UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Southwest Power Pool, Inc. Docket No. ER06-451-000

ORDER ON PROPOSED TARIFF REVISIONS

(Issued March 20, 2006)

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1. On January 4, 2006, the Southwest Power Pool, Inc. (SPP) filed proposed open access transmission tariff (OATT or tariff) revisions pursuant to section 205 of the Federal Power Act (FPA).[1] SPP requests an effective date of May 1, 2006 for its filing. In this order, the Commission addresses SPP's filing intended to implement a real-time energy imbalance market (imbalance market) and establish a market monitoring and market power mitigation plan. We note that SPP has further developed its imbalance market and market monitoring and mitigation plan pursuant to our September 19, 2005 Order, which provided guidance on several issues we considered critical to the success and monitoring of SPP's imbalance market.[2] However, as discussed below, we find that SPP's proposed tariff provisions require modification or elaboration before we can determine whether its imbalance market is designed and monitored properly and is just and reasonable. Accordingly, we will reject in part, conditionally accept and suspend in part, SPP's filing for five months from the requested effective date and permit it to become effective October 1, 2006, subject to further orders as discussed below.

2. We recognize that the implementation of organized markets is to some extent an iterative process that requires modifications to tariff provisions after the transmission provider and market participants gain actual market experience. We also believe that, as modified and subject to further orders, SPP's proposal will mark a significant improvement in the provision of imbalance service bringing benefits to market participants. For instance, if load serving entities offer their power into the market and cheaper resources are available to serve their needs, both the load serving entity and the supplier will benefit from the more efficient dispatch available through the imbalance

[1] 16 U.S.C. § 824d (2000).

[2] *Southwest Power Pool, Inc.*, 112 FERC ¶ 61,303 (*September 19 Order*), *reh'g denied*, 113 FERC ¶ 61,115 (2005).

market. Also, independent power producers will have access to real-time markets to sell their power without the need for pre-arranged transmission service. Further, the entire footprint will benefit from more efficient use of the constrained transmission system and fewer Transmission Loading Relief (TLR) events. We acknowledge SPP for pushing forward with its market proposal in order to bring these benefits to its market participants at the earliest possible time.

3. While we recognize the potential benefits of the market and the iterative nature of organized market development, we cannot accept SPP's proposed May 1, 2006 effective date or unconditionally accept SPP's proposal. The importance of a well-designed market with explicit and understandable market rules cannot be overstated. The Commission has had to address flaws in market designs and market rules after markets have started. Given these experiences with other markets, the stakes are too high to allow implementation of a market design, such as SPP proposes, that is missing important elements and assurances regarding reliable and stable market operations. Thus, while we are accepting SPP's imbalance market proposal for filing, we are suspending the effective date of SPP's proposal for five months. The Commission acknowledges that SPP has made substantial changes to several parts of its proposal to address the Commission's concerns raised in the *September 19 Order*. Therefore, today, in order to facilitate implementation of the market, we are acting on the parts of SPP's proposal that contain sufficient information on market and monitoring operations, and we will require a compliance filing by SPP no later than 60 days from the date of this order modifying those parts of SPP's proposal. Where there is a need for additional information in order to understand SPP's proposal or where SPP acknowledges that it has not yet filed parts of its imbalance market proposal, we require that SPP make further filings in a timeframe that allows timely review by the Commission prior to the effective date for market implementation of October 1, 2006.

I. Background

4. SPP has been authorized as a regional transmission organization (RTO) since October 1, 2004,[3] and submits the proposed tariff revisions under section 205 of the FPA, pursuant to Commission orders addressing SPP's RTO application. The Commission accepted SPP's commitment to develop an imbalance market, including implementation of a real-time, offer-based energy market that will be used to calculate the price of

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

imbalance energy.[4] The Commission also required SPP to provide a market monitoring plan, including market power mitigation measures that address market power problems in the spot market and a clear set of rules governing market participation conduct, with the consequences for violations clearly laid out.[5] The Commission further stated that the market monitoring plan must include the process that the independent market monitor would use if the market monitor determines that the markets are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure.[6] The Commission also required that the market monitoring plan provide for periodic reports.[7]

5. On June 15, 2005, SPP submitted proposed tariff revisions in Docket No. ER05-1118-000 intended to implement an imbalance market and establish a market monitoring and market power mitigation plan. The Commission rejected SPP's original imbalance market proposal and mitigation and monitoring plan as inadequate and provided guidance concerning: (1) reliable and stable market operations; (2) market-based rates in the new market; and (3) mitigation and monitoring issues.[8]

6. In this filing, SPP submits proposed Attachment AE to its tariff, which is intended to implement least cost bid-based security constrained economic dispatch and locational marginal pricing, including provisions allowing the bidding, scheduling and dispatch of generating units. As further detailed below, Attachment AE establishes how the locational prices will be developed and charged. This attachment also sets forth: market participant and transmission provider obligations; procedures regarding development of the next day, hour-ahead and real-time operating plans; billing, invoice and dispute resolution procedures; and confidentiality provisions.

7. SPP further submits, as proposed Attachment AF, its market power mitigation plan, and, as proposed Attachment AG, its market monitoring plan. As further detailed

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[4] *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 at P 134, *order on reh'g*, 109 FERC ¶ 61,010 (2004).

[5] *Id.* at P 173. Recognizing that SPP planned to implement its imbalance market in three phases, the Commission directed SPP to file its market monitoring plan no later than 60 days prior to implementing Phase 3 of its imbalance market.

[6] *Id.*

[7] *Id.*

[8] *September 19 Order*, 112 FERC ¶ 61,303.

below, Attachment AF sets out the principles for mitigating economic withholding and requires the Market Monitor[9] to monitor for violations of existing market behavioral rules and monitor for potential instances of market manipulation.

8. In addition, SPP proposes to make the following conforming changes to the OATT to implement Attachments AE, AF and AG. Section 1 contains new definitions relating to the imbalance market. Since Attachment AE provides for billing on a more expedited basis, section 7 states that the standard OATT billing provision does not apply to the use or provision of energy imbalance service (imbalance service). Schedule 4 is revised to reflect that market participants will be charged for transmission service in excess of their reserved transmission capacity in the imbalance market. Attachment L addresses the revenues associated with SPP's imbalance market. In particular, SPP proposes changes to reflect adjustments to revenue allocations in the event of customer non-payment. SPP is allowed to declare a default if it is not paid by a market participant. SPP proposes to make up the deficiencies in revenue resulting from a default by an uplift charge. This attachment sets out how market participants will be paid if a defaulting party eventually pays. Finally, Attachment L also ensures that SPP will have sufficient revenues to pay parties providing services.

9. SPP's market protocols define the terms, procedures, obligations and responsibilities of SPP and market participants relating to SPP's imbalance market functions.[10]

10. SPP states that all of the proposed tariff revisions were approved by its Regional Transmission Working Group and Markets Operations Policy Committee (MOPC). It notes that its Board of Directors (Board) approved substantially all of the proposed tariff revisions. SPP states that it is awaiting Board approval of the contract revision with the external market monitor to delineate the responsibilities delegated to it by the SPP internal market monitor and a form of reserve sharing agreement before filing these elements of its proposal with the Commission.

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[9] Market Monitor is defined in section 1.18a of the SPP OATT as "the entity within SPP that is responsible for performing the monitoring and mitigation activities described in Attachments AF and AG." *See also* further discussion on this issue under the "Market Monitoring" section of this order.

[10] SPP's Market Protocols, Revision 2.5 at 7 (last revised 12/02/2005) (market protocols), attached as Exhibit 2 to the Testimony of Mark A. Rossi (Rossi Testimony), attached as Exhibit IV to SPP's filing.

II. Notice of the Filing and Responsive Pleadings

11. Notice of the filing was published in the *Federal Register*,[11] with comments, protests, and interventions due on or before January 25, 2006. Timely interventions were filed by: American Electric Power Service Corporation, Calpine Corporation and Oklahoma Gas and Electric Company (OG&E). Timely interventions and comments were filed by: Exelon Corporation; Union Power Partners, L.P. (Union Power); and Western Farmers Electric Cooperative (WFEC). Timely motions to intervene and protests were filed by: East Texas Cooperatives (East Texas); Golden Spread Electric Cooperative, Inc. (Golden Spread);[12] Kansas Municipal Utilities (KMU); the Lafayette Utilities System of Lafayette, Louisiana, Mississippi Delta Energy Agency, the Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi, and the Public Service Commission of Yazoo City of the City of Yazoo City, Mississippi (collectively, Lafayette); Missouri Joint Municipal Electric Utility Commission, Oklahoma Municipal Power Authority and West Texas Municipal Power Agency (collectively, TDU Intervenors); Redbud Energy LP (Redbud); Southwest Industrial Customer Coalition (Southwest Industrials); Westar Energy Inc. and Kansas Gas and Electric Company (Westar); and Xcel Energy (Xcel).

12. SPP filed an answer to the protests (SPP Answer). Also, Westar submitted an answer to KMU's protest arguing that KMU's arguments with regard to the lack of available transmission in Kansas are inaccurate and irrelevant. Lafayette, Southwest Industrials and TDU Intervenors filed replies to SPP's answer that generally reiterate the arguments set forth in their protests. SPP submitted an answer to the replies by Southwest Industrials and TDU Intervenors.

III. Discussion

A. Procedural Matters

13. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2005), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

14. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2005), prohibits answers to protests unless otherwise ordered by the decisional authority. We will accept SPP's Answer because it has provided information

[11] 71 Fed. Reg. 3,081 (2006).

[12] Golden Spread's filing also included a motion to reject SPP's filing.

that assisted us in our decision-making. However, we are not persuaded to accept Westar's answer or Lafayette, Southwest Industrials, TDU Intervenors and SPP's replies to an answer, and therefore will reject them.

15. We reject TDU Intervenors' request for a technical conference because we are ordering various reports and modifications to SPP's filing.

B. Readiness and Market Startup Safeguards

16. SPP recognizes that its proposal to implement an imbalance market is missing certain elements.[13] SPP also recognizes that there may be aspects of its proposal that will need further development in the future, but states that these issues do not justify delay of a market that under its current proposed structure will bring the region substantial reliability and economic benefits.[14] SPP further states that the imbalance market should be allowed to start up as filed because market participants will recognize immediate benefits from the market and such action is consistent with the Commission's actions in accepting Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO's) initial incomplete market proposal. SPP adds that all energy imbalance markets have experienced a startup period and, based on experience, have made changes to improve the market over time. SPP believes this is a much more efficient and effective way to enhance SPP's imbalance market. SPP commits to fix any issues that may arise after the startup of the imbalance market.[15]

17. Numerous intervenors contend that SPP's filing remains incomplete and deficient, and moreover, has failed to address all the issues raised by the Commission in the

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[13] For instance, SPP notes that it has revised its loss compensation procedures since it made the instant filing and intends to make a separate filing of these proposed revisions. Further, SPP states that it is planning to complete a reserve sharing proposal in March 2006. SPP states that it has identified several inadvertent errors in its filing, including the omission of the market participant service agreement in Attachment AH. SPP commits to making these revisions in a subsequent compliance filing. SPP Answer at 9-10.

[14] SPP Answer at 6-7. SPP cites to a Charles River Associates cost-benefit study completed for the Regional State Committee on July 27, 2005 that showed aggregate trade benefits of $614 million and net benefits of $373 million over a 10-year period to SPP's transmission owners. SPP Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, April 23, 2005 (revised July 27, 2005) (CRA Study).

[15] SPP Answer at 4-6.

September 19 Order.[16] In addition, Westar and Southwest Industrials point out that several components of a comprehensive imbalance market plan still need to be completed or are awaiting stakeholder process or market participant review, including specific market protocols addressing pricing and settlement of losses in the imbalance market, the implementation of readiness metrics, conversion plans and certain approvals required from the North American Electric Reliability Council (NERC) for the imbalance market. Most of the protestors ask the Commission to reject SPP's proposal and provide guidance to SPP on its implementation of the imbalance market. As an alternative to rejection of the filing, Xcel requests that certain issues in SPP's filing be set for hearing. TDU Intervenors request that the Commission convene a technical conference on SPP's proposal. TDU Intervenors believe that it is more important to implement the imbalance market fairly and with a complete understanding of its operations than implement the imbalance market by May 1, 2006 as SPP proposes. Other intervenors have requested measures to provide both transitional and permanent safeguards of various kinds.

18. Given the concerns raised and SPP's own admission that it is missing important provisions, and for further customer protection, we will require SPP to create, file and operate under a set of transitional safeguards, as an addition to its imbalance market proposal. The safeguards should provide additional confidence in the reliable implementation and initial functioning of the imbalance market and provide some additional limits on exposure to imbalance market prices during the first months of the market's operation.

1. <u>Reliability and NERC Evaluation</u>

19. We continue to have concerns regarding the reliable implementation of SPP's proposed imbalance market. As discussed below in section III(E)(3) Control Area-SPP Relationship of this order, SPP has not complied with the guidance provided in the *September 19 Order* to develop and define the functional responsibilities necessary for the reliable operation of the imbalance market. We find that the SPP has not provided adequate assurance that the transition in functional responsibilities will not adversely affect reliability. We will, therefore, require SPP to file an amended SPP Membership Agreement or other document better defining and allocating the balancing function responsibilities, along with the allocation of costs and liabilities to control areas no later than 60 days from the date of this order. Additionally, we will require SPP to take stock of the readiness and the capabilities of these entities prior to the implementation of the imbalance market.

[16] *See* Westar, Golden Spread, Southwest Industrials, East Texas, Xcel, TDU Intervenors and KMU.

20. Further, as we discuss in section III(E)(1) Locational Pricing and Congestion Management of this order, SPP has not provided an adequate description of its newly developed Curtailment Adjustment Tool and other mechanisms it will use to manage the interaction of TLRs and flows in the imbalance market. We require SPP to incorporate additional detail from its market protocols into the OATT. We note that SPP states that two NERC committees have approved these mechanisms and that NERC is expected to evaluate and certify its market tools in March 2006.[17] We direct SPP to forward to the Commission the results of NERC Interchange Distribution Calculator (IDC) Working Group's on-site evaluation of SPP's markets and NERC's recommendation on the readiness of SPP's imbalance market when, as described below, SPP certifies that its systems are ready for reliable operations upon the start of the imbalance market.[18]

2. Performance Metrics and Reversion Plan

21. In the *September 19 Order*, we encouraged SPP to include a discussion of the steps it intended to take prior to implementing the market, including any metrics to evaluate its readiness.[19] The Commission also recommended that SPP adopt a reversion plan to address the event of a market failure.[20] In response, SPP states that it commissioned a consultant to prepare an independent readiness assessment that included reviews of project plans and key deliverables. SPP states that from this assessment, the consultant developed the "Market Readiness Matrices," a series of metrics to measure and track progress in addition to making recommendations to minimize implementation

[17] SPP Answer at 18.

[18] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 110 FERC 61,289 at P 26-29 (2005) (NERC sent a letter to the Chairman of the Commission making a recommendation on Midwest ISO's readiness to reliably operate its markets. NERC based its recommendation in part on reliability readiness audits conducted one year prior to implementation of the Midwest ISO markets). *See also PJM Interconnection, L.L.C. and Midwest Independent System Operator, Inc.*, 107 FERC ¶ 61,087 (2004) (In response to blackouts in the upper Midwest and eastern Canada in August of 2003, PJM and Midwest ISO were required to submit reliability plans for NERC approval. NERC imposed conditions on the reliability plan approvals, including Midwest ISO passing a reliability readiness audit prior to commencing operation of its LMP markets).

[19] *September 19 Order*, 112 FERC at P 30.

[20] *Id*.

risks. In addition, SPP states that it is developing a conversion plan with two components: a "Transition Plan" and a "Reversion Plan."[21] SPP states that the Market Readiness Matrices and Reversion Plan remain works in progress, but that it has made drafts available on its website.[22]

22. Several parties fault SPP's response to the Commission's directives regarding its implementation and reversion plans. Xcel states that a reversion plan is a mission-critical item and that while a plan is under development, it is not clear at this point whether the plan will be comprehensive enough to ensure an adequate response if problems occur after the market goes live.[23] Similarly, Southwest Industrials assert that these critical pieces are not "far enough down the tracks" for the Commission to even consider the merits of the energy market proposal.[24] Xcel states that it is concerned that SPP has not performed sufficient proof-testing to assess aspects of the market design and systems due to incomplete or absent documentation. Xcel asks the Commission to direct SPP to undertake a proof testing process to detect loopholes and errors and establish criteria for other critical market operations.

23. We remain concerned about SPP's readiness to operate the market and SPP's ability to revert to its current operating procedures in the event of a serious market operational problem. Since SPP's Market Readiness Matrices are still in draft form, the Commission cannot evaluate whether SPP's market systems and measurements used to develop market prices are sufficiently accurate and dependable. Therefore, we will require the SPP to file with the Commission, on an informational basis, its independently evaluated metrics related to commercial operations readiness and the testing plan, no later than 60 days prior to the implementation of the imbalance market. As discussed above, such a plan must also consider the sharing of balancing function responsibilities and the control area operators' readiness to perform the allocated functions. Also, SPP must certify to the Commission, no later than 30 days before market startup, the readiness of its systems (Market Readiness Certification). Market readiness is an operational issue consisting, in part, of the functioning of the SPP's security constrained economic dispatch model and the day-ahead resource plan process, as well as the effectiveness of the

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[21] *See* Exhibit V to SPP's filing, Testimony of Carl Monroe at 7 (Monroe Testimony).

[22] SPP Answer at 9. SPP adds that it "hopes to complete" the Market Readiness Matrices and Reversion Plans by mid-March 2006. *Id*.

[23] Xcel at 27.

[24] Southwest Industrials at 7.

bidding and scheduling procedures. Also, SPP must substantially complete the items in its market readiness metrics in order to meet this Market Readiness Certification requirement.[25]

24. We have supported reversion plans for New York Independent System Operator's markets and required Midwest ISO to propose a plan to address system operations in the event of a severe operations failure.[26] Hence, we will require that SPP file with the Commission, by no later than 60 days from the date of this order, a detailed plan, including demonstration of successful testing of the plan, for cutover to decentralized power system operations in the event of a serious failure of imbalance market operations. Control area operators will need sufficient capabilities through this period to reliably operate their systems and obtain interchange schedules through the SPP's OASIS site.

3. <u>Transitional Limits on Supply Offers in the Imbalance Market</u>

25. Under the imbalance market proposal, SPP will apply mitigation measures for economic withholding during times when transmission is constrained. Elsewhere in this order, we discuss the merits of the proposed market power mitigation. In this section, we discuss transitional safeguards on bids into the imbalance market that will coexist with the proposed mitigation plan, for a period of six months following the start of the market.

26. We will institute a temporary cap on supply offers into SPP's imbalance market to limit the price impacts of any early problems with market operations. SPP acknowledges that unforeseeable issues may arise after the implementation of the market provisions that probably will require modifications to its tariff.[27] Additionally, SPP has not developed provisions to allow resources that are external to the SPP system to participate in the imbalance market.[28] We will require a protective measure to offset these risks and thus

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[25] See *Midwest Independent Transmission System Operator, Inc.*, 110 FERC ¶ 61,289 at P 12, 35 (2005).

[26] *See New York Independent System Operator, Inc.*, 88 FERC ¶ 61,228 (1999); and *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 58 (*TEMT II Order*), *order on reh'g*, 109 FERC at P 427-47 (2004) (*TEMT Rehearing Order*), *order on reh'g and offer of proof*, 111 FERC ¶ 61,448 (2005), *order on reh'g and compliance filing*, 113 FERC ¶ 61,081 (2005)..

[27] SPP Answer at 5-6.

[28] As noted below, SPP is directed to submit a filing, two months after the start of market operations, which incorporates tariff provisions that allow external generators to participate in SPP's imbalance market. Also, we have required that external generator

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establish a transitional mitigation mechanism for the start-up period. We direct SPP to apply a two-tier bid cap during the first six months of the market to address start-up period issues, in addition to SPP's proposed offer cap mitigation. During the first three months of imbalance market operation we direct SPP to apply a cap on all bids into the market of $400/MWh. During the next three months of market operation we direct SPP to require an upper limit on all bids into the market of $1000/MWh. Accordingly, we direct SPP to file tariff sheets implementing these temporary offer caps and designating a sunset date upon which the offer caps will expire no later than 60 days from the date of this order.

27. We do not take the imposition of bid caps lightly and we recognize that these temporary bid caps may lead to fewer bids in the imbalance market during the transition period. However, we require this transitional mechanism because of the risk that SPP's imbalance market, like all new markets, will experience unforeseen issues on start-up as SPP implements new ways of managing congestion and market participants become familiar with bidding and scheduling protocols. Moreover, we expect that SPP's proposed day-ahead and hour-ahead process will maintain the current resource adequacy of the SPP region and not result in bid insufficiency.

