.*, by agreeing to the terms of the Bilateral Settlement Schedule or agreeing that the seller will register the buyer's load as seller's load). However, in the event the parties are unable to agree, the Commission requires SPP to adopt a transition mechanism for any unsettled existing bilateral agreements to reduce the risk to buyers. This transition mechanism should provide a default method of addressing settlement of bilateral agreements entered into prior to the start of the Integrated Marketplace. The Commission required a similar transition mechanism in MISO for the allocation of Firm Transmission Rights for system purchase contracts, finding that while it would be preferable for the parties themselves to agree on the assignment of Firm Transmission Rights, in the short term the Commission would require sellers to nominate and hold the Firm Transmission Rights until an alternative solution could be reached.[492]

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[491] TDU Intervenors Protest at 25 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,157, at PP 161-162 (2004), *on reh'g*, 111 FERC ¶ 61,043, at P 35, *reh'g denied*, 112 FERC ¶ 61,086, at PP 23-24 (2005), *review denied sub nom. Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir 2007)).

[492] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,157 at PP 161-162.

327. Finally, we note that SPP's proposed tariff revisions to implement the Bilateral Settlement Schedule are unclear in several respects. For example, Attachment AE, section 8.2 of the proposed tariff states that SPP can terminate a Bilateral Settlement Schedule for "settlement disputes," but SPP in its answer states that it can only terminate the "auto-approve" feature, not the Bilateral Settlement Schedule itself. Additionally, SPP provided clarification in its answers on the alternatives to the Bilateral Settlement Schedule process (`., the seller registering the buyer's load) for addressing bilateral agreements in the Integrated Marketplace that are not present in the tariff language. Accordingly, we direct SPP to revise its tariff in a compliance due 90 days after the issuance of this order a transition mechanism to provide a default method of addressing settlement of existing bilateral transactions, incorporate the clarifications made in its answers on Bilateral Settlement Schedule, and clarify the disputed termination provisions in section 8.2.

3. General Seams Issues

a. Protests

328. Protesters raise various objections to the application of the Integrated Marketplace to entities external to the SPP Integrated Marketplace. L-M Municipals and Louisiana Authority request the Commission to require SPP to clarify that the rules and practices of the Integrated Marketplace do not extend beyond the geographic boundary of the SPP market footprint, and that it does not include external members of SPP. L-M Municipals adds that the broad and largely undifferentiated description of the members who will be subject to the new market requirements could be read to suggest that all SPP members, both internal and external to the SPP footprint, will be subject to the Integrated Marketplace rules.

329. NPPD is concerned that SPP's proposal may cause NPPD to be responsible for the market costs associated with generation and load in NPPD's Balancing Authority Area that does not take network service from SPP or from NPPD. NPPD's concern relates to two municipalities, the City of Grand Island, Nebraska and the City of Hastings, Nebraska, both of which are located within the NPPD Balancing Authority Area but operate their own generation to supply their load. NPPD asserts that these municipalities are not SPP members and do not take network transmission service from either SPP or NPPD. Similarly, NPPD states that the load of Tri-State Generation and Electric Cooperative, Inc. is located in the NPPD Balancing Authority Area, but it is supplied by resources outside of the NPPD Balancing Authority Area from an entity that is not an SPP member. NPPD argues that it cannot be held responsible for any SPP Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads. NPPD contends that imposing any such responsibility on NPPD would be contrary to cost causation and, therefore, would be unjust and unreasonable. Moreover, NPPD claims that any attempt by NPPD to shift

such costs to its native load could be determined by its Board of Directors to be contrary to state law.

330. Western requests the Commission to require SPP to include proposed language in the proposed Integrated Marketplace that would enable Western to utilize the SPP markets.[493] Specifically, Western argues that its proposed language is necessary to enable Western to comply with its obligations under Federal law, allow it to buy and sell power within the SPP markets and allow it to buy and sell transmission service from and with entities under the Tariff. Western states that the language has already been approved by the Commission and it was incorporated into other tariffs (e.g., the Mid-Continent Area Power Pool Restated Agreement, MISO's Tariff, and Western's Tariff).[494]

b. Answers

331. SPP challenges NPPD's concerns that section 2.2(2) of Attachment AE[495] may cause NPPD to be responsible for load that does not take service from SPP or NPPD. SPP contends that the registration requirements and expectations for the Integrated Marketplace are not materially different from those in the current EIS market. SPP explains that it is proposing to modify the registration requirements only to reflect certain definitional changes in the Integrated Marketplace for two categories of load – Non-Conforming Load[496] and Demand Response Load.[497] SPP assumes, absent information

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[493] Western's proposed language provides that Western's participation is subject to acts of Congress and regulation of the Secretary of Energy; is contingent upon appropriations and authorization to participate; requires SPP, as a contractor, to utilize equal opportunity employment practices, to abide by the Contract Work Hours and Safety Standards Act, and to avoid using convict labor.

[494] Western Protest at 4 (citing *Mid-Continent Area Power Pool*, 87 FERC ¶ 61,075, *reh'g denied*, 89 FERC ¶ 61,135, *appeal docketed sub nom. MidAmerican Co. v. FERC*, No. 99-1448 (D.C. Cir. Nov. 10, 1999); *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033; *Western Area Power Admin.*, 133 FERC ¶ 61,193).

[495] SPP Answer at 57 (citing SPP Tariff, Proposed Attachment AE section 2.2(2) (requires that "Market Participants must register all Resources and load, including applicable load associated with [GFAs], Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols"); SPP Tariff, Proposed Attachment AE section 2.2(2) (0.0.0)).

[496] Non-Conforming Load is defined as "[l]oad that is process driven that does not follow a predictable pattern." SPP Tariff, Proposed Attachment AE section 1.1 N.

to the contrary, that NPPD will be responsible in the Integrated Marketplace for the same loads for which it is currently registered in the EIS market.

332. SPP states that it is committed to working with Western, and any other interested Market Participant, to facilitate access to all products and services available in the Integrated Marketplace. However, SPP takes issue with Western's proposed Tariff revisions claiming that they could: (1) implicate the contracting terms and conditions of other Market Participants that transact directly or indirectly with Western through the Integrated Marketplace; (2) introduce implementation issues by cross-referencing U.S. Department of Energy regulations, rate schedules and "federal participation provisions" that would take precedence over otherwise applicable terms of the SPP Tariff; and (3) require arbitration for any disputes related to Western's Integrated Marketplace participation, posing a potential conflict with the dispute resolution and remedy provisions of SPP's Tariff and Attachment AE. SPP contends that it is both premature and outside SPP's normal course of business for the Commission to adopt Western's proposed Tariff changes without the benefit of review by SPP's stakeholders. SPP therefore requests that the Commission refer the issues raised in Western's comments, including the proposed Tariff insert appended to Western's filing, to SPP's stakeholder process. SPP commits to provide the Commission with updates on developments concerning this matter.

c. Commission Determination

333. We conditionally accept SPP's proposal subject to a compliance filing. While SPP accredits many benefits to participation in the Integrated Marketplace, participation is voluntary. Parties that choose not to participate, such as L-M Municipals and Louisiana Authority, must be assured that they will not be subject to the rules and practices of the Integrated Marketplace. Similarly, SPP members with non-participating embedded loads, such as NPPD, must be assured that they are not responsible for Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads. While SPP has asserted that the rules and practices of the Integrated Marketplace will not extend beyond the geographic boundary of the SPP market footprint to include external members of SPP, we find that this assertion is not clearly articulated in SPP's proposed Tariff language. Thus, we direct SPP to revise the Tariff in a compliance filing due 90 days after the issuance of this order

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[497] Demand Response Load is defined as "[a] registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider." SPP Tariff, Proposed Attachment AE section 1.1, Definitions D.

to specify that entities that are in any of the other SPP footprints[498] but that choose not to participate in the Integrated Marketplace will not be subject to the Integrated Marketplace's rules and practices.

334. Likewise, SPP's answer indicates it believes that NPPD will be responsible in the Integrated Marketplace for the same loads for which it is currently registered. However, the Tariff is not clear on this point. Accordingly, we require SPP to revise its Tariff to clarify that SPP members with non-participating embedded loads are not responsible for Integrated Marketplace costs or requirements attributable to the operation of generation and transmission used to serve these loads.

335. With regard to Western's requested Tariff revisions, we find the intent and implications of the proposed Tariff revisions to be unclear. Therefore, we grant SPP's request to refer the issues raised in Western's comments, including the proposed Tariff revisions appended to Western's filing, to SPP's stakeholder process.

4. Reserve Sharing

a. SPP Proposal

336. SPP notes that with the creation of the new SPP Balancing Authority Area, the existing reserve sharing arrangements[499] will be eliminated. However, SPP states that proposed Attachment AE contemplates SPP's involvement in reserve sharing arrangements with other Balancing Authority Areas. SPP states that it may execute reserve sharing agreements to maintain, allocate, and share Spinning and supplemental reserves with neighboring Balancing Authority Areas.

b. Protests

337. L-M Municipals and LEPA oppose SPP's proposed changes to the reserve sharing arrangement. L-M Municipals argue that as SPP has drafted the Tariff, SPP would not be required to enter into new reserve sharing agreements with external Balancing Authority Areas. Both L-M Municipals and LEPA raise concerns that a new reserve sharing agreement may be more costly than the existing arrangements. LM Municipals contend

[498] SPP currently has five footprints: a Regional Entity footprint, a Reserve Sharing Group footprint, a Reliability Coordinator Area footprint, a Regional Transmission Organization/Tariff footprint and an EIS Market footprint. The entities participating in the various footprints are different.

[499] The current Balancing Authority Areas in the SPP footprint participate in a Reserve Sharing Group to share reserves as needed.

that SPP should be required to explain whether eliminating the existing reserve sharing group arrangements with external Balancing Authority Areas is necessary for its new market proposal or if SPP is using it as a pretext for shedding an arrangement internal SPP members no longer find to their liking.

338. In addition, L-M Municipals assert that many external Balancing Authority Areas joined SPP and exposed themselves to the prospect of being assessed exit charges upon withdrawal from SPP in order to participate in the reserve sharing group. L-M Municipals state that they would be subject to exit fees if they were now to withdraw from SPP due to the termination of the only service they got from SPP. L-M Municipals contend that SPP should forgo assessing exit fees to external Balancing Authority Areas that withdraw from SPP because SPP has eliminated the benefit of membership. L-M Municipals argue that assessing an exit fee is especially egregious because the exit fee would be based upon the growing debt SPP has recently incurred to fund activities that primarily benefit members within the market footprint. L-M Municipals request that the Commission reject those portions of SPP's filing that would terminate the existing SPP reserve sharing group arrangement, or at a minimum, suspend the provisions and set them for hearing to determine if they are just and reasonable.

339. LEPA notes that SPP's proposal will replace the reserve sharing group with the operating reserve market for internal Balancing Authority Areas, but there is no specified replacement arrangement for the external Balancing Authority Areas. LEPA asserts that to the extent any such replacement arrangements for external Balancing Authority Areas is more costly or less reliable than the existing arrangement, LEPA opposes SPP's proposed change.

340. Xcel notes that SPP's filing refers to a Reserve Sharing Group Agreement, but that it is unable to comment without knowing the content of the document. Xcel states that SPP should indicate to interested stakeholders where such a document can be found.

c. <u>Answers</u>

341. SPP contends that it has no intention of terminating its voluntary participation in reserve sharing arrangements with entities external to the SPP Balancing Authority Area after commencement of the Integrated Marketplace.[500] SPP indicates that the Tariff provisions relating to elimination of reserve sharing agreements were only intended to refer to the elimination of reserve sharing among the current individual Balancing Authority Areas, which are being consolidated into one Balancing Authority Area. Because SPP is not currently a Balancing Authority Area, some revisions to existing

[500] SPP May 15 Answer at 28-30.

reserve sharing arrangements with outside parties will be necessary, and SPP states that it intends to explore such modifications with the parties to those agreements.[501]

d. Commission Determination

342. We conditionally accept SPP's proposed revisions to the existing reserve sharing arrangements subject to a compliance filing. As part of the Integrated Marketplace, SPP is proposing to become the sole Balancing Authority Area for the SPP region. Thus, the existing reserve sharing arrangements involving the individual Balancing Authority Areas will no longer be necessary and will be eliminated. However, SPP has clarified in its answer that it is not terminating voluntary participation in reserve sharing arrangements with entities external to the SPP Balancing Authority Area, with whom SPP currently has a reserve sharing agreements, once the Integrated Marketplace commences. Pursuant to the proposed Integrated Marketplace provisions, SPP may enter into or modify existing reserve sharing agreements with external Balancing Authority Areas. Moreover, despite protestors' claims, SPP is not obligated to provide reserve sharing service to external parties. The Commission has previously allowed other RTOs to terminate reserve sharing service with external parties, finding that "there is no NERC standard that requires such a reserve sharing group to exist."[502] In addition, the Commission has stated that terminating an existing reserve sharing agreement does not require a showing of decreased costs and enhanced regional reliability for the broader regional group.[503]

343. As discussed below, the Commission accepts SPP's proposal to become the sole Balancing Authority Area subject to compliance and NERC certification of SPP as the sole Balancing Authority Area for the region. Because the proposed reserve sharing revisions are predicated on consolidation of the Balancing Authority Areas, we condition our acceptance of these reserve sharing revisions on SPP's compliance with the Commission's directives and receipt of NERC certification as the sole Balancing Authority Area in SPP.

344. We require SPP to make the following revisions to the proposed reserve sharing provisions in a compliance filing due 90 days after the issuance of this order to ensure that they are just and reasonable. Proposed section 6.3.3 (Reserve Sharing Group Scheduling Procedures) uses the term "Reserve Sharing System," but the term is

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[501] *Id*. at 29-30.

[502] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,281, at P 26 (2009).

[503] *Id*. P 29.

undefined in Attachment AE. SPP indicates the Reserve Sharing System automatically creates the energy schedules implemented through the reserve sharing contingency reserve deployment, but absent greater detail, SPP's language may be unjust and unreasonable. Thus, we direct SPP to define the term Reserve Sharing System in Attachment AE.[504]

5. Pseudo-Tie Arrangements

a. SPP Proposal

345. SPP states that Market Participants may create a "pseudo-tie" arrangement[505] to deliver energy and operating reserve from a specific resource that is outside of the SPP Balancing Authority Area into the SPP Balancing Authority Area. These external resources are treated the same as any other resource within SPP for purposes of commitment, dispatch, and operating reserve clearing.[506] Such arrangements are made pursuant to the proposed revisions to Attachment AO of the Tariff.[507] SPP has also proposed an External Dynamic Resource that will allow resources not pseudo-tied to provide operating reserve within the SPP region.

b. Protests

346. Protesting parties express concern about the inability to pseudo-tie load into SPP. TDU Intervenors state that MJMEUC has operated a power pool, called Missouri Public Energy Pool (MoPEP), with load located in MISO, SPP and within the transmission system of Associated Electric Cooperative. TDU Intervenors state that MoPEP has been electrically consolidated by pseudo-tying the loads and almost all of the resources into the Westar balancing area within SPP. This arrangement allows MoPEP to provide more

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[504] We also direct SPP to review and revise Attachment AK (Treatment of Reserve Sharing Charges and Revenues), as necessary, to make it consistent with SPP's reserve sharing provisions in the Integrated Marketplace. For example, Attachment AK still references the EIS Market.

[505] Generally, a pseudo-tie arrangement is the electronic transfer of all or a portion of an external generator from an external Balancing Authority Area to the SPP Balancing Authority Area at a non-physical electrical interconnection point between the source and sink balancing authorities.

[506] Dillon Testimony at 39.

[507] *See* SPP Tariff, Proposed Attachment AO, Agreement Establishing External Generation Non-Physical Electrical Interconnection Point.

efficient and cost-effective service to MoPEP's member cities than would be possible using the separate balancing areas where the loads are located. TDU Intervenors explain that Westar has provided the balancing area and other ancillary services needed by MoPEP since the pool's inception. TDU Intervenors assert that it should be possible for MJMEUC to replace the services provided by Westar under contract with services directly through the new SPP markets. However, while the proposal allows for pseudo-tying external resources and treats such external resources the same as internal resources, TDU Intervenors state that the proposal does not explicitly provide for pseudo-tying load into the Integrated Marketplace. TDU Intervenors request the Commission to direct SPP to work with MJMEUC to allow pseudo-tying load into SPP and to clarify the Tariff to make it so.

c. Answers

347. In its June 26 answer, SPP states that SPP is committed to accommodating load external to the SPP Balancing Authority Area within the design of the Integrated Marketplace. SPP states that the development of pseudo-tie arrangement rules for load is currently being discussed by SPP's Market Working Group, and SPP expects that appropriate tariff revisions will be developed through this stakeholder process.

348. In their answer, TDU Intervenors state that SPP has indicated it is willing to continue the MoPEP arrangement and has set a date to discuss resolving this issue. However, because the issue is in the earliest stages of settlement, TDU Intervenors want to keep the issue before the Commission.

d. Commission Determination

349. We conditionally accept SPP's proposed revisions to Attachment AO to incorporate pseudo-ties as just and reasonable. As the Commission has found previously, participation by external generators in a market can be beneficial for the market as a whole.[508] SPP's proposed revisions will facilitate participation of external resources in the market by providing a starting point for negotiations between SPP and external resources that wish to offer into the market. In its order accepting SPP's *pro forma* Attachment AO in the EIS market, the Commission stated that it intended SPP to use the *pro forma* Agreement as a basis upon which the parties can work to negotiate appropriate pseudo-tie arrangements on a case-by-case basis.[509] We reiterate the requirement here

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[508] *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289, at P 227 (2006). (Commission found that participation by external generators in the EIS market is helpful to addressing market power and bid insufficiency).

[509] *Southwest Power Pool, Inc.*, 123 FERC ¶ 61,062, at P 17 (2008).

that the *pro forma* Agreement in Attachment AO is merely a starting point for negotiations because arrangements to integrate external resources (e.g., through pseudo-tie arrangement) may require provisions unique to that resource.

350. Additionally, in the May 15 amendment, SPP explained its proposal for a new arrangement to integrate external resources, called External Dynamic Resource, and submitted rules for these resources to participate in the market in the Market Protocols. However, SPP did not propose conforming revisions to its Tariff. Therefore, we require SPP to submit revised tariff sheets and conforming language in a compliance filing due 90 days after the issuance of this order that incorporates External Dynamic Resources into the appropriate sections of the SPP Tariff.

351. Finally, with respect to the concerns expressed by TDU Intervenors, the Commission encourages SPP, MJMEUC and other interested parties to continue to work toward a negotiated agreement that accommodates the pseudo-tie of load into the SPP Balancing Authority Area.[510] In Order No. 890-A, the Commission stated that, "we are encouraged, however, by the increased availability of pseudo-ties and dynamic schedules in the industry," also noting that parties "have been able to secure dynamic scheduling agreements on a negotiated basis."[511] At this time, we will reject TDU Intervenors' request to require SPP to provide tariff provisions for pseudo-tie of load into the SPP Balancing Authority Area, as we believe this issue is best resolved through negotiation.

