

# **A REVIEW OF THE SOUTHWEST POWER POOL'S INTEGRATED MARKETPLACE PROPOSAL**

Prepared by:

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As an Independent Advisor to the  
SPP Board of Directors

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## I. INTRODUCTION AND SUMMARY

The Southwest Power Pool (SPP) Board of Directors (Board) asked Boston Pacific Company, Inc. (Boston Pacific) to review the major elements of the Integrated Marketplace proposal. The request was made in anticipation of the Board's upcoming decision at its January 2011 meeting on whether to direct SPP to proceed with vendor contracts to implement the proposal. The purpose of this Report is to provide the results of Boston Pacific's review.<sup>1</sup>

Our Report attempts to do three things. The first and most important is to make recommendations on additions, deletions, or modifications to the specific major proposals – with an emphasis on unresolved issues. The second is to set the stage for our recommendations by providing concise descriptions of the major elements of what is being proposed and to do so in Plain English. The third is to pay special attention to potential abuse of the market rules and to assess the need for additional or more vigilant monitoring and mitigation.

At the outset, we should note that the hard work of the SPP Staff, the Market Working Group, and other stakeholder groups has clearly paid off. The Integrated Marketplace proposal is a comprehensive, intelligent proposal that builds on experience from across the United States.

### A. Our Broad Recommendations

Boston Pacific recommends that the Board authorize SPP to move forward on the Integrated Marketplace proposal with the modifications we recommend herein. The primary basis for our recommendation is the potential for important ratepayer cost savings and other ratepayer benefits with the implementation of the proposal.

We see strong *conceptual* support for three primary types of ratepayer benefits. The first is ratepayer cost savings from centralized unit commitment as achieved with the proposed Day-Ahead Market. The proposal removes the constraints of the current, balkanized unit commitment processes of the individual Market Participants to allow SPP to choose the least expensive units to commit throughout the footprint. The second is ratepayer cost savings from the creation of competitive markets for operating reserves. The benefits are achieved simply by opening the provision of reserves to new competitive players with new ideas. The third is the potential for higher-value use of the transmission system by allowing transmission rights to be traded. These savings are achieved through the assignment of Auction Revenue Rights, or ARR, and the trading of Transmission Congestion Rights, or TCRs.

We emphasize the *conceptual* support that such benefits will be realized because we agree with those who argue that the quantification of those benefits is uncertain. We agree further that much of that uncertainty comes from what has been characterized by many as a “revolution” in shale gas supply and its impact in terms of lower natural gas market prices. When we look back to find the market's expectations about natural gas prices for 2012 right after the price spikes of Summer 2008, the futures markets told us that the expectation was for prices

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<sup>1</sup> Boston Pacific provided two status reports to the Board's Oversight Committee – the slides are available in the minutes from September 30, 2010 and December 6, 2010.

above \$10 per MMBtu.<sup>2</sup> In Fall 2010, in sharp contrast, the futures markets tell us that the expectation for prices in 2012 is now below \$5 per MMBtu.<sup>3</sup> The forecasts we now see say that the United States has shifted in ‘just two years’ from a forecast of shortage to a forecast of surplus – primarily because of shale gas.

While the shale gas story is convincing, in truth, the abrupt change in natural gas price forecasts has only made us more skeptical. This is evidence that natural gas prices remain highly unpredictable. In short, today’s forecasts have made natural gas prices lower, but they have not made them more certain. The quantification of potential ratepayer cost savings for the Integrated Marketplace proposal should be done over a very broad range of natural gas price forecasts.

Our recommendation to move forward with implementation also is based on a threshold requirement set by the Board being met – that is, the Board told SPP to “not re-invent the wheel” with its market design. Most of the features included in the Integrated Marketplace proposal have been included in other, long-standing wholesale power markets. Given this, there is the opportunity for lower risks and lower costs in the SPP market implementation. However, lower cost and risks must be proactively pursued by reaching out to other Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) and by assuring the software vendors know this is among the Board’s directives.