4. <u>Price Correction Authority in the Event of Temporary Market or System Operational Problems</u>

28. Under section 4.4 of Attachment AE, SPP proposes a method for calculating locational imbalance prices (LIPs) when there is no input data available on its system, due to system failures. However, SPP's proposed tariff does not contain provisions allowing for price corrections if SPP identifies market software or data input errors that result in incorrect prices. Rather, SPP proposes this type of price correction authority in section 12.3 of its market protocols. Section 12.3 of the market protocols describes notification requirements that SPP will follow in instituting price corrections. The market protocols also provide that SPP will recalculate LIPs "as closely as reasonably practicable" to those that "would have resulted but for the Market Software and Data

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participation must be in effect no later than six months after the start of SPP's imbalance market, at the same time that system-wide bid caps are removed.

Input Error" and use these as the basis for settlement.[29] SPP proposes that it will use uplift charges to make market participants whole if the price correction results in excess charges or underpayments to market participants.[30]

29. The Commission accepts the price correction proposal made by SPP in its market protocols as just and reasonable and consistent with the mechanism SPP proposes in section 4.4 of Attachment AE for calculating LIPs in response to lost data. Because the provisions significantly impact the formulation of jurisdictional rates, they must be included in the tariff. Accordingly, we direct SPP to revise its tariff to recognize the need to correct imbalance market prices after the fact in the event of transitory data and software errors, system failures, and other operational problems. We direct SPP to make a compliance filing no later than 60 days from the date of this order to revise its OATT to include the price correction proposal currently contained in its market protocols. This action is consistent with the Commission direction to Midwest ISO to draft and file price procedures consistent with those in other RTOs and ISOs to avoid *ad hoc* measures if problems occur.[31]

C. <u>Day-Ahead and Hour-Ahead Process</u>

a. <u>SPP's Proposal</u>

30. SPP proposes that each market participant submit, prior to the operating day, a resource plan and ancillary services plan that provides a sufficient amount of capacity to meet all of the market participant's obligations, including the load forecast provided by SPP, ancillary service needs as calculated by SPP, and any third-party sales. A resource plan must include the hourly maximum and minimum output limits and ramp rate limits of the market participant's generation resources, the forecasted hourly output of each resource, and the resource status for SPP dispatch for the next seven days. An ancillary service plan must include the identification of the market participant's resources providing the services and the identification of any bilateral transactions that transfer resources to or from the market participant. SPP proposes to evaluate the resource and ancillary services plans submitted in the day-ahead timeframe using a contingency analysis that will "ensure there is sufficient operating capacity scheduled so that [SPP] may operate the system reliably to meet the load forecast and ancillary service

[29] *Id.,* section 12.3.2.4.

[30] *Id.,* sections 12.3.4.5 and 12.3.2.6.

[31] *See TEMT II Order*, 108 FERC at P 95-96.

requirements."[32] If SPP finds that a market participant's resource plan cannot be implemented reliably, SPP proposes to notify the market participant and have the market participant modify and resubmit its resource plan. Within two hours of being notified, the market participant will be required to resubmit its resource plan or ancillary service plan back to SPP. If SPP finds that "additional capacity is required for system reliability purposes,"[33] Pursuant to section 2.4.3 of Attachment AE, SPP will have the authority to direct a market participant to commit additional generation in order to ensure that there are sufficient resources to meet the market participant's obligations. SPP states that this reliability commitment process is analogous to the Midwest ISO's Resource Assessment Commitment (RAC) process.

31. SPP also proposes to require market participants to submit resource and ancillary services plans prior to the start of the operating hour. Pursuant to section 3.2, SPP will review hour-ahead resource and ancillary services plans using the same process it uses for the day-ahead resource and ancillary services plans.

32. SPP proposes that market participants may submit schedules based on their resource plans. SPP also proposes that market participants may submit offers for resources included in their resource plans if the market participant wants to have SPP dispatch the resources. SPP states that a market participant must commit sufficient generation through a combination of self-dispatched schedules, offers into the energy market, and controllable load to meet its obligations for the next day and for the next hour.[34]

b. <u>Protests</u>

33. Southwest Industrials state that SPP's proposal to force generators to be committed through the day-ahead resource plan process is unjust and unreasonable.

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[32] Attachment AE, section 2.4.2. Also, SPP's market protocols state that this contingency analysis will include a simultaneous feasibility analysis. Market Protocols, Section 3.4 at 13.

[33] Attachment AE, section 2.4.3.

[34] Rossi Testimony at 11-12. SPP's market protocols at section 6.5.2 also require that each resource included in a resource plan must be either offered into the market or self-dispatched. Market Protocols at 227.

Southwest Industrials state that SPP should not be able to force a resource to participate in the imbalance market if those generators are serving another purpose such as providing power for native load.[35]

34. In its protest, Xcel takes issue with the accuracy of SPP's load forecasts and the financial consequences of load deviations from the forecast, which could result in scheduling penalties.[36] Xcel argues that SPP's proposed day-ahead unit commitment with its requirement that load serving entities commit units to serve 100 percent of its load will cause persistence of the current unit commitment practices (*i.e.*, load serving entities will continue to commit resources they own or resources under contract to them) and not efficiently use resources within the SPP footprint. Xcel explains that this requirement will minimize the benefits of the imbalance market because each committed unit will have to be run at the unit's economic minimum leading to economic dispatch that is limited to the dispatchable range of units committed in the day-ahead time period. Xcel concludes that SPP's proposed day-ahead process will also lead to lessened participation in the market by independent generators because these generators will have no assurance of payment of start-up and minimum load through the day-ahead process for keeping their units available for real-time use.[37]

35. In addition, Xcel protests SPP's ability to require action should there be an over-commitment of resources in the market. Xcel states that the tariff fails to provide specific language in order for SPP to properly identify a unit should it need to be de-committed.[38] In addition, Xcel states that the data submitted by load serving entities does not contain enough detail on sources and sinks for generator-load pairs for SPP to conduct a simultaneous feasibility analysis. Xcel also states that SPP fails to indicate whether or not it will conduct a simultaneous feasibility analysis.[39]

36. TDU Intervenors state that the SPP should clarify what it means when it refers to "energy obligations" so that market participants can formulate their resource plans. Furthermore, TDU Intervenors take issue with SPP's definition of "Resources," contending that market participants may include purchased power as resources in their resource plans. Moreover, TDU Intervenors argue that the requirement that each

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[35] Southwest Industrials at 17-19.

[36] Xcel at 30.

[37] *Id.* at 21-22.

[38] *Id.* at 18.

[39] *Id.* at 19.

resource included in a resource plan must be either offered into the market or self-dispatched is an important provision of the market protocols that should be incorporated into SPP's OATT.[40] Likewise, Westar requests that the Commission direct SPP to clarify whether a market participant is required to schedule a sufficient amount of capacity to meet its total energy obligations in the next day or next hour.[41] Westar states that SPP has failed to address what would happen if a market participant failed to commit the resources identified in its resource plan. Lastly, Westar points out that the Midwest ISO's RAC process provides financial incentive for its market participants to ensure adequate capacity, while SPP's process does not.

37. In addition, TDU Intervenors protest the provisions requiring that all market participants obtain certain ancillary services consistent with SPP's determination of each market participant's ancillary service needs. TDU Intervenors state that the tariff should make clear that the obligation to submit an ancillary services plan, and the related obligation to procure regulation and spinning and supplemental operating reserves will only apply to control area/transmission owner sellers of ancillary services, rather than to ancillary service customers. TDU Intervenors claim that market participants that are transmission customers should have the option to rely on the control area/transmission owner to provide regulation and spinning and supplemental operating reserves at the zonal rates set forth in Schedules 3, 5, and 6 to whatever extent they are actually needed, as opposed to amounts projected to be needed by SPP.

c. Commission Determination

38. We find that SPP's proposal to ensure reliability through submission and analysis of day-ahead and hour-ahead resource plans, as modified, is reasonable. We are convinced SPP's proposed approach regarding the submission of resource and ancillary services plans for contingency analysis will meet resource adequacy needs. Moreover, we note the important interaction between the day-ahead process and the role served by the imbalance market. With commitment by market participants of sufficient and deliverable resources to serve their loads in the day-ahead timeframe, there should be infrequent and limited reliance on the imbalance market to serve resource adequacy needs.

39. SPP's proposed structure allows market participants to take energy offered in the imbalance market that is less costly than the cost of operating their committed resources, but it does not allow market participants to rely on the imbalance market for capacity.

[40] TDU Intervenors at 38.

[41] Westar at 9.

We disagree with Xcel that SPP's proposed day-ahead and hour-ahead processes will necessarily result in less efficient resource commitment as compared to a resource commitment process managed through a day-ahead market. We have approved self-scheduling in the day-ahead market for every RTO in the Eastern Interconnect. We find that SPP's proposal represents a significant step forward in managing congestion, dispatching regionally and in creating a market that will bring benefits to buyers and sellers alike. Xcel has not shown that SPP's approach using self-scheduling is unjust and unreasonable. Moreover, the just and reasonable standard under the FPA allows a range of alternative approaches that may be just and reasonable. Since SPP's proposal marks an improvement in the efficiency of dispatch through congestion management in the real-time market, we find SPP's proposed day-ahead and hour-ahead process, as modified, will produce rates that are just and reasonable and not unduly discriminatory.

40. Although SPP states that a market participant must submit a combination of schedules and offers to meet its energy requirements per its resource plan, SPP's tariff fails to reflect this requirement. Therefore, we direct SPP to modify its tariff to include language specifying that each resource included in a resource plan must be either self-dispatched or offered into the market at a level sufficient to meet its energy requirements. We believe that this change will clarify the meaning of energy obligation as TDU Intervenors and Westar request. We do not agree with Westar that SPP's process fails to provide financial incentives to ensure market participants meet their energy obligations through either self-scheduling, self-scheduling and offering, or offering into the imbalance market. Load serving entities that do no commit resources and do not schedule those resources will be subject to imbalance market charges as well as over- and underscheduling charges. However, given Westar's concern regarding market participant obligations to follow SPP instructions, we will direct SPP to immediately notify the Commission should a market participant refuse to follow an SPP order regarding resource committment, or should a market participant fail to meet its energy obligations through scheduling or offering into the imbalance market. The Commission will invoke appropriate sanctions for such action.

41. Additionally, as Xcel states, SPP's tariff only contains provisions for a contingency analysis in the day-ahead process, rather than the simultaneous feasibility analysis that SPP commits to undertake in its market protocols.[42] A simultaneous feasibility analysis of day-ahead resource plans is necessary to ensure that SPP will not

[42] Attachment AE, section 2.4.2. Also, SPP's market protocols state that this contingency analysis will include a simultaneous feasibility analysis. Section 3.4 of Market Protocols at 13. We note that SPP has not proposed in its market protocols to conduct a simultaneous feasibility test in the hour-ahead process.

rely on emergency curtailments to manage infeasible situations on an after-the-fact basis. Therefore, we direct SPP to modify its tariff to clarify that it will undertake a simultaneous feasibility analysis in evaluating the day-ahead resource plans and modify the submission requirements for resource plans so that the generator-load pairs are mapped to the nodes of the transmission system. Also, we find that SPP's tariff does not clearly allow for purchased power to be included as a resource in a resource plan. Accordingly, we direct SPP to modify its tariff to allow for power purchases to be included in resource plans, as long as the resource plans map the generators providing the purchased power to specific load nodes.

42. Further, we find that SPP should control for the over-commitment of resources in a resource plan. Thus, we direct SPP to modify section 2.4.3 of Attachment AE to provide that SPP may advise a market participant to resubmit its resource plan if the resource plan represents resources in excess of load and SPP may direct a market participant to de-commit a resource in the market participant's resource plan if SPP encounters an over-commitment problem. Finally, we find that section 2.4.3 of Attachment AE could be understood to provide SPP with the ability to direct a market participant to change a resources' commitment for a generic system reliability need. If SPP intends to order changes in resource commitment to respond to generic system reliability needs, it must propose a mechanism to compensate market participants who are meeting their own obligations but change their resource commitment at SPP's request to respond to system reliability needs. Otherwise, SPP must clarify section 2.4.3 of Attachment AE to provide for the commitment or de-commitment of resources only if a market participant has not committed appropriate or sufficient resources to meet its own energy and ancillary services obligations.

43. Southwest Industrials misunderstand SPP's proposal to require load serving entities to commit sufficient appropriate resources in the day-ahead timeframe as an obligation for those resources to bid into the imbalance market. Rather, SPP proposes that market participants with load serving obligations plan to meet those obligations in the day-ahead and hour-ahead time periods. Should a market participant wish to serve its load with the resources solely included in its resource plan, it need only indicate to SPP that it will self-dispatch its resources through submission of a physical schedule. If the market participant's resources remain deliverable in real time, *i.e.*, no redispatch or TLR is required to address transmission congestion, the market participant that self-schedules should not incur additional cost or obligations through the imbalance market.

44. We are not persuaded by Xcel's assertion that independent power producers will not participate in the market to their full capability because they cannot recover their start-up and no-load costs through a day-ahead market. Xcel has not shown that under SPP's proposed mitigation measures, independent generators will not be able to

incorporate start-up and no-load costs in their bids. More importantly, with implementation of the imbalance market, independent generators will have the benefit of unprecedented access to buyers and to the transmission system within SPP's footprint.

45. The accuracy of SPP's load forecasts may have a financial impact on a load-serving entity whose load deviates from the forecast. This issue has been addressed by other RTOs through a sharing of the responsibilities for load forecasting between the load serving entities and the RTO.[43] We believe this is a reasonable approach. Therefore, we direct SPP to modify its tariff to provide that the hourly load forecast for each settlement area will be developed by SPP based upon input from control area operators and from load-serving entities. SPP must also explain in its market protocols the process for receiving and incorporating such input. With regard to ancillary services, we note that SPP's proposal to notify market participants of their ancillary service requirements is not a change from SPP's current duties under the tariff. SPP's proposal that all market participants, including transmission customers, specify the resources for ancillary services in their resource and ancillary services plan is a provision necessary for the protection of grid reliability and consistent with the pro forma Order No. 888 OATT.[44] The transmission customer may acquire these services from the control area operator through Schedule 3, 5, and 6, but it must make arrangements for the service in advance consistent with the deadlines for submission of an ancillary services plan to SPP and consistent with SPP's determination of the transmission customer's ancillary service obligations. Therefore, we reject TDU Intervenors request to change these provisions.

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[43] For example, Midwest ISO TEMT, at section 1.169, provides that a load forecast is prepared by the Midwest ISO based upon input from control area operators and load serving entities.

[44] In reference to regulation and spinning and supplemental operating reserves, the pro forma OATT in Order No. 888 provides that "[t]he transmission customer serving load within the transmission provider's control area is required to acquire these ancillary services, whether from the Transmission Provider, from a third party, or by self-supply." Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 at Original Sheet No. 21 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *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).

46. SPP is directed to submit a compliance filing with modified tariff provisions, no later than 60 days from the date of this order.

D. Schedules and Scheduling Charges

a. SPP's Proposal

47. SPP proposes to allow market participants to submit schedules reflecting bilateral trades, unilateral transactions for serving network load, and reserve sharing events. SPP proposes to allow market participants to submit both market and physical schedules. Market schedules are submitted for generation units offered into the imbalance market by a market participant. SPP can instruct a generation unit with a market schedule to run above or below its schedule depending on the offer and the result of the bid-based security constrained dispatch. Physical schedules are submitted for generation units that are self-dispatched. SPP will instruct resources with physical schedules to be dispatched at their scheduled level.

48. SPP proposes to maintain the three types of transmission service under its OATT, non-firm network,[45] firm network and point to point service. SPP allows market participants to submit schedules based on the type of service acquired, however, the submitted schedules must be balanced so that scheduled injections equal scheduled withdrawals plus self-provided losses. SPP states that market participants can submit and revise schedules up to twenty minutes prior to the operating hour. SPP proposes to use the schedules to provide dispatch instruction for self-dispatched resources and in market settlements.

49. SPP explains that even though market participants are not required to schedule their entire load, they will not be able to collect the differential in imbalance prices for providing counterflow energy that is normally used to serve their firm load obligations, *i.e.*, underscheduling, and they will not be allowed to profit from submitting schedules in excess of their firm load obligations, *i.e.*, overscheduling.

50. To address over- or underscheduling by market participants, SPP proposes to assess a charge. A market participant may be subject to an over- or underscheduling

[45] Non-firm network refers to secondary network service under SPP OATT section 28.4, which states that "[t]he Network Customer may use the Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis . . . and will have a higher priority than any Non-Firm Point-to-Point Transmission Service.").

charge during an hour if locational prices diverge and the deviation between a market participant's scheduled load and actual load is greater than four percent. In its Attachment AE, SPP sets forth detail on how it will use the scheduled load, the actual load and actual generation to assess the over- or underscheduling charge.[46] If a market participant is subject to over- or underscheduling charges, SPP will charge it the difference between the locational prices multiplied by the amount of energy that was over- or underscheduled. SPP contends that this charge reflects the benefit that the market participant received by over- or underscheduling.

b. Protests

51. Westar argues that the Commission should carefully weigh the benefits of the over- or underscheduling penalties against the risks, such as, uplift surcharges and cost socializations.[47] Westar argues that the Commission should reject any form of after-the-fact uplift.

52. Xcel notes that under SPP's proposed tariff provisions, over- or underscheduling penalties will only apply if the market participant has both load and generation. Therefore, it argues that the proposed tariff language will enable a market participant to defeat over- or underscheduling penalties by simply registering its load and resources under separate entities.

53. TDU Intervenors argue that the Commission should require SPP to develop and implement an appropriate megawatt cap, such as a 2 MW minimum, on a market participant's ability to over- or underschedule because the four percent is too restrictive for smaller entities.

c. Commission Determination

54. The Commission agrees with SPP that over- and underscheduling charges are necessary to prevent gaming by market participants when the transmission system is congested.[48] The Commission recognizes that without effective over- or underscheduling

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[46] Attachment AE, sections 5.3 and 5.4.

[47] Westar at 11-12.

[48] Although SPP proposes to continue to base its operation on physical transmission rights, SPP's proposed over- and underscheduling charges operate in an analogous way to obligation financial transmission rights (obligation FTRs) that are allocated in all other RTOs. For example, if a market participant in Midwest ISO is assigned an obligation FTR for counterflow it regularly produces, the market participant

(continued)

charges, the ability of market participants to schedule could be limited and uplift charges would be imposed on other market participants if the schedules were infeasible. For example, if one market participant over-scheduled between two points and another market participant submitted a schedule as well between the same two points, and the schedules were simultaneously infeasible, SPP would need to cut one or both of the schedules. If the market participant that overscheduled had a higher priority, the other market participant would likely have its schedule removed or prorated. If the overscheduling had not taken place, the lower priority market participant would not have had its schedule adjusted to the same degree.

55. SPP proposes to assess under-scheduling charges when both load and generation are under-scheduled, *i.e.*, actual load and generation levels are greater than the scheduled levels. SPP proposes to assess over-scheduling charges when both load and generation are over-scheduled, *i.e.*, actual load and generation levels are less than the scheduled levels. We believe that the charges for over- or underscheduling should be based only on the deviations between scheduled load levels and actual load levels, and should not take into account the output of resources.[49] For example, SPP proposes not to assess an overscheduling charge when a market participant that overschedules load meets its scheduled level of generation output in real time, even though this level of output exceeds its load's real-time needs. In his testimony, Dr. Roach explains that SPP's "exception actually encourages scheduling and offering because it allows a market participant to avoid the penalty if it "earns" its generation sales through the [imbalance market]."[50] We agree that such an exception likely encourages bidding into the imbalance market. Nevertheless, we find that such an exception from the overscheduling charges could result in transmission hoarding.[51] The Commission directs the SPP Market Monitor to identify over- and underscheduling relative to the market participant's actual load (when congestion occurs in the real time market), and to submit monthly reports to the Commission to continue for one year after the market start-up on the benefits gained by those market participants, the charges made to market participants for over- or underscheduling, and any other issue the Market Monitor deems relevant to over- and underscheduling. Alternatively, SPP can implement a charge for over- and

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must pay congestion charges in any particular hour that it does not operate the resource that provides the counterflow. *See generally*, *TEMT II Order*, 108 FERC at P 139-202.

[49] Attachment AE, sections 5.3 and 5.4.

[50] Exhibit III to SPP's filing, Testimony of Craig R. Roach at 20 (Roach Testimony).

[51] *See September 19 Order*, 112 FERC at n.21.

underscheduling that does not provide an exception if a market participant's actual generation does not deviate from its generation schedule by submitting tariff changes in the compliance filing ordered below.

56. Each market participant is required to submit a resource plan that identifies the resources to serve its loads.[52] Therefore, we disagree with Xcel that market participants can defeat over- or underscheduling penalties by simply registering its load and resources under separate entities.

57. The Commission believes a 4 percent deadband for over- and underscheduling charges would be beneficial, for example, to provide market participants with flexibility when using the imbalance market and to decrease administrative burdens. In that regard, we agree with the TDU Intervenors that a 2 MW cap will protect smaller entities from bearing a disproportionate burden. As such, we will require SPP to modify these provisions to exclude over- or underscheduling charges for the higher of 2 MW or a 4 percent deadband and to submit such modifications as part of its compliance filing no later than 60 days from the date of this order.