6. Seams Coordination of Congestion

a. SPP Proposal

352. SPP explains that it will manage congestion between the SPP Balancing Authority Area and external Balancing Authority Areas in the real-time balancing market by submitting the Market Flow[512] impact on each Coordinated Flowgate and Reciprocal Flowgate to the NERC Interchange Distribution Calculator (IDC).[513] SPP will determine

[510] We note that the MISO Tariff contains provisions for pseudo-tie of load and resources into and out of the MISO BA. *See* MISO Baseline Electric Tariff, pending in Docket No. ER10-1997-000.

[511] Order No. 890-A, FERC Stats & Regs. ¶ 31,261 at P 631.

[512] Attachment AE defines Market Flow as the "aggregate Megawatt flow on a Coordinated Flowgate or a Reciprocal Coordinated Flowgate caused by the Real-Time Balancing Market." SPP Tariff, Proposed Attachment AE section 1.1 M.

[513] *See* SPP Tariff, Proposed Attachment AE section 6.2.2.3(a).

the Market Flow associated with the real-time balancing market and will assign curtailment priorities to the Market Flow on each flowgate utilizing the proposed Tariff process for Coordinated Flowgates, Reciprocal Coordinated Flowgates, and undefined flowgates. When congestion occurs on a flowgate and the NERC IDC identifies the amount of relief required from Market Flows on flowgates, SPP will use SCED to achieve the required reduction. SPP states that because operation of the real-time balancing market is substantially the same as the current EIS market operation, this seams coordination of congestion management with external Balancing Authority Areas is the same procedure that is currently implemented in the EIS market. SPP expects this procedure to work equally well in the Integrated Marketplace.[514]

b. Protests

353. Acciona takes issue with SPP's addition of this congestion management protocol involving curtailment under SPP's seams coordination protocol.[515] Acciona states that implementing a reasonable seams coordination and congestion management program is critical for renewable energy projects in SPP. While Acciona intends for all of its resources in SPP to be dispatchable, it is concerned with the prospect of manual dispatch (including dispatch instructions to curtail) proposed by SPP because its wind projects in SPP have been experiencing manual curtailments in lieu of binding constraints in the market. Acciona requests clarification that if there is a potential need for manual curtailment or dispatch, SPP must first seek market solutions to address problems associated with emergency conditions before engaging in manual curtailment or dispatch. Because Acciona believes SPP's procedures for manual dispatch need to be more transparent and to ensure proper tracking and use of market-based congestion management before manual dispatch is engaged, Acciona requests that the emergency condition be declared as soon as possible. Acciona also believes that such situations should be posted on SPP's OASIS and that market actions displace manual dispatch as soon as possible.

354. KCP&L-GMO states that the success of the Integrated Marketplace will largely depend on the satisfactorily resolution of seams issues. KCP&L-GMO asserts that effective flowgate utilization requires close coordination between SPP and its neighboring transmission service providers, including MISO. KCP&L-GMO argues that such coordination is especially vital after implementation of the Integrated Marketplace because ARR allocation depends on the amount of loop flows. NPPD notes that congested flowgates could be significantly affected by the SPP and MISO Joint

[514] SPP Transmittal at 39.

[515] Acciona Protest at 4.

Operating Agreement Congestion Management Process, which is currently in dispute resolution proceedings.[516] Despite MISO's and SPP's obligations to negotiate in good faith to address revisions to their Joint Operating Agreement's congestion management provisions, they have not yet reached agreement.[517] Consequently, KCP&L-GMO asks the Commission to monitor and support efforts to address loop flow issues between the two RTOs in a timely manner.[518]

355. MISO states that its footprint is adjacent to SPP's and that it manages a market seam with SPP pursuant to a Joint Operating Agreement. MISO explains that the Joint Operating Agreement is designed to manage this seam reliably and equitably under both RTOs' existing tariff provisions, as well as SPP's proposed Integrated Marketplace design. MISO states that SPP's proposed joint operating agreement with Western (Western-SPP Joint Operating Agreement) filed in Docket No. ER12-1586-000 gave it cause to protest. Its specific concern is that the Western-SPP Joint Operating Agreement imposes a contract path methodology on SPP that could be inconsistent with the SPP Integrated Marketplace's design. MISO argues, for example, that section 5.5 of the Western-SPP Joint Operating Agreement appears to require transmission service to be acquired on Western's system for energy delivered by SPP, within SPP's market under certain conditions. These conditions require transmission service acquisition when the amount of energy delivered exceeds the "sum of capacity of all direct interconnections between the Transmission owners; and/or . . . Contractual transmission agreements between the Party's Transmission Owners."[519] MISO expresses uncertainty about how to calculate the energy delivery limitation. MISO also states that it cannot find any reference in the proposed Tariff revisions or supporting testimony to this artificial constraint placed on the day-ahead unit commitment or real-time unit dispatch. It contends that it needs to understand how SPP proposes to effect its energy market

[516] NPPD Protest at 6, 24-5. NPPD contends that it has no assurance that a resolution of the dispute will resolve its congestion issues or lessen its financial exposure during the first few years after market launch. NPPD also notes that if Entergy joins MISO, this circumstance would exacerbate its congestion problems.

[517] KCP&L-GMO states that parties raised seams issues in Docket No. EL11-34-000 with respect to the Joint Operating Agreement between SPP and MISO. KCP&L-GMO Protest at 3-4. *Midwest Indep. Transmission Sys. Operator, Inc.*, 136 FERC ¶ 61,010 (2011), *order on reh'g*, 138 FERC ¶ 61,055 (2012).

[518] KCP&L-GMO Protest at 4.

[519] MISO Protest at 4 (citing Western-SPP Joint Operating Agreement Filing, section 5.5).

dispatch under this constraint so that it can calculate when and whether SPP will be able to respond to a market-to-market dispatch request without the need for additional transmission reservations on neighboring systems.[520] MISO also alleges that the proposed Tariff and supporting testimony do not explain how the constraint will affect ARR allocation or how it has been factored in determinations of simultaneous feasibility. Finally, MISO states that the testimony provided by SPP does not indicate whether the need for off-system transmission service will be entirely at the cost of the individual transmission customer or if SPP will arrange for and socialize the cost of such service. If the Commission approves the Western-SPP Joint Operating Agreement, MISO asks that the Commission condition its approval of SPP's Integrated Marketplace filing on SPP identifying the Western-SPP Joint Operating Agreement contract path constraint and its implications for transmission customers and other Market Participants.[521]

c. Answers

356. SPP contends that the Western-SPP Joint Operating Agreement will have little impact on SPP's implementation of its Integrated Marketplace. According to SPP, it will calculate parallel path flow impacts when addressing TCRs to account for Western's contract path rights. SPP also states that it will model the obligations, injections, and withdrawals that will affect flowgates and the commitment of congestion rights. SPP also argues that the Western-SPP Joint Operating Agreement will not affect its resource commitment and dispatch related to the coordinated flowgates that SPP and MISO currently monitor and observe under their Joint Operating Agreement. According to SPP, the only change under the Western-SPP Joint Operating Agreement is that the Western contract path amounts will be translated into flowgate responsibilities and this information will be shared with MISO so that MISO is fully informed. SPP further states that "the party that creates excess flows will be responsible for obtaining, and paying for, any necessary transmission service."[522] However, SPP also notes that the Western-SPP Joint Operating Agreement contemplates that the parties will operate their respective systems within their physical capabilities so that they do not place unauthorized flows on other systems.[523]

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[520] *Id*. at 5.

[521] *Id*. at 6.

[522] SPP May 15 Answer at 53.

[523] *Id*.

357. Western contends that MISO has raised issues outside the scope of this proceeding.[524] It argues that MISO has misconstrued section 5.5 of the Western-SPP Joint Operating Agreement and that the intent of the provision is clear. It also argues that if any ambiguity exists, it should be resolved in Docket No. ER12-1586-000. Furthermore, Western states that it is incumbent on any entity making a day-ahead commitment to ensure that it has the right to sufficient transmission capacity to accommodate the real-time dispatch of the unit, and that there is sufficient transmission capacity in real time to accommodate the real-time unit dispatch. According to Western, SPP will take the Western-SPP Joint Operating Agreement into account when determining flowgate capability, and if an entity does not have sufficient physical transmission capacity or contractual transmission rights to implement its transactions in the Integrated Marketplace, it will have to take and pay for transmission service on a third-party system. However, Western states that such an obligation would exist regardless of whether the Western-SPP Joint Operating Agreement is in effect. Additionally, Western states that SPP will conduct its simultaneous feasibility study taking into account the physical capacity of the transmission facilities under its control and that it will not grant ARRs based on the physical capability of Western's transmission system. Finally, Western contends that nothing in the Integrated Marketplace filing or the Western-SPP Joint Operating Agreement changes the basic principle that an entity that uses transmission service must pay for it.[525]

358. MISO argues that the Joint Operating Agreement between MISO and SPP currently has no market-to-market coordination provisions and for that reason, cannot be relied upon in its present form for the coordination of SPP's proposed market and MISO's existing market. MISO states the procedures currently in effect between MISO and SPP are substantially identical to the Phase 1 procedures relied upon for coordination between MISO and PJM.[526] MISO states that when it started its Day 2 market in April 2005, PJM and MISO advanced to the more sophisticated Phase 2, market-to-market procedures.

359. MISO states that the Commission accepted a truncated Joint Operating Agreement filed by SPP as a limited interim solution and required SPP to address issues raised by

[524] Although Western, Basin Electric and Heartland filed a joint answer to the protest of MISO about the Western-SPP Joint Operating Agreement, for simplicity, the Commission will identify the parties that filed this answer as Western.

[525] Western Answer at 5.

[526] The phase 1 period covered the period during which PJM was a market operator while MISO still was a Day 1 transmission service provider.

MISO with respect to market-to-non-market coordination.[527] MISO notes that the Commission made it clear that market-to-market provisions must be included prior to the effectiveness of SPP's Day 2 market. The Commission stated, in part, that "SPP and the Midwest ISO must execute a Phase 2 Joint Operating Agreement, and SPP must file it, in sufficient time to ensure that all issues are addressed prior to commencement of SPP's markets."[528]

360. MISO states that the proposal does not address Phase 2, market-to-market procedures, to address coordination and SPP has indicated in testimony before a state commission that it does not view such market-to-market procedures as a condition to the effectiveness of the Integrated Marketplace. MISO submitted testimony filed by SPP-witness, Carl Monroe, before the Arkansas Public Service Commission, that such market-to-market protocols are not needed unless Entergy Arkansas, Inc., joins MISO as a transmission owner which is inconsistent with the Commission's earlier directive requiring a Phase 2, market-to-market procedures. Moreover, MISO states that SPP has acknowledged that if Entergy Arkansas Inc. joins MISO and the Phase 2 protocols are not implemented, then "SPP and its members expect to suffer harm in lost benefits of the Integrated Marketplace."[529]

361. Further, MISO argues the Commission should give SPP a firm directive to ensure that such market-to-market coordination process is operational on the commencement date of the Integrated Marketplace. MISO notes that SPP has acknowledged that "it could take up to a year to implement market-to-market protocols."[530] However, MISO states that the Phase 2 process in the Joint Operating Agreement between MISO and PJM, updated and improved with seven years of experience could provide a ready template for a Phase 2 process between SPP and MISO.

362. MISO states that this issue has assumed heightened significance since the Commission's recent order accepting SPP's use of physical path limitations in a proposed Joint Operating Agreement between SPP and Western.[531] MISO states that the Western

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[527] MISO October 11 Answer at 5 (citing *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,008, at P 28 (2004)).

[528] *Id*. P 34.

[529] MISO October 11 Answer, Attachment 2, at 29:14-29:15.

[530] *Id*. at 29:13.

[531] MISO October 11 Answer at 2 (citing *Southwest Power Pool, Inc.*, 140 FERC ¶ 61,199 (2012) (Western JOA Order)).

JOA Order may be interpreted as compromising the requirement for market-to-market coordination between SPP and MISO. MISO argues that the Western JOA Order rejected MISO's comments that the contract path limitations proposed in the Joint Operating Agreement between SPP and Western are inconsistent with the proposed market dispatch and by extension, future market-to-market coordination between SPP and MISO.

363. MISO states that it is critical that the Commission confirm these long-standing directives and expressly require SPP, as a condition of approval of the Integrated Marketplace, to develop and file jointly with MISO appropriate market-to-market provisions for the Joint Operating Agreement between MISO and SPP. MISO also requests that the Commission clarify that nothing in the Western JOA Order preempts, modifies or obviates such procedures.[532] Additionally, MISO requests the Commission to direct SPP to participate with MISO and PJM in the Joint and Common Market process to implement cost effective initiatives to further reduce the economic and operational inefficiencies of the RTO seams.

d. Commission Determination

364. With regard to the concern of KCP&L-GMO and NPPD about congested flowgates, we agree that effective flowgate coordination is important to the success of the Integrated Marketplace. Accordingly, we require SPP to begin negotiations with MISO on developing a market-to-market coordination process for managing congestion across the seam of MISO and SPP. As the Commission stated, such "market-to-market mechanisms have been shown to economically relieve congestion and align border prices successfully."[533] Given these benefits of the Phase 2, market-to-market mechanisms, and our earlier requirement for SPP to implement a Phase 2 Joint Operating Agreement, we require SPP to begin negotiations with MISO and file the phase 2 Joint Operating Agreement by June 30, 2013, which should be "sufficient time to ensure that all issues are addressed prior to the commencement of SPP's markets."[534] If the parties use the Phase 2 Joint Operating Agreement between MISO and PJM as a template, SPP should be able to meet the compliance deadline.[535]

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[532] MISO October 11 Answer at 9.

[533] *New York Indep. Sys. Operator*, 133 FERC ¶ 61,276, P 32 (2010).

[534] *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,008, P28 (2004).

[535] Similar to the Commission's finding when directing SPP to file a phase 1 Joint Operating Agreement, we acknowledge that the some adjustments to the phase 2 Joint Operating Agreement between MISO and PJM may be necessary. *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,008, P32 (2004).

365. We will deny MISO's second request to clarify that nothing in the Western JOA Order preempts, modifies or obviates such procedures. The Commission stated in the Western JOA Order that, "[w]e also agree with SPP and Western that sections 5.4-5.6 of the proposed Western-SPP JOA are not inconsistent with Day 2 markets." The Commission explained MISO's Day 2 market operated despite the contract path capacity limitations in some of its agreements. Because the Commission has already addressed MISO's concern in the Western JOA Order, which is still subject to rehearing, we will not address it here.

366. Additionally, with respect to MISO's request to require SPP to participate with MISO and PJM in the Joint and Common Market process, the Commission notes that there is nothing in SPP's filing of the Integrated Marketplace or in this order that modifies any of the existing requirements on SPP with regard to the Joint and Common Market.

367. Regarding Acciona's request for clarification, we agree that in those times when manual curtailment is necessary, the process should be as transparent as possible. Accordingly, we direct SPP to amend the Tariff to state explicitly that SPP will declare the emergency condition as soon as possible, post it on the SPP OASIS and displace manual dispatch with a market solution as soon as possible consistent with system safety and reliability. Therefore, we direct SPP to make a compliance filing due 90 days after the issuance of this order to address the issue raised by Acciona, as discussed above.

7. Consolidation of Balancing Authority Areas

a. SPP Proposal

368. SPP proposes to consolidate the current 16 separate Balancing Authority Areas in the SPP region into a single Balancing Authority Area operated by SPP. SPP explains that the objective of the consolidation is to improve the efficiency of the Integrated Marketplace,[536] facilitate centralized unit commitment, and provide for centralized operating reserve procurement.

369. SPP notes that to facilitate the creation of the new SPP Balancing Authority Area, SPP and the Consolidated Balancing Authority Steering Committee currently are working to finalize the agreement that will transfer the appropriate authority to SPP and detail the new division of responsibilities necessary to implement a single Balancing Authority

[536] SPP states that it expects operational efficiency from the new consolidated Balancing Authority Area arrangement, given the greater opportunities presented for managing individual generation to load imbalances, which likely will result in lower overall dispatch of generation to correct the individual balances.

Area in the SPP Region.[537] SPP states that it will file the agreement with the Commission after it has been finalized.[538] SPP explains that it will assume the NERC Balancing Authority Area responsibilities once the Commission accepts the agreement regarding the consolidation of the Balancing Authority Areas and SPP receives certification as a registered NERC Balancing Authority Area.[539] While the details of the division of responsibilities between SPP and the current Balancing Authority Areas are not yet finalized, SPP and the Consolidated Balancing Authority Steering Committee anticipate that, at a minimum, the current Balancing Authority Areas will retain tasks relating to tie line metering and telemetry responsibilities with adjacent Balancing Authority Areas and frequency measurements.

b. Protests

370. Acciona supports the consolidation of the Balancing Authority Areas because it will create one set of rules and practices, thereby increasing efficiency and improving reliability. Nonetheless, Acciona requests the Commission to require SPP to clarify that, as the Balancing Authority Area for the footprint, SPP will treat existing generators in a just and reasonable manner. For example, Acciona notes that generators like Bear Creek were prevented from requesting and obtaining SPP footprint-wide Network Resource Interconnection Service (NRIS) due to the disaggregated existence of SPP's various balancing areas.[540] Acciona states that with the consolidation of the Balancing Authority Areas, the limitations on NRIS no longer apply. Acciona argues that existing generators should now be restudied and receive footprint-wide NRIS on an as-available basis, before new requests for NRIS are processed. Acciona contends that requiring existing generators to place new interconnection service requests for footprint-wide NRIS when

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[537] Specifically, SPP and the current Balancing Authority Areas will amend or replace the Agreement Between Southwest Power Pool, Inc. and Southwest Power Pool Balancing Authority Areas Relating to Implementation of the energy imbalance energy Market (Balancing Authority Area Agreement) set forth in Attachment AN of the Tariff.

[538] Additionally, SPP states that it anticipates receiving its certification from NERC as the single Balancing Authority Area for the SPP Region in the fourth Quarter of 2013.

[539] SPP's responsibilities will include maintaining balance between load and generation resources and maintaining system frequency. SPP also will be responsible for managing a single Balancing Authority Area Control Error (ACE).

[540] These generators could choose either NRIS service for the control area where the generating facility is located or take Energy Resource Interconnection Service (ERIS).

they were denied it earlier, would be unjust and unreasonable and discriminatory because it would place existing generators behind later interconnection requests and would require additional deposits. Acciona states that the request is not premature because the consolidation of Balancing Authority Areas must be found just and reasonable. Acciona contends that there is more than enough time between now and March 2014 to evaluate the extent to which existing ERIS rights can be transitioned to NRIS rights.

371. Xcel complains that SPP's filing does not provide sufficient detail on how SPP will coordinate generation and transmission outages in consolidating Balancing Authority Areas. For example, a resource can circumvent the must-offer requirement by claiming an "outage" or "reserve shutdown" but SPP does not define reserve shutdown or explain how a resource qualifies for a "reserve shutdown" how long a resource can claim a "reserve shutdown" and whether SPP can deny a resource's request for a reserve shutdown. Additionally Xcel contends that it is not clear how unaffiliated resources in the existing Balancing Authority Areas will communicate with SPP when it becomes the Balancing Authority Area. Xcel also states that the filing lacks a compensation mechanism for delaying or rescheduling outages that have been previously approved.