In addition, we recommend that the Board give SPP Staff three big picture principles to guide the implementation going forward. First, “let ratepayer benefits be your guide.” The goal is *not* to get the perfect market design, it is to get the most ratepayer benefits – a focus that sometimes is lost as we market designers get into the weeds. Second, “be an advocate for simplicity” when that lowers costs and risks for implementation. There is no such advocate now – SPP Staff has to meet sometimes competing demands from Market Participants and software vendors have no incentive to simplify. Third, “start training for implementation right away” with efforts to have SPP operators and others reach out to other RTOs and ISOs as well as to the vendors SPP hires.

The bulk of this Report presents and supports our recommendations on the major elements of the Integrated Marketplace proposal. In the remainder of this Introduction and Summary, we provide our recommendations for six features. For each one we give (a) a basic primer on what is being proposed and what benefit is being sought, (b) our recommendation, and (c) our cautions and work plan going forward.

## **B. Our Recommendations on Specific Features**

### **1. Transmission Congestion Cost Management**

#### **a. Primer**

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<sup>2</sup> MMBtu is shorthand for one million British thermal units.

<sup>3</sup> At the peak price for natural gas futures on July 3, 2008, prices were \$10.63 for settlement year 2012, \$10.63 for settlement year 2013, and \$10.83 for settlement year 2014. By October 15, 2010, prices for settlement year 2012 had dropped to \$4.70, and as of December 27, 2010, prices for settlement year 2012 were at \$4.66.

The primary intended benefits of the proposals related to transmission congestion costs are (a) to provide ratepayers with protection from paying for congestion and (b) possibly, to allow for higher-valued use of the transmission system.

Today, the protection against paying for congestion is provided by scheduling (“physical transmission rights”). As background, note that, when there is transmission congestion, the locational imbalance prices (LIPs) include a component for congestion costs. Today, say a utility schedules the delivery of 100 MWh of power on a certain portion of the SPP transmission system. If it keeps with its schedule – that is, it actually delivers 100 MWh in real-time – the utility does not pay the LIP so it does not pay for congestion. Only to the extent that it deviates from its physical schedule does the utility pay the LIP and, thereby, pay for congestion; for example, if it delivers 95 MWh it would pay the LIP (including the congestion component) to buy 5 MWh.

With the Integrated Marketplace, the protection against paying for congestion is achieved through Transmission Congestion Rights, or TCRs. Put simply, the holder of the TCR is entitled to a refund of the congestion component of the Day-Ahead locational marginal price (LMP).

As to the higher-valued use, this reflects the fact that the Market Participants who are originally assigned the transmission rights – that is, assigned the Auction Revenue Rights, or ARR – can sell those rights to others through the Annual and Monthly TCR Auctions. The thought is that the willingness to purchase the congestion protection at a higher price may reflect higher-valued transactions. Plus, this facilitates optimal unit commitment because it encourages Market Participants to participate in the Day-Ahead Market since they will be protected from paying congestion regardless of whether or not their physical resources are dispatched.

#### **b. Our Recommendation**

Boston Pacific’s recommendation is to approve the approach proposed to address transmission congestion costs. This recommendation is based, in part, on the fact that ARRs and TCRs are not new and have been used by several other RTOs and ISOs. In addition, (a) since it is based on historical firm transmission use, the initial allocation should be fair, (b) the transmission rights are unlikely to be oversold, and (c) as noted above, there are ratepayer benefits that can accrue including protection from paying congestion costs and possible higher-valued use of the transmission system.

#### **c. Cautions and Work Plan**

Our first two cautions are driven by the fact that the ARR and TCR proposals give rise to other requirements that SPP will have to meet. The third is driven by the fact that TCRs increase the incentive for market power abuse. The fourth points to language that the Federal Energy Regulatory Commission (FERC) might find gives SPP too much discretion.