E. Real-Time Process

1. Locational Pricing and Congestion Management

a. SPP's Proposal

58. SPP seeks to operate a real-time energy market to provide energy imbalance service and to allow SPP to dispatch resources that bid into the market. SPP proposes that all imbalances be settled in the imbalance market; self-provision of imbalances will no longer be allowed. Participation as a seller into the imbalance market is voluntary. Dispatchable resources, *i.e.*, those resources that bid into the SPP imbalance market, must meet minimum operating criteria in order to be eligible to set the imbalance price. Self-dispatched resources that are not controlled by SPP are not eligible to set prices in the imbalance market.

59. SPP will calculate LIPs at each specific location (node) in the SPP region and issue dispatch instructions every five minutes. Section 4.4 of Attachment AE provides that the formula for calculating LIPs at each meter settlement location is the market clearing price at that location based on the security constrained economic dispatch, the

[52] Attachment AE, section 2.2.

bids and characteristics of dispatchable resources and data from the state estimator. SPP further defines the LIP as the marginal cost of serving load at a specific location as calculated by SPP's economic dispatch algorithm.

60. Pursuant to Attachment AE, section 4.1, after SPP determines the five-minute dispatch through its security constrained economic dispatch process, it will communicate the dispatch instructions that specify the output of dispatchable and self-dispatched resources to market participants.[53] SPP proposes that it will then adjust the net scheduled interchange for each control area to account for these dispatch instructions and communicate the adjusted net scheduled interchange to the control areas for implementation.

61. Attachment AE, section 4.3, provides that SPP will manage congestion through a combination of TLR procedures and imbalance market solutions. For physical flows into, through or out of SPP, SPP will tag transactions with priority levels according to the current NERC TLR procedures. Then, SPP's tariff provides that flows within SPP associated with dispatch in the imbalance market (market flows) will be assigned one of three curtailment priority levels specified in section 4.3 of Attachment AE, that correspond to the order of curtailment under TLR procedures. When congestion occurs that requires a TLR curtailment, reliability coordinators using the NERC IDC will send signals for the curtailment of physical schedules for transactions that have a source or sink outside of SPP and SPP will manage the market flows (including internal physical schedules). Also, the reliability coordinators using the NERC IDC tool will signal the total curtailment required of SPP's market flows.

62. SPP proposes to use a combination of market and non-market mechanisms to achieve the required reductions in market flows. First, section 4.3(d)(i) of Attachment AE provides that dispatchable resources will be redispatched to eliminate market flow problems and LIPs will be recalculated. Second, section 4.3(d)(ii) provides that internal physical flows will be curtailed based on the curtailment priority assigned and the resource's impact on the constrained flowgate. SPP states that curtailed internal physical schedules will not directly impact the LIP because self-dispatched resources cannot set the LIP as set forth in Attachment AE, section 4.4(a). SPP states that it will use a curtailment adjustment tool to manage this internal curtailment and schedule adjustment process.[54] SPP states that this tool, along with two others will ensure that NERC is made

[53] The dispatch instructions for each self-dispatched resource will be based on the output level specified in physical schedules for each resource.

[54] Rossi Testimony at 5.

aware of impacts of all transactions within SPP and that a transparent mechanism is created for assigning curtailment priorities to market flows so that existing TLR procedures can be used to eliminate congestion.[55]

b. Protests

63. TDU Intervenors state that SPP has failed to show that its proposed market operating rules will ensure that imbalance charges will be just and reasonable. That is, TDU Intervenors add that SPP has not provided a comprehensive walk-through of its proposed market operations or fully explained the relationship between market operations and the TLR process. TDU Intervenors request that the Commission convene a technical conference to elicit adequate explanation of SPP's proposed market operations.[56] Xcel states that SPP has failed to provide the formula rate for determining LIPs.

64. TDU Intervenors protest the voluntary nature of the market. TDU Intervenors state that SPP has not ensured that generation will be bid into the market rather than self-dispatched and, thus, the proposed market may be artificially thin and contain only high-cost bids. TDU Intervenors request that the Commission require SPP to provide periodic reports detailing the depth of the market and the effects of self-dispatch.[57]

65. Xcel commends SPP's effort to develop the curtailment adjustment tool, an objective tool to address reliability situations where economic dispatch capability has been exhausted. However, Xcel argues that the curtailment adjustment tool has not been approved by NERC or thoroughly evaluated and that the tool has not been adequately tested concerning its potential impacts on NERC processes or seams coordination. Specifically, Xcel is concerned that the curtailment adjustment tool will be unable to respect minimum unit dispatch levels and that SPP has made no provision for circumstances where a curtailment adjustment tool-directed reduction would put the unit below its minimum output capability. In addition, Xcel requests that the Commission require SPP to engage in a comprehensive pilot test of the curtailment adjustment tool, with NERC involvement in design and critique of the pilot test results.

66. Also, Xcel states that while a self-dispatched unit as a price-taker cannot set the LIP, SPP has not described the manner in which the LIP for the price-taking unit will be determined. Additionally, Xcel states that since SPP will manage system contingencies

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[55] *Id*.

[56] TDU Intervenors at 9-10.

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

through a blend of market-based redispatch and curtailment of physical schedules, SPP needs to address the timing of LIP updates in a contingency situation, *i.e.*, whether LIPs will be updated before or after physical schedules are curtailed.

67. Xcel believes that when a TLR event is called, SPP directs the control area to redispatch units to address the problem. Xcel states that SPP takes the view that it has not directly redispatched any unit. Xcel argues that when the curtailment adjustment tool becomes operable, however, SPP will be directly dispatching self-dispatched units, making it necessary to address the issue of the appropriate compensation for redispatching generators. Xcel believes that SPP has no rate schedules that would apply in this situation, which is a significant flaw in the SPP's present proposal and that this is inconsistent with the present requirements of the SPP Membership Agreement, properly interpreted. Southwest Industrials state that since SPP is not providing a capacity payment, it should not be able to require self-dispatched resources to follow dispatch instructions for the purpose of serving the imbalance market needs.[58] Westar requests that the Commission require SPP to clarify that it will only redispatch self-dispatched resources with a firm schedule when SPP has exhausted all redispatch of the dispatchable resources in the imbalance market and declared a TLR level 5 emergency.[59]

68. Westar states that SPP has failed to fully address unusual market or system conditions, including: (1) the steps that SPP will take if the dispatchable ranges of dispatchable resources do not match the demands for imbalance; and (2) SPP's and control areas' ability to manually dispatch to respond to new flowgate or system emergencies such as a substation fire or tornadoes.

69. TDU Intervenors assert that SPP should be required to incorporate into Attachment AE the market protocols that significantly affect rates, terms or conditions of service in the imbalance market. TDU Intervenors explain that some provisions of the market protocols create additional rights or obligations for SPP and market participants and that these provisions should be filed with the Commission so that they cannot be changed without Commission approval. Specifically, TDU Intervenors state that the following should be included in SPP's OATT: (1) the right of owners of multi-owner generating units to bid their share of generation separately; and (2) the procedures for scheduling and dispatch.

[58] Southwest Industrials at 17-18.

[59] Westar at 8.

c. SPP's Answer

70. SPP states that with regard to compensation for self-dispatched resources, its Membership Agreement allows SPP to direct a generator to run for reliability reasons. SPP adds that "in the absence of a generic Tariff provision, compensation of self-dispatched resources will need to be handled on a case-by-case basis."[60]

71. Additionally, SPP states that the Market Monitor will watch the depth of bids in the market, compare the capacity bid into the market with the self-dispatched resource capacity and "will take the necessary steps to address such behavior if detected."[61]

d. Commission Determination

72. We find that SPP's proposed real-time operating rules, as modified, will ensure just and reasonable imbalance prices. We also find that SPP's revisions to the LIP formula are sufficient to meet the Commission's formula rate requirements and are similar in level of detail to the locational marginal price (LMP) formulae contained in other RTO tariffs.[62] We do not find that the voluntary nature of the bidding in SPP's imbalance market is a threat to the stable operations of the market or will necessarily result in "high-cost" bids. We find that the most important protection for customers from a thin imbalance market is SPP's day-ahead and hour-ahead resource planning process that requires commitment of sufficient deliverable resources. If a load serving entity

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[60] SPP Answer at 16.

[61] SPP Answer at 14.

[62] *See, e.g.*, Midwest ISO FERC Electric Tariff Third Revised Volume No. 1, at section 1.174, Superceding Original Sheet No. 93 (LMP is the market clearing price for energy at a given node and equivalent to the marginal cost of serving demand at the node) and at Attachment DD, Original Sheet No. 1808 (detailing the calculation of day-ahead LMP where the Marginal Energy Component is simply "the marginal cost of energy available to the Referenced Bus"); PJM Interconnection, L.L.C. (PJM) FERC Electric Tariff Sixth Revised Volume No. 1, Attachment K, section 2.5 at Second Revised Sheet No. 373 (real-time prices shall be calculated "by applying an incremental linear optimization method to minimize energy costs, given actual system conditions, a set of energy offers, and any binding transmission constraints that may exist"); New York Independent System Operator, Inc. FERC Electric Tariff Original Volume No. 2, Attachment B, section I at Substitute Eleventh Revised Sheet No. 331 (real-time LMP prices will be based on the system marginal costs and produced by either the Real Time Dispatch program or the Real-Time Commitment program).

commits sufficient resources that are deliverable to its load, it will pay no more than its cost of production (or bilateral purchase) and can thus avoid buying imbalance energy at prices that it believes are high. However, since SPP's Market Monitor will be monitoring the depth of the imbalance market and the effects of self-dispatch, we will require monthly informational filings for the first year of imbalance market operation, from the Market Monitor on these subjects. This report should include a measure of the total megawatts of bids at each node relative to the available megawatts of generation at each node, and detail regarding how congestion and imbalances were resolved, whether through TLR or imbalance market mechanisms.

73. Section 1.2.7 of Attachment AE requires market participants to follow SPP's dispatch instructions relating to dispatchable and self-dispatched resources during normal system conditions and system emergency conditions. We disagree with SPP's proposal to address compensation for SPP's dispatch of self-dispatched resources, in the absence of a generic tariff provision, on a case-by-case basis.[63] Therefore, SPP is directed to either delete the language allowing for dispatch of self-dispatched resources during normal system conditions or submit tariff provisions that provide for compensation for these resources when SPP instructs them to deviate from their schedules during non-emergency conditions. If SPP decides to delete the language allowing for dispatch for self-dispatched resources during normal system conditions, it is directed to submit a compliance filing to this effect no later than 60 days from the date of this order. If SPP decides to propose a compensation mechanism for these resources, it must inform the Commission of such a decision in its compliance filing due to the Commission no later than 60 days from the date of this order, and it must submit generic tariff provisions with a compensation mechanism no later than 60 days prior to the implementation of the imbalance market.

74. With respect to Xcel's arguments that SPP's curtailment adjustment tool has not been thoroughly tested and has not been approved by NERC, we note SPP states that it has sought waiver from relevant NERC standards consistent with the actions of other RTOs and is involved in NERC's modification of certain standards related to the curtailment adjustment tool.[64] Also, SPP states in its answer that it expects NERC will evaluate and certify the curtailment adjustment tool and other market tools in March 2006.[65] Further, SPP has scheduled market trials to test the curtailment adjustment tool

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[63] SPP Answer at 16.

[64] *See* Monroe Testimony at 5-6.

[65] *See* SPP Answer at 18.

scenarios as part of its broader market testing effort.[66] The Commission believes that these are reasonable steps to take in implementing the curtailment adjustment tool and other imbalance market tools.

75. We agree with Xcel that the curtailment adjustment tool is an important tool to address reliability situations where economic dispatch capability has been exhausted. However, we find that the tariff lacks much of the detail necessary to understand how the curtailment adjustment tool will function, and the economic impacts of the curtailment adjustment tool. SPP has not provided the detail in its tariff to enable the Commission to discern all the steps of the iterative process that SPP will perform using the curtailment adjustment tool. Therefore, we direct SPP to modify its tariff to incorporate the provisions of the market protocols that specify the adjustment and curtailments SPP will make using the curtailment adjustment tool, especially sections 5.4 and 6.7.2 of the market protocols. SPP's modifications should also detail the recalculation of LIPs in a contingency situation, including each step at which LIPs will be updated and whether LIPs will be updated after physical schedule curtailment.

76. Finally, we direct SPP to incorporate into Attachment AE the provisions in its market protocols that allow for particular bidding protocols for jointly-owned units. However, we will not direct SPP to incorporate in its tariff all of the market protocols related to scheduling per TDU Intervenors' request. We find that the tariff provisions, as proposed, already contain the provisions that impact rates, terms and conditions relating to scheduling. We will not order generic inclusion of every provision of the market protocols in SPP's tariff, as this would exceed the Commission's rule of reason precedent.[67]

77. Unless specified otherwise, SPP is directed to submit a compliance filing with the tariff modifications discussed above no later than 60 days from the date of this order.

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[66] See SPP Market Alert (February 22, 2006), available at http://www.spp.org/Publications/SPP_Market_Alert_022206.pdf (updating on schedule for unscripted CAT scenarios testing and other unscripted testing).

[67] *See ANP Funding*, 110 FERC ¶ 61,040 at P2 (2005) ("rule of reason" applies in determining the types of documents related to operating procedures that must be filed for Commission approval, and those that significantly affect rates and services must be filed).

2. Uninstructed Deviation Penalties

a. SPP's Proposal

78. SPP proposes to calculate uninstructed deviations charges for each hour in which a resource fails to follow SPP's dispatch instructions within an acceptable operating range. The charges, calculated pursuant to section 5.5 of Attachment AE, will be based on the LIP at the resource's node. Additionally, section 4.1(e) of Attachment AE provides exemptions from the uninstructed deviation charges for certain resources, including intermittent resources and resources operating in test mode, start-up mode or shut-down mode.

b. Protests

79. TDU Intervenors state that section 5.5 is ambiguous as to whether the uninstructed deviation charges apply to all resources or whether they apply only to dispatchable resources. TDU Intervenors request that section 5.5 be corrected to delete reference to dispatchable resources, so that the charge clearly applies to all resources.

80. Xcel states that it identified a problem with the formula for calculating uninstructed deviation penalties, but that SPP has not addressed the problem. Specifically, Xcel is concerned that when LIPs are negative, the formula provides a payment instead of a penalty for not meeting SPP's dispatch instructions.

c. Commission Determination

81. The Commission believes the uninstructed deviation charges should apply to both dispatchable and self-dispatched resources and thus we direct SPP to remove the ambiguity in section 5.5 of Attachment AE. The Commission agrees with TDU Intervenors that SPP's tariff should provide self-dispatched resources with incentives to follow their submitted schedules in real-time. Such incentives provide for reliable operation of the system and comport with obligations to use good utility practice.

82. We recognize that the formula for determining uninstructed deviation charges may allow for payments to resources that do not follow SPP's dispatch instructions when LIPs are negative. SPP should not make payments to generators that fail to follow its instructions when the LIPs are negative. Therefore, we direct SPP to modify the formula it uses to calculate uninstructed deviations penalties to account for negative LIPs, in a compliance filing no later than 60 days from the date of this order.

3. Control Area-SPP Relationship

a. SPP's Proposal

83. SPP states that it does not propose changes to its filing to manage the relationship between the control areas and the imbalance market processes. SPP asserts that the split of responsibilities and obligations of SPP and the control area operators is well defined in the Commission-approved SPP Operational Authority Reference Document which is Appendix A to the SPP Membership Agreement. SPP states that the obligations between SPP and the control area operators will not change once the imbalance market is implemented.[68] SPP states that changes in the administrative process, such as changing the entity responsible for providing monthly balancing and energy accounting and administering inadvertent energy payback accounts, are being evaluated by SPP and its control area operators.

b. Protests

84. Xcel and Westar state that the delineation of responsibilities between SPP and the control areas lacks both the specificity and accuracy required to ensure reliable operations within the SPP footprint. Specifically, Westar states that neither SPP's OATT nor its market protocols gives the control areas the capability to take immediate action to preserve grid reliability should the imbalance market demands exceed deliverable energy supply available through the imbalance market.[69]

85. Xcel states that upon imbalance market implementation, SPP will be largely, if not solely, responsible for dispatch and review of resource commitments. Xcel states that the SPP Membership Agreement does not address the movement of functional responsibilities from the control areas to SPP, such as the new SPP responsibilities to redispatch resources for congestion management and formulation of an operational plan for reliability assessment.[70] Xcel concludes that SPP's failure to sufficiently delineate these functional responsibilities upon implementation of the imbalance market has significant implications for reliability and costs. According to Xcel, the potential for conflicting actions and directives is high and resource owners may be forced to choose between conflicting directives.[71]

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[68] Rossi Testimony at 18.

[69] Westar at 4-5.

[70] Xcel at 15-16.

[71] *Id.* at 17.

86. Also, Westar claims that SPP's OATT lacks clear guidance or procedures to pass through the costs that control areas would incur in committing additional resources to address such situations.[72] Further, Westar states that SPP's proposal does not provide clear procedures to pass through the costs of reserves and regulation services. Westar claims that control areas will be providing regulation service with new external factors, and thus incurring higher production costs that are not contemplated in the control area's FERC-accepted Schedule 3 calculation.

87. Additionally, Westar states that SPP's OATT must be amended to provide each control area with operational information relating to the calculation of the net scheduled interchange[73] and specific scheduling details for market participants in the control area. Westar explains that control areas need to be able to quickly determine which market participants are deficient when NERC issues an energy emergency alert so that the control area can take appropriate responsive actions. Westar states that the SPP Membership Agreement is not relevant to these issues because it was created for non-market operating conditions. Westar concludes that the Commission should direct SPP to work with control areas to identify operational, cost-recovery and cost shifting issues and develop mutually beneficial resolutions to these issues.

c. <u>SPP's Answer</u>

88. SPP states that its filing describes how SPP and the control areas have agreed to an appropriate division of responsibilities, liabilities and other issues. SPP reiterates that this division of responsibilities detailed in its filing is adequate and complies with the Commission's requirements. SPP adds that there is no need to delay the startup of the imbalance market or Commission approval of SPP's filing. SPP states that acceptance of SPP's filing would be consistent with the Commission's approval of the Midwest ISO energy market, where the Commission did not delay action on tariff sheets even though the Midwest ISO needed to work out its relationship with the control areas with regard to implementing its market proposal.

d. <u>Commission Determination</u>

89. Although the SPP Membership Agreement provides some detail on the NERC functional responsibilities, the functional responsibilities of SPP and the control areas are not adequately described and it is unclear how they will work together to effectuate the

[72] Westar at 4-5.

[73] "Net Scheduled Interchange" is defined as the "algebraic sum of all Energy Schedules into or out of a Control Area." Section 1.1.21 of Attachment AE.

new imbalance market arrangements, especially during emergency situations. Xcel and Westar raise valid concerns about the cost obligations and liabilities that will be associated with SPP's and the control areas' new roles in the implementation of the imbalance market. Through its implementation of the imbalance market, SPP will unilaterally carry out many balancing authority functions that it shared with control areas in the past, but will continue to share some balancing authority tasks with the control areas. The SPP Membership Agreement provides, for example, that the control areas and SPP will share responsibility for the balancing function task of reviewing generation commitments, dispatch and load forecast both before and after implementation of the imbalance market.[74] But the SPP Membership Agreement does not specify how this task will be shared or whether SPP or the control areas will have the sole or primary responsibility for this task.

90. First, it is critical that the division of balancing functions between SPP and control areas be clear prior to market start up. Therefore, we direct SPP to submit a more detailed allocation of the tasks within the balancing function, and, as appropriate, the reliability function prior to market implementation. SPP should submit this filing with the proposed resolution ordered below.

91. Second, we find that the SPP Membership Agreement does not adequately define the relationship between SPP and the control areas in the SPP system. We have stated a preference for negotiation among RTOs and their respective control areas in resolving these relationship issues.[75] Additionally, SPP, in its answer, has requested that the Commission follow the same procedures that we adopted for in Midwest ISO to address how the RTO and control areas will work together to effectuate the new market arrangements.[76] Therefore, as we did in the *TEMT II Order*,[77] we direct SPP and control area operators to negotiate before a settlement judge the proper allocation of functional responsibilities, costs and liability associated with SPP's new role in its region. They may seek the assistance of the Commission's dispute resolution staff for this process. SPP is directed to make a filing no later than 60 days from the date of this order containing a detailed allocation between SPP and the control areas of the tasks within the

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[74] SPP Membership Agreement Original Volume No. 3 at Original Sheet No. 52.

[75] *See TEMT II Order*, 108 FERC at P 138 (2004).

[76] SPP Answer at 25.

[77] *TEMT II Order* at P 138 (requiring the Midwest ISO and transmission owners to negotiate the allocation of functional responsibilities, costs and liability of Midwest ISO markets and to file a proposed resolution well before the start of the Midwest ISO markets).

balancing function and the reliability function. In the same filing, the parties are directed to submit their proposed resolution of the allocation of the functional responsibilities, costs and liability among SPP and the control areas.