372. AWEA strongly supports the consolidation of Balancing Authority Areas because it offers a number of benefits for wind integration and for power system efficiency in general.

c. <u>Commission Determination</u>

373. We conditionally accept SPP's proposal to become a consolidated Balancing Authority Area[541] in order to effectuate the Integrated Marketplace. We note that SPP has not finalized the details of the division of responsibilities between itself and the current Balancing Authority Areas, nor has it received NERC certification as the sole Balancing Authority Area. However, as part of SPP's overall proposal to implement the Integrated Marketplace, we find that consolidation of the current 16 separate Balancing Authority Areas in SPP into a single Balancing Authority Area will improve the efficiency of the market, facilitate centralized unit commitment, and provide for centralized Operative Reserve procurement. Thus, we find it reasonable to accept SPP's general proposal to consolidate the Balancing Authority Areas conditioned on SPP fulfilling certain filing commitments.[542]

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[541] The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

[542] *See* MISO Guidance Order, 119 FERC ¶ 61,311 at P 49 (accepting MISO's Ancillary Services Market conditioned on, among other things, the conclusion of

(continued…)

374. We emphasize the importance of SPP concluding its overall consolidation negotiations with the current 16 separate Balancing Authority Areas so that SPP can become the sole Balancing Authority Area and be certified by NERC to centrally manage the Integrated Marketplace. Therefore, we require SPP to complete the Balancing Authority Area negotiations and file the Balancing Authority Area agreement in a compliance filing due no later than June 30, 2013. This deadline will allow sufficient time for the Commission to review the proposal, issue an order, and provide SPP with enough time to be certified as the Balancing Authority Area by NERC.[543]

375. Xcel contends that SPP's proposal to become the sole Balancing Authority Area in SPP lacks sufficient detail regarding the approval and coordination of generation and transmission outages. As discussed above, while we are accepting SPP's proposal to consolidate its current Balancing Authority Areas, approval is conditioned on SPP filing its Balancing Authority Area agreement with the Commission by June 30, 2013 and receiving NERC certification as the single Balancing Authority Area prior to the start of the planned commencement of the Integrated Marketplace. In order to receive the appropriate NERC certification, SPP will be subject to myriad NERC reliability standards, including the requirement to coordinate between a reliability coordinator and its transmission operators and generator operators with respect to outages that could affect the bulk electric system,[544] and requirements governing coordination of generation and transmission outages.[545] Thus, we expect Xcel's requests for clarification will be addressed in SPP's Balancing Authority Area agreement filing and the NERC certification process.

376. We deny Acciona's request to clarify that existing generators should be evaluated as part of the transition to the Integrated Marketplace to receive SPP footprint-wide NRIS on an as available basis before new NRIS requests are processed. Footprint-wide NRIS will be a new service not previously available under the SPP Tariff and, therefore, all generators will need to place a new request for NRIS. Because this will be a new service, we find that it is reasonable to require that all SPP customers submit such a request.

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negotiations regarding consolidation of Balancing Authority Areas and NERC certification of MISO as the sole Balancing Authority Area).

[543] The Commission expects this certification to be included in SPP's Integrated Marketplace final readiness certification application, which is to be filed with the Commission at least 60 days prior to the planned Integrated Marketplace start-up.

[544] *See* NERC Reliability Standard TOP-001.

[545] *See* NERC Reliability Standard TOP-003.

F. Market Power and Mitigation

377. As part of its amended filing, SPP makes several proposals to address the treatment of market power and mitigation in the Integrated Marketplace. These are addressed below.

1. Market Power Study

a. SPP Proposal

378. SPP supports its Integrated Marketplace proposal with a market power study of its proposed ancillary services markets. The study assesses the competitiveness of SPP's proposal to implement market-based procurement for two types of ancillary services, regulation and contingency reserves. SPP's market power study includes the following: (1) a definition of each ancillary services product to be sold at market-based rates; (2) definitions of the relevant geographic markets; (3) estimates of both total demand for the market and total supply available for each ancillary service; (4) a calculation of market shares for each seller within each product market; (5) a calculation of Hirschman-Herfindahl Indices (HHI) for each product market; (6) a pivotal supplier test for each ancillary service; and (7) an analysis of barriers to entry and potential competitors.

379. SPP engaged Potomac Economics, Ltd. (Potomac Economics) to perform the market power study. SPP states that Potomac Economics identifies seven potential relevant geographic markets — the entire SPP footprint and six reserve zones, the reserve zones because they have potential transmission constraints. SPP further states that Potomac Economics identifies two product categories, regulating reserves and contingency reserves. SPP explains that Potomac Economics finds no market power concerns for contingency reserves in the SPP footprint, but does find market power concerns for regulating reserves in both the SPP footprint and reserve zones. Additionally, Potomac Economics finds market power concerns for both products in all of the reserve zones.

b. Protests

380. APPA asserts that SPP's market power study does not provide an adequate analysis of generation market power.[546] TDU Intervenors add that SPP's market power study fails to consider market power for all components of the Integrated Marketplace, specifically for the day-ahead and real-time balancing markets for energy. TDU Intervenors argue that in the operating reserve markets, the market power study finds that in every zone there were many hours in which SPP's largest supplier was pivotal and that

[546] APPA Protest at 4.

the pivotal supplier was able to exert market power. Further, TDU Intervenors conclude that the ancillary services market power study shows that generation ownership in each SPP zone is highly concentrated. Given those ownership concentrations and the absence of an energy-specific market power study, TDU Intervenors presume that an examination of the energy markets would reveal that market power exists whenever transmission constraints or other sourcing restrictions apply.[547]

381. Further, TDU Intervenors argue that because SPP's current EIS market is residual, while the Integrated Marketplace is comprehensive, the opportunities for exercising market power in the Integrated Marketplace are both greater and more serious. TDU Intervenors rely upon the Commission's determination in the EIS Rehearing Order that concluded that the proposed market design at that time was "significantly different from other RTO market structures," in that it (a) lacked a day-ahead market, (b) lacked a "multi-part bidding mechanism to ensure recovery of start-up and minimum load costs," and (c) when it mitigated prices, it tied the mitigated price to the long-run fixed cost of a hypothetical, generic gas turbine."[548] TDU Intervenors also argue that because SPP's Integrated Marketplace design will provide substantial additional market revenues through the day-ahead and real-time balancing markets, the premises upon which the Commission accepted the EIS market no longer apply and increase the need for sufficient mitigation in the Integrated Marketplace.[549]

c. <u>Answers</u>

382. SPP states that it conducted a comprehensive market power study for the EIS market showing that the market will be competitive except in times of transmission congestion.[550] SPP explains that, as with the EIS market, the presence of local market power is assumed only where transmission congestion or local reliability issues stifle competition. Thus, SPP asserts that its reliance upon the EIS market is entirely appropriate and justified inasmuch as the experience gained through five years of EIS market operations confirms that the EIS market has functioned in a workably competitive manner. SPP contests TDU Intervenors' suggestion that the development of the

[547] TDU Intervenors Protest at 37-40.

[548] *Id*. at 42-43 (citing SPP EIS Market Rehearing Order, 116 FERC ¶ 61,289 at PP 20-21). TDU Intervenors also mention mitigation to the long-run fixed cost of a hypothetical efficient generic gas turbine, which is no longer applicable given SPP's revised filing.

[549] *Id*.

[550] SPP May 15 Answer at 6-7.

Integrated Marketplace requires a new energy market power study. According to SPP, TDU Intervenors' claim improperly assumes that the day-ahead market and the real-time balancing market constitute two different products. SPP argues that the day-ahead market is simply a forward market for energy and that the real-time balancing market is the spot market for energy. SPP comments that both markets depend on the same resources and the same transmission facilities, and both generate LMPs through the operation of a security-constrained economic dispatch model. In fact, SPP argues that, with the exception of virtual transactions, the day-ahead market is merely a subset of the real-time balancing market.[551] Finally, SPP asserts that the Commission did not require MISO to submit a market power study for its energy market to support its proposed market design, and that, in fact, MISO did not do so. SPP states that the Commission specifically rejected a request that MISO be required to develop a comprehensive market power study.[552]

d. **Commission Determination**

383. The Commission accepts SPP's market power study for ancillary services. The Commission recognized in Order No. 697 that there is a potential for market power when ancillary services are sold to an RTO or an ISO that has no ability to self-supply ancillary services but, instead, depends on third parties. In cases where the RTO or ISO performs a market analysis demonstrating a lack of market power for those ancillary services, the Commission has approved the sale of certain ancillary services at market-based rates.[553] Further, Order No. 697 notes that the Commission carefully analyzes ancillary service markets in ISOs and RTOs before authorizing market-based rate pricing, ensuring that protections, such as market monitors, are established to reduce the risk that market power can be exercised.[554]

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[551] *Id*.

[552] *Id*. at 9.

[553] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 1069, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Public Citizen, Inc. v. FERC*, 2012 U.S. LEXIS 4820 (U.S. June 25, 2012).

[554] *Id*. P 1071.

384. We find that SPP's market power study for ancillary services provides the information required by Order No. 697 for assessing ancillary services market power in the SPP footprint. The market power study identifies two ancillary services product categories, regulating reserves and contingency reserves, and examines those products for seven potentially relevant geographic areas, the SPP footprint and six reserve zones.

385. With regard to contingency reserves in the entire SPP footprint, the market power study shows that the contingency reserves product market is not concentrated and, therefore, it raises few market power concerns. However, with regard to regulation reserves in the SPP area-wide market and to both products in the reserve zones, the market power study identifies relatively high levels of market concentration that raise market power concerns. In response to these findings, SPP proposes to implement market power mitigation measures that are known to function successfully in other markets.[555] Although we direct SPP to make specific revisions to its market power mitigation proposal that we find are necessary to support a competitive Day 2 market, as discussed in detail below, we find that SPP's revised mitigation measures will mitigate the regulation reserves market power concerns identified in the market power study and remedy market power should it occur within the Integrated Marketplace's ancillary services market.[556]

386. In response to comments from APPA and TDU Intervenors, we do not agree that an additional market power study for energy is needed. First, the Commission notes that any seller wishing to make market-based rate sales of energy within the SPP market will provide in their application a study demonstrating that they do not possess market power. Second, we are accepting, as modified herein, SPP's comprehensive mitigation proposal that will also serve to address energy market power concerns.

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[555] *See, e.g.*, the mitigation measures used by MISO, ISO-NE, and NYISO.

[556] *Cf. Midwest Indep. Trans. Sys Operator, Inc.*, 122 FERC ¶ 61,172, at P 54 (2008) (Finding that even though MISO's reserve market power study identified high levels of market concentration that raise market power concerns, the mitigation measures appropriately address any market power concerns); Order No. 697, FERC Stats. & Regs. ¶ 31,252 (The Commission found that "to the extent a seller seeking to obtain market-based rate authority is relying on existing Commission-approved RTO/ISO market monitoring and mitigation, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns."); *Dominion Energy*, 125 FERC ¶ 61,070 (2008); *PSEG Energy Resources*, 125 FERC ¶ 61,073 (2008).

2. Parameters for Mitigation of Economic Withholding

a. SPP Proposal

387. In its February filing, SPP proposes to extend its mitigation for energy bids, established for its existing EIS market in Attachment AF of its Tariff, to day-ahead and RUC offers and to start-up and no-load offers within those markets. SPP also proposes to add an impact test that would limit the application of the mitigation. SPP proposes to limit mitigation to the times and locations affected by a congested transmission element or a local reliability issue that does not constitute a transmission constraint. For offers that were found to exceed the mitigated level (called an "Offer Cap") and that caused increases in associated LMPs or make whole payments exceeding the impact test, the offer would be mitigated to the Offer Cap which, in the case of energy, was to be the long run marginal cost of a new peaking generator. SPP also proposes mitigation of start-up and no-load offers, basing the mitigated offer primarily upon previously accepted offers.

388. In its May amendment, SPP significantly revises its economic withholding mitigation proposal. SPP adds mitigation of operating reserve offers. It also proposes a conduct test to be used along with the previously proposed impact test.[557] Further, SPP proposes replacing the previously proposed mitigation of energy offers to the long run marginal cost of a new peaking unit, and of start-up and no-load offers to a measure of past accepted offers, with cost-based, resource specific mitigated offers.[558] Dr. Hyatt states that the revised mitigation measures are designed to better reflect the individual incremental energy costs of each registered resource.[559] SPP proposes that mitigated energy offer curves and mitigated start-up and mitigated no-load offers are to be

[557] SPP does not use the labels "conduct test" or "conduct threshold," however, this is what it is applying in its May proposal, and we will use these terms for clarity. In its May amendment, SPP maintains the impact threshold that it proposed in the February filing. Conduct tests compare offers to thresholds levels (either dollar or, in the case of physical offer parameters, non-dollar thresholds) to determine if those offers may be subject to mitigation. If an offer exceeds the conduct threshold level, the impact test is run to determine if the impact of the above conduct threshold offer on the applicable market price exceeds a specified threshold level price increase or if the impact on make whole payments exceeds a specified threshold level. If the offer fails both the conduct and the impact test, it is then subject to mitigation to a reference level. For more on these threshold levels, see the section below on conduct and impact thresholds.

[558] SPP May 15 Transmittal Letter at 6.

[559] Hyatt May 15 Testimony at 7.

developed and submitted by the Market Participant "in accordance with the mitigated offer development guidelines in the Market Protocols."[560]

389. Newly revised section 3 of Attachment AF addresses economic withholding for the day-ahead, RUC, real time balancing market, energy and operating reserves markets. Proposed section 3.1 provides that mitigation will be applied only at the time of, and in places affected by, a congested transmission element or a local reliability issue not represented by a transmission constraint. The overview statement in Section 3.2 provides that when any transmission constraint is binding, the provisions in sub-sections of 3.2 will apply. Within section 3.2, however, section 3.2.2 (Determination of Offer Capped Resources[561]) provides that mitigation measures applicable to energy offer curves, Operating Reserve offers,[562] start-up and no-load offers shall apply to all resources that are committed by the transmission provider to address a local reliability issue not represented by a transmission constraint.

390. Section 3.2.2 further provides that resources that are in a binding reserve zone or on the same side of a transmission constraint as the constrained load ("Offer Capped Resources") may be subject to mitigation measures applicable to energy offer curves, operating reserve offers, start-up offers, and no-load offers. Further, resources that have Resource-to-Load Distribution Factors[563] greater than or equal to five percent shall be

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[560] SPP Tariff, Proposed Attachment AF, sections 3.2.3, 3.2.4.

[561] In its May amendment, SPP continues to use the term "Offer Cap," which is not an accurate description of its revised mitigation for economic withholding, and has a different meaning than the offer caps it provides for in Attachment AE Section 4.1.1 (Offer Caps and Floors) of its Tariff. SPP continues to use the terms "Offer Capped" and "Offer Cap" to describe mitigation of economic withholding despite using a conduct and impact approach. This issue is discussed below.

[562] SPP's original filing did not include mitigation for operating reserve offers.

[563] SPP defines the Resource-to-Load Distribution Factor to be the simulated impact of incremental power output from a specific Resource ("source") on the loading of a specific flowgate based on delivery to a representation of the locational weighting of all loads within all Settlement Locations ("sink"). NAESB defines Generation-to-Load Distribution Factor as the sum of a Generation Shift Factor and a Load Shift Factor. NAESB defines a Generation Shift Factor to be a factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose upon an identified transmission facility or monitored flowgate. Load Shift Factor is a factor to be applied to a load's expected change in demand on such a facility or flowgate.

subject to an energy Offer Cap. Section 3.2.2 provides that resources that have Resource-to-Load Distribution Factors greater than or equal to five percent and that were committed by the transmission provider shall be subject to mitigation of energy, start-up and no-load Offers. If any of a Market Participant's resources are subject to mitigation based on the resource's Resource-to-Load Distribution Factor, all resources represented by the same Market Participant that are located on the importing side of the same constrained flowgate shall be subject to mitigation of energy, start-up and no-load offers. For mitigated offers to be applied, the offer would need to meet these criteria and exceed conduct and impact thresholds. Section 3.2.2 further provides that a list of all resources subject to an energy offer cap and the associated energy offers caps will be posted electronically on a daily basis for each flowgate. Section 3.2.2 provides that all resources, including those resources identified under section 3.2.2, will be settled on the LMP associated with each resource, as described under the settlement procedures in Attachment AE.

391. SPP proposes mitigation measures for time-based resource offer parameters and resource offer parameters expressed in units other than time or dollars in section 3.3 of Attachment AF. Although SPP cites to a non-existent section 3.1.1 of Attachment AF as determining when mitigation applies, it appears that under section 3.1 of Attachment AF this mitigation could occur only at the time of, and in places affected by, a congested transmission element or a local reliability issue not represented by a transmission constraint.

b. <u>Protests</u>

392. APPA states that a number of its SPP members have specific questions about and concerns with the inadequate analysis of generation market power issues and the lack of support for the proposed mitigation methods.[564]

393. TDU Intervenors contend that SPP's proposal does not mitigate market power in the SPP-wide market when market concentration creates market power in the absence of a binding constraint. TDU Intervenors argue that because the proposed mitigation is applied only when transmission is constrained, to the extent that market power exists in the SPP market as a whole during hours when a supplier is singly or jointly pivotal, there is no mitigation to prevent generators from exercising market power to increase the prices for energy or operating reserves above the competitive level.[565]

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[564] APPA Protest at 4.

[565] *Id*. at 62-63.

394. Similarly, TDU Intervenors challenge SPP's proposal for mitigation when and where there is "a local reliability issue not represented by a transmission constraint," arguing that this standard is vague and is not clarified through other provisions or through testimony. They argue that SPP does not explain what it will do when it finds that such a local reliability issue exists and is giving rise to market power. Accordingly, they recommend that the Commission require SPP to explain what it means by "local reliability issue" and ensure that the Tariff language is sufficiently clear for a determination that mitigation applies and will be objectively implemented.[566]

395. E.ON argues that SPP fails to adequately explain how its market monitoring and mitigation procedures will apply to Dispatchable VERs. E.ON asks whether SPP's physical withholding threshold will apply to Dispatchable VERs and how SPP will monitor energy offers of VERs, given the unique characteristics of VERs and their use of forecasts. E.ON also asks how monitoring and mitigation will apply if SPP uses its own forecast rather than offer information submitted by the VER. E.ON requests that the Commission direct SPP to explain how all facets of its market monitoring and mitigation will, or will not, apply to VERs, noting that the Commission required similar clarifications in MISO.[567]

c. <u>Answers</u>

396. SPP filed an answer on May 15, several days before submitting its revised mitigation proposal. SPP states that it currently uses in its EIS market, and plans to continue to use, a five percent "shift-factor cut-off" (the Resource-to-Load Distribution Factor) to make a local market power determination where there is transmission congestion. It states that the same methodology is approved and in use in the MISO marketplace with similar cutoffs for MISO's Broad Constrained Areas.[568]

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[566] *Id*. at 68-69.

[567] E.ON Protest at 15 (citing MISO DIR Order, 134 FERC ¶ 61,141).