The first caution concerns credit requirements for those participating in the TCR auctions. There was an incident in another RTO that helped prompt the FERC to issue new

credit requirements in Order No. 741, dated October 2010.<sup>4</sup> SPP will now have to comply with that Order. The second caution is that it appears SPP will now have to address long-term transmission rights. With its Integrated Marketplace proposal, SPP may now be considered an “organized electricity market” and, as such, will have to comply with Order No. 681.<sup>5</sup>

The third caution is that the addition of TCRs increases the potential payoff from a generating company causing congestion. Recall that a generator in a congested area can benefit if congestion drives up the LMP. Now that generator can also benefit if congestion increases the price paid for its TCRs. The action required in response to this caution is more vigilance by the Market Monitoring Unit (MMU) going forward. The fourth caution is that FERC may find SPP’s proposal for adjusting the ARR nomination cap gives SPP too much discretion. Moderate changes in language would take care of this.

## **2. Transmission Losses**

### **a. Primer**

The intended benefit is to lower the costs of serving load by taking transmission losses more explicitly into account when choosing which power sources to use. Everyone understands that some of the electricity produced at a power plant “over there” is lost as it is transmitted to customers that use the power “over here.” So, for example, if we need 100 MWh to serve some customers at one location and we know we will lose 4% of the power that we send from the power plant, then we will have to actually produce about 104 MWh.

Today, we generally take account of losses by recognizing the need for the extra 4 MWh – this is referred to as the “average loss method” in which losses are modeled as additional customer load.

The Integrated Marketplace proposes the use of the “marginal loss method.” With this method, we would take account of losses when we choose which power plants to use to meet each increase in load – that is, we take account of losses from each power plant when we “dispatch” the system. In this way we would use a generator less if its losses made it more expensive than another source.

### **b. Our Recommendation**

Boston Pacific’s recommendation is to approve the proposal to use the marginal loss method except that the method for refunding over-collections would be modified as explained below under “Cautions and Work Plan.” One of the reasons for our recommendation to use the marginal loss method is the fact that this method is used in other RTOs and ISOs. In addition, we believe it will lower the overall production cost of electricity. Our reason for modifying the approach to refunding over-collections is that the proposed method may be unnecessarily complex.

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<sup>4</sup> *Credit Reforms in Wholesale Electric Markets*, Order No. 741, 133 FERC ¶ 61,060 (2010) (Order No. 741).

<sup>5</sup> *Long-Term Firm Transmission Rights in Organized Electric Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 (2006), *reh’g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006) (collectively, Order No. 681).

### **c. Cautions and Work Plan**

From the perspective of an “advocate for simplicity,” this is one of the features for which we would ask whether the complexity is worth it. That is, do the ratepayer benefits warrant the complexity of the initial software development and the complexity of the ongoing operation?

This is one of the features for which we should advocate simplicity. The most complex part of the marginal loss method as proposed lies in refunding the over-collection of payments for losses. The proposal is to refund losses through a method based on “loss pools.” We understand that, at least in part, this complex method was proposed to accommodate the FERC opposition to direct refunds – that is, refunding to each Market Participant the exact amount of over-collected losses for its account. We understand that FERC’s objection is that direct refunds might blunt the incentive to minimize losses. To draw an analogy, consider the refunding of a gasoline tax – a driver would not use less gasoline in response to a 50 cent per gallon gasoline tax if she knew she would simply get the 50 cents back.

With electricity, however, we do not have to worry as much about blunting the incentive because the dispatch computer will always take account of marginal losses so the effect on which power plants are used has less to do with the method of refunding over-collected losses. Given this, we recommend that SPP promptly approach the FERC about allowing direct refunds. Then, presuming direct refunds are easier and less costly to implement than the loss pool approach, the proposal would be modified.

### **3. Virtual Bidding**

#### **a. Primer**

The primary intended benefit is to provide another risk management tool to those who serve ratepayers. Today, there is no virtual bidding.