4. Reserve Sharing

a. SPP's Proposal

92. Per section 1.2.2(e) of Attachment AE, SPP proposes that a market participant must be part of a reserve sharing group or enter into a reserve sharing cost allocation agreement (Reserve Sharing Cost Allocation agreement) in order to participate in the energy imbalance market. In its answer, SPP states that it is currently working on its reserve sharing proposal with the objective to complete the proposal in March 2006.[78] SPP further states that SPP stakeholder organizations are focusing on two issues: (1) establishing the criteria for initiating a call on reserve sharing energy; and (2) determining cost liability for parties for the resulting charges.

b. Protests

93. Redbud asserts that SPP's reserve sharing proposal changes imbalance service from an as-available non-firm energy sale into a firm product. Redbud states that the reserve sharing proposal assigns the cost of procuring replacement energy to market participants and thus, is different from the way other imbalance markets operate. Further, Redbud states that the reserve sharing proposal will restrict market participation by independent power producers and other transmission dependent entities who are not members of existing reserve sharing arrangements. TDU Intervenors state that SPP's proposed reserve sharing requirements were not explained or supported by SPP, unduly burden transmission dependent utilities and independent power producers, and serve as a barrier to participation in SPP's imbalance market. Moreover, Redbud states that since operating reserves are already provided for and charged pursuant to Schedules 5 and 6 of the SPP OATT, SPP's reserve proposal represents a duplicative, unnecessary charge.

94. Redbud and TDU Intervenors note that SPP has not defined or included the "Reserve Sharing Cost Allocation" agreement referred to in section 1.2.2.(e) of Attachment AE and further, SPP has failed to propose a cost allocation method or support the precise costs to be allocated under the agreement.[79] TDU Intervenors request that the

[78] SPP Answer at 10.

[79] Redbud at 6-7; TDU Intervenors at 11-12.

Commission reject SPP's proposed change to the reserve sharing requirements or, in the alternative, defer acting on this provision until SPP sets out the rates, terms and conditions by providing the pro forma Reserve Sharing Cost Allocation agreement.[80]

95. Xcel states that SPP has failed to integrate the imbalance market and the reserve-sharing process. Xcel explains that under SPP's imbalance market proposal, it will take SPP approximately 20 minutes to resolve a generator outage through the imbalance market, but that in the past, the control area had the opportunity to address resource outages during that 20 minute period by dispatching its own units or invoking a reserve-sharing event. In addition, Xcel states that with implementation of the imbalance market, any unit deployed by the control area to address a generation loss would be subject to imbalance charges, uninstructed deviation charges and over- and underscheduling charges. Xcel asserts that these costs consequences will probably increase the number of reserve-sharing deployments that will in turn result in increased costs to customers but decrease the ability of the reserve-sharing groups to respond to real emergencies.

c. <u>Commission Determination</u>

96. Because SPP has failed to provide a pro forma reserve sharing agreement that would detail the obligations and responsibilities of parties entering into such agreements, we cannot evaluate the reasonableness of section 1.2.2(e) of Attachment AE, and therefore, reject this section. In order to allow for timely review of its proposal to institute a reserve sharing requirement, SPP must file a pro forma reserve sharing agreement under section 205 of the FPA that details the duties and rights of parties to the agreement for Commission approval no later than 60 days prior to implementation of the imbalance market. In this subsequent filing, SPP must explain: (1) why any proposed reserve sharing requirement is not duplicative of SPP's OATT Schedules 5 and 6; (2) why the reserve sharing agreement is necessary for implementation of the imbalance market; (3) whether the reserve sharing requirement would reduce participation in the market by burdening independent power producers and transmission dependent utilities; and (4) whether the reserve sharing requirement is consistent with the operation and cost allocation methods in other real-time imbalance markets.

97. With regard to Xcel's concern that control areas will incur additional costs and liabilities by responding to generator outages, we believe that this is one of the issues appropriately resolved through the SPP-control area negotiations ordered above. SPP's

[80] TDU Intervenors at 13-14.

reliance on reserve-sharing groups as opposed to control areas as a means of responding to generator outages should be specified in the reliability clarification ordered above so that all parties are aware of their responsibilities.

F. Transmission Charges for Imbalance Service

a. SPP's Proposal

98. Under SPP's proposal, market participants pay for transmission service pursuant to the existing provisions of the OATT unless they take additional transmission service through the imbalance market.[81] SPP states that market participants that use energy imbalance service to serve their load but have not paid a transmission service charge (either through point-to-point service reservations or network integration transmission service) will be charged a separate transmission service charge. Market participants will be allowed to deviate from their point-to-point service reservation amount by up to four percent without an additional charge.[82] SPP states that this threshold provides customers with the ability to make ordinary use of the imbalance market within a deadband without worrying about transmission; the charge above the threshold prevents abuse.[83] Since the access charge for network integration transmission service is based on network load, SPP does not propose an additional charge for market participants taking network integration transmission service.

99. SPP states that market participants that use the imbalance market to serve load will be charged the hourly non-firm point-to-point transmission service rate for the amount that deviates from the market participant's point-to-point reservation amount by the greater of four percent or 1 MW. SPP also proposes to charge an imbalance transmission service charge to the transmission owners that provide service under grandfathered agreements or to bundled retail load but do not take network integration transmission service on behalf of their load. Pursuant to Schedule 4, SPP provides that this charge will be calculated by multiplying the hourly non-firm point-to-point transmission service rate by "the actual amount of Imbalance Energy transmitted in excess of 4% of the sum of such [t]ransmission [o]wner's bundled retail load and load under [g]randfathered [a]greements in each hour."[84] SPP proposes to exempt a transmission owner from paying transmission charges associated with the delivery of imbalance energy, if the

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[81] Monroe Testimony at 10.

[82] Also, SPP will not charge for deviations of less than 1 MW.

[83] Monroe Testimony at 10-11.

[84] Schedule 4, Original Sheet No. 100A.

transmission owner has a pending application before a state commission to serve its bundled retail load with network integration transmission service under the SPP tariff prior to the effective date of the final order or decision resulting from that application.

b. Protests

100. East Texas objects to SPP's proposal to exempt a transmission owner from paying transmission charges associated with the delivery of imbalance energy during the period when its application is pending before a state commission to serve its bundled retail load.[85] East Texas asserts that a transmission owner that receives an exemption will not have an incentive to schedule accurately. East Texas contends that the Commission should direct SPP to remove this discriminatory exemption from Schedule 4 or require SPP to clarify that the costs avoided by a transmission owner under this exemption will not be recovered from other SPP members or market participants.[86]

101. TDU Intervenors support SPP's proposal to charge market participants for the use of the transmission system when they use the imbalance market to serve their load. TDU Intervenors argue that the Commission should require SPP to increase the 1 MW minimum to a 2 MW minimum to prevent exposing smaller entities to a disproportionate risk.

c. Commission Determination

102. The Commission supports SPP's proposal to charge market participants, who have not otherwise paid for their share of the transmission access cost, for their use of the transmission system when they use the imbalance market to serve their load. However, we will require SPP to increase the 1 MW minimum to 2 MW to protect smaller entities.

103. Schedule 4 proposes to charge transmission owners serving grandfathered and/or bundled retail load, and not taking transmission service under SPP's tariff, a non-firm point-to-point transmission service rate "multiplied by the actual amount of *Imbalance Energy* transmitted *in excess of 4%* of the sum of such Transmission Owner's bundled retail *load* and *load* under Grandfathered Agreements in each hour." (emphasis added) We believe the intent of this provision is to allow SPP to charge these transmission owners for transmission service taken in excess of 4 percent of their scheduled load. In the interest of clarity, we will direct SPP to add "scheduled" before "load" in the above clause. Additionally, we direct SPP to include the 2 MW minimum, so that transmission

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[85] East Texas at 15.

[86] *Id.* at 16.

owners serving grandfathered and/or bundled retail load pay for transmission usage in excess of the greater of 2 MW or 4 percent of scheduled load. Therefore, the Commission directs SPP to file revised tariff sheets no later than 60 days from the date of this order.

104. With regard to SPP's proposal to exempt a transmission owner from paying transmission charges associated with the delivery of imbalance energy during the period when its application is pending before a state commission to serve bundled retail load using network integration transmission service under the SPP tariff, we disagree with East Texas. SPP's attempt to encourage transmission owners with grandfathered and bundled retail load to transition to SPP's tariff is consistent with the Commission's direction.[87] Therefore, we find that SPP's decision to offer an exemption to these transmission owners is just and reasonable.

G. Settlement and Billing Issues

1. Settlement Process and Timelines

a. SPP's Proposal

105. Under section 1.2.2(a) of Attachment AE, all market participants that plan to provide services in the imbalance market must register with SPP no later than 45 calendar days before their expected date of participation. Completed registrations must contain the information required in the registration package included in the market protocols (Registration Package). As part of the registration process, market participants must register all resources and loads, including applicable load associated with grandfathered agreements. Registration identifies each load and/or resource with a settlement location. A settlement location may either be a single meter settlement location (the effective point at which a market participant's registered load and resources interchange energy with the imbalance market) or, for load, an aggregation of meter settlement locations within one settlement area if the market participant elects such aggregation. SPP further proposes a system of nodal pricing that allows for LIPs calculated at each meter settlement location for generation resources and for aggregations of meter settlement locations into load zones.[88] In addition, SPP proposes that for the first year of the energy market, the

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[87] *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 at P 108-109, *order on reh'g*, 109 FERC ¶ 61,010 at P 52-53 (2004).

[88] Section 1.1.33 of Attachment AE defines a Settlement Area as:

(continued)

balancing authority (control area operators and/or transmission owners) will act as meter agents (entities responsible for acquisition and transfer to SPP of all meter data, losses, and application of settlement data to settlement intervals).

106. Sections 5 and 6 of Attachment AE govern the energy imbalance service settlement and billing process. SPP proposes to calculate each market participant's imbalance energy amounts in megawatts per hour at each settlement location using a settlement interval of one hour under section 5.1 of Attachment AE. SPP also proposes in section 5.1(a) of Attachment AE to adjust each market participant's reported load within the settlement area if there is a difference between the reported load and the settlement area net load. SPP will produce daily settlement statements and weekly invoices for each market participant.[89]

107. SPP proposes to have three types of settlement statements; a preliminary (or initial) statement, a final Statement, and a resettlement statement.[90] Under section 6.1(a) of Attachment AE, SPP will issue a preliminary settlement statement for an operating day no later than five calendar days following the respective operating day, unless the fifth day is not a business day, in which case, it shall be issued on the first business day thereafter. SPP will issue a final settlement statement for an operating day "no later than 44 Calendar Days" after the applicable operating day with settlement considered final at the end of the 365th calendar day following the applicable operating day.[91] If a market participant fails to submit meter data, SPP may estimate the data for both preliminary and final settlement statements. Resettlement statements will be produced using corrected settlement data due to resolution of disputes or correction of data errors and any corrections occurring prior to the production of a final settlement statement.[92] Resettlement corrections will be included in the final settlement statement.[93] Pursuant to the market protocols, SPP will generate and publish settlement statements, which may be accessed by market participants through an internet interface between SPP's computer systems and market participants on business days.

An area within a single control area in the Transmission System for which interval metering can account for the net injections and net interchange associated with that area.

[89] Market Protocols at 50.

[90] *Id.* at 57.

[91] Attachment AE, section 6.1(c).

[92] Market Protocols, section 1.6.3 at 57.

[93] *Id.*

108. SPP proposes to invoice market participants on a weekly basis. Invoices will be prepared on a net basis with payments to SPP required by the third business day and payments by SPP to market participants by the fifth business day following the day the invoice was issued. All amounts are subject to payment or crediting whether or not a settlement or billing dispute exists. Customer default will be handled under SPP's existing credit policy (filed with the Commission as Attachment X on December 30, 2005, in Docket No. ER06-432-000).

b. Protests

109. Redbud states that it is unclear from the definition of settlement location what LIPs will be posted by SPP each hour. Redbud requests that the Commission direct SPP to post LIPs for all nodes individually as well as all nodes aggregated in a settlement area, since loads may be aggregated with settlement locations. Redbud asserts this type of price transparency is essential to identify congestion, send correct price signals, and allow market participants to maximize economic opportunities. Xcel questions whether SPP's settlement system will be able to distinguish between third parties using a settlement location for purchase or delivery of energy and those who registered a load or resource at the settlement location; such failure to distinguish will result in assigning all activity to the registered entity.[94] Xcel contends that this will place an additional and costly burden on the market participants.

110. TDU Intervenors argue that the proposal that the transmission owners act as meter agents for the first year is just one reason (of many) that the market protocols should be filed or incorporated into the tariff.[95] Similarly, while it supports SPP's decision to make the transmission owner the meter agent the first year, Westar claims that SPP did not address the recovery of the costs of the meter agent service, the limitations on liability for those performing the function, the standards for estimating meter data when metering equipment malfunctions, and the responsibility of market participants to coordinate with transmission owners in reporting meter data.[96]

111. TDU Intervenors assert that, as proposed, loads and resources located in multiple control areas will have to be balanced in each control area. They argue that they should have the ability to schedule, balance and settle their loads (and resources) in multiple control areas on an aggregate basis, to avoid paying for imbalances in multiple control

[94] Xcel at 26-27.

[95] TDU Intervenors at 40-43.

[96] Westar at 6-7 and 12.

areas and eliminate potential unnecessary uplift charges that will be borne by all market participants. They also assert that this practice is not comparable because one member with loads (and resources) scattered over three control areas cannot aggregate them, while another SPP member with four loads (and resources) in separate geographic areas but consisting of a single control area can aggregate its loads (and resources).[97]

112. TDU Intervenors argue that SPP fails to provide adequate information about the state estimator[98] that it proposes to use to determine LIPs and differences in the way the loads of the investor owned utilities and the TDUs are determined. In particular, TDU Intervenors are concerned as to whether the state estimator will overcome the discrepancies in the granularity of metering. TDU Intervenors assert that these discrepancies can obscure the price impacts of constraints internal to the control area to the detriment of embedded load serving entities since the embedded load serving entities typically have more sophisticated meters. Further, TDU Intervenors object to SPP's proposed method to calibrate all loads, including those measured by more accurate meters and suggest that calibration should be limited to those loads not measured by "revenue-quality" meters.[99] TDU Intervenors also suggest that the Commission should ensure that transmission-dependent load serving entities have the option to become part of a consolidated settlement location with their host control area operators to limit disproportionate impacts of congestion internal to a control area. TDU Intervenors state that while SPP intends to offer this option, it fails to propose it in its proposed tariff language.[100] Finally, TDU Intervenors contend that there is a payment date discrepancy because SPP, in its transmittal letter, states that payments are due within five days, however, section 6.2 of Attachment AE states that payments are due within three days.[101] TDU Intervenors argue that this section should be revised to reflect a five-day payment deadline.

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[97] TDU Intervenors at 14-18.

[98] A state estimator is the computer software and systems used to estimate the properties of the electric system based on a sample of system measurements.

[99] TDU Intervenors also request that SPP clarify that estimated data will only be used when actual data is not available. TDU Intervenors at 39.

[100] *Id.* at 21-24.

[101] *Id.* at 35-36.

c. <u>Commission Determination</u>

113. The Commission accepts SPP's settlement provisions as just and reasonable. No party has demonstrated that they are unjust, unreasonable, unduly discriminatory or preferential. We will however, direct SPP to post nodal prices for aggregate settlement locations within 15 minutes after the hour in response to Redbud's protest. The Commission agrees that additional price information makes the market more transparent.

114. The Commission shares Xcel's concern over whether the settlement system can distinguish between third-party transmission reservations to a settlement location and a market participant's imbalance market activity at that location. We agree that additional effort will be necessary by a market participant to monitor transmission reservations to its settlement locations, but we also conclude that if errors occur, the settlement procedures permit price corrections necessary to overcome the errors. In addition, SPP should design an automated systems check to avoid these issues and report to the Commission on its progress in developing this system one year after the date of market implementation.

115. The Commission accepts as reasonable the role that the transmission owners act as meter agents in the first year. In serving as meter agents, the transmission owners will be the conduit for data that they currently collect to allow them to assess charges for ancillary service under their own OATTs. We do not see that there are measurable additional costs to transmission owners in forwarding the information that they already collect to SPP. However, we concur with Westar that two issues related to this conduit role, *i.e.*, the limitations on liability for transmission owners performing the function and the standards for estimating meter data when metering equipment malfunctions, need clarification prior to market implementation. Therefore, we direct SPP to resolve these issues and submit a standard metering agent agreement no later than 60 days prior to the date of market implementation.

116. We reject TDU Intervenors' request to aggregate loads over multiple control areas. We agree with SPP that multiple control area aggregation would create gaming opportunities (through mis-scheduling withdrawals of energy to unconstrained sinks and not scheduling to the constrained sinks) and violate NERC's direction regarding inter-control area transactions.[102] TDU Intervenors note that SPP is considering control area consolidation in relation to developing an ancillary services market and we encourage SPP to continue its efforts in this regard.

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[102] SPP Answer at 14-15.

117. TDU Intervenors also raise two related pricing issues regarding the granularity of metering, *i.e.*, calibrating all loads and having the option of becoming part of a consolidated settlement location in order to aggregate LIPs. With regard to the first issue, SPP proposes to calibrate all load regardless of the quality of meter data. We find that SPP's proposed approach is appropriate for the initial months of market operation. However, we will direct SPP to measure the effects of its calibration method as compared with calibrating only the loads not measured with revenue quality meters, using the first six months of market operation information. With regard to aggregating LIPs, the Commission considers nodal pricing for load to be a just and reasonable pricing method, as it provides price transparency and accurate price signals for demand response.[103] We note that TDU Intervenors have a choice between nodal pricing and aggregation of LIPs into zonal pricing. If TDU Intervenors find that aggregation is inappropriate for their load they can always opt to settle using just and reasonable nodal prices. However, consistent with our actions in *Midwest Independent Transmission System Operator, Inc.*, we direct SPP to evaluate the option proposed by TDUs to become part of a consolidated settlement location with the host control area.[104] We direct SPP to present both of these studies to its stakeholders, and make an informational filing at the Commission detailing the results, proposals for next steps and alternatives, if appropriate, one year after market operations begin.

118. SPP's transmittal letter states that under section 6.2 of Attachment AE "payment is due within 5 days" without explaining who receives the payment. On the other hand, section 6.2 (c) explicitly states that market participants are required to pay SPP in three business days, while the market participant is paid on the "5th business day following the day the invoice was issued" under section 6.2(d). We do not believe there is a payment date discrepancy as asserted by TDU Intervenors, and therefore, there is no need to amend section 6.2(c). A difference in the dates that payments are due to SPP and due from SPP is reasonable since SPP, as a non-profit organization, is a conduit of these funds. SPP cannot pay out before it receives payment. We find two days after receipt of payment is a reasonable period of time for SPP to make payments.

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[103] *See Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,043 at P 47 (2005). *See also New England Power Pool and ISO New England, Inc.*, 106 FERC ¶ 61,059 at P 15 (2004).

[104] *Midwest Independent Transmission System Operator, Inc.*, 111 FERC at P 50.

2. Billing/Settlement Disputes

a. SPP's Proposal

119. Section 6.3 of Attachment AE sets forth the process for resolving disputed initial or final settlement statements within an invoice. It requires a market participant to challenge an invoice based on a final settlement statement within 30 calendar days after issuance of an invoice. SPP is required to notify the market participant within 30 days if it needs additional information and the market participant has 30 days after that to provide this information. SPP has to use its best efforts to notify the market participant of the approval or denial of the submitted notice of dispute within 20 days or notify the market participant if it needs more than 20 days with an estimate of the amount of time it needs to complete its analysis. A market participant may initiate dispute resolution procedures under section 12 of the Tariff, if SPP denies the market participant's notice of dispute or the market participant is not satisfied that it is receiving timely consideration of the dispute.

b. Protests

120. Golden Spread notes that section 6.3(a) of Attachment AE requires a market participant's notice of dispute to contain minimum information specified in the market protocols, however, tariff section 1.18c allows SPP to amend these protocols periodically without obtaining Commission approval.[105] It contends that the minimum content of a notice of dispute should not be subject to amendment without Commission approval.[106]

121. TDU Intervenors argue that the proposed 30-day limit to dispute invoices is not just and reasonable and therefore, should be rejected.[107] It notes that there is no time limit on a customer's ability to bring a complaint on a service provider's refund liability for improper implementation of formula rates under section 206 of the FPA. However, TDU Intervenors argue that the energy imbalance rates are formula rates and SPP's proposed 30-day limit on disputing invoices violates a customer's FPA section 206 rights. Furthermore, they note that SPP's imbalance market will probably encounter some difficulties in the initial stages of its settlement and billing procedures and imposing an arbitrary time limit will only encourage customers to routinely challenge their invoices to protect themselves. TDU Intervenors note that they are not opposed to a finality

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[105] Golden Spread at 13.