[568] SPP May 15 Answer at 11. MISO defines Broad Constrained Areas to be electrical areas in which sufficient competition usually exists even when one or more transmission constraints or reserve constraints are binding, or into which the transmission constraints or reserve constraints bind infrequently, but within which a binding constraint can result in substantial locational market power under certain market or operating conditions. It defines a Narrow Constrained Area to be an electrical area that has been identified by the Independent Market Monitor that is defined by one or more binding transmission constraints or binding reserve constraints that are expected to be binding for at least five hundred hours during a given year and within which one or more suppliers is pivotal.

397. SPP maintains that its market-based operating reserve procurement is supported by its market power study, and that its market plan is not deficient for failing to include mitigation measures applicable to SPP-wide regulation or reserve markets. SPP submits that it followed the independent recommendations of Potomac Economics who found footprint-wide mitigation to be unnecessary. It states that on an annual basis, for regulation up, regulation down, and contingency reserve, Potomac Economics identified a single, region-wide, pivotal supplier for only 87, 96, and 35 hours respectively, which it states is less than one percent of the hours for each product. SPP also states that because a pivotal supplier cannot know with certainty when these pivotal hours occur, this will minimize any opportunity or incentive to attempt to exercise market power. SPP states that the co-optimization of its energy and operating reserve markets increases the substitutability of the products and reduces market power. For example, the costs of regulation-down are limited by the cost to de-commit a resource.[569]

398. SPP also addresses the meaning of a local reliability issue, which might lead to the need for mitigation, by providing the example of a resource that normally would not be committed economically, but that is required to be on-line to address a low voltage issue. SPP states that typically these types of voltage-related issues cannot be directly modeled in the market clearing engines through the use of thermal transmission line constraints. Thus, on occasion, the system operator will instruct the resource to go to a certain level of output and to maintain that level for several hours to address the local, voltage-related issue. SPP argues that while it is unlikely that this resource would have market power if it were not regularly committed, SPP's mitigation rules would allow the Market Monitor to respond if market power is detected. It asserts that market power concerns theoretically could arise if the resource is regularly committed and/or dispatched to address a recurring voltage issue, thus giving the resource the ability to systematically increase its offer price, and making mitigation in such instances reasonable.[570]

399. In response to TDU Intervenors' arguments that more stringent mitigation measures should apply where generators are committed for reliability reasons, SPP states that mitigation measures are in place to detect recurring local reliability problems that are susceptible to remedy only by certain resources.[571]

400. TDU Intervenors, in its June answer, reassert that SPP's Integrated Marketplace proposal is deficient because it fails to provide any market power mitigation to the SPP-wide markets when there is no local constraint. They contend that SPP's arguments are

[569] *Id*. at 11-12.

[570] *Id*. at 13.

[571] *Id*. at 13-14.

unavailing. Specifically, they argue that SPP has offered no evidence that a Market Participant would be unable to determine that it will be a pivotal supplier during a particular period. They also maintain that in a highly concentrated market, sophisticated Market Participants may be able to make accurate estimates as to when they will be pivotal simply by watching the weather. They assert that because the exercise of market power in the SPP-wide market does not depend on the existence of transmission constraints, but instead upon a higher-than-expected need for energy or operating reserves, the danger of tacit collusion is substantially higher during such periods of scarcity. From this premise, TDU Intervenors conclude that a single-pivotal-supplier test may not even capture all opportunities for the exercise of market power. They conclude that the market power study showed that regulation and operating reserves markets are highly concentrated and, thus, energy markets may be as well. [572]

401. TDU Intervenors assert that they agree with SPP's fundamental premise with respect to mitigating when there are local reliability issues, and they believe that it is appropriate for SPP to propose mitigation where a generator knows it is needed to address a recurring constraint. However, they remain concerned that without corresponding tariff language, the mitigation provisions cannot be applied in a consistent and non-discriminatory manner. Thus, they ask that the Commission require SPP to propose Tariff language to clarify the meaning of "local reliability issues."[573]

402. Finally, TDU Intervenors argue that it makes no sense to apply the standard mitigation measures where unit commitments are made outside of the normal unit commitment and dispatch process to resolve local reliability issues because the generator can achieve higher make-whole payments than are purely cost-justified. They argue that, at the very least, the impact threshold should be set to zero in such circumstances, as has been done by NYISO and proposed by MISO.[574]

d. <u>Commission Determination</u>

403. We find that SPP's amendment modifying Attachment AF to provide for mitigation to a generating unit's own costs and to provide for mitigation of operating reserves enhances its mitigation plan. However, we find a number of areas where additional changes are needed with respect to the mitigation and monitoring proposals, as discussed below. We conditionally accept SPP's proposal for mitigation of economic

[572] TDU Intervenors Answer at 14-15.

[573] *Id*. at 16-17.

[574] *Id*.

withholding, subject to the changes, explanations, and reports we require herein.[575] We require SPP to make these changes and provide these explanations in a compliance filing due 90 days after the issuance of this order.

404. In examining SPP's proposal for mitigation and monitoring, we find that stronger mitigation is appropriate in this market than was necessary for SPP's EIS market. In ruling on the proposed EIS market, the Commission stated that it found SPP's mitigation and monitoring plans adequate to ensure just and reasonable rates in the EIS market.[576] The Commission also noted that SPP's EIS market differed substantially from other RTO markets in that it was a market just for the provision of real-time imbalance services; thus, the Commission stated that the need to protect against market power in the imbalance market is offset by each Market Participant's set of resources that are designated to serve its load and any reserve needs.[577] Now that SPP is proposing an integrated market, with associated day-ahead and real-time energy and operating reserve markets, a significantly more comprehensive monitoring and mitigation system is appropriate. We discuss necessary changes to SPP's monitoring and mitigation program below.

405. We find that the combination of conditions in which mitigation will apply under section 3.2 of Attachment AF is not clear, and is in some cases contradictory. First, section 3.2 states that the mitigation measures discussed within that section apply when any transmission constraint is binding, yet section 3.2.2 states that mitigation will occur when there is a local reliability issue not represented by a transmission constraint. Accordingly, we require SPP either to rewrite section 3.2 to explicitly allow for the possibility of mitigation without a binding transmission constraint when there is a local reliability issue, or to put the mitigation associated with such local reliability constraints into a separate section of Attachment AF. We agree with TDU Intervenors that SPP also must provide a definition within its Tariff for "local reliability issue" as it relates to mitigation, and direct SPP to provide that Tariff definition in its compliance filing. As discussed below, we also require SPP's Market Monitor to justify the thresholds it proposes for conduct and impact that would apply when there are local reliability issues.

[575] Finally, we note that SPP will be required either to submit tariff provisions for market power mitigation methods appropriate to redesigned frequency regulation markets or to explain how its Integrated Marketplace mitigation methods are sufficient to address market power associated with frequency regulation, as a part of its Order No. 755 compliance filing.

[576] SPP EIS Market Order, 114 FERC ¶ 61,289 at P 203.

[577] *Id*. P 172.

406. Section 3.2.2 of Attachment AF provides that resources that are in a binding reserve zone or on the same side of a constraint as the constrained load "may" be subject to mitigation measures applicable to energy offer curves, Operating Reserve Offers, start-up offers, and no-load offers. Section 3.2.2 then makes statements about when mitigation "shall" apply. In particular, it states that resources that have Resource-to-Load Distribution Factors greater than or equal to five percent shall be subject to an energy offer cap. Further, it states that resources that have a Resource-to-Load Distribution Factor greater than or equal to five percent shall be subject to an energy "Offer Cap," a default start-up "Offer Cap," and a default no-load "Offer Cap." It states that if any of a Market Participant's resources are subject to the "Offer Cap" based on the Resource-to-Load Distribution Factors, all resources represented by that Market Participant that are located on the importing side of the same constrained flowgate also shall be subject to an energy "Offer Cap," Default start-up "Offer Cap" and/or no-load "Offer Cap."[578] For resources not committed by SPP to deal with local reliability issues, section 3.2.2 does not clearly establish when mitigation is to occur. In particular, it is unclear whether the condition (on if a resource in a binding reserve zone or on the same side of a transmission constraint will be mitigated) is that the resource have the specified Resource-to-Load Distribution factor, or if there are other conditions as well. Accordingly, we require SPP to modify section 3.2.2 of its Tariff to establish clearly that mitigation will occur, in the absence of a local reliability issue, only when there is a binding constraint or a binding reserve zone, *and* the additional conditions relating to the Resource-to-Load Distribution Factors apply.[579]

407. The Tariff language in section 3.2.2 relating to mitigation also appears to set different mitigation standards for operating reserve offers than energy, start-up, and no-load offers. While it is clear that SPP purposefully added mitigation of operating reserves in the May Amendment, section 3.2.2 only establishes mitigation for operating reserve offers when there is a local reliability issue not represented by a transmission constraint. It does not provide for other mitigation of operating reserve offers. In particular, when section 3.2.2 states when mitigation "shall" apply (after discussing when

[578] We find that SPP's use of the term "Offer Cap" is incorrect, and therefore inappropriate as described in more detail below.

[579] As discussed further below, the later condition would relate to the mitigation SPP has proposed that is styled after MISO's Broad Constrained Area mitigation. We are also requiring SPP address the mitigation needs for more frequently constrained areas. We are also requiring frequently constrained area mitigation that would not be associated with the conditions related to Resource-to-Load Distribution Factors. Further, we also require changes to the specific Resource-to-Load Distribution Factor SPP proposes for the Broad Constrained Area-style mitigation, as discussed further below.

it "may" apply with a binding reserve zone or on the same side of a transmission constraint as the constrained load), it provides for mitigation with an energy "Offer Cap," a default start-up "Offer Cap," and default no-load "Offer Cap," without mentioning any mitigation of operating reserve offers. Proposed section 3.2.2 also establishes that resources identified under section 3.2.2 (as subject to mitigation) would be settled based upon the LMP associated with each resource, as described under the settlement procedures in Attachment AE. Clearly, operating reserve offers would need to be settled at the market clearing price for the specific operating reserve, rather than at the LMP. It is not clear why SPP should treat Operating Reserve Offers differently with respect to the general conditions for mitigation. Market participants could potentially exercise market power with respect to Operating Reserve Offers when there are binding transmission constraints or binding reserve zones, and not just when there is a local reliability issue. Accordingly, we require SPP to establish clearly that mitigation of Operating Reserves Offers will occur under the same general conditions discussed in section 3.2.2 of Attachment AF for other resources,[580] and to provide in the last paragraph of proposed section 3.2.2 of Attachment AF that settlement is based on "LMP or market clearing price as applicable."

408. We also require SPP to remove references to the terms "Caps," "Offer Caps" and "Offer Capped Resources" in Attachment AF (and as needed elsewhere in its Tariff) as these terms do not accurately portray the mitigation that SPP is proposing, and the use of these terms may cause confusion. While SPP does provide for general offer caps in section 4.1.1 of its Tariff, SPP's "Offer Caps" as used in Attachment AF are thresholds set at a stated percentage over the mitigated offer level, prescribed in sections 3.2.4, and 3.2.5. SPP uses a conduct test, with conduct thresholds for energy, start-up, no-load, operating reserve offers, and other offer parameters that are tied to the mitigated or default offer levels similar to the mitigation approach used in MISO, New York ISO, and ISO-NE. Under SPP's proposal, entities are allowed to bid in excess of the "Offer Caps" and are not mitigated unless the general conditions for mitigation, as discussed above apply. Accordingly, these levels are conduct thresholds, and are not "Offer Caps," because an "offer cap" imposes a strict maximum limit on an offer, and is not associated with conduct tests. We require SPP to modify its Tariff to use language consistent with that of the other RTOs and to use the terms "conduct threshold(s)" and "reference levels" or "default (with specification of type of service) offer(s)" as appropriate in its Tariff. In addition, because the conduct thresholds are unit-specific (as opposed to market-wide as they were in SPP's February filing), we require SPP to remove the language from section 3.2.2 that provides for the electronic posting of "Energy Offer Caps" of resources

[580] We make a similar requirement below for time-based offer parameters and offer parameters that are neither time nor dollar based.

that are subject to mitigation. Posting of such unit-specific information would reveal confidential information and could facilitate collusion.

409. SPP's proposed mitigation for economic withholding of offer parameters (those that are dollar-based as opposed to time-based, as we discuss later) is tied to a Resource-to-Load Distribution Factor of positive five percent. However, SPP has not defined Resource-to-Load Distribution Factor in its tariff, nor has it explained why five percent is the appropriate Resource-to-Load Distribution Factor cut-off for mitigation in its markets. Without such an explanation, we cannot determine if the appropriate resources' offers are considered for mitigation. We require SPP to explain its choice of cut-off value, including why it has not established a cut-off value for mitigation that will capture uneconomic production[581] on the other side of a constraint (by focusing on a cut-off value of the *absolute value* of the Resource-to-Load Distribution factor rather than just the Resource-to-Load Distribution factor).[582] We also direct SPP to address how often the Resource-to-Load-Distribution Factors that are used in determining the applicability of mitigation will be re-computed.

410. SPP's proposed mitigation for economic withholding of time-based offer parameters and resource offer parameters expressed in units other than time under section 3.3 of Attachment AF is not tied to there being binding constraints and the required Resource-to-Load-Distribution Factor being met, as SPP has provided for other offer parameters. SPP simply states that the mitigation measures in section 3.3 apply to this group of resources and will only apply in the presence of local market power as described in section 3.1.1 of Attachment AF. However, there is no such section. Under SPP's proposal (perhaps because of the missing section), units may be mitigated for changes in these parameters even when they cannot exercise market power. SPP has not addressed any reason for mitigation of time-based offer parameters and non-time and dollar-based economic withholding to differ from mitigation of other economic withholding. Accordingly, we direct SPP to explain the reason for this difference or to revise its Tariff to treat mitigation of these parameters as it does other offer parameters with respect to the

[581] SPP states in Attachment AG section 4.6.1 that uneconomic production by a resource causes congestion on transmission facilities or price separation between Reserve Zones not justified by reliability concerns. A concern related to uneconomic production is that a resource owner could have a resource produce uneconomically and in some circumstances could thereby cause a constraint to bind, and then exercise market power with other units it owns on the other side of the constraint unless mitigation is applied.

[582] In contrast, for example, MISO's Broad Constrained Area mitigation is tied to a default Generation Shift Factor Cutoff of an *absolute value* of six percent or more, rather than being a test for values only greater than 6 percent.

conditions for mitigation, including its Resource-to-Load Distribution factor requirement, as discussed above. SPP should also remove references to non-existent section 3.1.1 of Attachment AF.

411. We also direct SPP to address the need for more stringent mitigation for electrical areas defined by one or more transmission constraints that are expected to be binding for a significant number of hours in the year, within which one or more suppliers is pivotal. Such frequently constrained areas can be expected to be subject to the exercise of market power more often than other areas that may only need mitigation on an intermittent basis. With an expectation that constraints may be binding, more market participants in these areas may find the exercise of market power to be profitable, and thus may try to offer accordingly. We conclude that it may be appropriate to reduce or eliminate the Resource-to-Load Distribution Factor cut-off to ensure that appropriate mitigation can occur for the resources in these areas.[583] Different conduct and impact thresholds, with tighter thresholds for frequently constrained areas also may be necessary. It appears that there are regions on the SPP system that are frequently constrained, making it appropriate for SPP to apply more stringent mitigation where there is a constraint and a pivotal supplier.[584] As a result we require SPP to provide in its Tariff more stringent mitigation in frequently constrained areas, in a manner such as the Narrow Constrained Area mitigation MISO employs. We also require SPP to justify the number of hours of expected binding constraint and any Resource-to-Load Distribution factor it chooses for a designation of an area as a frequently constrained area.

412. Once the Commission approves initial frequently constrained areas (Narrow Constrained Area-type areas) on SPP's system, which will be subject to more stringent mitigation, SPP may subsequently remove the frequently constrained area designation for such an area that is subject to more stringent mitigation. However, SPP may do so only if the Market Monitor determines that the binding transmission constraint or binding

[583] We note that MISO's Tariff is structured so that Narrow Constrained Area mitigation is applied without the Generation Shift Factor threshold; thus, there is mitigation of units that affect a constraint at lower levels than those applied for a Broad Constrained Area impact. Mitigation is also associated with tighter thresholds for Narrow Constrained Areas than Broad Constrained Areas, as discussed below.

[584] *See, e.g.*, SPP's 2011 State of the Market Report at 85, which shows significant periods with constrained flowgates in the Texas Panhandle and the Kansas City area. The report shows the Texas Panhandle experiences constrained flowgates over 18 percent of market intervals, and one flowgate into Kansas City is congested more than 9 percent of intervals. 2011 State of the Market Report, SPP Market Monitoring Unit, published July 9, 2012.

reserve zone constraints that define the zone are expected to be binding less than the requisite number of hours in the calendar year. We direct SPP to provide in its Tariff that it will seek Commission approval before designation of any additional frequently constrained areas for the purpose of mitigation, and for any change or removal of such designations for reasons other than an expectation that there will be insufficient hours of constraint for them to be so designated.

413. We believe that the addition of frequently constrained area mitigation, along with the other required changes to SPP's proposed mitigation should address the potential for the exercise of market power by economic withholding in the SPP Integrated Marketplace. The report on the potential for the exercise of market power in SPP's Integrated Marketplace developed by Potomac Economics shows that the exercise of market power is unlikely with respect to operating reserves and is effectively dealt with by mitigation. This conclusion is based upon Potomac Economics' analysis that hours with pivotal suppliers are rare, and because co-optimization of markets allows for substitution between energy and operating reserves. SPP's experience with its EIS market has not shown a need for market-wide mitigation of energy in the absence of a binding constraint or a local reliability event. We believe that the addition of frequently constrained area mitigation associated with a pivotal supplier should further address any additional need for mitigation.[585] Further, given the overall offer caps in the market established in section 4.1.1 of SPP's Tariff, we believe that provisions for market wide mitigation (i.e. in areas without binding constraints or a local reliability issue) are not necessary in the SPP Integrated Marketplace at this time.[586] We require an informational report 15 months following commencement of the Integrated Marketplace reflecting a full 12 months of data that includes any recommended changes to the mitigation measures. SPP must also discuss any need for mitigation when there is no binding constraint. The report must detail any evidence of the exercise of market power by Market Participants in the first year of operations that is not addressed by SPP's market mitigation.

414. We direct SPP to address the issues E.ON raises and how its market monitoring and mitigation procedures will apply to VERs. This explanation must include information on economic withholding, physical withholding, unavailability of facilities and uneconomic production.

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[585] We note that MISO's mitigation, upon which SPP has based its proposal, is tied to the existence of a binding constraint.

[586] Section 4.1.1 establishes a safety-net Energy Offer Cap of $1,000/MWh, a Regulation Offer Cap of $500, and a Contingency Reserve Offer Cap of $100.