The Integrated Marketplace proposal would create virtual bidding. A virtual bid is a financial offer to buy or sell in the Day-Ahead Market that then must be reversed (liquidated) in the Real-Time Balancing Market. For example, say a Market Participant expects a higher LMP in the Real-Time Balancing Market than in the Day-Ahead Market. With that expectation, he or she would buy one or more MWh in the Day-Ahead Market for say \$30 per MWh. Then, in the Real-Time Balancing Market, he or she would reverse the transaction by selling that same number of MWh at, say, \$35 per MWh. With these assumptions, the Market Participant would gain a net \$5 per MWh on its virtual bid.

#### **b. Our Recommendation**

Boston Pacific recommends that the Board approve the proposal to include virtual bidding. Virtual bidding is used elsewhere and, when used appropriately, it does provide another risk management tool. Virtual bidding can also promote convergence of prices in the Day-Ahead and Real-Time Markets. We recommend that the proposal be modified so that uplift cost

allocation more closely reflects cost causation by requiring (a) virtual suppliers to share only in RUC uplift and (b) virtual demand to share only in Day-Ahead Market uplift.

### **c. Cautions and Work Plan**

This is another case in which we should ask whether the benefit justifies the complexity. To us it is a close call, but it appears to be worth including virtual bidding. The primary caution is that virtual bidding gives another means of causing congestion to inflate TCR values. The MMU will have to be vigilant for this form of potential abuse. Also, SPP may want to consider some of the limitations on virtual bids that are used in other RTOs and ISOs. For example, SPP could consider a limitation on the total magnitude of virtual bids or a limit on the share of the market. SPP must also comply with FERC's new credit requirements highlighted in Order No. 741 to help protect Market Participants from the risk of a defaulting virtual bidder.

## **4. Must-Offer Requirement and Manual Dispatch**

### **a. Primer**

The primary intended benefit of the Must-Offer Requirement is to help to assure reliability. Today, SPP has a voluntary real-time energy market (the Energy Imbalance Service or EIS Market), but SPP can order all resources to serve in an emergency Manual Dispatch. Although the proposal is in flux, with the Integrated Marketplace proposal we reviewed, all suppliers must offer into the Day-Ahead Market all of their available power plant capacity.<sup>6</sup> If they are selected in the Day-Ahead Market, they keep all the revenue they earn in that Market and, if the revenues prove insufficient, the supplier may get a "make-whole payment" to cover its total energy costs. The proposal also continues the Manual Dispatch right.

### **b. Our Recommendation**

Boston Pacific recommends that the Must-Offer Requirement be imposed only on Designated Resources – that is, on capacity that has been explicitly included to serve the capacity needs of ratepayers. Designated Resource-like limitations are used widely – in markets operated by PJM Interconnection LLC (PJM), Midwest Independent System Operator, Inc. (Midwest ISO), ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and California Independent System Operator Corporation (CAISO). Our presumption is that these Designated Resources get some form of capacity payment in return for their capacity obligation – either they are utility-owned power plants in rate base or they sell capacity under a power purchase agreement.

### **c. Cautions and Work Plan**

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<sup>6</sup> Since our initial review, the Market Working Group has taken up this issue again and has modified the Day-Ahead Must-Offer Requirement. Instead of applying the Day-Ahead Must-Offer Requirement to all resources, the new Must-Offer Requirement only requires Market Participants with load obligations to offer enough capacity to cover their individual load and reserve obligations.

The caution concerns the fact that, in addition to the Must-Offer Requirement, SPP will still have the right to order non-Designated Resource capacity in an emergency under Manual Dispatch. SPP's right to call on non-Designated Resource capacity without some form of capacity payment may not meet FERC's standard for "adequate fixed cost recovery." In addition, we are concerned that new power plant capacity will not be enticed to enter the SPP markets "on spec" without any hope of a capacity payment if they serve a capacity need on an emergency basis.