[106] *Id.*

[107] TDU Intervenors at 31-32.

requirement with respect to data input for the settlement statements and invoices, *e.g.*, section 6.1(d) limits the time within which a market participant may seek to substitute actual metered data for estimated output to load data used in the settlement statement.

c. <u>SPP's Answer</u>

122. SPP states that it has followed the "rule of reason" under Commission precedent to evaluate its market protocols and develop tariff provisions to reflect certain protocols.[108] In response to various protests that a number of these market protocols should be filed with the Commission, SPP argues that its decision is reasonable, however, if it becomes apparent after the start up of the imbalance market that certain market protocols are being used inconsistently with the OATT, SPP will take appropriate measures to address the matter.

d. <u>Commission Determination</u>

123. We agree with Golden Spread that the minimum content of a notice of dispute should not be subject to amendment without Commission approval and therefore, we direct SPP to include such information in section 6.3(a) of Attachment AE instead of in its market protocols. We direct SPP to submit a compliance filing no later than 60 days from the date of this order.

124. In the RTO context, we have allowed time limits on disputing invoices.[109] Since RTO billings disputed successfully by one participant, generally must be paid by others, there would be too much uncertainty on billing and settlement issues if a party was allowed to dispute an invoice for months or years after the transmission provider had been paid and it had in turn paid the market participants. However, we will direct SPP to

[108] SPP Answer at 21 citing *ANP Funding*, 110 FERC ¶ 61,040 at P2 (2005) ("rule of reason" applies in determining the types of documents related to operating procedures that must be filed for Commission approval, and those that significantly affect rates and services must be filed).

[109] *See, e.g.,* Section 7.9 of Midwest ISO's OATT notes that section 12 (Dispute Resolution) of the OATT governs invoice dispute and in section 12.9, billing disputes involving transmission service have to be initiated within 90 days from the date of the invoice and disputes for service under Module C have to be initiated within 115 days from the operating day; and under section 6.3 of ISO New England, Inc.'s OATT, a customer must dispute bills within three months.

amend section 6.3 of Attachment AE to allow market participants to challenge an invoice based on a final settlement statement within 90 calendar days after issuance of an invoice. SPP's compliance filing is due no later than 60 days from the date of this order.

3. Uplift Charges/Credits

a. SPP's Proposal

125. SPP proposes to remain revenue neutral, *i.e.*, receive enough revenue to pay what it owes, by assessing an uplift charge or credit to each market participant (Energy Imbalance Uplift Charge or Credit).[110] Section 5.6 of Attachment AE governs the calculations SPP will use to ensure that the uplift charges or credits are directed at those using the market for that hour.[111] SPP states that the Commission has approved similar uplift charges for other RTOs, citing Midwest ISO Open Access Transmission and Energy Markets Tariff (TEMT) sections 40.3.3(a)(ii) and (iii). In addition, SPP states that it expects the uplift charges to be very low and commits to report to the Commission if it finds that these charges are no longer relatively small.[112]

b. Protests

126. TDU Intervenors state that they do not fully understand how this section will operate and express concern that it will not allocate the uplift charges fairly. Westar also states that the Commission should reject the use of after-the-fact uplifts, surcharges and cost-socialization.[113] Westar claims that if there is any potential for the ultimate costs of imbalance energy to exceed a market participant's cost of production, the value of the market and the incentive to participate will diminish. Southwest Industrials assert that SPP's uplift charge proposal is not just and reasonable since it does not include any incentive to minimize the costs and does not include any cap. Southwest Industrials point to Midwest ISO's experience with uplift costs as an example of why SPP's expectation that uplift charges will be small is unrealistically optimistic.[114] Similarly, Golden Spread

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[110] Attachment AE, section 5.6.

[111] Attachment AE, section 5.6(h).

[112] SPP Transmittal Letter at 9.

[113] Westar at 10-12.

[114] Southwest Industrials at 19-21.

argues that the Commission should not consider approval of the energy market unless SPP can demonstrate how its market design will prevent the level of uplift from becoming a significant problem.[115]

c. SPP's Answer

127. SPP reiterates that its proposed uplift charges are similar to those previously accepted by the Commission; albeit more limited than the Midwest ISO's since it addresses only one issue – revenue neutrality uplift.[116] In addition, SPP offers to file monthly informational reports for six months after market start-up detailing the level and causes of uplift to ensure transparency and to propose remedies to reduce excessive amounts if they occur.[117]

d. Commission Determination

128. The Commission accepts SPP's uplift charge formula as reasonable. SPP clearly needs an uplift procedure in order to remain revenue neutral. In addition, we find that the proposal is consistent with other uplift procedures accepted by the Commission and allocates the charges fairly, *i.e.*, on a pro rata basis.[118] While we agree with Westar that excessive uplift costs diminish or eliminate savings from market participation, the Commission anticipates that SPP's scheduling process, including the SPP curtailment adjustment tool, over- and underscheduling charges, and day-ahead simultaneous feasibility test, will create a market with a minimal amount of uplift charges related to shortfalls in net revenue from the energy market. Further, SPP's proposed uplift formula is more limited than other uplift procedures we have previously accepted. Nonetheless, to ensure that the market meets these expectations and uplift costs do not become sizeable, the Commission accepts SPP's offer to file monthly reports on the level and causes of the uplift charges, but we extend the requirement to include the first year of market operations rather than the first six months in order to capture any seasonal variations in the charges. We do not believe that SPP's proposal will result in excessive charges, and if SPP's monthly reports indicate excessive uplift costs, we expect that SPP will propose an alternative addressing the issue.

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[115] Golden Spread Protest at 9.

[116] SPP Answer at 11.

[117] *Id.* at 11-12.

[118] *See* Midwest ISO TEMT, sections 40.3.3(a)(ii) and (iii) (providing for the calculation and imposition of the real-time revenue sufficiency and guarantee charge).

H. Market Monitoring

1. Role of the Market Monitor and External Market Monitor

a. SPP's Proposal

129. Pursuant to Attachment AG, section 3.1, SPP proposes that an internal market monitoring unit primarily perform the market monitoring, hereinafter referred to as the Market Monitor. SPP proposes that the Market Monitor shall be an organization within SPP, comprised of SPP employees. The Market Monitor shall report to SPP's President and Board and the Board shall assign duties to the Market Monitor. Pursuant to section 3.2 of Attachment AG, the Market Monitor may at any time bring any matter to the attention of the Commission, SPP's Board, SPP's officers or affected state regulatory authorities. Pursuant to sections 1.4 and 3.3 of Attachment AG, the Market Monitor shall be independent from market participants in order to provide impartial and effective market monitoring.

130. Additionally, SPP proposes that an External Market Monitor, under contract to SPP, may "perform certain market monitoring services as specified in its contract with SPP,"[119] as delegated by SPP pursuant to the terms of the contract.[120] Although SPP states that it is not obligated to have an External Market Monitor, SPP plans to file with the Commission a separate contract delineating the responsibilities of the External Market Monitor in a future filing.[121]

b. Protests

131. Golden Spread protests the approval of the entire imbalance market filing stating that it is unjust and unreasonable until the duties of the Market Monitor are clearly defined.[122] Redbud requests that the Commission require SPP to file the contract with the External Market Monitor within 30 days of the issuance of this order.[123]

132. Xcel and TDU Intervenors take issue with the internalization of any market monitoring function and state that allocating the responsibility of monitoring to the staff

[119] Attachment AG, section 2.3.

[120] Attachment AG, section 3.1.

[121] Filed February 15, 2005 in Docket No. ER06-641-000.

[122] Golden Spread at 8.

[123] Redbud at 7-8.

of SPP will negate the notion of independent monitoring. Furthermore, Xcel and TDU Intervenors assert that the internalization of the monitoring function is inconsistent with the requirements of section 3.17 of SPP's Bylaws.[124] TDU Intervenors specifically request that section 1.4 of Attachment AG be modified to clarify that the Market Monitor will be granted complete independence to perform the market monitoring activities and that no person may screen, alter, delete or delay the findings, conclusions and recommendations developed by the Market Monitor.

133. East Texas states that the division of functions between the Market Monitor and the External Market Monitor are still not clear; however, it will reserve judgment on the issue until the new External Market Monitor agreement has been filed.[125] OG&E supports granting SPP the authority to be the Market Monitor to oversee all market transactions occurring within the SPP footprint.[126]

c. Commission Determination

134. Since SPP did not elaborate on the split of functions between its internal Market Monitor and External Market Monitor in this filing, but did file its contract with the External Market Monitor in Docket No. ER06-641-000 on February 15, 2006, we will conditionally accept SPP's market monitoring proposal as to the split of functions between the internal and external market monitors, subject to further orders in Docket No. ER06-641-000.

135. We direct SPP to correct the inconsistencies in section 3.1 of Attachment AG to clarify whether the Market Monitor reports to the President of SPP or its Board, in a compliance filing no later than 60 days from the date of this order. The Market Monitor should report to the entire Board, especially given SPP's proposal to have the Board assign duties to the Market Monitor.

2. Market Monitoring Responsibilities

a. SPP's Proposal

136. In section 1.3 of Attachment AG, SPP outlines the objectives of the Market Monitor. The Market Monitor is required to: (1) monitor and report on possible abuses of

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[124] Xcel at 25 and TDU Intervenors at 87. *See* Southwest Power Pool Bylaws (Bylaws), Original Volume No. 4, effective May 1, 2004.

[125] East Texas at 7.

[126] OG&E at 3.

horizontal and vertical market power in the SPP market by any market participant; (2) monitor and recommend changes to the design and implementation of SPP's markets and services in order to benefit customers, market participants and the overall operation of the market; and (3) monitor market participants' compliance with market rules. SPP states that the Market Monitor will ensure that its functions and activities are implemented fairly and consistently, provide protection and encourage competition while minimizing interference with open and competitive markets. Pursuant to section 1.3 of Attachment AG, the Market Monitor will also make recommendations in order to improve the operation of the market and to prevent any exercise of market power in advance rather than punishing offenders afterwards.

137. In section 4.1 of Attachment AG, SPP proposes that the Market Monitor be responsible for monitoring SPP's markets and services. SPP proposes that the Market Monitor will not have the responsibility for monitoring bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP. Nor will the Market Monitor monitor markets and services in regions adjacent to SPP. The Market Monitor, however, will assess the impact of these markets and services on SPP's markets and services.

138. Under section 6.1 of Attachment AG, the Market Monitor will administer the market mitigation plan and remedy any actual or potential abuse of market power or market design inefficiencies. This section limits the Market Monitor's activities to matters that: (1) are expressly set forth in the tariff; (2) involve objectively identifiable behavior; and (3) do not subject market participants to sanctions other than those approved by the Commission and specified in the tariff. Section 6.1(a) of Attachment AG provides that the Market Monitor may engage in discussions with market participants to informally resolve issues of mitigation and compliance. Further, section 6.1 of Attachment AG provides that "Market Participants shall also be encouraged to initiate discussions with the Market Monitor to obtain an informal opinion regarding potential compliance consequences of any further actions such participant may wish to take that would impact SPP's Markets and Services."

b. <u>Protests</u>

139. East Texas asserts that more detail is needed in section 4.1of Attachment AG to clarify which markets the Market Monitor will monitor and which markets the Market Monitor will "assess."[127] East Texas also takes issue with SPP's compliance with the

[127] East Texas at 14.

Commission's *Policy Statement on Market Monitoring Units*,[128] stating that SPP's market monitoring plan should be modified to require the Market Monitor to evaluate the effectiveness of the markets in signaling the need for transmission investment.[129]

140. Golden Spread states that section 1.3 of Attachment AG focuses exclusively on preventing the exercise of market power in advance. Golden Spread requests that section 1.3 be changed to clarify that compensating the customers who are victimized by market manipulation is no less important than making recommendations aimed at making market manipulation more difficult in the future.[130] TDU Intervenors argue that SPP's monitoring for transmission withholding is too narrow in its application because the monitoring plan applies only to market participants that own and control both generation and transmission, and therefore, they argue that SPP should also monitor stand-alone transmission companies.[131] Further, TDU Intervenors state that since "SPP will maintain balancing authority functions at the control area level," the Commission should direct SPP to monitor for exercise of market power by control areas.[132]

c. <u>Commission Determination</u>

141. We will not require changes to section 4.1 of Attachment AG per East Texas' request. Section 4.1 is reasonable in that the Market Monitor will monitor only SPP's markets and services. In meeting the obligation under section 4.1, the Market Monitor necessarily must review the impact of the non-SPP markets and services, such as bilateral transactions, on SPP markets and services, but need not develop its own studies of non-SPP markets and services. We will grant East Texas' request that Attachment AG be modified to provide for evaluation of the effectiveness of SPP's market in signaling the need for transmission investment. To ensure consistency with the Commission's Policy Statement on Market Monitoring Units,[133] we direct that SPP modify Attachment AG to require the Market Monitor to: evaluate regularly the effectiveness of SPP's markets in signaling needed investment in generation, transmission, and demand response

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[128] 111 FERC ¶ 61,267 (2005).

[129] *Id.* at 14.

[130] Golden Spread at 15.

[131] TDU Intervenors at 85-86.

[132] *Id.* at 87.

[133] *Policy Statement on Market Monitoring Units*, 111 FERC at P 7 (market monitoring units perform an important role in assisting the Commission in enhancing the competitiveness of ISO/RTO markets by performing several valuable tasks).

infrastructure; and recommend proactively to SPP any proposed changes related to signaling needed investment. Therefore we direct SPP to make these modifications in a compliance filing no later than 60 days from the date of this order.

142. We are not persuaded by Golden Spread's or TDU Intervenors' arguments that the proposed monitoring plan is too narrowly focused. One objective of the market monitoring plan is to monitor and report on possible abuses of horizontal and vertical market power in SPP's Markets and Services by any market participant. Thus, stand-alone transmission companies and control areas, to the extent they participate in or impact SPP's markets and services, are subject to monitoring. Further, although the monitoring plan contains language stating a preference for preventing the exercise of market power rather than addressing it after-the-fact, this does not relieve the Market Monitor from bringing instances of market manipulation to the Commission's attention so that the Commission can craft the appropriate remedy.[134]

143. SPP has proposed a mitigation plan that minimizes the discretion afforded to the Market Monitor due to the generic nature of the offer caps. Thus, we do not see the need for the Market Monitor to informally resolve issues of mitigation and compliance as proposed in section 6.1(a) of Attachment AG. Therefore, SPP is directed to modify this provision to allow the Market Monitor and market participants to communicate in order to implement mitigation and compliance. Additionally, since the Market Monitor is not authorized to interpret the tariff or the Commission's rules regarding market manipulation,[135] we direct SPP to clarify or remove the provision in section 6.1 of

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[134] *Prohibition of Energy Market Manipulation*, Order No. 670, 71 Fed. Reg. 4,244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202 (2006) (Order No. 670).

[135] *See Policy Statement on Market Monitoring Units*, 111 FERC at P 6 (market monitors to refer situations to the Commission "where market participants' behavior falls outside of the limited area of objectively identifiable, specific penalty rule violations the ISO/RTO may administer"). In addition, the Commission has processes in place to enable market participants to obtain informal Commission staff advice on such matters. It recently clarified that staff "no-action letters" may be obtained, under 18 C.F.R.§ 388.104(a), to get informal staff advice under the Commission's regulations related to the Standards of Conduct for Transmission Providers and the Prohibition of Energy Market Manipulation Rules. *Informal Staff Advice on Regulatory Requirements*, "Interpretive Order Regarding No-Action Letter Process," 113 FERC ¶ 61,174 (2005). In addition, aggrieved entities may make informal contact with Commission staff via the enforcement hotline with their complaints or concerns. 18 C.F.R. § 1b.21; *see also* Order No. 670 at P 73.

Attachment AG that allows the Market Monitor to provide informal opinions. We direct SPP to submit these modifications no later than 60 days from the date of this order.

3. Market Behavior Rules and Reporting of Market Manipulation

a. SPP's Proposal

144. Section 6 of SPP's Market Power Mitigation Plan (Attachment AF) provides that the Market Monitor will monitor for violations of the Commission's Market Behavior Rules[136] and report any violations to the Commission in accordance with the Commission's reporting protocols for market monitors. With this provision, SPP states that it has attempted to draft a provision that will comply with the Commission's monitoring requirements related to violations of the Market Behavior Rules. According to SPP, this approach attempts to eliminate the need to revise and refile its tariff whenever the Commission changes its market behavior rules or for compliance purposes.[137]

b. Protests

145. Southwest Industrials contend SPP should incorporate the Commission's Market Behavior Rules in the tariff so that the tariff provides for customer reimbursement in the event of market manipulation. More specifically, Southwest Industrials request that the Commission require SPP to include the Market Behavior Rules verbatim in SPP's tariff.[138]

c. Commission Determination

146. We agree in principle with Southwest Industrials that SPP should list the specific Commission rules and regulations relating to market behavior that it will employ in monitoring its markets. Although we previously provided guidance regarding verbatim

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[136] In February, 2006, the Commission rescinded the Market Behavior Rules 2 and 6. *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, "Order Revising Market-Based Rate Tariffs and Authorizations," 114 FERC ¶ 61,165 (2006). In a concurrent order, the Commission codified Market Behavior Rules 1, 3, 4, and 5 in its regulations at 18 C.F.R. §§ 35.36 and 35.37. *Conditions for Public Utility Market-Based Rate Authorization Holders*, 71 Fed. Reg. 9,695 (February 27, 2006) (Order No. 674).

[137] SPP Transmittal Letter at 12; and Rossi Testimony at 31.

[138] Southwest Industrials at 23.

incorporation of the Market Behavior Rules, we now believe that it is sufficient for SPP to reference by citation the specific Commission rules and regulations, namely the Commission's Order No. 670[139] and the Commission's new Conditions for Public Utility Market-Based Rate Authorization Holders,[140] and we require SPP to revise section 6 accordingly. We further require SPP to relocate section 6 of SPP's Market Power Mitigation Plan (Attachment AF) to SPP's Market Monitoring Plan (Attachment AG), as this section 6 relates to the responsibilities of the Market Monitor and not to mitigation measures. SPP must also revise section 6 to state that the Market Monitor will report market manipulation and violations of the conditions on market-based rate authorizations to the Commission in a timely manner, not "as required pursuant to section 7 of Attachment AG," as section 7 relates to the provision to Commission staff of reports to SPP's Board of Directors and reports requested by Commission staff. Finally, we direct SPP to revise section 6 to remove references to Market Behavior Rule 2. SPP is directed to submit a compliance filing no later than 60 days from the date of this order

4. <u>Data Access, Collection and Retention by Market Monitor</u>

a. <u>SPP's Proposal</u>

147. In section 8 of Attachment AG, SPP proposes that the Market Monitor shall regularly collect and maintain data and information in order to monitor SPP's markets and services. More specifically, in section 8.3, SPP proposes that market participants will retain the following data and information for a minimum of three years relating to: (1) the costs of operating a generating unit including heat rates, start up fuel requirements, fuel purchase costs, environmental costs, and operating and maintenance expenses; (2) the opportunity costs of a generating unit which include regulatory, environmental, technical, or other restrictions limiting run-time characteristics; (3) the operating status of a generating facility, including generator logs, generating status, forced or planned outages or derating of a generating unit; (4) the operating status of a transmission facility, a contingency, forced or planned outages or derating of a transmission system component; (5) transmission system planning including studies, reports, plans, models, analyses, and filings with FERC or any state regulatory commission; and (6) the ability of a market participant or affiliate to determine the pricing or output level of generating capacity owned by another entity.

148. If any additional data and information, not required under sections 8.3 or section 4 of Attachment AG, is required from a market participant, the Market Monitor may

[139] 71 Fed. Reg. 4,244.

[140] Order No. 674, 71 Fed. Reg. 9,695.

request such data and information as needed. Any requests must be accompanied by an explanation of the need for such information in a specific format, and an acknowledgement of the obligation of the Market Monitor to maintain confidentiality. If a market participant receiving the request for data and information not required under section 8.3 or section 4 believes that the production of such data would impose a substantial burden or expense, or would be irrelevant to the plan's objectives, the market participant receiving the data is required to notify the market monitor. The Market Monitor will review the request to determine whether the request can be modified to reduce the burden or expense of compliance. The Market Monitor would then modify the request accordingly.

149. If the Market Monitor determines that the requested data and information has not or will not be provided in a timely manner, the Market Monitor may use: (a) the dispute resolution procedures under the OATT or SPP Bylaws; or (b) a filing with the appropriate regulatory or enforcement agency to compel the production of the requested information.

b. <u>Protests</u>

150. In its protest, WFEC asserts that the list of data and information outlined in section 8.3 is too broad. WFEC points out that such a generalized list could be construed to encompass all aspects of data, information, documents and other records possessed by WFEC.[141] WFEC asserts the need to have this section clarified and to be limited to matters directly relevant to the market monitor's function and responsibilities. In addition, WFEC recommends that the record retention requirements be modified to specify that a market participant, not already required to collect information specified in section 8.3, will not be required to create new systems or practices, or expand existing ones, to collect additional information.[142] Lastly, WFEC states that the Market Monitor should be required to specify the format and content of the data and information needed to be retained.[143]

c. <u>SPP's Answer</u>

151. SPP notes that the Commission has previously approved broader data collection and retention provisions.[144] SPP points out that section 9.2 of Attachment AG provides

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[141] WFEC at 5.

[142] *Id.* at 6.

[143] *Id.* at 6.