415. Because SPP establishes in Attachment AF section 3.2.2 that its mitigation applies to resources and SPP defines resources to include demand response resources,[587] it appears that all the mitigation proposed will apply equally to demand response resources and to generators. SPP has not identified its concerns regarding the potential exercise of market power by demand response resources and has not analyzed demand response resources in its market power study. Further, SPP has not explained how its proposed conduct and impact tests would apply to demand response resources and how these tests would be effective in determining whether a demand response resource is exercising market power. Additionally, SPP has not explained how the proposed methods for calculating bid reference levels would be effective in mitigating attempts by demand response resources to exercise any market power that they have. We recognize the importance of ensuring the comparable treatment of demand response resources in SPP's markets, including the ability of such resources to help mitigate market power in the market.[588] Accordingly we require SPP to explain whether it intends to mitigate demand response, and if so, how it will determine if a demand response resource is exercising market power. Further, if SPP intends to mitigate demand response offers, we require SPP to discuss the reference levels and conduct and impact thresholds under which they would do so.

416. Finally, we note that the title of section 3 of Attachment AF is "Mitigation Measures for Economic Withholding -- Energy Market Power," even though now there are provisions for mitigation in operating reserves. Accordingly, we require SPP to amend the title to include operating reserves. The amended title should be "Mitigation Measures for Economic Withholding —Market Power in Energy and Operating Reserves."

3. Mitigated Offer Development

a. SPP Proposal

417. Under SPP's revised proposal, mitigated energy, operating reserves, start-up, and no-load offers are to be developed and submitted each day by the Market Participant, in accordance with mitigated offer development guidelines to be set forth in Appendix G of SPP's Integrated Market Protocols. Dr. Hyatt's testimony states that the guidelines will be developed by SPP's Market Monitor and a sub-group of the SPP Market Working Group, and are expected to be completed in 2012.[589] SPP's transmittal letter provides

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[587] *See, e.g.,* SPP Tariff, Proposed Attachment AE, section 4.1.2.1.

[588] *Midwest Indep. Transmission Sys. Operator,* 122 FERC ¶ 61,172 at P 189.

[589] SPP Amendment, Hyatt Testimony at 6.

that the mitigated offers will be cost-based. Further, SPP explains that the guidelines, will be similar to those used by PJM to develop cost-based offers, and will specify acceptable practices for calculating incremental energy, start-up, no-load, and opportunity costs for inclusion in a mitigated offer.[590]

b. Protests

418. TDU Intervenors assert that the Commission cannot determine whether SPP's amended market power mitigation provisions will ensure just and reasonable market prices without understanding the details of the mitigated offers that are intended to protect consumers from the exercise of market power. They maintain that the rules for Market Participants to develop and submit their offers must be set forth in the Tariff, given their direct and vital role in the pricing of energy and ancillary services. They argue that the Commission should direct SPP to submit proposed Tariff provisions as soon as possible outlining the processes and standards for Market Participants to establish their mitigated offers.[591]

c. Answers

419. SPP disagrees with TDU Intervenors that the mitigated offer development guidelines must be filed as a part of the OATT. SPP argues that every guideline will be vetted thoroughly by stakeholders and will be the result of consensus stakeholder approval. It maintains that placing the guidelines in non-tariff Market Protocols is consistent with the approach followed in PJM. SPP notes that PJM describes the components of offer price caps in Schedule 2 of its Operating Agreement, but includes detailed discussion and computation of costs in its Cost Development Task Force Manual.[592] SPP asserts that including the mitigated offer development guidelines in the

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[590] SPP May 15 Transmittal at 5 and n.14. Under SPP's proposal, like MISO, when an offer exceeds the reference level by a certain amount (the threshold) and the other conditions for mitigation are met, mitigation occurs to that reference level.

[591] TDU Intervenors June Reply and Protest at 5.

[592] PJM provides a statement of the costs that may be included in cost-based offers on its system in Schedule 2 of its Operating Agreement. It provides in section 6.4.2 of Schedule 1 of that Agreement that one of the ways that its offer cap may be determined is to set them to be the incremental operating costs plus 10 percent of such costs. Other methods for determining those offer caps include (1) using the weighted average of the LMPs at the delivery bus, with the hours over which the averaging is to occur to be determined by PJM's Office of Interconnection, and (2) variable costs plus given percentages of such costs, depending on the frequency with which the generator's unit is

(continued…)

Market Protocols will facilitate more timely adjustments in the event the Market Monitor, either on its own, or in response to a stakeholder initiative, determines that the guidelines require modification. SPP also notes that the guidelines will serve only to establish inputs to mitigated offer prices, which are then adjusted to set offer thresholds above which offers cannot go without being subject to a market impact test before there is a determination that mitigation will be applied. Accordingly, SPP asserts that while there is a connection between offer guidelines/inputs and market prices, the connection is not so direct that, under Commission precedent, tariff incorporation is required.[593]

d. Commission Determination

420. SPP proposes that the mitigated offers for all offer inputs (except time parameters and other offer parameters that are non-dollar based) be submitted by the Market Participant each day, and that they be developed by the Market Participant consistent with the formula(s) that will be developed and placed in the Market Protocols. While SPP notes that inputs are adjusted to set offer thresholds, it describes neither the inputs nor the adjustments in any detail. SPP's proposal lacks sufficient information on the development of mitigated offers. Accordingly, we require SPP to include the details for development of mitigated offers for energy, each type of operating reserve, start-up and no-load in its Tariff, along with clear definition and explanation of the formula terms.[594] We require SPP to make these changes in a compliance filing due 90 days after the issuance of this order. SPP has stated that offers would be mitigated to incremental costs; however, SPP must be more specific and establish that offers are to be mitigated to their short run marginal costs of the generating unit. Further, SPP must define the costs to be measured in the short run marginal costs. SPP mentions opportunity costs as a part of the costs to be included in the mitigated offer. However, SPP's statement is unacceptably vague. In order for SPP to include opportunity cost in mitigate offers, the method for determining opportunity cost must be fully specified in SPP's Tariff.

421. SPP has proposed the submission of mitigated offers by Market Participants. It proposes placing guidelines for the development of such offers in SPP's Market Protocols, asserting that this is comparable to the approach used in PJM. However, we find that SPP has failed to discuss a major component of PJM's approach, the

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offer capped. PJM's Manual 15: Cost Development Guidelines provide detailed information on the calculation of costs for inclusion in cost based offers.

[593] SPP June 26 Answer at 8-9.

[594] Further details associated with the exact costs could then be included in the Market Protocols, to allow for changes in the implementation but not the concept of such changes, without necessitating changes to tariff language.

involvement of the Market Monitor in assuring that the offers are constructed appropriately using those guidelines. PJM's Manual 15 contains numerous references to the role of the PJM Market Monitor, including its role to verify that the individual cost-based offers are properly developed using PJM's guidelines.[595] In contrast, SPP provides in the Tariff only that intra-day revisions to the mitigated offer curve will be reviewed by the Market Monitor.[596] It does not provide for examination of the inputs to that mitigated offer curve or other general monitoring of the mitigated offer curve.

422. Accordingly, we are concerned about SPP's proposal for the submission of mitigated offers by the Market Participant, rather than their creation by an experienced disinterested party, such as the Market Monitor or SPP itself. Mitigated offer submission by the Market Participant would provide opportunities for either inadvertent miscalculation or intentional padding of the offers. SPP does not discuss review of offers, beyond intra-day changes to offers, nor does it discuss the timeliness with which its Market Monitor will conduct any review. We conditionally accept SPP's proposal for determination of mitigated offers, subject to SPP explaining in a compliance filing due 90 days after the issuance of this order, how it will provide for monitoring mitigated offers of Market Participants to ensure that the Market Participants apply the formula and definitions of costs correctly. Should SPP be unable to demonstrate adequate monitoring for submission of appropriate mitigated offers, SPP must revise its proposal to provide that SPP or SPP's Market Monitor develop the mitigated offers and to provide for substitution of those offers when the conditions for mitigation of economic withholding are met.[597]

423. We also note that the other RTO markets provide for the determination of mitigated offers by basing them on accepted offers, or market prices during similar periods. For example, the MISO market determines its reference levels for mitigation (and also its default offer levels when mitigation is applied) based first upon accepted

[595] *See*, *e.g.*, section 2.4.2 of PJM's Manual 15 which provides that engineering judgment in start-up costs must be made available to the PJM Market Monitoring Unit and PJM.

[596] SPP Tariff, Proposed Attachment AF section 3.2.3.

[597] While it is the RTO/ISO that conducts prospective mitigation, the Commission provided in Order No. 719 that the market monitor may provide inputs to that process. Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 375. The determination of the amount and other parameters of an offer constitute an input to the mitigation process and, thus, may be delegated to the market monitor.

offers, then upon market prices, before turning to the unit's costs.[598] Similarly, PJM allows determination of the offer cap as a function of a weighted average market price, rather than as a function of the costs of the unit.[599] By basing reference levels upon accepted offers and market prices during similar periods, the mitigation offers may be more easily updated to reflect changes in costs associated with market conditions. We encourage SPP to provide for mitigated offers calculated in these manners, rather than solely allowing mitigated offer determination based upon costs.

4. Conduct and Impact Thresholds

a. SPP Proposal

424. SPP proposes a conduct threshold of a 25 percent increase over the mitigated offer for start-up, no-load, and Operating Reserve Offers.[600] It proposes a conduct threshold for energy that varies according to whether the resource is subject to mitigation for 2,000 hours or more per year.[601] SPP proposes an energy offer curve conduct threshold of a 25 percent increase above the mitigated energy offer curve for all resources that are subject to mitigation according to section 3.2.2 for less than 2,000 hours per year. For resources that are subject to mitigation for 2,000 hours or more, SPP proposes a potentially higher energy offer curve threshold of the greater of 25 percent or a $50 increase above the mitigated energy offer curve. SPP proposes to mitigate bids that meet the general conditions for mitigation (discussed above) and that fail their proposed conduct and impact tests. In section 3.4 of Attachment AF, SPP proposes an impact threshold at market start for energy, operating reserve, start-up, and no-load offers of a

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[598] MISO Tariff, Module D section 64.1.4.

[599] PJM Operating Agreement Schedule 1 section 6.4.2.

[600] SPP establishes the thresholds in Attachment AF, sections 3.2.3, 3.2.4, and 3.2.5. In the case of energy offers, SPP establishes in section 3.2.3 that the energy offer curve threshold "is a 25% increase above the mitigated Energy Offer Curve for all Resources that are subject to mitigation…" as opposed to it providing thresholds for other offer parameters. "The offer threshold is…. a 25% increase above the mitigated offer for the applicable … offer." Accordingly, in the case of energy offers, the proposed language could be read as being tied to the group of energy offers from a variety of resources (such as all resources in the market) rather than the individual resource's energy offer. As SPP revisits its thresholds, as required below, it should provide clearer language that reflects its intent in setting the threshold levels.

[601] However, in no case would offers lower than $10/MWh for operating reserves, and $25/MWh for energy be mitigated.

$5/MWh increase in the LMP or in make whole payments. At the beginning of each six month period thereafter, the impact thresholds will be increased by $10/MWh, unless the Market Monitor finds market behavior that warrants keeping the threshold constant for the next six months. SPP proposes that periodic increases will continue until the impact thresholds reach $25/MWh.[602]

425. In the SPP amendment, SPP submitted testimony from Dr. Hyatt who states that there are uncertainties for Market Participants associated with their mitigated offers, and that it is well-accepted that flexibility is needed in comparing hourly offers to reference levels. He states that PJM, MISO, ISO-NE and New York ISO all use a similar methodology for establishing a range of acceptable offers, but that the amount of flexibility in the offers varies between markets. He provides the example of PJM using a threshold for energy offers of 10 percent over the reference offer, while MISO and ISO-NE use a (conduct) threshold of the lower of $100 or 300 percent over the reference offer.[603] Dr. Hyatt maintains that the thresholds in place at MISO and ISO-NE reflect the higher level of uncertainty associated with their reference level approach and, thus, the need for more flexibility. Dr. Hyatt asserts that the methodology used by SPP, like that of PJM, is thought to have less uncertainty because Market Participants can include more accurate information in the mitigated offer submission. Dr. Hyatt argues that because uncertainty remains, some flexibility is needed. He states that SPP stakeholders agreed that a threshold of 25 percent above the reference level would provide an acceptable offer range, and SPP's Market Monitor agreed.[604]

426. Proposed section 3.3 of Attachment AF provides for a conduct threshold for physical capability offers.[605] It uses an increase of three hours or an increase of six hours in total for multiple time-based resource offer parameters. For resource offer parameters expressed in units other than time or dollars, it provides for a conduct test of 100 percent increase for parameters that are minimum values, or a 50 percent decrease for parameters that are maximum values. Section 3.3 requires the Market Monitor to initiate a discussion with the Market Participant concerning the parameter changes, should the effects of the parameter change exceed the impact test. The Tariff provides that if the

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[602] SPP also proposes thresholds for time-based offer parameters and for parameters expressed in units other than time or dollars.

[603] We note that the implication of the thresholds differ between PJM and the other RTOs cited as we explain in more detail below.

[604] SPP Transmittal, Exh. No. SPP-5, Hyatt Supplemental Testimony at 9.

[605] An example of such parameters would be start-up times, minimum run times, minimum down times, or ramp rates.

Transmission Provider, in consultation with the Market Monitor, concludes that the Market Participant has demonstrated the validity of the submitted resource parameter, no further action will be taken.

427. Dr. Hyatt testifies that the proposed SPP thresholds for price impact are based on an historical analysis of the system marginal price for the EIS market. He states that the \$25/MWh impact test value represents the standard deviation for the system marginal price over the last three years. On the basis of these data, he states that price changes of up to \$25/MWh are consistent with the operation of competitive forces in the SPP electric market and are not indicative of the exercise of market power. He notes that upon a determination by SPP's Market Monitor that market behavior does not warrant an increase in the thresholds (as proposed for six month periods until the impact threshold reaches \$25), the Market Monitor may freeze the threshold for any successive six month period.[606]

b. <u>Protests and Answers</u>

428. TDU Intervenors argue in their April protest to SPP's initial filing that SPP has failed to justify the impact test.[607] They state that, as a threshold matter, SPP has not shown why, given other opportunities for cost recovery under the market rules proposed initially, it would be just and reasonable to implement any market impact test.

429. TDU Intervenors contend that other RTOs such as NYISO and MISO have discovered that the market power mitigation provisions they adopted were insufficient to keep generators from obtaining supra-competitive make whole payments, even when LMPs are competitive. They argue that, due to reliability concerns, NYISO has adopted stringent criteria for economic and physical withholding where a generator is pivotal. They argue that MISO is proposing conduct and impact tests that apply specifically when there are voltage and local reliability problems, with a conduct test of an offer 10 percent over cost and an impact test of \$0. TDU Intervenors ask the Commission to require SPP

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[606] SPP Transmittal, Exh. No. SPP-5, Hyatt Supplemental Test at 10-11. As is the case with the contents of an offer, threshold levels for conduct and impact tests are inputs to the mitigation process that can be delegated to the market monitor. *See* Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 375.

[607] TDU Intervenors calculated that a supplier would have been able to offer a price more than six times higher than in other RTOs and would have been mitigated to a price that was more than 18 times higher than other RTOs. These provisions were replaced in the May Filing by SPP.

to adopt more stringent mitigation measures for make-whole payments, when generators are needed for reliability.[608]

430. SPP states that the $25/MWh impact test represents the standard deviation for system marginal price over the last three years, and that based on these data, SPP's Market Monitor concluded that price changes up to $25 are consistent with the operation of competitive forces in the SPP electricity market, and are not indicative of market power.[609]

431. SPP elaborates on the definition of a "local reliability issue," providing the example of a resource that the system operator instructs to go to a certain level of output and to maintain it for several hours in order to address a local voltage reliability issue. SPP contends that typically, voltage-related issues cannot be directly modeled in the market clearing engines through the use of thermal transmission line constraints. SPP argues that its mitigation rules allow the Market Monitor to respond in the event that the presence of market power is detected. In response to TDU Intervenors' concerns that more stringent mitigation measures should apply to make whole payments, where generators must be committed for reliability, SPP responds that the mitigation measures proposed detect local reliability problems that are susceptible to remedy only by certain resources.[610]

432. TDU Intervenors argue that it is impossible to determine if SPP's proposed mitigated offer development guidelines will produce effectively mitigated offers.[611] They argue that the Commission should find that the proposed conduct offer threshold in the revised proposal will permit unjust and unreasonable market prices because it will allow generators with market power to charge at least 25 percent above their incremental energy cost (their mitigated energy offer level), or the mitigated offers for start-up, no-load, and operating reserves, or potentially up to $50 in the case of energy offers for resources subject to mitigation for 2,000 hours or more in a year. According to TDU Intervenors, in a competitive market, resource owners are motivated to offer their generation at something close to their short-run marginal costs, but the 25 percent conduct offer threshold allows offers significantly above marginal costs. TDU Intervenors assert that market concentrations as high as shown in SPP's study can be

[608] TDU Intervenors Protest at 70.

[609] SPP May Answer at 12.

[610] *Id*. at 13-4.

[611] TDU Intervenors Answer at 4-5.

expected to produce prices that exceed just and reasonable rates, with suppliers with market power receiving supra-competitive prices of 25 percent or more.[612]

433. TDU Intervenors challenge SPP's justification for these thresholds, stating that SPP in no way quantifies the "uncertainties" for which offer price flexibility is needed, other than to state that the mitigated offers are placed several hours prior to actual generation and the incurrence of associated costs. TDU Intervenors also argue that comparisons SPP makes to the higher conduct thresholds in other RTOs are inapposite. They point to SPP not providing more stringent mitigation in more frequently constrained areas, which the other RTOs provide. They argue that very high concentrations and pivotal supplier levels shown in SPP's market study are of sufficient concern that it would be inappropriate to rely on the offer thresholds applicable to the relatively unconstrained areas in MISO and ISO-NE. Moreover, TDU Intervenors state that the MISO and ISO-NE do not have Market Participants providing their own mitigated offers and argue that it is highly unlikely that a generator would underestimate its costs by 25 percent.[613]

434. TDU Intervenors assert that SPP has not made a relevant distinction between the PJM and SPP markets that would justify the use of a conduct offer threshold of 25 percent over mitigated levels, as opposed to a 10 percent threshold. They argue that SPP's inclusion of a separate impact test as compared to PJM's market having none, suggests that SPP's offer thresholds will result in less flexibility than PJM's (i.e. under 10 percent), not more. They further argue that SPP's justification that stakeholders have agreed on the offer thresholds is insufficient, as the Commission cannot delegate its statutory authority to ensure that rates in SPP's new integrated market place will be just and reasonable. TDU Intervenors argue that SPP should be directed to implement offer thresholds that are no higher than the PJM threshold of 10 percent threshold over mitigated offers.[614]

435. TDU Intervenors also argue that SPP has not justified setting the conduct offer threshold at the greater of 25 percent or $50 over the mitigated energy offer curve for resources that are subject to mitigation for 2,000 hours or more per year. They state that by way of comparison, in MISO's Narrow Constrained Areas, the offer threshold is set at Net Annual Fixed Cost divided by the hours of constraint (500 to no more than 2,000), and provide an example with a $26 mitigated price in the MISO North WUMS Narrow Constrained Area as compared to a $90 mitigated price in SPP (assuming $40

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[612] *Id*. at 6-7.

[613] *Id*. at 8-9.