To address these concerns, we would suggest that an opportunity for some form of fixed cost payment to non-Designated Resources be considered for the times in which they are called upon in real-time. Since this is a resource adequacy issue, the Regional State Committee should take the lead.

## **5. Combined-Cycle Modeling**

### **a. Primer**

The intended benefit is more efficient dispatch of natural gas-fired, combined-cycle power plants, which means lower ratepayer costs. Combined-cycle power plants produce electricity twice with the same fuel. Natural gas is supplied to a combustion turbine and electricity is produced for the first time. Then, the exhaust gases from that combustion turbine are used to make steam. That steam is used in a steam turbine to produce electricity a second time. Combined-cycle power plants can have multiple configurations of combustion turbines and steam turbines. Each configuration has different performance requirements.

Today, a combined-cycle power plant can make only a single offer to the SPP real-time energy market. With the Integrated Marketplace proposal, a combined-cycle power plant could submit multiple, mutually exclusive offers related to different configurations.

### **b. Our Recommendation**

Boston Pacific recommends that this feature be *deferred* until other elements of the Integrated Marketplace proposal are completed. While we agree that there could be benefits to allowing multiple configurations to be offered, our reason for recommending deferral is that this feature is very complex and is not included at many of the major RTOs and ISOs. And, equally important, for the two entities in which it has been attempted – the CAISO and the Electricity Reliability Council of Texas (ERCOT) – there have been repeated deferrals and other delays.

### **c. Cautions and Work Plan**

Again, we recommend deferral because of the difficulties encountered elsewhere in trying to implement this feature.

## **6. Settlements**

### **a. Primer**

The EIS Market is dispatched every five minutes and there is a LIP determined every five minutes. However, the market is settled (paid for) on an hourly basis – a simple average of the twelve, five-minute LIPs in an hour is used as the price. Those five-minute prices can vary substantially if, for example, demand changes suddenly. Five-minute settlement would better capture variations in prices and their effect on payments.

#### **b. Our Recommendation**

Boston Pacific recommends that five-minute settlement for the Real-Time Balancing Market *be rejected*. However, because five-minute settlements creates stronger incentives to follow dispatch than does hourly settlements, we recommend that the Board direct the Market Working Group to look into methods to increase the incentives for participants to follow dispatch instructions under the hourly settlements approach. These methods could include strengthening or altering the uninstructed resource deviation provisions in the proposed Integrated Marketplace Market Protocols.

#### **c. Cautions and Work Plan**

Five-minute settlement is not a feature in most other RTOs and ISOs in the United States – we understand that only the NYISO does it. By definition, there is about a twelve-fold increase in the amount of data for settlement. We do not see five-minute settlement as a vital part of the Integrated Marketplace proposal so the added complexity is not warranted.

## II. CONCISE SUMMARY OF THE INTEGRATED MARKETPLACE PROPOSAL

SPP Staff, the Market Working Group, and other stakeholders have been working diligently for the past few years to craft a design proposal for new markets now known as the “Integrated Marketplace.” The culmination of that effort is the Integrated Marketplace Market Protocols, a 700-plus page document that will be discussed at the January Markets and Operations Policy Committee (MOPC) and Board of Directors’ meetings. Given the length and breadth of SPP’s proposal, this section of our Report cannot possibly serve as an exhaustive overview. Instead, the purpose of this section is to provide a concise summary of the core components of the Integrated Marketplace proposal. This summary sets the stage for our recommendations on specific elements of the proposal that we present in the next section of the Report.

Table One, on the next page, provides a snapshot of the five major components of SPP’s market proposal and how they compare with SPP’s current practices. Below, we provide a short overview of each of these components.

### A. Day-Ahead Market

The primary purpose of the Day-Ahead Market is to achieve centralized unit commitment. That is, through the Day-Ahead Market, SPP will choose the most cost-effective resources to be online the following day to serve load and meet reserve requirements. This represents a major change from today in that, currently, these commitment decisions are being made by individual Market Participants. The primary benefit of allowing for a centralized commitment process is lower total production costs in the SPP footprint.