[144] ISO-NE Transmission, Markets and Service Tariff § III, App. A, § III.A.11.1 (requiring market participants to provide the ISO with "any and all information within

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that any dispute concerning the implementation or compliance with the market monitoring plan will be referred to the dispute resolution procedures under SPP's OATT or Bylaws. It also notes that section 8.3 of Attachment AG permits market participants to challenge requests for data or information not specified by SPP's in Attachment AG if the market participant believes that the requested information would impose a substantial burden or expense, or is simply not relevant. Furthermore, SPP states that the generation information that market participants are required to maintain only applies to requests by such market participants for offer cap exemptions. SPP does not prescribe a format for the data, provided the data can be produced in the format specified in section 8.3 of Attachment AG. Finally, SPP argues that standardized record retention requirements for all market participants are important in order for the market monitor to access comparable information from each participant.[145]

d. Commission Determination

152. We note that the Commission has approved[146] and instituted broad data collection and retention provisions.[147] Also, sections 9.2 and 8.3 of Attachment AG provide a dispute resolution process and an opportunity for market participants to challenge SPP's requests for data or information that is not specified in SPP's tariff if such information imposes a substantial burden or expense, or is not relevant. In its compliance filing not

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their custody or control that the ISO deems necessary to perform its obligations under this Agreement").

[145] SPP Answer at 20-21.

[146] MISO TEMT, section 61.1 ("Market Participants, Transmission Owners, or the Transmission Provider shall retain the following categories of data or information for at least two years, beginning with the date of initial operation."); and New York ISO OATT, Article 10, Recordkeeping and Audit (ISO and each customer is required to keep complete and accurate records of certain data).

[147] The Commission proposed to extend the record retention requirement for market-based rate sellers to maintain certain records for five years to match the statute of limitation that applies to Commission's authority to impose the civil penalties for violation of its new anti-manipulation rules. Order No. 674 at n13; and *see* Order No. 670 at P 62-63. The Commission decided that in order to permit the Commission and interested entities to better monitor market-based rate sales and to allow the Commission sufficient time to investigate possible violations of the anti-manipulation rules it would adopt the five year record retention requirement. Order No. 674 at P 16. *See also* record retention requirements under 18 C.F.R. §125.3.

later than 60 days from the date of this order SPP should clarify that a market participant will be required to retain data that is in the custody and control of the market participants and produce it in the format specified in section 8.3 of Attachment AG. We agree with SPP that standardized record retention requirements for all market participants are important in order for the market monitor to access comparable information from each participant. Therefore, we will require that SPP work with the Market Monitor to specify the format and content of the data and information that market participants need to retain and submit a compliance filing no later than 60 days from date of this order.

I. Market Mitigation

1. General Mitigation Proposal

a. SPP's Proposal

153. In Attachment AF, SPP proposes mitigation measures to address economic withholding of energy in the imbalance market. SPP proposes to apply an offer cap during transmission constraints and only to bids from certain generators within electrical proximity to the transmission constraint. SPP states that the offer cap is designed to recover the full variable and long-run fixed costs of a new peaking generator with the fixed costs spread over the number of hours a constraint is binding at a particular location. SPP further states that the offer cap is structured so that it will never be below the price necessary to justify new generation investment in the transmission constrained area.

154. SPP proposes to determine whether a transmission constraint is binding for groups of transmission elements, *i.e.*, flowgates, based on the TLR congestion management process and the imbalance market security constrained dispatch process.[148] SPP proposes that an offer cap will apply to generators located on the importing side of a binding transmission constraint if the generator has a generator-to-load distribution factor of five percent or greater. For example, SPP will cap the generator's bid when a 100 megawatt increase in that generator's output reduces flowgate imports by five megawatts or more. SPP proposes to electronically post a list of all resources subject to the offer cap for each flowgate. The Market Monitor will reassess the status of the resources subject to offer caps on an annual basis or more frequently when transmission and generation facility additions, outages, changes, or changes in ownership may reasonably cause the offer capped status of a particular generator to change.

[148] Attachment AF, section 3.3.1.

155. SPP does not propose to apply a single maximum bid level, *i.e.*, a safety net bid cap, to all bids in the market. SPP does not propose any specific mitigation measures to address concentrated ownership of resources. SPP also does not propose mitigation to address physical withholding of energy or transmission, economic withholding of transmission or unavailability of energy or transmission facilities. SPP states that it removed transmission market power mitigation provisions proposed in its earlier market proposal and now proposes to monitor for transmission market power and resolve any exercise of transmission market power through the provisions of its monitoring plan.

156. SPP states that its proposed mitigation plan minimizes discretion on the part of the Market Monitor because the offer cap is formulaic and generic. SPP also contends that its mitigation plan does not create barriers to generation investment in the market, but in fact, enables a prospective investor to predict prices to sufficiently recover the full costs of a peaking generator, even if the generator runs only in the hours that bids will be mitigated.[149] Additionally, SPP states that its mitigation plan is based on the economic theory that the average total cost of a new entrant, including return on and of investment, is a fair estimate of the long-run equilibrium price that would otherwise prevail in a competitive market.[150] Finally, SPP claims that its proposed mitigation is similar to the mitigation approved for Midwest ISO. SPP notes that the Midwest ISO employs a similar generator-to-load distribution factor in areas with fewer than 500 annual hours of transmission constraints and the RTO uses the cost of entry to set bid thresholds in areas with more than 500 annual hours of transmission constraints.[151]

157. SPP does not provide specific mitigation measures to address strategic bidding issues;[152] rather SPP proposes to monitor generally for violations of the Market Behavior Rules. SPP explains that the congestion will block competitors from the exporting side, thus allowing the market participant's generation on the importing side of the constraint to exercise its market power in order to raise its offer price above the competitive levels. SPP states that the exercise of market power through uneconomic production would be more prevalent through self-dispatch of generators in SPP, but that SPP's mitigation, for the most part, protects against uneconomic production.

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[149] Roach Testimony at 3.

[150] *Id.* at 5.

[151] *Id.* at 7.

[152] SPP states that one form of strategic bidding, uneconomic production, is a concern when a market participant that owns resources on both sides of a transmission constraint runs its generation at a level above that dictated by economic dispatch in order to cause transmission congestion.

158. SPP suggest that a finding by the Market Monitor of the following would warrant referral to the Commission for uneconomic production: (1) a self-dispatched resource is causing congestion; (2) a self-dispatched resource is uneconomic (compare incremental cost with system lambda costs); and (3) the uneconomic production is not obviously justified by reliability or other operational concerns.[153] SPP suggests that monitoring for artificial transmission congestion as a violation of the Market Behavioral Rules is sufficient to address this form of strategic bidding.

159. SPP describes another form of strategic bidding, portfolio bidding, as a situation in which a market participant controls a pivotal share of the generation on the importing side of a transmission constraint and some of the generation is not subject to the offer caps. Under SPP's proposed mitigation, generators with a generation to load distribution factor on a particular flowgate of less than five percent are not subject to offer caps. SPP states that since 88 percent of megawatts in SPP are expected to be offer capped, portfolio bidding is not expected to be a large problem. However, SPP states that it will monitor for portfolio bidding as a violation of the Market Behavioral Rules and refer any findings of sufficient credible information of a violation to the Commission.

b. <u>Protests</u>

160. Golden Spread, Southwest Industrials and TDU Intervenors assert that the proposed mitigation is insufficient to protect against the exercise of market power and will result in unjust and unreasonable rates.[154] Golden Spread, TDU Intervenors and Southwest Industrials state that the mitigation will permit suppliers that own or control existing generators in load pockets to collect amounts up to the long-run marginal costs of new peaking facilities, even where the actual cost of running existing generation is considerably lower.[155] TDU Intervenors state that, according to economic theory and Commission policy,[156] the competitive price in short term markets should reflect short-

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[153] Roach Testimony at 15.

[154] Golden Spread at 11-13, Southwest Industrials 21-24 and TDU Intervenors at 43-87.

[155] Golden Spread 6-7, Southwest Industrials at 22, and TDU Intervenors at 61(TDU Intervenors state that the proposed offer caps would mark price increases above short-run marginal costs of between 140 percent and nearly 3000 percent).

[156] TDU Intervenors at 56 *citing PJM Interconnection, LLC,* 110 FERC ¶ 61,053 at P 25 and n.9 (2004) (stating that under PJM's pricing system, generators have an incentive to bid marginal costs because the generators will recover some contribution to

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term marginal costs, especially when the imbalance market faces no shortage of generation, but only shortage of bids. Southwest Industrials and TDU Intervenors argue that since the imbalance market is a short-term hourly market that is limited in scope, generators should not be expected to recover long-run costs; rather long-run costs should be recovered through long-term bilateral contracts or state commission-approved retail rates. Southwest Industrials and TDU Intervenors add that an LMP market is premised upon generators bidding short-run marginal costs and requests that SPP's mitigation proposal be changed consistent with this premise, *i.e.*, the offer cap should be based on the actual variable operating costs of the least efficient unit dispatched to provide imbalance.[157] Golden Spread adds that when transmission constraints are binding only a few hours of the year, SPP's proposed offer cap could be well above the level of the $400/MWh cap in the California ISO.

161. Redbud supports SPP's mitigation approach because it is applied only at those times and locations when market power is most likely to be exercised and is not applied to depress prices that reflect the normal interaction of supply and demand. Further, Redbud supports SPP's offer cap proposal that drops as the hours of congestion increase because this makes it self-defeating to increase congestion for the purpose of raising prices. TDU Intervenors disagree that SPP has justified its proposed offer cap mechanism based on a theory of attracting new entry. TDU Intervenors state that imbalance market revenues are unlikely to encourage new entry given that: (1) there are many other sources of revenue in SPP; (2) no independent generator can finance based solely on the imbalance market revenues given the meltdown in the merchant industry; and (3) incumbent resource owners in load pockets have strong incentives not to increase generation available in load pockets.[158]

162. TDU Intervenors argue that when the market is in true shortage, and there is limited ability for load to reduce consumption, there is incentive and ability for existing generators to get high prices. Thus, TDU Intervenors and Golden Spread request that the Commission require a safety-net bid cap for the SPP market. TDU Intervenors explain that the existence of the offer cap does not eliminate the need for a safety-net bid cap because the safety-net bid cap is targeted at a situation where all generation is needed and there is no competing supply to keep prices in check. TDU Intervenors further explain

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fixed costs during the times the clearing price is above the generator's specific marginal costs).

[157] TDU Intervenors request that the Commission require a marginal cost plus 10 percent offer cap consistent with the mitigation used by PJM.

[158] TDU Intervenors at 50-51.

that in such a situation, consumers should respond to high prices but with the current lack of demand response, a safety-net bid cap is needed as a proxy for consumer response. Golden Spread believes that a safety net bid cap is necessary because the SPP market is untested and likely to experience periodic or systemic failures and because only weak remedies for the exercise of market power are available to the market monitor. TDU Intervenors argue that the Commission should direct SPP to adopt a $1000/MWh bid cap because this measure is consistent with all the other organized markets in the Eastern Interconnect and would reduce seams issues.

163. TDU Intervenors, Golden Spread and Southwest Industrials assert that the proposed mitigation measures are not supported by an adequate analysis of market conditions as required by the Commission. Specifically, TDU Intervenors state that SPP has presented no facts regarding market conditions that exist at the time of binding transmission constraints and thus there is no empirical data on which the Commission can judge the adequacy of the proposed mitigation. TDU Intervenors and Southwest Industrials suggest that SPP must determine where load pockets are expected to arise and market conditions within the load pocket, especially with regard to concentrated ownership of resources within a load pocket.[159] Southwest Industrials is also concerned about concentrated ownership of resources leading to the exercise of market power in areas without transmission constraints. Additionally, TDU Intervenors state that SPP should examine the potential for artificial shortages, given the voluntary bidding characteristic of SPP's proposed market.[160]

164. TDU Intervenors and East Texas state that SPP's proposed use of generator-to-load distribution factors is unreasonable. East Texas states that the five percent generator-to-load distribution threshold is arbitrary and would exempt from mitigation certain generators that have the ability to exercise market power. East Texas explains that basing the threshold on the level used when a TLR is called has no bearing on whether a supplier in a constrained area can exercise market power and, further, that the purpose of the imbalance market is to reduce TLRs by providing a market solution to resolve congestion. East Texas requests that the Commission reject SPP's proposal to limit mitigation to generators with generator-to-load distribution factors greater than the five percent threshold. TDU Intervenors add that SPP has not addressed an issue concerning the calculation of generator-to-load distribution factors at two flowgates bounding the Southwestern Public Service control area. TDU Intervenors explain that in SPP's imbalance market tariff filing in Docket No. ER05-1118-000, the external market monitor stated that all generators with a negative generator-to-load distribution factor for

[159] *Id.* at 48.

[160] *Id.* at 49.

these two flowgates have the same negative generator-to-load distribution factor and thus the generator-to-load distribution factor analysis cannot appropriately identify capped resources.[161] TDU Intervenors state that the Market Monitor has not justified revisiting offer cap status based on ownership changes per section 3.2.3 and has not explained how, if at all, ownership is used to determine which resources will be offer capped.[162]

165. East Texas argues that SPP must provide a clear explanation of how it plans to monitor for transmission market power and the tests it will use to determine whether a market participant is engaging in economic withholding of transmission, physical withholding of transmission, or unavailability of facilities. TDU Intervenors argue that SPP's proposal for transmission market monitoring and mitigation is not just and reasonable because the tariff fails to provide standards to determine when transmission is deemed to be withheld or what penalties could apply. TDU Intervenors request that SPP develop criteria for assessing transmission withholding and mitigation measures similar to those developed by Midwest ISO.

166. TDU Intervenors argue that the market monitoring and mitigation plan should explicitly address strategic bidding. Specifically, TDU Intervenors state that the mitigation plan should contain provisions for mitigating units on the export side of a constraint in addition to mitigating on the import side of constraints. TDU Intervenors explain that a seller located on the import side can cause constraints by withholding and over production and that a seller with resources on both sides of the constraint has incentive to engage in uneconomic overproduction. TDU Intervenors request that the Commission direct SPP to include in its tariff: (1) the steps that the Market Monitor will take for monitoring uneconomic overproduction; (2) penalties that the Commission can impose when uneconomic overproduction is referred by SPP to the Commission; and (3) measures for monitoring strategic withholding of generation, especially for resources that are not subject to the offer cap.[163]

167. East Texas requests that the Commission either require SPP to include more details on the mitigation plan in its tariff or include the market protocols mitigation provisions in the tariff. East Texas also asserts SPP does not: (1) explain how to determine whether a resource is in electrical proximity to a flowgate; (2) does not specifically assign responsibility for making the determination; and (3) does not allow for challenges to the determination that a resource is offer capped.

[161] *Id*. at 71.

[162] *Id.* at 73.

[163] *Id.* at 76-78.

c. Commission Determination

168. We accept SPP's proposal to limit mitigation for economic withholding to generators that have a significant impact on a constraint, when the constraint is active. As discussed below, we will allow SPP to apply this mitigation without additional caps once SPP and its market participants have gained sufficient experience with operation of the market.

169. We find that SPP's proposal to apply an offer cap to resources that have a generator-to-load distribution factor of five percent or greater is appropriate. We note that this is a more stringent standard than Midwest ISO was directed to adopt in its infrequently constrained areas.[164] We find that, pursuant to SPP's proposal and consistent with the Midwest ISO's methodology for applying mitigation to infrequently constrained areas,[165] a generator's generator-to-load distribution factor is determined by the market model and will reflect the configuration of the SPP grid. We are convinced that the application of the generator-to-load distribution factor is reasonable because it will address market power where well-defined structural barriers to competitive performance exist. However, this does not imply that the Market Monitor will not monitor those generators that have a smaller impact on the constrained flowgate. The market monitoring plan requires monitoring of the entire SPP system on an ongoing basis. The Market Monitor is obligated to monitor for and report problems that arise in the imbalance market that are not addressed by the offer cap mitigation.

170. We will require certain clarifications to the section related to determining the resources that are offer capped. First, we find that SPP has failed to explicitly address the calculation of generator-to-load distribution factors for generators impacting the two flowgates that bound the Southwestern Public Service control area. We note that the external market monitor suggested an exception to the generator-to-load distribution factor method in SPP's imbalance market tariff filing in Docket No. ER05-1118-000.[166] This exception would apply the generator-to-load distribution factor method to each monitored element of the two Southwestern Public Service flowgates, separately instead of simultaneously. We direct SPP to modify Attachment AF to provide that any exception to the generator-to-load distribution factor analysis will be set forth in the

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[164] *TEMT II Order*, 108 FERC at P 274 (Midwest ISO was directed to adopt a six percent generator shift factor).

[165] *Id.* at P 265.

[166] TDU Intervernors at 71 *citing* Roach Testimony in ER05-1118-000 at 54.

tariff. Until such an exception is filed and accepted by the Commission, SPP is directed to apply the same generator-to-load distribution factor method to each flowgate including the two flowgates that bound the Southwestern Public Service control area. Second, we direct SPP to clarify the role that ownership of or control over offer-capped resources plays in the assessment and reassessment of offer capped resources. We interpret the proposed tariff provisions in sections 3.2.2. and 3.2.3 of Attachment AF to require that resources that impact a particular constraint and that are also owned or controlled by the same supplier will be subject to an offer cap, regardless of whether an individual resource has a generator-to-load distribution factor of less than five percent.

171. We find that SPP's proposal to base its offer cap on the new costs of entry is reasonable. The premise of not mitigating below the cost of entry ensures that the mitigation will not suppress prices and deter needed investment in new supply.[167] We are not convinced by protestors' arguments that SPP's proposal does not adequately protect against the exercise of market power or that SPP should adopt a marginal cost plus 10 percent capping mechanism. Additionally, this proposal should give entities serving load in persistent load pockets an appropriate incentive against relying too heavily on the short-term imbalance market. To reliably serve load in persistent load pockets, entities should secure self-dispatched resources in those load pockets on a longer-term basis to the greatest extent possible. Load serving entities can, in that way, avoid high imbalance prices based on the costs-of-entry offer caps.

172. We find that SPP's proposed market differs substantially from other RTO markets in that SPP proposes only to operate a market for the provision of imbalance service in real time. SPP's day-ahead and hour-ahead resource planning processes supplant the need for a must offer requirement because load-serving entities must commit a sufficient level of deliverable resources to meet their load in the day-ahead and hour-ahead periods. Thus, the need to protect against the exercise of market power in the imbalance market is offset by each market participant's set of resources designated to serve its load and any reserve needs. Except when unexpected transmission outages occur or unexpected transmission elements bind that were not foreseen in the day-ahead simultaneous feasibility analysis, load-serving entities should be able to control their reliance on the imbalance market and thus reduce their demand for the imbalance service if prices in the market exceed their costs. In times when unexpected transmission outages occur or unexpected transmission elements bind, generators should not be mitigated below the cost of a new generator that would resolve the transmission congestion because new development to relieve constraints may not occur.

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[167] Roach Testimony at 3.

173. Additionally, we note that SPP has a surplus of generation relative to load in excess of 40 percent during the Summer peak.[168] This system surplus combined with the requirement that load-serving entities commit sufficient deliverable resources to serve their load makes unnecessary the adoption of a safety-net bid cap. We recognize that the lack of a safety-net bid cap in the SPP market and the adoption of a $1000/MWh safety-net bid cap in the other RTOs in the Eastern Interconnect could raise seams issues. However, we are not persuaded to require a permanent safety-net bid cap, in part, because no affected RTOs have raised seams issues.

174. We reject protestors' arguments that Attachment AF must explicitly address transmission withholding and strategic bidding. It is sufficient that the Market Monitor monitors for the exercise of transmission market power activities pursuant to Attachment AG, section 4.3. With regard to strategic bidding, while we are not ordering SPP to develop mitigation measures for uneconomic overproduction or strategic withholding, we will direct SPP to amend Attachment AG to explicitly require monitoring by the Market Monitor of strategic bidding. Specifically, we direct SPP to file no later than 60 days from the date of this order, tariff sheets detailing the steps that the Market Monitor will take for monitoring uneconomic overproduction and strategic withholding through portfolio bidding as consistent with the steps outlined in Dr. Roach's testimony.[169]

175. Finally, we find that the level of detail in Attachment AF is sufficient and that it is not necessary to incorporate the relevant sections of the market protocols into the tariff. East Texas is incorrect in its assertion that the tariff does not define electrical proximity or assign responsibility for making offer cap determinations. Further, while the tariff does not allow for challenges to the offer-capped status of a resource, section 3.3.1 does allow for an exception and possibly an exemption in whole from the offer cap.

176. SPP is directed to submit a compliance filing no later than 60 days from the date of this order.

2. Level of the Offer Cap

a. SPP's Proposal

177. SPP proposes to calculate the level of the offer cap by including the generic estimated capital and operating costs of a new natural gas fired combustion turbine peaking resource spread over the cumulative hours of transmission constraints reported in

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[168] TDU Intervenors at 50.

[169] *See* Roach Testimony at 15-17.

the previous twelve months experienced by each resource. SPP proposes a formula of Annual Fixed Costs (AFC) divided by Annual Hours of Constraint (AHC) plus variable non-fuel Operations and Maintenance (O&M) plus the fuel cost of a generic combustion turbine. Additionally, SPP proposes an offer cap floor, *i.e.*, that the fixed cost term (AFC/AHC) in the above formula will not fall below $100/MWh plus the estimated fuel costs and variable operating costs of a generic new peaking resource.