[614] *Id*. at 9-10.

incremental cost and $50 threshold over that level).[615] TDU Intervenors maintain that resources in areas with more severe locational market power concerns should be subject to lower thresholds (tighter mitigation) rather than higher thresholds. It notes that SPP has failed to justify the higher thresholds. TDU Intervenors also assert that even if the higher threshold is designed to allow recovery of fixed costs, the threshold is poorly designed as it bears no relationship to a resource's fixed costs or to the proportion of those costs it will recover from centralized market during the hours when it is not mitigated, or from regulated retail service and wholesale bilateral sales. TDU Intervenors contend that recovery of fixed costs may be inappropriate where entry is unnecessary.[616]

436. TDU Intervenors continue to argue against SPP's proposed use of an impact test in its mitigation proposal, stating that SPP fails to justify implementing of a market impact test that will weaken the overall market power mitigation measures, and which they state will result in unjust and unreasonable prices when sellers can exercise market power. TDU Intervenors note that the standard deviation for system marginal price over the last three years would include effects of both competition and the exercise of market power. This is especially true given that SPP's current EIS mitigation measures (mitigation to the cost of a new natural gas fired combustion turbine peaking generation facility) are more lax than those of other RTOs. Furthermore, TDU Intervenors assert that these lax mitigation measures have allowed substantial exercise of market power without mitigation. They argue that any exercise of market power leads to supra-competitive prices even if the impact is small, and that "not even a little unlawfulness is permitted."[617]

437. TDU Intervenors argue that SPP's answer acknowledges that a generator can know that it is able to increase its offer price and Make-Whole Payments when there is a local reliability issue. Accordingly, they assert that the impact threshold should be set to zero in those circumstances, as NYISO has done and MISO has proposed.[618]

438. In contrast, Golden Spread argues changes to SPP's market power mitigation do not address its core concern that, when there is a binding transmission constraint, Market Participants do not necessarily have market power. It states that it has added all of its

[615] We note that in MISO's determination of Net Annual Fixed Costs, the revenues from other sources are netted out prior to the calculation. *See* MISO Tariff, Module D section 64.1.2.d.

[616] TDU Intervenors Answer at 10-11.

[617] *Id*. at 11-13 (quoting *Farmers Union Cent. Exch. v. FERC*, 734 F.2d 1486, 1507-08 (D.C. Cir. 1984)).

[618] *Id*. at 16-17.

new dispatchable generation in areas that SPP shows as congested 3,000 to 4,000 hours per year. It states that despite this showing of congestion, for 50 percent of this new generation, the variable cost is greater than the market clearing price as represented by the EIS market's locational price during most of these periods of congestion. Golden Spread is concerned that SPP's proposed mitigation will make it even more difficult for Market Participants with new, high capital cost generation.[619]

439. SPP replies that TDU Intervenors, in advocating a lower conduct offer threshold such as PJM's thresholds and those in MISO's North WUMS[620] inappropriately ignore the significantly higher thresholds in use in ISO-NE and in other MISO Narrow Constrained Areas.[621] It notes that the North WUMS area, with its threshold of $26 over short-run marginal costs, is the only threshold that is less than $50 over short-run marginal costs. It also notes that the WUMS threshold is not $26. Rather, assuming a short-run marginal cost of $40, it would be $66 ($26 above the short-run marginal cost), as compared to the potential $90 threshold in SPP in frequently constrained areas. SPP points to thresholds in MISO's other Narrow Constrained Areas of $104 and $136.[622]

440. SPP asserts that its proposed mitigation measures are the product of extensive deliberation by and between SPP's Market Monitor and stakeholder groups. It states that they are modeled after mitigation plans adopted in approved regional markets and, for most elements, reflect middle ground positions relative to the other RTOs. SPP maintains that the Commission should therefore reject protests to SPP's proposed mitigation measures.[623]

c. <u>Commission Determination</u>

441. Mitigation measures can not be accepted simply because they are the result of stakeholder agreement. The Commission has an obligation to ensure that mitigation prevents the exercise of market power and results in just and reasonable rates, consistent

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[619] Golden Spread June Protest at 3.

[620] In the MISO market, the North WUMS (Wisconsin Upper Michigan System) Narrow Constrained Area contains portions of Wisconsin and Upper Michigan. MISO's 2011 State of the Market Report at 9 states that North WUMS was the most congested area in MISO in 2011.

[621] SPP June 26 Answer at 9.

[622] SPP June 26 Answer at 9-10.

[623] *Id*. at 10-11.

with workable competition. We agree with TDU Intervenors that SPP has not provided sufficient justification for its conduct and impact thresholds, especially given that SPP did not provide sufficient information regarding how it will determine mitigated offers, sufficient monitoring for the creation of such offers, and because it did not sufficiently address mitigation needs for more frequently constrained areas. We are not persuaded by SPP's argument that basing its price impact threshold on an historical analysis of the standard deviation for the system marginal price over the last three years is consistent with the appropriate mitigation in the SPP Integrated Marketplace. If there are areas that are often subject to the exercise of market power, this standard could allow unjust and unreasonable rates. In addition, SPP does not address the reasoning for its thresholds for the different operating reserve products, and for start-up and no-load offers. Further, SPP's justification of the proposed impact threshold also does not address why movements of the system marginal price for energy should be used to determine when operating reserves, start-up or no-load offers should be mitigated.

442. However, given the changes to mitigation that we are requiring SPP to make in a compliance filing due 90 days after the issuance of this order, we do not believe that PJM's conduct threshold (as advocated by TDU Intervenors) and its lack of an impact threshold is the appropriate mitigation model for the SPP market. It is important to note that PJM's mitigation model differs from SPP's proposed (and amended) model in several ways. Rather than having a conduct and impact test approach, PJM has a 10 percent offer cap that applies when a variety of conditions related to market power exist. PJM's 10 percent adder above marginal costs determines an offer that applies if the offer is mitigated, as compared to the other RTOs and to SPP's proposal in which mitigation causes the offer to fall to the unit's short-run marginal costs (i.e., in SPP the offer would *not* be mitigated to 125 percent of the marginal costs). In PJM, in that circumstance, offers are capped at 10 percent over the variable costs of the unit. In contrast, should mitigation occur for a unit that violates the conduct and impact tests in the SPP market, the offer will not be mitigated to 25 percent over its variable cost level, rather it will be mitigated to its variable costs. Accordingly, the PJM thresholds are not just and reasonable as applied to SPP's market.[624]

443. We also require changes to several aspects of SPP's mitigation proposal that address many of the concerns raised by TDU Intervenors. In particular, we require SPP

[624] PJM's 10 percent adder over the reference offer applies only to those offers that are determined as a function of incremental costs and not to those reference offers that are determined as a weighted average of LMPs at the associated generation bus. We also note that PJM provides for different percentage adders depending on the frequency with which units are mitigated as a percentage of their run hours. *See* PJM Operating Agreement Schedule 1 section 6.4.2.

to specify in its Tariff the formulas by which mitigated offers are to be developed, and to provide for appropriate monitoring of the development of offers under the guidelines or to have those cost-based offer mitigation levels developed by the Market Monitor. We also require SPP to further address mitigation in frequently constrained areas on SPP. We require SPP to propose tighter mitigation and to address the need for tighter conduct and impact tests for these frequently constrained areas than on other areas associated with Broad Constrained Area-type mitigation.

444. SPP's proposed thresholds for Broad Constrained Area-type mitigation are lower than those of other RTOs using conduct and impact mitigation, across the offer types (energy, operating reserves, start-up, and no-load) except in the limited circumstance of mitigation associated with local reliability issues which we address below. Indeed, the thresholds are substantially lower for each of the offer types, except time- and non dollar-based parameters, than those of other RTOs using conduct and impact style mitigation. This may be appropriate given daily development of mitigated offers by Market Participants that could result in less uncertainty with respect to some costs than if mitigated offers were developed in advance by the Market Monitor.[625] However, we require SPP to provide for mitigated offer development by the Market Monitor if SPP cannot show how it will monitor mitigated offers of Market Participants to ensure that they apply the formula for mitigated offers and associated definitions of costs accurately. In that circumstance, the thresholds that SPP has provided may lead to over-mitigation. Accordingly, in a compliance filing due 90 days after the issuance of this order, we direct SPP to justify its conduct and impact thresholds for prices and make whole payments for energy, operating reserve, start-up, and no-load offer parameters.

445. We also direct SPP to revise its thresholds for conduct and impact associated with voltage and local reliability commitment events.[626] We find that more stringent

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[625] For example, there should be less uncertainty with respect to the Market Participant's opportunity costs including those associated with regulatory, environmental, technical or other limitations that limit the run-time or other operating characteristics of a generation resource. We expect, however, that the Market Monitor would incorporate changes in fuel prices into reference or default offers, however, making this not a substantive factor in the reduced uncertainty associated with a participant created mitigated offer.

[626] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,171, at PP 116, 118 (2012). MISO proposed a conduct threshold tied to the increase in total production costs due to an increase in the Market Participant submitted offer from the applicable reference level for the generation resource, and to uneconomic production levels. Its impact threshold to determine a substantial effect upon day-ahead or real-time

(continued…)

economic withholding thresholds are necessary to prevent market participants with resources that are committed due to voltage and local reliability events from exercising market power by submitting bid levels or bidding parameters substantially different from their reference levels. Also, we require SPP to address if tighter thresholds are needed, to identify uneconomic production to address situations where a generation resource is committed to address a local reliability event.[627]

446. In response to Golden Spread's concerns about being unable to recover its costs in frequently constrained areas if mitigation occurs at the variable cost, we note that the proposed mitigation is designed to address the exercise of market power and to ensure that market prices clear at competitive levels. We find that SPP's proposal to mitigate resources based on marginal cost is appropriate in ensuring competitive market results and we disagree that such a mitigation approach will inappropriately impact the ability of resources to recover fixed costs. Accordingly, we are not persuaded that Golden Spread's concern regarding fixed cost recovery warrants any modification to SPP's proposal.

447. We also require SPP to modify section 3.4 of Attachment AF such that the impact test also addresses the price impact on energy *or* on operating reserves, i.e., it should address impacts upon market clearing prices as well as upon LMPs. We will require SPP to make this change in a compliance filing due 90 days after the issuance of this order. Finally, we note that SPP has provided for a Market Monitor consultation for offer parameters that are time-based and that are expressed in units other than time or dollars that may potentially forestall the mitigation of valid offers that fail the conduct and impact tests. However, it does not appear to allow such consultation and lack of mitigation under similar circumstances for other offer parameters. Accordingly, we require SPP to provide that the Market Monitor shall, as soon as practicable and if warranted in light of the information available to the Market Monitor, contact the Market Participant to request an explanation of the conduct in cases when the Market Participant's offer has exceeded the conduct and impact levels. Also, we require SPP to provide that if a Market Participant anticipates submitting an offer that will exceed the relevant conduct threshold, it may contact the Market Monitor to provide an explanation of the changes in its offer. Further, we require SPP to provide that if the Market Participant's explanation indicates to the Market Monitor that the questioned behavior is consistent with competitive behavior; in such instances, SPP will not conduct mitigation with respect to that offer unless and until circumstances appear to warrant it, and SPP or

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revenue sufficiency guarantee credits paid to resources with voltage and local reliability commitments is $0 per MW per hour. MISO Tariff Section 64.1.2.

[627] *Id*. P 117.

the Market Monitor so notifies the Market Participant. We require SPP to include in Attachment AF a requirement that the Market Monitor will record instances where, after Market Participants have notified the Market Monitor with an explanation of the offer prior to submitting an offer that will fail the conduct test, the offer subsequently fails the conduct and impact screens but, due to consultation, the Market Monitor has determined that mitigation would not be appropriate. We require SPP to include in Attachment AF language that provides that SPP's Market Monitor will report on such instances to the Commission's Office of Enforcement every three months during the first year of Integrated Market operations, and yearly thereafter. To the extent that the report contains sensitive data, SPP should include any such data in a non-public portion (or version) of the report. We require SPP to make the required changes in a compliance filing due 90 days after the issuance of this order.

5. Physical Withholding and Unavailability of Facilities

a. SPP Proposal

448. SPP details mitigation for economic withholding and excessive price divergence associated with virtual bids in Attachment AF. SPP outlines its Market Monitoring Plan in Attachment AG of its Tariff. Within AG, SPP discusses physical withholding by transmission owners and unavailability of transmission facilities. In section 4.6 of Attachment AG, SPP provides that the Market Monitor will monitor SPP's markets and services for potential abuse associated with economic withholding, uneconomic production, physical withholding, and uneconomic virtual bids and virtual offers. SPP notes that the mitigation measures for each of these behaviors are described in Attachment AF.[628] However, SPP does not describe screens for unavailability of facilities or physical withholding in Attachment AF.

449. With respect to facilities generally, including generation facilities, Attachment AG discusses physical withholding and the unavailability of facilities. Section 4.6.4 provides that the Market Monitor will monitor participation to determine whether decisions to participate in the market have a significant adverse impact on market outcomes. Attachment AG section 4.6.5 provides that the Market Monitor will monitor for any potential instances of unavailability of facilities. Both sections provide that, if appropriate, the Market Monitor will make a referral to the Commission's Office of Enforcement.

[628] We address this sentence again in the section relating to general monitoring.

b. Commission Determination

450. We find that SPP must provide further definition of physical withholding and unavailability of facilities in a compliance filing due 90 days after the issuance of this order. As noted above, with the adoption of the Integrated Marketplace, a significantly broader monitoring and mitigation approach is needed. Based upon our review of SPP's Tariff language relating to physical withholding, we find a more specific focus on physical withholding is needed for the new market. In particular, as specified by SPP, it appears that the Tariff provisions relating to physical withholding or unavailability of facilities could be read such that they are all-or-nothing events. However, a Market Participant could physically withhold part of its capability, or make its generation facilities available on a diminished basis in order to exercise market power. Such actions would also qualify as physical withholding or inappropriate unavailability of facilities.[629] While the SPP Market Monitor should bring to the attention of the Commission's Office of Enforcement any concerns it has about physical withholding or inappropriate unavailability of facilities,[630] we find that SPP must also develop clearer specifications or screens of what constitutes physical withholding and unavailability of facilities.

451. In particular, SPP needs to define physical withholding within Attachment AG as the term pertains to withholding of an electric facility or generation resource. SPP also needs to establish thresholds for the Market Monitor to identify such conduct, as other

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[629] As we noted in our discussion of SPP's must offer condition, just because there is no must-offer condition for some resources in the day-ahead market and only a limited one for load-serving entities, does not mean that those Market Participants are allowed to withhold from the day-ahead market in order to exercise market power. SPP's Market Monitor has an obligation to monitor for physical withholding, and in this order we are requiring it to report instances of physical withholding to the Commission. If the market monitor suspects there is a concerted effort by one or more Market Participants to stay out of the day-ahead market (without selling outside the market) in order to raise the prices in the real-time market, it must report this to the Commission's Office of Enforcement. It must also make a referral of such conduct if it has credible information to believe that a market violation has occurred.

[630] This is true whether or not the Market Monitor's concerns have reached the point of believing a referral for a market violation is appropriate. The Commission stated in *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,046, at P 21 (2011), that "Commission regulations require Market Monitoring Units to identify and notify the Office of Enforcement of all instances in which a market participant's behavior may require investigation, including, but not limited to, suspected market violations."

RTOs have defined in their Tariff.[631] We require SPP to revise its definition of physical withholding and unavailability of facilities to provide that it may include a Market Participant: (1) declaring that an electric facility has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified; (2) refusing to provide offers or schedules for an electric facility when it is required to offer into the market when it would otherwise have been in the economic interest to do so without market power; (3) operating a generation resource in real-time to produce an output level that is less than dispatch targets; (4) derating a transmission facility or interface for technical reasons that are not true or verifiable; (5) operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding reserve zone constraint or local reliability issue; and (6) declaring that the capability of resources to provide energy or operating reserves is reduced for reasons that are not true or verifiable. SPP must provide that Market Participants will not be deemed to be physically withholding under this definition if they are following the directions of the SPP Balancing Authority or applicable reliability standards. In addition, SPP must provide that Market Participants will not be determined to have physically withheld if they are selling into another market at a higher price.

452. Further, we require SPP to establish, in a compliance filing due 90 days after the issuance of this order, initial screening thresholds similar to those established in MISO, New York ISO, and ISO-NE for which the Market Monitor will identify physical withholding in Attachment AG of its Tariff. For example, MISO provides that the initial threshold for physical withholding is: (1) withholding more than the lower of five percent or 200 MW of the total capability owned or controlled by a Market Participant and its affiliates; or (2) operating a unit in real-time at an output level that is less than 90 percent of the transmission provider's dispatch instructions.[632] These guidelines should not preclude the Market Monitor from informing the Commission's Office of Enforcement of other types of suspected physical withholding or unavailability of facilities that it believes are market violations.

453. We require SPP, in a compliance filing due 90 days after the issuance of this order, to include in Attachment AG a requirement that the Market Monitor record instances where Market Participants have failed SPP's defined physical withholding

[631] *See, e.g.*, MISO Tariff, Module D sections 63.3 and 64.1.1, and NYISO Market Rule 1 Appendix A, sections III.A.4.1 and III.A.4.2.

[632] MISO Tariff, Module D section 64.1.1. *See also* New York ISO Market Administration and Control Area Services Tariff, Attachment H section 23.3.1 and ISO New England Inc. Transmission, Markets and Services Tariff, Appendix A, section II.A.4.3.

screen, and to notify the Commission's Office of Enforcement, or successor organization, of such behavior. In the event the Market Monitor determines there is credible evidence of a market violation (such as manipulation) in connection with any instance of withholding, whether or not the conduct is identified by SPP's screen for physical withholding, it shall refer such conduct to Commission's Office of Enforcement.

454. As noted above we require SPP to explain how its market power mitigation procedures will apply to VERs in a compliance filing due 90 days after the issuance of this order. This explanation must include information on how mitigation of physical withholding and unavailability of facilities would apply to VERs.

6. Monitoring and Mitigation of Virtual Bids and Offers

a. SPP's Filing

455. SPP also provides for monitoring for the divergence between the day-ahead market LMPs and real-time balancing market LMPs associated with Virtual Energy Offers and Virtual Energy Bids. Section 4.6.2 of Attachment AG provides that if there is excessive divergence in those LMPs, the Market Monitor will determine if the LMP divergence is attributable to Virtual Energy Offers and Virtual Energy Bids. Section 4.6.3 of Attachment AG defines excessive divergence to be more than the absolute value of 10 percent. If the Market Monitor identifies one or more Market Participants as having caused the excessive LMP divergence, then SPP will impose the mitigation measures described in section 4.0 of Attachment AF.