178. SPP's Market Monitor proposes to calculate the AFC of a generic combustion turbine by extrapolating from US Energy Information Administration (EIA) data to produce a fixed cost of $68,640 per megawatt-year in 2006. Specifically, the Market Monitor assumes a 50 percent debt/50 percent equity ratio, a debt repayment over 15 years at an interest rate of 9.25 percent, a minimum debt service ratio of 1.5, a target project equity return of 12.5 percent, and a 15 year depreciable life for income tax at a federal tax rate of 35 percent and state tax rate of three percent. The Market Monitor also proposes a variable non-fuel O&M adder of $3.43 per megawatt hour based on inflation adjusted EIA data for a combustion turbine. Finally, the Market Monitor proposes to adopt the average heat rate for a combustion turbine in 2003 of 10,450 Btu/kWh as estimated by EIA. In calculating the fuel costs for the offer cap, SPP proposes to multiply this heat rate by a fuel price "based on an industry accepted natural gas pricing index for the natural gas pricing point nearest to the [o]ffer-[c]apped [r]esource(s)"as adjusted to account for fuel transportation costs from the index location to the resource.[170]

179. Attachment AF, section 3.2.4 provides that the AFC and the variable, non-fuel O&M adder of a new combustion turbine will be reviewed annually by the Market Monitor with input from SPP. SPP's tariff also provides that any changes to these costs, along with justification for the changes, will be posted electronically by SPP and filed with the Commission for approval. The Market Monitor is also required to evaluate annually alternative fuel pricing points.[171]

180. SPP proposes a process for a market participant to seek an exception to the offer cap, but proposes that the Commission have the final decision-making authority on an exception. Under Attachment AF, section 3.3.1, a supplier seeking an exception to the offer cap for a particular resource may either request a change to the offer cap through a request to the transmission provider, who in consultation with the Market Monitor will decide whether to submit a filing to the Commission or by making a filing directly with the Commission.

[170] Attachment AF, section 3.2.4(d).

[171] Attachment AF, section 3.2.4(d).

181. SPP proposes that the offer cap for each resource will be calculated daily and disclosed to the market participant responsible for submitting bids for each resource.[172] SPP proposes that each offer cap will be effective until replaced by a new offer cap.[173]

b. Protests

182. TDU Intervenors assert that if the Commission accepts the offer cap, it should reduce the level of the cap by incorporating a credit into the offer cap formula to account for revenues that a new peaking generator would receive from other sources outside the imbalance market. While TDU Intervenors agree with SPP that its proposed offer cap is similar to Midwest ISO's offer cap for severely constraint load pockets, TDU Intervenors point out that Midwest ISO offsets the annual fixed costs of a natural-gas fired generator with the revenues that such a generator would receive from the markets and services provided under Midwest ISO's tariff. TDU Intervenors explain that generators in SPP will continue to receive revenues from long-term contracts, inclusion of facilities in wholesale and retail rate-base and the sale of generation-based ancillary services. TDU Intervenors suggest that SPP can calculate location-specific infra-marginal revenues, *i.e.*, the revenues that a generator in the bid stack would receive when the market clearing price is above its marginal costs, by determining when the generic peaking generator used in the offer cap formula would be dispatched in the imbalance market given a bid based on the generator's generic variable operating costs. TDU Intervenors further suggest that SPP could then deduct these infra-marginal energy revenues as well as revenues from other services from the offer cap formula. TDU Intervenors state that failing to net out infra-marginal revenues and sources of revenue from other services from the offer cap would result in excessive rates due to over-recovery of fixed costs. Additionally, TDU Intervenors objects to the formulaic and generic characteristic of SPP's proposed offer cap because this characteristic allows for imprecise application resulting in a windfall for generators and burdening for consumers.

183. East Texas and TDU Intervenors argue that the proposed floor on the offer cap is unjust and unreasonable because it ensures that prices in locations with frequent transmission constraints will remain artificially high. Additionally, East Texas argues that the floor is unnecessary because the proposed provision for exceptions to the offer cap allows generators to show that the offer cap would not allow cost recovery. TDU Intervenors state that the offer cap should, at a minimum, be modeled after Midwest

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[172] Attachment AF, section 3.2.4.

[173] *Id*.

ISO's fixed-cost adder for load pockets which does not contain a floor. Further, East Texas and TDU Intervenors argue that the level of the price floor is arbitrary and that SPP has provided no support for it.

184. Xcel states that SPP's proposal to have the Commission rather than the External Market Monitor grant any exceptions to raise the level of the offer cap will disadvantage generators and cause unnecessarily high imbalance prices. Xcel explains that when a generator faces specific opportunity costs, risks or facility operating costs that would cause costs higher than the offer cap, and no offer cap exception is timely granted, a rational generator would not bid into the imbalance market. Xcel further explains that the length of time for securing approval from the Commission for an exception for a particular generator will likely compromise the participation of suppliers, particularly those with small generation portfolios, in the imbalance market. Without participation by these generators, Xcel argues that imbalance prices will rise.[174]

185. East Texas states that SPP has not provided details on the standards it will use to evaluate whether an offer capped resource will be granted an exception to the offer cap. East Texas argues that the standards must be included in the tariff so that market participants have a full understanding of when and how their resources will qualify for an exception to the offer cap.[175]

186. TDU Intervenors and Redbud are concerned about the cost assumptions relating to SPP's proposed inputs to the offer cap. Since these inputs were not vetted by SPP stakeholders, Redbud requests that the Commission direct SPP to study the performance and parameters of the offer caps through a stakeholder process initiated within six months of the market start date. Redbud further requests that SPP submit its study for Commission review within ten months of the market start date. TDU Intervenors state that SPP has provided no cost support by which the Commission can assess the reasonableness of the numbers or the assumptions SPP used regarding the type of combustion turbine evaluated. Also, TDU Intervenors protest the use of a 12.5 percent return on equity and a 15-year depreciable life for determining the fixed costs of the generator. TDU Intervenors state that the fixed cost calculation appears excessive as compared with the actual purchase cost of an existing combustion turbine in the OG&E territory. TDU Intervenors request that the Commission require SPP to file support for its proposed inputs consistent with the information required by Part 35 of the Commission's regulations.

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[174] Xcel at 23-25.

[175] East Texas at 9-10.

187. TDU Intervenors state that SPP's proposal to limit disclosure of each resource's offer cap level to the market participant responsible for submitting offers for each resource invites market power exercise. In particular, TDU Intervenors argue that in locations where there are few or no competitors, sellers will have a tendency to submit offers at or just below the offer cap because there will be little risk of being underbid by others and that limited disclosure will ease this ability to raise prices.[176] TDU Intervenors request that the Commission, at a minimum, require that the offer caps be disclosed to all market participants including consumers. TDU Intervenors state that such disclosure will allow consumers to determine if locational prices are tracking offer caps.

c. Commission Determination

188. We accept SPP's proposed offer cap formula. SPP has proposed an offer cap formula that requires no discretion on the part of the Market Monitor to implement. The formula is similar to the methodology approved for mitigation in Midwest ISO's severely transmission constrained areas.[177] We reject the TDU Intervenors' argument that the formula should be changed to account for revenues that a new peaking generator would receive in the imbalance market and through other power transactions. TDU Intervenors are correct that Midwest ISO's similar formula takes into account the revenues that a new peaking generator would receive from Midwest ISO's markets, thereby reducing the level of the bids allowed in the tightly constrained areas. However, the Midwest ISO mitigation differs in two material ways from SPP's proposed mitigation: (1) in Midwest ISO, a generator's bid is capped at its specific variable costs plus a threshold, whereas, in SPP, a generator's specific variable costs are not considered as part of the mitigation; and (2) Midwest ISO uses its offer cap based on the cost of new entry in severely constrained areas and less strict mitigation in less constrained areas, whereas, SPP proposes to apply its offer cap to all areas in its footprint with binding transmission constraints. We find that these differences are significant enough to warrant a slightly different formula in SPP for calculating the offer cap.

189. Further, we find that the inputs to the offer cap formula are reasonable. SPP has supported these inputs using reliable data sources and reasonable assumptions and has provided sufficient cost support. We will not grant TDU Intervenors' request that we require SPP file cost support consistent with Part 35 of our regulations.[178] SPP has

[176] TDU Intervenors at 72.

[177] *See TEMT II Order*, 108 FERC at P 277-298.

[178] 18 C.F.R. Part 35.

provided adequate information to show the reasonableness of its formula. We also are not persuaded by arguments to compare the inputs to the purchase cost of existing generation since the proposed mitigation is based on new entry in load pockets, not the purchase cost of existing generation that may not be located in transmission constrained areas. Without such a price signal, new generation investment may not be attracted to the constrained location. Finally, we find that annual review of the offer cap inputs by the Market Monitor and SPP is sufficient to ensure reasonable inputs, especially given that the studies relied upon are updated annually. Thus, we will not grant Redbud's request for additional stakeholder process on the inputs and an additional submission to the Commission within 10 months.

190. We reject SPP's proposal that the offer cap level will never fall below $100/Mwh plus the variable operating cost of a generic new peaking plant. SPP has not explained this provision of the offer cap formula in its transmittal letter or its testimony. SPP also has not provided any support for the provision for the $100/MWh amount. SPP bases its mitigation on a cost of new entry theory rather than an existing generation cost recovery theory and has not explained why it would abandon its new entry theory when transmission is constrained for a significant period of the year. SPP has not explained why a new peaking unit should be able to recover its cost when the annual hours of constraint are 686 hours or less, but suddenly not be able to recover its costs when constraints are binding more than 686 hours of the year. Moreover, we find that the proposed floor is unnecessary given that generators are not required to bid into the market and the tariff contains provisions for a resource to seek an exception to the offer cap from the Commission. Therefore, we direct SPP to remove the provision in section 3.2.4 of Attachment AF that proposes a minimum value for the offer cap.

191. With regard to protestors' concerns that the exception provisions related to offer caps are insufficient in that they require a time-consuming application process with the Commission, we find that the exception provisions appropriately limit the discretion of the Market Monitor in making such decisions. Xcel is also concerned that the requirement for Commission approval of any exception to the offer cap will reduce the number of bids in the imbalance market, causing prices to rise. We acknowledge the possibility that some existing generators in SPP might have operating costs greater than the full fixed and variable costs of a new peaking generator, but consistent with the theory of new entry, such generators should be replaced by new units over time. Existing generators with costs higher than the entry cost of a peaking generator that are needed for reliability should already be owned by or under contract to the load that requires the reliability services. However, there may be unusual circumstances that might require an exception to the offer cap and the Commission is the appropriate entity to evaluate the circumstances to determine whether an exception is warranted.

192. We agree with TDU Intervenors that SPP should disclose the offer caps to all market participants. SPP's proposed offer caps represent the fixed and variable cost of a generic peaking plant and do not convey the market monitor's conception of each individual generator's variable costs that is relevant in other RTO's mitigation plans. Additionally, while suppliers with generators located at the same constraint as a competitor's generator would likely to be able to calculate their competitor's offer cap, buyers without their own generators would not have information to calculate the offer caps. Limited disclosure of offer caps would thus limit information to buyers but not limit competitors' access to the information. Accordingly, we direct SPP to modify its tariff, in a compliance filing no later than 60 days from the date of this order, to provide that the offer cap for each offer capped generator will be disclosed to all market participants. We note that section 2.2 of Attachment AF provides that SPP will electronically post a list of all resources subject to an offer cap. We direct SPP to post the offer caps in this list.

J. Market-based Rates

a. SPP's Proposal

193. SPP proposes that its mitigation measures and monitoring plans should be used to support market-based rate authority for the imbalance market on a case-by-case basis.[179] SPP explains that in situations where the Commission has denied market-based rate authority for sellers because the seller has failed one or both of the Commission's indicative market power screens, the seller should be able to gain market-based rates for the imbalance market by pointing to SPP's market power mitigation and monitoring measures. SPP states that any assessment of the adequacy of the SPP mitigation measures should apply only to the imbalance market and not to other products offered by sellers.[180] SPP states that control areas should be used as the relevant geographic market to gauge market power for these other transactions.[181]

194. Alternately, SPP requests that the Commission find that it will operate a single energy market with single, central commitment and dispatch.[182] In terms of single

[179] Roach Testimony at 28.

[180] *Id.* at 29-30.

[181] *Id*.

[182] Rossi Testimony at 27.

central

unit commitment and dispatch, SPP compares itself favorably to Midwest ISO, the designated default geographic market for market-based rate applicants in Midwest ISO's footprint.[183]

195. SPP states that, should the Commission not provide for market-based bidding into the SPP market, it foresees barriers to timely implementation of the imbalance market. SPP states that should the Commission require some market participants to submit cost-based bids, SPP would need to develop standard costing methodology that defines what costs are eligible to include in offers. Also, SPP states that it would need to develop procedures to monitor the cost-based bids to ensure that they were submitted in accordance with the applicable rules. Finally, SPP states that it might need to develop a separate set of settlement procedures to deal with cost-based bids. SPP argues that these implementation issues are significant and could jeopardize its ability to implement the imbalance market within its current schedule.

b. <u>Protests</u>

196. Redbud supports SPP's assertion that SPP employs single unit commitment and central dispatch and agrees that the Commission should designate SPP as the relevant geographic market. Redbud also agrees that the unit commitment that SPP proposes is not diminished by the fact that there are multiple control areas or by the fact that SPP proposes to ensure that reliability is maintained by directing unit commitment rather than accepting bids. Redbud further agrees with SPP that self-dispatch is both a market protocol that is present in all RTOs and an important feature that provides flexibility to enter into and meet the obligations of bilateral transactions. Redbud concludes that the proposed market will not function efficiently if prices are determined through a mix of market and cost-based bids and remains concerned that such a requirement could cause

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[183] *Id*. at 24-27. SPP states that like Midwest ISO, it performs a single unit commitment in a multiple control area format with voluntary participation. SPP points out that, while Midwest ISO relies on supplemental market offers to make up an initial shortfall in the supply of energy in its Day-Ahead Market, SPP does so by exercising its authority to direct that additional capacity be committed, consistent with Attachment AE, section 2.4.3. SPP also notes that the ability to not bid into the imbalance markets and to instead self-dispatch in real time is a feature of every RTO and likewise does not have any relevance to the determination of single central dispatch.

significant delay in market implementation. Additionally, should any market participant fail the Commission's market screens, Redbud proposes that the Commission use SPP's mitigation proposal rather than rely on mitigation reflecting individual company costs.

197. TDU Intervenors argue that the Commission should not rule in this proceeding on whether SPP mitigation suffices where a market-based rate applicant is found to have market power or whether SPP is the default geographic market. TDU Intervenors request that the Commission not rule on these issues because this proceeding does not involve a specific request for market-based rate authority. Southwest Industrials adds that because the SPP imbalance market is still in its infancy and because no entity has shown that a competitive market exists in the SPP region, the Commission should not revisit any denials of market-based rate authority. Moreover, TDU Intervenors note that any assessment of the mitigation measures should only apply for market-based rates in the imbalance market and not for other products, such as day-ahead energy, ancillary services or capacity, since SPP has not developed markets or appropriate mitigation plans for these products.[184]

198. KMU, Southwest Industrials, TDU Intervenors and Golden Spread urge the Commission to reject SPP's arguments for designation as a relevant geographic market. Given the failure of market power screens by Aquila, Inc. and Westar Energy, KMU argues that the mere existence of an RTO does not eliminate market power concerns, nor does it establish an adequate platform for competitive wholesale markets. Golden Spread, Southwest Industrials and KMU argue that SPP should not be treated as a single market because SPP has insufficient transmission infrastructure to enable all resources to reach substantially all SPP loads.[185] Golden Spread and TDU Intervenors argue that SPP does not meet the requirements of a single energy market because it still proposes to dispatch only those resources that voluntarily bid into the imbalance market.[186] Golden Spread and TDU intervenors add that SPP's comparison of its proposed market to the Midwest ISO market is unavailing because Midwest ISO mitigates physical withholding of energy from its real-time market while SPP does not. Moreover, TDU Intervenors argue that the Commission should find that SPP does not have a central unit commitment process because SPP has not proposed a day-ahead market.

199. TDU Intervenors argue that the Commission requires security constrained economic dispatch before it designates an RTO as the relevant geographic market and

[184] TDU Intervenors at 79-80.

[185] Golden Spread at 11.

[186] Golden Spread at 10 and TDU Intervenors at 81.

here, since SPP will operate without a must offer requirement, its proposal cannot meet the economic dispatch requirement. TDU Intervenors explain that because self-dispatched resources in SPP's imbalance market will not participate in real-time dispatch, and because SPP admits that this can inflate locational prices, SPP will not have economic dispatch.

200. Additionally, TDU Intervenors state that this situation will result in limited oversight of pricing behavior in the imbalance market, a situation that fails to meet the Commission's market power mitigation requirements for market-based rates.[187] Further, TDU Intervenors argue that the Commission should find that SPP's proposed mitigation measures are inadequate for mitigating market-based rate applicants with market power. They state that SPP has not demonstrated that its proposed mitigation measures will yield imbalance market rates that are just and reasonable where sellers with market power are permitted to submit offers that are not constrained by competition or offer caps.

201. KMU requests that the Commission direct SPP to resolve cost-based bidding issues so that it can operate its imbalance market to include sellers who do not have market-based rate authority.[188]

c. Commission Determination

202. SPP requests affirmation that all entities participating in its imbalance market will have market-based rates for the imbalance market product. We act on this request because SPP has made a convincing case that the imposition of cost-based rates layered on top of SPP's proposed imbalance market would delay, for a substantial undetermined period, the start of the imbalance market and thus delay realization of the benefits of the market discussed above. We recognize that SPP requires certainty about the bidding structure that will apply to its imbalance market in order to proceed with implementation.

203. We have stated that we will allow case-specific mitigation that eliminates the ability to exercise market power when market-based rate applicants fail the market power screens.[189] We find that SPP's proposed mitigation and monitoring plans, as modified, are adequate mitigation measures to ensure just and reasonable rates in the imbalance

[187] TDU Intervenors at 80-82.

[188] KMU at 1.

[189] *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018 at P 147 (2004).

market. Further, SPP has demonstrated that its proposed mitigation measures will eliminate the exercise of market power when structural constraints limit competitive outcomes in the imbalance market. Therefore, we conclude that all market participants will be granted market-based rates for sales of imbalance energy into SPP's imbalance market. Thus, all suppliers will be able to bid into the market at market-based rates and be paid the market clearing price. Although we make this blanket determination for the imbalance market product, we will still require entities that seek market-based rates for the SPP imbalance product or any other product to make the requisite filings.

K. Definition of Market Participant

a. SPP's Proposal

204. SPP defines a market participant in proposed section 1.18b of the OATT as an entity that generates, transmits, distributes, purchases, or sells electricity or provides ancillary services within, into, out of, or through Transmission System. According to SPP, Transmission Owners and any of their affiliates providing transmission service to bundled retail load or load being served by grandfathered agreements qualify as market participants. Market participants can also be transmission or network customers, generation interconnection customers or any eligible customers that offer resources for sale into the imbalance market with an executed or unexecuted but filed service agreement as specified in Attachment AH. SPP proposes in Attachment AE, section 1.2.1, that a market participant must execute the imbalance market participant service agreement in Attachment AH prior to submitting an offer to sell energy into the imbalance market.

b. Protests

205. In its protest, East Texas states that SPP's definition of "market participant" is long, confusing and too detailed.[190] East Texas believes that such amount of detail can lead to disputes over who qualifies to be a market participant. East Texas points to the Midwest ISO Energy Market Tariff as a good model for such a definition.

206. In addition, TDU Intervenors state that they believed that it was SPP's intent to require execution of Attachment AH imbalance market participant service agreement only by those market participants who have not already committed to abide by the terms and conditions of the OATT under transmission owner or transmission service agreements with SPP. TDU Intervenors argue that SPP's imbalance market tariff filing in Docket No. ER05-1118-000 was drafted accordingly. Thus, TDU Intervenors believe

[190] East Texas at 14-15.

that "unless the market participant is already a transmission customer or transmission owner" should be inserted at the end of section 1.2.1 of Attachment AE.

c. Commission Determination

207. While SPP's proposed definition of market participant may be long and detailed, it is not unreasonable. Therefore, we accept the proposed definition.

208. We reject TDU Intervenors' request to add language exempting transmission customers and transmission owners from the imbalance market participant agreement. We find that it is reasonable to require the execution of an imbalance market participant agreement by those that have already committed to abide by the terms and conditions of the prior version of the OATT because new obligations may arise from selling in the imbalance market. An executed imbalance market participant agreement might be especially important for a transmission customer who may take on new obligations as a seller under the imbalance market provisions of the OATT.

209. Because the imbalance market participant service agreement will contain important rate-related obligations and rights of market participants and because intervenors have not had the opportunity to comment on the imbalance market participant service agreement due to inadvertent omission of Attachment AH noted above, we cannot rule on whether Attachment AH is just and reasonable. Therefore, SPP is directed to make a filing under section 205 of the FPA to submit its proposed Attachment AH no later than 60 days prior to implementation of the market.

L. Confidentiality Provisions

a. SPP's Proposal

210. Section 7 of Attachment AE governs the confidentiality policy and procedures related to SPP's imbalance market. In general, SPP proposes to restrict all parties from disclosing confidential information "except as specifically permitted." If a market participant is subject to a freedom of information act or similar statute, it must provide SPP with a statement that it is subject to such a statute and then provide a copy of the statute, rule or regulation, or practice that shows that despite such a requirement, the market participant will be able to keep the information confidential.[191] In addition, in all instances, parties disclosing confidential information must notify the Disclosing Party, *i.e.*, the party from whom the information was received.

[191] Attachment AE, section 7.1.

211. SPP proposes that Receiving Parties, *i.e.*, parties to whom information is given, shall adopt procedures within their organizations to maintain the confidentiality of all confidential information. These procedures must include a requirement that information will only be disclosed internally on a "need to know" basis; all confidential information must be designated/marked as confidential; and before disclosing confidential information, it shall require that the Receiving Party execute a non-disclosure agreement.

212. Section 7.1.2 of Attachment AE states that a Receiving Party may disclose certain confidential information under the following circumstances:

> (a) As required by any law, regulation, or order, or expressly required or permitted by this Tariff, provided that the Receiving Party must make reasonable efforts to restrict public access to the Disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or
> (b) If the Disclosing Party that supplied the Confidential Information to the Receiving Party has given its prior written consent to the Disclosure as set forth in Subsection 7.1.4(c), which consent may be given or withheld in Disclosing Party's sole discretion; or
> (c) If, before it is furnished to Receiving Party, the Confidential Information is in the public domain; or
> (d) If, after it is furnished to Receiving Party, the Confidential Information enters the public domain other than through a manner inconsistent with the provisions of this Section; or
> (e) If reasonably deemed by the Receiving Party to be required to be Disclosed in connection with a dispute between Receiving Party and Disclosing Party; provided that the Receiving Party must make reasonable efforts to restrict public access to the Disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or
> (f) To a Transmission Owner engaged in transmission or distribution system planning and operating activities, provided that the Transmission Owner has executed a confidentiality agreement with requirements substantially similar to those in this Section 7; or
> (g) To a vendor or prospective vendor of goods and services to SPP so long as such vendor or prospective vendor: (i) is not a market participant and (ii) executes a confidentiality agreement with terms substantially similar to those in this Section 7.

However, under section 7.1.4(b) of Attachment AE, SPP may also disclose confidential information to NERC or any Regional Reliability Councils if:

> (i) the SPP determines, in its reasonable discretion, that the exchange of such information is required to enhance and/or maintain reliability within the SPP Region and its neighboring Control Areas; (ii) such receiving entity is bound by a written agreement to maintain such confidentiality; and (iii) the SPP has notified the affected market participant of its intention to release such information no less than five (5) Business Days prior to the release.[192]

213. Sections 7.2, 7.3, and 7.4 of Attachment AE govern disclosure of confidential information to the Market Monitor, the Commission and state regulatory commissions, respectively. SPP proposes that it is authorized to provide "market participant Confidential Information and any other information, data or materials that constitutes Confidential Information" to the Market Monitor. Likewise, SPP may disclose Confidential Information to the Commission and State Commissions (or other state governmental entity or authorized staff members, counsels, consultants, etc., collectively Authorized Requestor). In disclosing the information, SPP must request that the requestor treat the information as confidential and non-public. In the case of an Authorized Requestor, SPP proposes that it provide to both SPP and the Market Monitor, a list of the constitutional and/or statutory authority, obligation or duty establishing the Authorized Requestor's duty or responsibility to request information. SPP also proposes that the Authorized Requestor provide a statement and copies of any statutes, rule or regulations that permits the Authorized Requestor to keep information confidential and non-public and of limited distribution within the Authorized Requestor.[193]

b. <u>Protests</u>

214. TDU Intervenors assert that section 7.1 of Attachment AE unduly restricts public power entities subject to state sunshine laws from ever receiving any confidential information, thus limiting their ability to participate in the RTO planning process, *e.g.*, by denying their access to information to verify invoices and preventing them from participating in the market on a comparable basis to other entities. However, TDU Intervenors point out that public power entities routinely keep information confidential

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[192] Attachment AE, section 7.

[193] Regional State Committee staff will be deemed to meet this requirement by the execution of a non-disclosure agreement with SPP and the Market Monitor. Attachment AE, section 7.4(c).

and that section 7.1.5(a) of Attachment AE provides procedures for minimizing disclosure.[194] On the other hand, they note that other confidentiality provisions afford overbroad access to transmission owners, *e.g.*, section 7.1.1(a) of Attachment AE may permit disclosure that extends beyond the Commission's standards of conduct and the information disclosed to transmission owners is not limited solely to information necessary to perform transmission operation functions.[195]

215. Golden Spread argues that sections 7.2(a) and 7.1.2(b) of Attachment AE read together can be interpreted to permit SPP, if it is treated as the Disclosing Party when disclosing information to the Market Monitor, to give written consent to the Market Monitor to further disclose a market participant's confidential information and that such permission is inappropriate.[196]

c. **Commission Determination**

216. We will accept portions of SPP's confidentiality provisions in section 7 of Attachment AE, subject to modification as discussed below, and require a compliance filing in 60 days after the date of this order. While many provisions in Attachment AE, section 7 track those in the recently accepted Midwest ISO's TEMT, the provisions governing disclosure to state commissions (section 7.4 of Attachment AE) are virtually identical to those rejected by the Commission in that proceeding.[197] Therefore, we will likewise reject those provisions and require SPP to file provisions in accord with Midwest ISO's TEMT, Module C, section 38.9.4.[198]

217. We reject TDU Intervenors' objection to section 7.1 of Attachment AE, the provision that limits access to confidential information by public power entities subject to sunshine laws. While there may not be a statute, rule or regulation at public power entities' disposal, we are satisfied that they are permitted to access confidential information by providing SPP with "the particular statute, rule or regulation, protective

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[194] Section 7.1.5(a) of Attachment AE governs the procedures to be followed for disclosure required by law, judicial proceedings, etc. and requires notice and opportunity for the Disclosing Party to pursue lawful, preventive measures.

[195] TDU Intervenors at 32-34.

[196] Golden Spread at 13-14.

[197] *TEMT II Order*, 108 FERC at P 537-65, *TEMT Rehearing Order*, 109 FERC at P 427-47. *See also PJM Interconnection, LLC,* 107 FERC ¶ 61322 (2004).

[198] Midwest ISO TEMT, Module C, Substitute Third Revised Sheet Nos. 466-469 and Original Sheet Nos. 469A-469U.

order, or *practice*" (*emphasis added*) since, they already have "practices" whereby they "routinely" keep information confidential. We agree with TDU Intervenors that section 7.1.2(f) of Attachment AE appears to provide transmission owners with unlimited access to confidential information and direct SPP to limit transmission owner's access in the manner that confidential information is limited to NERC, *i.e.*, for specific purposes. Therefore, SPP should determine that the exchange of information is required to enable a transmission owner to perform necessary transmission operations, the transmission owner must sign a non-disclosure agreement and notify the disclosing party.

218. We will reject Golden Spread's argument that section 7.2 permits inappropriate disclosure. Section 7.2 must be read with section 7.6, which prohibits SPP, except in limited circumstances, from disclosing information without notifying the disclosing party, in this case the original disclosing party. Therefore, we agree with SPP that these sections safeguard confidential information from being disseminated on behalf of a market participant inappropriately as feared by Golden Spread.

219. As noted above, section 7.4 of Attachment AE is virtually identical to the provisions proposed by Midwest ISO and rejected by the Commission.[199] In the *TEMT II Order*, the Commission rejected sections of the Midwest ISO's proposal pertaining to sharing of confidential information between the Midwest ISO (or its market monitor) and state regulators.[200] The Commission found that "[n]either the Midwest ISO's filing nor the intervenors' make clear why [the Regional State Committee] and the states seek access to data that is comparable to the Commission's access, how they will keep that data confidential, or for what purpose they will use the data."[201] Furthermore, in rejecting the Midwest ISO provisions, the Commission directed that a revised proposal should not permit Authorized Requestors to disclose confidential information to other Authorized Requestors;[202] SPP's proposal contains no such restriction. In addition, Midwest ISO procedures require an order of the Commission prohibiting release of confidential information;[203] none is required here.

[199] *TEMT II Order*, 108 FERC at P 537-65, *TEMT Rehearing Order*, 109 FERC at P 427-47.

[200] *TEMT II Order* at P 557-65.

[201] *Id.* at P 561.

[202] *See id.*

[203] MISO TEMT, section 38.9.4.1(b)(i).

220. Subsequently, Midwest ISO proposed confidentiality provisions that allowed state regulators access to confidential information by qualifying as an "Authorized Requestor."[204] The Commission accepted these confidentiality provisions finding that they struck an appropriate balance between protecting market participants' confidential information and enabling state entities with appropriate jurisdiction to exercise their investigatory authority.[205]

221. Given the discussion above that SPP's section 7.4 of Attachment AE is virtually identical to provisions previously rejected by the Commission, we will reject this provision and direct SPP to align its tariff with that of the Midwest ISO and PJM with regard to state access to confidential information. We find that SPP's adoption of the confidentiality provisions similar to those of Midwest ISO and PJM will allow state regulators within SPP to obtain confidential information that they believe is necessary for them to satisfy their statutory responsibilities, while at the same time ensuring that this information remains confidential and protected from unauthorized disclosure. In addition, SPP is directed to delete the phrase "or to a state regulator or its staff" from sections 7.1.5 and 7.2(c) of Attachment AE, and make necessary conforming changes to other proposed tariff provisions consistent with our direction above. Further, Midwest ISO filed its non-disclosure agreement with the Commission; we will also direct SPP to file its non-disclosure agreement as part of its compliance filing.

M. <u>Other Issues</u>

1. <u>JOA with Midwest ISO/Midwest ISO-SPP seams issues</u>

a. <u>SPP's Proposal</u>

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[204] An Authorized Requestor has to execute a non-disclosure agreement with the transmission provider stating: his/her position or relationship with the Authorized Agency; that he/she has the authority to enter into such an agreement; that his/her Authorized Agency has practices or procedures to protect against unauthorized release of confidential information; that he/she is familiar with and will comply with such practices and procedures; and that he/she is not in breach of any non-disclosure agreements. Sections 38.9.4.1 of Midwest ISO's OATT. Section 38.9.4 of Midwest ISO TEMT also sets forth the transmission provider's obligations and the Authorized Agency's obligations with regard to confidential information that will be released to an Authorized Requestor.

[205] *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,448 at P 2 (2005).

222. SPP states that it submitted a joint filing of revisions to the Joint Operating Agreement (JOA) and Congestion Management Process (CMP) with the Midwest ISO, in Docket No. ER06-15-000. The proposed revisions refine the SPP JOA and align them more closely with the JOA executed between PJM and Midwest ISO. The Commission issued a deficiency letter seeking clarifications to some of the changes and consistency between the JOA and the CMP, and SPP and Midwest ISO made a compliance filing in January 2006.

b. Protests

223. Xcel states that SPP's imbalance market should be abandoned. Instead, Xcel supports Commission direction to SPP to develop a plan to enter into a Joint and Common Market with the Midwest ISO and PJM Interconnection, LLC.[206]

c. Commission Determination

224. The Commission has conditionally accepted SPP's joint filing of revisions to the JOA and CMP in Docket No. ER06-15-000.[207] We do not believe SPP's imbalance market proposal hinders its JOA and CMP efforts and therefore see no reason to require SPP to abandon its imbalance market proposal.

2. Participation by External Generators in Imbalance Market

a. SPP's Proposal

225. Under the proposed section 4.1 (Dispatch Process) of Attachment AE, as part of the security constrained economic dispatch, SPP will calculate the Adjusted Net Scheduled Interchange (ANSI) for each control area and communicate this to the control areas for implementation. The effect of this provision is that only generators located within a control area will be subject to SPP and control area operator instructions.

b. Protests

226. Lafayette and Union Power object to this limitation and argue that generators outside of SPP control areas should be able to participate in the imbalance market.[208]

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[206] Xcel at 33-34.

[207] *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,245 (2005) (Commission letter order).

[208] Lafayette at 7-13 and Union Power at 3-4.

Lafayette alleges this limitation is similar to an unreasonable restrictive trade tariff provision that limits market access to a specific group of parties; here, generators inside the SPP footprint. The effect of this restriction, then, is that the number of resources competing is limited and may yield higher prices for the benefit of certain "protected" parties. Lafayette and Union Power ask the Commission to direct SPP to eliminate this restriction. Lafayette also acknowledges the significant challenges SPP faces to initiate the imbalance market and states that it would not oppose a proposal by SPP to defer action on this point until a reasonable period of experience with the imbalance market has been achieved; although development of arrangements should not be deferred indefinitely.

c. Commission Determination

227. We believe that participation of external generators in SPP's proposed imbalance market is key to addressing issues of market power and bid insufficiency. As an initial matter, we note that there is no restriction on load serving entities including external generators in their day-ahead and hourly resource plans as long as the load-serving entities make the appropriate generation and transmission arrangements for these resources. Further, we note that in its answer, SPP states that it supports accommodating external generators in the imbalance market and commits to address this issue in the future.[209] Based on SPP's commitment to address this issue, we will direct SPP to make a filing two months after the start of market operations that incorporates tariff revisions to allow participation of external generators in SPP's imbalance market. Also, SPP's provisions for external generator participation must be in effect within six months of the start of SPP's imbalance market, at the same time that system-wide bid caps are removed.

3. Demand Resource Provisions

a. Protest

228. Southwest Industrials argues that under well established Commission precedent, demand resources are a necessary component of competitive markets.[210] They contend that the Commission should require SPP to work with retail customers in the SPP footprint to ensure that complete rules for allowing curtailable consumption to participate in any imbalance market are clearly stated in the SPP OATT before the imbalance market "goes live." They note that under SPP's proposal, there is only one reference to

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[209] SPP Answer at 23-24.

[210] Southwest Industrials at 27-28.

"curtailable consumption" in SPP's tariff, *i.e.*, in the definition of "Offer Curve".[211]

c. Commission Determination

229. Southwest Industrials are correct that the Commission has acknowledged the importance of demand response programs as an element of efficient and reliable markets,[212] however, we have not mandated them in RTOs. Therefore, while we will not require SPP to institute a demand response program at this time, SPP is directed to provide a report to the Commission one year from the date of market implementation on ways it can incorporate demand response into its imbalance market.

4. No Jurisdiction over Retail Rates

a. Protests

230. Southwest Industrials argue that costs associated with the imbalance market and the risk of the imbalance market should be borne by wholesale customers. They also ask the Commission to confirm that any subsequent recovery of energy imbalance service costs from retail customers is a matter of state commission jurisdiction. They urge the Commission to take such an action on behalf of retail customers to hedge the risks of SPP's proposed imbalance market. But, Southwest Industrials argues that if the imbalance market produces net benefits, the gross benefits should be used to pay for the implementation of energy imbalance service, and the new benefits should flow through to retail customers after the energy imbalance service costs are fully amortized.

b. Commission Determination

231. With regard to Southwest Industrial's jurisdictional concerns pertaining to the flow-through of costs associated with the imbalance market and energy imbalance service, we note that recovery of such costs from retail customers is not at issue in this proceeding. By conditionally accepting SPP's imbalance market proposal cost allocation plan, the Commission does not intend to, and is not, intruding upon matters within state

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[211] Attachment AE, section 1.1.22.

[212] *See TEMT II Order*, 108 FERC at P 376, *TEMT Rehearing Order*, 109 FERC at P 296 (2004); and *PJM Interconnection, L.L.C.*, 95 FERC ¶ 61,306 at 62,042-043 (2001).

jurisdiction.[213]

5. Cost-Benefit Study

a. Protests

232. Southwest Industrials assert that without a cost-benefit study, no one can evaluate the impact of SPP's imbalance proposal. It asserts that SPP should be required to submit a cost-benefit study that takes into account SPP's proposed imbalance market rules, recent filings by generation in the SPP region that failed the Commission's market power screens and now has to use cost-based rates, recent fuel prices and SPP's proposed revisions to its market monitoring and market power mitigation rules.[214] It argues that the CRA study has not been updated to reflect these changes.[215] Furthermore, Southwest Industrials argue that all parties should have a reasonable opportunity to comment on the study, before the Commission's evaluation process begins.[216]

b. SPP's Answer

233. SPP acknowledges that it will be necessary for market participants to undertake new obligations to participate in the imbalance market, however, it notes that this market will provide numerous benefits as demonstrated by the CRA Study.[217] SPP urges the Commission to avoid delaying the start up of the imbalance market based on the protestor's vague allegations.

c. Commission Determination

234. The Commission declines to require SPP to submit a cost-benefit study that takes

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[213] *Southwest Power Pool, Inc.*, 111 FERC ¶ 61,118 at P 88 (2005) (recovery of transmission upgrade costs from retail customers).

[214] Southwest Industrials at 24-25.

[215] *Id.* at n.57.

[216] *Id*. at 24-25 (criticizing a revised-cost-benefit study in the Arkansas Public Service Commission for not evaluating the new conditions facing the SPP footprint).

[217] SPP Answer at 15 citing the CRA Study.

into account the specifics of the current proposal, since SPP and its Regional State Committee commissioned a cost-benefit study on the merits of implementing an imbalance market, albeit not specific to this proposal. The study addressed: (1) the costs/benefits of SPP members continuing to participate in the RTO versus returning to a stand-alone status and (2) the costs and benefits of an imbalance service market operated by SPP. The CRA study found that there will be benefits if an imbalance market is implemented in SPP's region, including economic and reliability benefits, and improved transparency and price signals.[218] The study results found overall, strong positive net benefits associated with the imbalance service market: $373 million net present value for 2006-2014 timeframe.[219] This study was recently updated to reflect the almost doubling of the natural gas price used in the original study (August 2004 prices vs. 2006 New York Mercantile Exchange futures fuel prices). The updated results show a $54 million increase in 2006 benefits from $50.5 million to $104.4 million for transmission owners under the SPP tariff as a result of trade benefits from production cost savings. Given this analysis, we deny Southwest Industrials' request that SPP undertake a new cost-benefit study to evaluate the costs and benefits of its current market proposal.

6. **Additional Tariff Revisions**

235. The Commission identifies and SPP acknowledges that there are several inadvertent errors in SPP's filing. We accept SPP's commitment to make the following corrections in its compliance filing. SPP is directed to: (1) define the term SPP Bylaws in the tariff and provide a reference to the FERC-filed document for access to the dispute resolution procedures referenced in Attachment AG, section 8.3; (2) revise the definition of System Impact Study on First Revised Sheet No. 16A, which currently contains text from the Ancillary Services portion of tariff; (3) change the reference in section 4.1(e) of Attachment AE from section 4.1(c) to section 4.1(d) (for the procedure to determine whether a resource fails to follow dispatch instructions); (4) delete duplicate language in section 3.2.4(c) of Attachment AF that is repeated on the bottom of First Revised Sheet No. 673 and the top of First Revised Sheet No. 674; (5) define terms that are capitalized and used in section 4.3 of Attachment AE without a definition in SPP's OATT, including Coordinated Flowgate, Reciprocal Coordinated Flowgate, NERC IDC and Market Flow; (6) insert in section 1.2.8 of Attachment AE ",where actual data is not available," after "actual load consumption, or"; (7) insert the accepted inputs to the offer cap formula into

[218] CRA Study at IX and XIV (for example, the imbalance market will provide optimal aggregate trade benefits of $614 million and net benefits of $373 million over a 10-year period to SPP's transmission owners).

[219] *See* Cost Benefit Analysis Final Report at http://www.spp.org/publications/CBARevised.pdf.

Attachment AF; (8) replace the reference to section 5.3.1 with section 5.6(a) in section 5.6(c) of Attachment AE, and (9) insert the references to relevant sections in 5.3(c) of Attachment AE. We direct SPP to submit a compliance filing no later than 60 days from the date of this order with these changes.

The Commission orders:

(A) SPP's filing is hereby rejected in part, conditionally accepted and suspended in part, for five months from the requested effective date and permitted to become effective October 1, 2006, subject to further orders as discussed in the body of this order.

(B) SPP is hereby required to make filings discussed in the body of this order within timeframes specified in the body of this order.

(D) SPP is hereby directed to submit reports as discussed in the body of this order.

(E) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.603, the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within five days of the date of this order. The designated settlement judge shall have all powers and duties enumerated in Rule 603, and shall convene a settlement conference as soon as practicable. The settlement judge process shall last no longer than 60 days from the date of this order.

(F) At the conclusion of the settlement judge process, the parties are instructed to file a joint report to the Commission on the results of the proceedings, including further detail on how the allocation of functions will be applied in practice and how issues of costs of liability will be resolved among the parties.

(G) Golden Spread's motion to reject SPP's imbalance market proposal is hereby denied.

By the Commission.

(S E A L)

Magalie R. Salas,

Secretary.