456. SPP proposes in section 4 of Attachment AF that SPP determines that if there is excessive divergence (more than 10 percent) between day-ahead and Real Time Balancing Market LMPs, resulting from Virtual Energy Bids and Virtual Energy Offers of one or more Market Participants, SPP will restrict the Market Participants in question. SPP would not allow these Market Participants to submit Virtual Energy Bids or Virtual Energy Offers at the settlement locations or similar settlement locations to those where the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused the excessive divergence. SPP proposes that this mitigation will apply for a period of three months, after which time the restriction will no longer apply.

b. Protests

457. DC Energy believes that SPP's focus on virtual transactions' potential impact on market price divergence is appropriate, and also agrees with the SPP's proposal not to exclusively use an automatic threshold for determining violations. DC Energy supports SPP's approach that considers the potential violation in the context of additional analysis and human judgment.

c. Commission Determination

458. We conditionally accept SPP's proposal with respect to monitoring and mitigation of virtual bids and offers. However, it is not clear what SPP means by its proposal to mitigate virtual offers and bids by a Market Participant at similar settlement locations, when it determines that there is excessive divergence between day-ahead and real-time balancing market LMPs caused by that Market Participant. We require SPP to insert the term "electrically" before "similar" in the phrase "similar Settlement Locations" in section 4.0 of Attachment AF, and to define the term "electrically similar" therein. We require SPP to make these changes in a compliance filing due 90 days after the issuance of this order.

7. General Monitoring

a. SPP Proposal

459. SPP proposes revisions to its market monitoring scope in section 4.2 of Attachment AG. It provides that the Market Monitor will monitor markets and services by reviewing and analyzing market data and information including, but not limited to: (1) Resource registration data; (2) Resource offer data including non-price-related offer parameters required for use in the day-ahead market, RUC, or RTBM, demand bids for the purchase of energy in the day-ahead market; (3) Virtual Energy Bids and Offers; (4) Export/Import Interchange Transaction Bids/Offers; (5) actual commitment and dispatch (including Resource MW capability and output and MWVAR capability and output, status and outages); (6) LMPs and zonal market clearing prices at all settlement locations in or affecting SPP's markets and services; (7) SPP Balancing Authority Area data; (8) conditions and or events both the supply and demand for, and the quantity and price of, products or services sold or to be sold in SPP's markets and services; (9) information regarding transmission service and rights including estimation and posting of Available Transmission Capacity and Available Flowgate Capacity, (10) the operation of the transmission system, any auctions or other market for transmission rights, and the reservation and scheduling of transmission service; (11) information on transmission congestion on SPP and other systems that affect SPP; (12) settlement data; (13) details of collusive or inefficient behavior; and (14) generation resource operating cost data for estimating resource incremental cost.

460. SPP also proposes revising section 4.6 of Attachment AG, which addresses the monitoring of market behavior that may warrant mitigation. SPP proposes requiring monitoring for economic withholding, uneconomic production, physical withholding, and uneconomic virtual bids. The language in section 4.6 provides that the mitigation measures for each of these behaviors are described in section AF. It provides that if the SPP Market Monitor determines that there is sufficient credible evidence about a specific

abusive practice, the Market Monitor will refer the issue to the Commission for possible investigation.

461. SPP proposes removing provisions related to strategic withholding as they relate to resources on the importing side of a constraint. According to SPP, this monitoring requirement, also known as Uneconomic Underproduction Monitoring, is unique to the SPP EIS market. Other RTOs monitor and mitigate this behavior through monitoring and mitigating economic and physical withholding. It states that this monitoring is subsumed by the economic and physical withholding mitigation and monitoring that SPP has adopted for the Integrated Marketplace.[633]

b. <u>Commission Determination</u>

462. As recognized in Order No. 719, Market Monitors perform an important role in assisting the Commission with enhancement of the competitiveness of ISO/RTO markets.[634] The Commission recognizes the crucial role of the Market Monitor in the oversight of SPP's new Integrated Market and the mitigation of attempts to exercise market power. To ensure that the Market Monitor has access to sufficient market data, resources, and personnel to carry out its functions, we require SPP to include the Market Monitor's implementation plan in the SPP Readiness Plan by March 2013. We also require SPP to include in this filing a timeline that ensures appropriate operations, staff, and resources are in place for the Market Monitor by the Integrated Marketplace's March 1, 2014 effective date.

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[633] SPP Transmittal at 49.

[634] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 354 (citing *Market Monitoring Units in Regional Transmission Organizations and Independent System Operators*, 111 FERC ¶ 61,267 (2005)). Order No. 719 adopted several functions for Market Monitors, including: evaluating existing and proposed market rules, tariff provisions and market design elements, and recommending proposed rule and tariff changes not only to the RTO or ISO, but also to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants; (2) reviewing and reporting on the performance of the wholesale markets to the RTO or ISO, the Commission, and other interested entities such as state commissions and market participants; and (3) identifying and notifying the Commission's Office of Enforcement staff of instances in which a market participant's behavior, or that of the RTO or ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies. *Id.*

463. While we note that SPP has provided a substantial list of market data and information that the market monitor will monitor, acknowledging that this is not an inclusive list, we will require SPP to expand its monitoring focus in a compliance filing due 90 days after the issuance of this order. The list of market data and information to be monitored should also include logs of Transmission Service requests and Generator Interconnection requests, along with the disposition of the request and the explanation of any refused requests. The list also needs to include generation and transmission facility outage data beyond the line status and outage data they currently provide for.

464. As noted above we require SPP's market monitor to explain how its market monitoring procedures will apply to VERs. This explanation must include information regarding how monitoring for economic withholding, physical withholding, unavailability of facilities and uneconomic production will occur for VERs.

465. We also require SPP's market monitor to monitor demand response resource participation in SPP's markets in a manner comparable to generation resources, and to notify the Office of Enforcement of any behavior by a demand response resource that the market monitor has reason to believe may constitute a Market Violation. We will also require the market monitor as part of its Annual State of the Market Report, to assess and report on uplift charges associated with the make whole payments given to the demand response resources, and to assess and report on the market effects of demand response resources in SPP's markets, including any market benefits and perceived market power risks.[635]

466. SPP provides in section 4.5 of Attachment AG that it will monitor for "potential transmission market power activities" and that it will refer any instances of "potential transmission market power" directly to the Commission. SPP's wording needs to be amended. SPP's Market Monitor should focus on and report instances of the suspected *exercise* of market power to the Commission, not the mere existence of market power. Accordingly, we require SPP to clarify in section 4.5 of Attachment AG that the Market Monitor is to monitor for the *exercise* of market power and that it will bring to the attention of the Commission's Office of Enforcement any potential instances of *the exercise of* market power that it believes may require attention, and that the Market Monitor will refer any instances of the exercise of market power that may be part of a suspected market violation, such as manipulation. We will require SPP to make this change in a compliance filing due 90 days after the issuance of this order.

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[635] *See, e.g., Midwest Indep. Transmission Sys. Operator,* 122 FERC ¶ 61,172 at P 189.

467. Further, we require SPP to revise section 4.6 of Attachment AF to modify the language to provide that mitigation measures for certain of those behaviors are provided in Attachment AF. We also require SPP to provide that nothing in section 4.6 limits the Market Monitor's obligation to refer other suspected market violations, even where the suspected behavior does not fall explicitly within these categories or descriptions. We require SPP to make this change in a compliance filing due 90 days after the issuance of this order.

468. Attachment AF sections 3.2.3(3), 3.2.4(3), and 3.2.5(3) refer to section 3.5 of Attachment AF (while referencing the impact test), when those sections should refer to section 3.4 of Attachment AF. We require SPP to correct these errors in the compliance filing due 90 days after the date of this order.

469. Finally, we require SPP to fix the Table of Contents to Attachments AF and AG such that they match the titles to the corresponding sections of those Attachments in the compliance filing due 90 days after the date of this order.

G. Miscellaneous Issues

1. Credit Policy

a. SPP Proposal

470. SPP proposes revisions to its credit policy detailed in Attachment O of the Tariff to incorporate credit and financial security requirements for Market Participants functioning in the Integrated Marketplace. These revisions reflect the creation of the new energy and operating reserve market and the TCR markets, and the implementation of virtual transactions. These revisions also establish the amount of unsecured credit and Financial Security[636] a Market Participant needs to support its activity.[637] SPP comments that these revisions do not change the overall structure or application of the Credit Policy, and that these revisions are consistent with the requirements of the *Credit Reforms in Organized Wholesale Electric Markets.*[638]

[636] Financial Security is defined as "A Cash Deposit or Irrevocable Letter of Credit in amount and in forms as described in Article Seven of the Credit Policy, provided by a Credit Customer to SPP as security." SPP Tariff, Proposed Attachment X, section 2.1.

[637] SPP Transmittal at 53 (citing Exh. No. SPP-4 at 10).

[638] Order No. 741, FERC Stats. & Regs. ¶ 31,317. SPP states that the Commission conditionally accepted SPP's June 30, 2011 filing to comply with Order No. 741. *See Southwest Power Pool, Inc.*, 136 FERC ¶ 61,189.

471. Currently, SPP uses a Total Potential Exposure calculation to determine whether a Market Participant has sufficient unsecured credit or Financial Security to support its activity, excluding TCR activity. To accommodate the Integrated Marketplace's energy and operating reserve market, SPP proposes to amend the portion of the Total Potential Exposure calculation that measures the potential non-payment associated with market transactions to include the real-time balancing market, day-ahead market and virtual transaction activity. SPP explains that TCR activity is excluded from the calculation because only Financial Security may be used to meet the credit requirements associated with TCR activity.[639]

472. SPP proposes a new Article Four A containing details for calculating the potential exposure associated with virtual transactions. SPP explains that because virtual transactions have the potential to create large obligations and risks that are different from those of other transactions in the day-ahead market, the calculation for the potential exposure is different for virtual transactions.[640] SPP states that under Attachment X, SPP will evaluate a Market Participant's Virtual Energy Bids and Offers to determine whether a Market Participant has sufficient available credit to support its Virtual Energy Bids and Offers.[641] Only those Virtual Energy Bids and Offers for which a Market Participant has sufficient available credit will be included in the day-ahead market. SPP asserts that this advance approval process ensures that a Market Participant will have sufficient credit to support its virtual transactions regardless of whether all or a subset of its Bids and Offers clear in the day-ahead market.

473. Finally, SPP proposes a new Article Five A to address the credit requirements associated with TCRs. SPP explains that consistent with Order No. 741, it proposes not

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[639] SPP Transmittal at 55 (citing SPP Tariff, Proposed Attachment X, section 5.2.3); *see also* Exh. No. SPP-4 at 14.

[640] SPP explains that this calculation includes two components: (1) the Estimated Virtual Exposure (EVE) for a Market Participant's Virtual Energy Bids and Offers prior to the close of the day-ahead market using historical reference prices or representative data based on simulations or other data during the time period when historical reference prices are not available; and (2) the EVE updated after the close of the day-ahead market to reflect the Market Participant's actual cleared Virtual Energy Bid and Virtual Energy Offer megawatts. *See* SPP Tariff, Proposed Attachment X, sections 4A.1.3, 4A.2, 4A.3.3, 4A.4; *see also* Exh. No. SPP-4 at 18-20.

[641] *See* SPP Tariff, Proposed Attachment X, sections 4.A.1.2, 4A.2, 4A.3.

to permit unsecured credit to be used to support TCR activity.[642] This section requires each Market Participant with TCR activity to provide Financial Security to support its TCR activity and does not allow netting of credit requirements between TCRs and other non-TCR activities.[643] SPP explains that TCR activity has increased risks compared to other activity in the energy and operating reserve markets; therefore, the Financial Security requirements differ from those for other services and activities under the SPP tariff. The Financial Security used to support a Market Participant's TCR activity is excluded from its available Financial Security to support its other market activities, which SPP states is also consistent with Order No. 741.[644]

b. <u>Protests</u>

474. DC Energy notes that as part of SPP's new set of credit requirements for virtual energy transactions, SPP plans to use historical reference prices for each settlement location in calculation of the Estimated Virtual Exposure. However, because historical reference prices will not be available during the first year of the Integrated Marketplace, DC Energy states that SPP plans to use representative data based upon simulations or other data during this time. DC Energy asserts that SPP is silent with respect to when and if SPP will provide Market Participants with an opportunity to review and comment on the details and results of these simulations. DC Energy also notes that SPP is silent with respect to the possible use of other unspecified data. DC Energy requests that the Commission direct SPP to submit an informational report outlining the assumptions used in and the results of relevant simulations, and to provide more specificity regarding the use of other types of data.

475. Additionally, DC Energy requests that SPP revisit its proposed reference prices for virtual transactions after market launch in order to determine if the 97th percentile is

[642] Order No. 741, FERC Stats. & Regs. ¶ 31,317 at PP 70, 75, 78. SPP notes that it plans to submit a request for waiver of the Commission's compliance submission deadline in Order No. 741 requiring RTOs to adopt steps to address the risk that RTOs may not be allowed to use netting and set-offs in the event of a Market Participant's bankruptcy, and submit its proposal later this year, to be effective with the commencement of the Integrated Marketplace. SPP Transmittal at 55.

[643] SPP Transmittal at 57 (citing SPP Tariff, Proposed Attachment X, section 5.3.1, Art. 5A).

[644] *Id*. Also, SPP proposes minor conforming revisions to accommodate its credit policy proposal herein. *Id*. at 59.

appropriate. In support of this request, DC Energy notes that MISO has a 50th percentile reference price.[645]

c. Commission Determination

476. We conditionally accept SPP's credit policy proposal subject to a compliance filing, as discussed below. The Commission recognizes that the use and management of credit in an organized wholesale electric market, such as SPP's EIS market and its proposed Integrated Marketplace, requires a balancing of varied interests. Market liquidity and transparency – necessities for a competitive market – must be balanced with the need for adequate safeguards to protect members from exposure to a Market Participant's default. Achieving this balance is essential for efficient and competitive market outcomes. We find that SPP's credit policy, as revised here, maintains its current ability to protect members from other defaulting Market Participants. Moreover, SPP's proposal includes tariff revisions that eliminate unsecured credit in all financial transmission rights, as is required by Order No. 741 for the commencement of the Integrated Marketplace.[646]

477. SPP's proposed revisions do not change the overall structure or application of SPP's credit policy provisions associated with the new services provided under the Integrated Marketplace. For example, the revisions set forth the calculation of the Total Potential Exposure to accommodate the energy and operating reserve market, provide the details for calculating the potential exposure associated with virtual transactions, and they address the credit requirements for TCRs. In addition, SPP is not proposing to change the credit assessment of provisions for determining the amounts of unsecured credit extended to Market Participants, the minimum criteria for market participation, the $25 million limit on the maximum amount of unsecured credit that maybe extended to a Market Participants or its affiliates, or how the credit policy addresses defaults and uncollectible amounts.[647] Furthermore, the only requirement in Order No. 741 affecting the commencement of the Integrated Marketplace is the elimination of unsecured credit

[645] DC Energy Protest at 25-26.

[646] In Order No. 741, the Commission adopted reforms to strengthen the credit policies used in organized wholesale electric power markets and directed RTOs and ISOs to revise their tariffs accordingly. The Commission has found that, to date, SPP is in compliance with the relevant portions of Order No. 741. *See Southwest Power Pool, Inc.*, 136 FERC ¶ 61,189; *Southwest Power Pool, Inc.*, 138 FERC ¶ 61,182 (2012).

[647] SPP Transmittal at 34; SPP Tariff, Proposed Attachment X, sections 3.1, 4.3.2, 4.3.4.1; *see also* Exh. No. SPP-4 at 10-12.

in all financial transmission rights or equivalent markets (i.e., TCRs in SPP).[648] We find that SPP's revisions are consistent with the Order No. 741 requirement in that only Financial Security (defined as cash deposits or letters of credit) can be used to support a Market Participant's TCR activity.[649]

478. While SPP's credit policy, as revised, will provide adequate safeguards for Market Participants, we find SPP's proposal to use representative data to calculate the Estimated Virtual Exposure during the first year of the market, before actual data becomes available, to lack the level of transparency necessary for the Commission to find the proposal to be just and reasonable. Therefore, we direct SPP to provide additional information regarding this proposal in a compliance filing, as discussed below.

479. We recognize that because SPP will not have historical reference prices to use during the first year of the market's operation, it must reply upon other data in order to complete the Estimated Virtual Exposure calculation.[650] However, SPP does not provide any information regarding what relevant simulations it intends to use, the assumptions it will use in those simulations, nor does it specify any other types of data that it may use. Market Participants need to have specific information about the simulations and data SPP intends to use for its calculation of the Estimated Virtual Exposure. Moreover, both SPP and Market Participants will benefit from informed discussions regarding this calculation. Thus, we direct SPP to provide more information outlining the simulations it intends to use, the assumptions it will use in the simulations, and to identify the data it will use. With this requirement, the Commission emphasizes that markets function best with sufficient transparency to allow informed discussion and participation. We require that SPP provide the information discussed above in a compliance filing due 90 days after the issuance of this order.

480. In regard to SPP's proposal to use the 97^{th} percentile of estimated reference prices, we note that establishing reference prices, similar to establishing collateral necessary to cover possible losses, involves the modeling of expected outcomes. The reference to "percentile," and in this case "97^{th} percentile," is a statement of how many possible outcomes can be covered in the modeling. In this case, modeling to the 97^{th} percentile indicates the intent is to cover 97 percent of possible modeling outcomes. The level of

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648 Order No. 741, FERC Stats. & Regs. ¶ 31,317 at PP 70, 75, 78.

649 *See* SPP Tariff, Proposed Attachment X, sections 5.2.3, 5.3.1, 5A.1.1, 5A.8.5.

650 In section 4A.2.1.5 of Attachment X, SPP proposes to "use data representative of the expected day-ahead and real-time market results based on simulations of the day-ahead market or other information" in its calculation of the Estimated Virtual Exposure during the initial year of the Integrated Marketplace.

percentage is an indication of "tail risk" or the ability to cover outlying events. Thus, SPP's proposal is very inclusive of tail risk and is more stringent than other organized markets, such as the MISO TEMT. While the Commission finds SPP's level of caution employing the 97th percentile understandable given its lack of experience running day-ahead markets, we will require that SPP revisit its reference prices one year after its market launch in order to determine if is appropriate to maintain this percentile, and to provide the necessary level of detail on projected reference prices. Consequently, we direct SPP to provide an informational filing to the Commission 15 months after market start-up detailing its findings based upon the first 12 months of the operations of the Integrated Marketplace.

2. Confidentiality Provisions

a. SPP Proposal

481. SPP addresses the release of confidential data in two sections of its tariff. Section 9 of Attachment AE provides that SPP will release offer curve data provided by a Market Participant 90 days after it was submitted for day-ahead Offers and Bids, real-time balancing market energy offer curves and operating reserves. Section 9.0 specifies that when this information is released, it will not include the identity of the Market Participant, the resource or the load. In contrast, section 11 has a broader scope. It governs the confidentiality of information within its Tariff Attachments AW, AF and AG. These provisions govern procedures for confidential information that is disclosed by a Market Participant to SPP or vice versa, or a designee, or to confidential information provided to the market monitor, the Commission or an authorized requestor. This Tariff language also provides procedures for the disclosure of confidential information required under applicable law, or in the course of administrative, judicial, or regulatory proceedings.

b. Protests

482. DC Energy argues that SPP's data release proposal in section 9.0 of Attachment AE is silent with respect to whether released information will include data for all bids and offers. DC Energy also notes that SPP's proposal is silent as to whether released information will include data for each settlement location. Accordingly, DC Energy requests that the Commission direct SPP to clarify the extent to which it will release bid and offer data. DC Energy notes that the Commission recently provided guidance on this matter, requiring all bid and offer data be provided rather than just cleared bids and offers.[651] DC Energy encourages SPP to create a stakeholder committee to serve as a

[651] DC Energy Protest at 22 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,214, at P 313 (2011)).

central point for collecting, evaluating, and prioritizing Market Participants' requests for data, noting that such committees have proven useful for streamlining RTO and ISO staffs' workloads and limiting tangential or redundant data requests.[652]

483. Cooperatives argue that SPP needs to impose reasonable limits on the provisions governing confidentiality of information, because the proposal unreasonably limits access to information. Cooperatives explain that their concern arises in part because of an on-going dispute with SPP over access to transmission planning data. The Cooperatives state that they are still without access to transmission planning information the Commission ordered SPP to provide in 2007.[653] Cooperatives argue that the proposed confidentiality provisions are not limited to bidding strategies or cost information but include any "commercially sensitive" information even if that information is required to be provided under other sections of the Tariff. Cooperatives recommend language to prevent the proposal from overriding other provisions in the Tariff that would permit or mandate disclosure of various categories of information.[654]

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[652] *Id*. at 22-23.

[653] Cooperative Protest at 5-8 (citing *Southwest Power Pool, Inc.*, 127 FERC ¶ 61,271, at P 15 (2009) and *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,227, at P 3 (2011)).

[654] Cooperatives recommend section 11.1 be changed as follows:

> The Transmission Provider or any Market Participant ("Receiving Party") may not disclose Confidential Information received from the other ("Disclosing Party") to any person, corporation, or any other entity except as specifically permitted in this Section 11 of this Attachment AE<u>, provided that nothing herein shall limit the Transmission Provider's or any Market Participant's obligation to make available information related to the SPP Transmission Expansion Plan or the underlying studies or models, as required by Attachment O, or information whose disclosure is otherwise authorized by applicable law or regulation or by this Tariff.</u>

Cooperatives also request that the phrase "Except as otherwise provided by law or this Tariff," be added to the beginning of section 11.1.4.(1). Additionally, Cooperatives request "except as otherwise provided by section 11.1.2, 11.1.5, 11.2 and 11.3" be revised to say, "except as permitted by the Tariff" in section 11.1.4(2) for similar reasons.

c. **Commission Determination**

484. We conditionally accept SPP's confidentiality proposal subject to a compliance filing, as discussed below. We agree with DC Energy that there is some ambiguity in section 9.0 of Attachment AE as to whether SPP will provide data on all bids and offers or only on cleared bids and offers as well as whether the data release will be by settlement location. We require SPP to submit revised Tariff provisions that clearly state that all bid and offer data will be provided rather than only cleared bids and offers. We also direct SPP on compliance to explain whyit should not release such data by settlement location.[655]

485. We find that SPP's revisions governing Confidentiality of Information in sections 11.0 through 11.6 of Attachment AE to be just and reasonable. While the Commission has stated that there is no bright line rule to determine the appropriate balance between fostering transparency and ensuring that confidential information is not disclosed inappropriately,[656] we find that the proposed revisions sufficiently bridge the gap between the transparency of market operations and the protection of a market participant's confidentiality.

486. Cooperatives are concerned that proposed section 11.1 may be overly broad. This section prohibits SPP from disclosing any confidential information "except as specifically permitted in this Section 11 of this Attachment AE."[657] Cooperatives argue that this provision could be interpreted so that any commercially sensitive information related to a Market Participant's business could be disclosed only pursuant to the provisions of section 11 of Attachment AE, even if disclosure would otherwise be mandatory under other sections of the Tariff. However, SPP's proposed section 11.0 of Attachment AE provides that:

> This Section 11 shall apply to Confidential Information disclosed by a Market Participant to the Transmission Provider or by the Transmission Provider to a Market Participant or its designee, the Market Monitor, the Commission, or an Authorized Requestor and *shall only be applicable to*

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[655] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,214 at P 313 (directing "MISO to clearly state in their Tariff on compliance that all bid and offer data will be provided rather than only cleared bids and offers.").

[656] *See Southwest Power Pool, Inc,* 137 FERC ¶ 61,227 at P 21.

[657] SPP Tariff, Proposed Attachment AE, section 11.1.

> *Confidential Information referenced within this Attachment AE, Attachment AF, and Attachment AG.*[658]

We find that this language sufficiently clarifies that the treatment of Confidential Information provided in section 11 will not be applicable to other sections of the Tariff, except as expressly stated. Therefore, we will not require SPP to provide further clarification.

3. Moratorium on Market Participant Registration

a. SPP Proposal

487. SPP requests that the Commission permit it to adopt a transitional one-year moratorium on registration of new Market Participants in the Integrated Marketplace. SPP states that the proposed moratorium would begin in August 2013, six months before the March 1, 2014 launch of the Integrated Marketplace and end in August 2014, six months after the Integrated Marketplace launch. SPP states that during the moratorium, it would not process any new Market Participant applications but would process changes to the registered assets of existing Market Participants.[659]

488. SPP states that good cause exists to grant the request for a one-year new Market Participant registration moratorium. SPP argues that the moratorium is necessary to ensure that all Integrated Marketplace models are validated and that market trials are completed prior to commencement of Integrated Marketplace operations. Because SPP's existing Market Participants will rely on the Integrated Marketplace to fulfill their retail obligations to serve, SPP must ensure that the Integrated Marketplace systems are fully tested prior to implementation, and that the Integrated Marketplace is functioning appropriately after launch. SPP explains that requiring SPP to register Market Participants during the months leading up to and following commencement of the Integrated Marketplace will divert SPP resources away from performing the necessary testing, training, and verifying that SPP needs to complete, and it could hamper the timely launch and effective operation of the Integrated Marketplace.

489. SPP has taken significant steps to ensure that all potentially interested entities are aware of the proposed moratorium, so as to minimize the adverse impact of a one-year

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[658] SPP Tariff, Proposed Attachment AE, section 11.0 (emphasis added).

[659] SPP states that the moratorium is primarily directed to the addition of resources in the Integrated Marketplace. Therefore, SPP is open to considering ways to accommodate the addition of new non-resource owning Market Participants during the moratorium.

moratorium on market registration. SPP states that it is working proactively to ensure that existing energy imbalance energy Market Participants and potential new Integrated Marketplace Market Participants are aware of the proposed moratorium. Specifically, SPP is currently involved in outreach to potential Market Participants to inform them of the registration deadlines and process given SPP's proposed moratorium. SPP states that it has targeted Market Participants in other RTO organized markets, including financial Market Participants, to provide information and facilitate registration.

b. Protests

490. AWEA states that while it understands the steps SPP must take to launch a new market, any moratorium must be sufficiently flexible so that it does not prevent new resources from coming on-line during the period.

c. Answers

491. SPP reiterates that a moratorium would apply only to the registration of new Market Participants; existing Market Participants would be permitted to modify their market registrations as necessary. Any new resources could come on-line during the moratorium period provided that the Market Participant registered the new resource prior to the start of the moratorium. After registration, the Market Participant can modify the resource as necessary to bring it on-line during the moratorium.

492. TDU Intervenors reply that the inconsistency between SPP's initial filing and its Answer leaves it concerned that MJMEUC will be unable to register resources and loads during the moratorium.[660] TDU Intervenors state that in the filing the moratorium only applies to the addition of new Market Participants and MJMEUC is already a registered Market Participant. However, TDU Intervenors note that even existing Market Participants will have to register new resources prior to the moratorium, which suggests that the moratorium applies to both the registration of assets (e.g., resources) <u>and</u> the registration of new Market Participants. While SPP's Answer responded to wind developers, TDU Intervenors state the Answer leaves unanswered whether load-serving entities will be able to register loads, which are much less predictable.

d. Commission Determination

493. We reject SPP's request to impose a year-long moratorium on new Market Participants as unsupported. While SPP argues that a moratorium is necessary to ensure

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[660] MJMEUC operates the MoPEP power pool and if able to do so under the Integrated Marketplace proposal, would pseudo-tie loads (and possibly new loads) into the SPP footprint.

that their systems will be prepared for launch, SPP has presented no evidence to support such a restriction. Additionally, SPP has revised its description of its proposed moratorium during this proceeding, but has not provided Tariff sheets for our consideration. Therefore, without additional support and a more explicit proposal, we reject the proposed moratorium.

494. We understand that it takes time to add a new Market Participant to the market software; SPP's application provisions already reflect the need for time to integrate new Market Participants.[661] While we reject SPP's proposed one-year moratorium as unsupported and overly burdensome, SPP may, with adequate support, propose to adjust the time when new Market Participants are added to the model (currently in April, August and December of each year), the time when applications are due, and to limit any exceptions to these timeframes. Additionally, SPP may justify why an adjustment to the entry and application dates would not accommodate SPP's implementation schedule and resource constraints.

4. Other Future Filings

a. SPP Proposal

495. As SPP notes in its initial filing, it still must make several important filings with the Commission prior to the commencement of the Integrated Marketplace. These filings are in addition to the compliance filings ordered herein and are subject to future orders. SPP states that it will file a Readiness Plan and Reversion Plan in March 2013 and a NERC Readiness Certification Plan in January 2014.

496. SPP explains that its Readiness Plan will address SPP's efforts to develop and satisfy appropriate readiness metrics, SPP's plan for performing readiness testing on all necessary Integrated Marketplace systems, and SPP's plan to achieve final readiness certification 60 days prior to the Integrated Marketplace launch.

497. SPP states that its Reversion Plan will address system operations in the event of a severe operations failure, including a detailed explanation of how SPP intends to cut over to alternative systems that can analyze and monitor, among other things: (1) ACE in the

[661] In section 2.2 of Attachment AE, SPP states that new Market Participants will follow the timeframe for applications to participate in the Integrated Marketplace as specified in section 6.4 and Appendix E of the Market Protocols. Section 6.4 provides that new Market Participants will be added to the model three times per year (i.e., on April 1st, August 1st and December 1st) with permissible exceptions on a case-by-case basis and an associated table indicates that they must have their applications turned into SPP six months before they are added to the model.

event of a failure in the centralized regulation monitoring system; and (2) Contingency Reserve in the event of a failure in the centralized reserve monitoring system.

498. SPP explains that the NERC Readiness Certification will demonstrate that SPP has satisfied all readiness metrics and fulfilled all aspects of its Readiness Plan, including obtaining NERC certification as a Balancing Authority Area.

b. Commission Determination

499. In addition to the compliance requirements stated above, SPP is expected to make several additional filings in the future in order to commence operation of the Integrated Marketplace. The Commission is not addressing these future filings in this proceeding. Our conditional acceptance of the Integrated Marketplace proposal is subject to future orders addressing these future filings. As stated above, the Commission expects the Consolidated Balancing Authority Area Agreement to be filed by June 30, 2013, based on our finding that a filing by that date would provide sufficient time for the Commission to review the proposal, issue an order, and provide SPP with enough time to be certified as the Balancing Authority Area by NERC. We direct SPP to file the Readiness Plan, Reversion Plan and NERC Certification by the dates that SPP committed to do so. Additionally, the Commission expects SPP, as the new consolidated Balance Authority, to submit to NERC its blackstart and restoration plan so that NERC can review it as part of the NERC certification. Finally, as stated above, SPP will also make a section 205 filing to implement the virtual transaction fee referenced in the proposal.

5. Other Miscellaneous Issues

a. Protests

500. DC Energy asserts that SPP's proposed Tariff revisions are silent with respect to potential or future discrepancies between the Market Protocols and the Tariff. Although DC Energy acknowledges that the Tariff is the governing document should a discrepancy arise, DC Energy requests that the Commission direct SPP to revise its proposed Tariff to clarify that the Tariff is the governing document.

501. TDU Intervenors state that KPP—one of the TDU Intervenors—has been a network customer under the SPP tariff since 2009 and has experienced numerous restrictions on its transmission use that will limit available capacity at delivery points. While these limitations will eventually diminish with construction of transmission upgrades, TDU Intervenors note that the completion of certain upgrades will occur well after the launch of the Integrated Marketplace. TDU Intervenors relate that KPP is

uncertain of the impacts of the Integrated Marketplace on its members and anticipates high LMPs.[662]

502. In regard to constraints on lower-voltage transmission facilities closer to KPP's loads, TDU Intervenors note that when these constraints bind, KPP's only solution is to utilize high-cost generating units located at cities' loads. While KPP may be no worse off than it is today (given that its generators would receive high LMPs when its loads pay high LMPs), it is unclear whether SPP market commitment and dispatch would occur, since the local transmission facilities are lower-voltage facilities. TDU Intervenors assert that if, instead, transmission owners control the commitment and dispatch of KPP's local generation, KPP would likely suffer harm because it would not receive the offsetting effect of receiving high LMPs for its generation.[663]

503. TDU Intervenors requests that the Commission require SPP to work with KPP to clarify the potential impacts of the Integrated Marketplace on KPP and to ensure that KPP will not be burdened with higher power costs due to the state of transmission facilities serving its load. TDU Intervenors also request that SPP ensure that upgrades necessary to provide the firm transmission service paid for by KPP are completed, as scheduled, before launch of the Integrated Marketplace.[664]

b. Commission Determination

504. SPP's proposed Tariff at section 3.2 states that "[t]he Transmission Provider shall prepare, maintain and update the Market Protocols consistent with this Tariff." We read this Tariff provision as applying not only to the proposed Tariff language SPP submitted in this docket, but as applying equally to future changes to the Tariff, such as revisions and updates. Therefore, as specified in this provision, there should not be discrepancies between the Tariff and Market Protocols now or in the future. Because we find that SPP's proposed Tariff language addresses the concern raised by DC Energy, we deny the request that SPP revise this provision.

505. Further, we expect SPP to discuss the concerns of the new market with Market Participants like KPP to address their concerns, perhaps as part of the Market Participant training. During the discussions, KPP will be able to discuss with SPP how the LMP market will affect it. KPP can also raise its concerns about network upgrades with SPP in an appropriate forum (e.g., transmission planning meetings).

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[662] TDU Intervenors Protest at 31-32.

[663] *Id*. at 32-33.

[664] *Id*. at 33.

6. **Compliance Requirements**

506. SPP will be required to make several filings to comply with this order. First, within 90 days of the date of this order, SPP will be required to make a compliance filing addressing issues as specified in the order, including making revisions to Tariff language and providing additional support for elements of its proposal. Also within 90 days, SPP shall make an informational filing reporting on its settlement discussions regarding GFAs. Additionally, by June 30, 2013, SPP must file its consolidated Balancing Authority Area Agreement, a Phase 2 market-to-market mechanism for managing congestion, as well as a filing in compliance with Order No. 755 on operating reserves. Furthermore, within 15 months of the commencement of the Integrated Marketplace, SPP must file a compliance filing to either revise the bid limit in its Tariff to a reasonable level or provide justification for retaining the current level based upon its experience.

507. We expect that SPP and its stakeholders will be able to learn from their experiences with the operation of the Integrated Marketplace. Accordingly, in several areas we ask SPP to make an informational filing with the Commission 15 months following market start-up evaluating certain elements, such as virtual transactions and the make whole payment proposal. SPP is also required to submit a compliance filing under Order No. 681 to establish long-term firm transmission rights due 180 days after the commencement of the Integrated Marketplace.

The Commission orders:

(A) The proposed revisions to SPP's Tariff, as marked in Appendix A, to implement the Integrated Marketplace are conditionally accepted, in part, and rejected, in part, subject to the conditions described in the body of this order.

(B) Waiver of section 35.3 of the Commission's regulations is granted to allow the proposed Tariff revisions to become effective March 1, 2014, as requested.

(C) SPP is required to make compliance and informational filings as described in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A.1
Filing Dated February 29, 2012
Southwest Power Pool, Inc. Designations – Docket No. ER12-1179-000[1]

Southwest Power Pool, Inc.
FERC FPA Electric Tariff
Open Access Transmission Tariff, Sixth Revised Volume No. 1

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[1] The tariff sections in Appendix A.1 that are marked with as asterisk were modified by the tariff sections filed in SPP's May 15 Amendment, Docket No. ER12-1179-001. *See* Appendix A.2.

Appendix A.2
Amendment filed May 15, 2012
Southwest Power Pool, Inc Designations – Docket No. ER12-1179-001

Southwest Power Pool, Inc.
FERC FPA Electric Tariff
Open Access Transmission Tariff, Sixth Revised Volume No. 1

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Att. AE (MPL) 8.6.7, Attachment AE (MPL) Section 8.6.7, 0.1.0
Attachment AF Section 3, Attachment AF Section 3, 4.1.0
Attachment AO, Attachment AO Agreement Establishing External Generation..., 1.1.0

Appendix B

Filing Parties

The following party filed a notice of intervention without comment:

Missouri Public Service Commission

The following parties filed motions to intervene without comment:

Ameren Service Company
American Electric Power Service Corporation
Associated Electric Cooperative, Inc.
Cargill Power Markets, LLC
City Utilities of Springfield, Missouri
City Water and Light Plant of Jonesboro, Arkansas
Dogwood Energy LLC
Edison Mission Energy
Empire District Electric Company
Kansas City, Kansas Board of Public Utilities
Lincoln Electric System, Lincoln, Nebraska
Missouri Public Service Commission
Municipal Energy Agency of Nebraska
Nemaha-Marshall Electric Cooperative, Kaw Valley Electric Cooperative, Co. Inc., and Doniphan Electric Cooperative
NextEra Energy Resources LLC
NRG Companies
Oklahoma Gas and Electric Company
Oklahoma Power Municipal Authority
Southwestern Power Administration
Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC
Tenaska Power Services Co.
Western Farmers Electric Cooperative

The following parties filed motions to intervene and comment:

Acciona Wind Energy USA LLC (Acciona)
American Public Power Association (APPA)
American Wind Energy Association (AWEA)
Arkansas Electric Cooperative, Inc. and Golden Spread Electric Cooperative (Golden Spread) (collectively, the Cooperatives)
Basin Electric Power Cooperative (Basin)

BP Wind Energy North America, Inc. (BP Wind Energy)
Calpine Corporation (Calpine)
City of Independence, Missouri; Kansas Power Pool; Missouri Joint Municipal Electric Utility Commission (MJMEUC) and West Texas Municipal Power Agency (collectively, TDU Intervenors)
DC Energy, LLC (DC Energy)
East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc. (collectively, Texas Cooperatives)
E.ON Climate & Renewables North American, LLC (E.ON)
Electric Power Supply Association (EPSA)
Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations (GMO) (collectively, KCP&L-GMO)
Kansas Municipal Energy Agency (KMEA)
Lafayette Utilities System and the Mississippi Delta Energy Agency (MDEA) and MDEA’s members Public Service Commission of the City of Yazoo City Mississippi and Clarksdale Public Utilities Commission of Clarksdale Mississippi (collectively, L-M Municipals)
Louisiana Energy and Power Authority (Louisiana Authority)
Midwest Independent Transmission System Operators, Inc. (MISO)
Missouri River Energy Services (MRES) and Heartland Consumers Power District (Heartland)
Nebraska Public Power District (NPPD)
Omaha Public Power District (OPPD)
TradeWind Energy LLC (TradeWind)
Westar Energy, Inc. (Westar)
Western Area Power Administration (Western)
Xcel Energy Services Inc. (Xcel)