The Day-Ahead Market is a *financially* binding market that is cleared one day in advance of real-time. It provides Market Participants with the opportunity to make offers to buy (demand bids) and sell (supply offers) electricity one day before the operating day. SPP takes these supply offers and demand bids and clears the market at the level where supply equals demand. It is important to note that the demand considered only includes load that was bid into the Day-Ahead Market. That is, the actual or forecasted load may be either higher or lower than that bid into the Day-Ahead Market. Furthermore, the Day-Ahead Market also allows “virtual” demand bids and supply offers. Virtual demand bids and supply offers are purely financial offers to buy or sell energy, and they are not linked to any physical resource.<sup>7</sup>

Each supply offer and demand bid that clears the Day-Ahead Market will be required to pay or be paid the Day-Ahead LMP at that location. Furthermore, each resource that clears the Day-Ahead Market is financially committed to supply or consume electricity the following day in real-time. These resources are financially committed in the sense that, to the extent that they do not supply or consume electricity the following day, they will be charged the Real-Time LMP for electricity.

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<sup>7</sup> Virtual bidding is discussed in detail in Section III(C) of this Report.

**Table One**  
**Concise Summary of Integrated Marketplace Core Components**

<b>Integrated Marketplace Proposal</b>	<b>Purpose</b>	<b>Purported Benefit</b>	<b>How it is done today?</b>	<b>Major Differences</b>
Day-Ahead Market	Centralized unit commitment	Lower total production costs	N/A	Entirely new market for SPP, centralized vs. self-commitment, Must-Offer Requirement, co-optimization
Reliability Unit Commitment (RUC)	Ensure adequate capacity	Maintain reliability at lowest total cost	SPP runs supply adequacy test using Market Participant Resource Plans, Ancillary Services Plans, and schedules	Entirely new process, centralized vs. self-commitment
Real-Time Balancing Market	Centralized Dispatch	Lower total production costs	Energy Imbalance Service (EIS) Market	Point of comparison for settlements, 5-minute settlement, co-optimization
Operating Reserves Procurements	Competitive procurement of Operating Reserves	Ensure adequate reserves at lowest possible cost	Regulation is carried on a Balancing Authority to Balancing Authority basis and spinning and supplemental reserves are carried within the Reserve Sharing Group	Entirely new markets, now competitive products (regulation up/down, spin/supp reserve)
Transmission Congestion Rights (TCRs)/Auction Revenue Rights (ARRs)	Allocation and enforcement of transmission rights	Protect ratepayers from congestion costs	Transmission schedules	Shift to financial from physical rights, entirely new auctions and processes

## **B. Reliability Unit Commitment**

The primary purpose of the Reliability Unit Commitment (RUC) process is to ensure that the right amount of *physical* capacity is online to meet SPP's demand forecasts. That is, the purpose of this process is to maintain short-term reliability at the lowest total cost.

The RUC process occurs after the Day-Ahead Market has closed. As opposed to the Day-Ahead Market solution, which uses demand bids as its measure of load, the RUC solution uses SPP's load and reserve forecasts. SPP excludes both virtual demand and supply offers for the purposes of the RUC process. The reason for doing so is because the RUC process is a reliability process that is only concerned with ensuring that the right amount of *physical* supply is online to serve *actual* demand.

If there is too much capacity committed through the Day-Ahead process, SPP will decommit resources through the RUC process. If there is too little capacity committed, SPP will commit additional resources. If a resource is committed through the RUC process, SPP will guarantee sufficient revenue to cover its fuel and other variable costs as a result of coming online – the guarantee is achieved through what is called a make-whole payment. That is, if a unit is committed by SPP in the RUC process, the resource will be given an additional payment if the revenues it earns in the Real-Time Balancing Market do not cover its start-up, no-load, and incremental energy and reserve costs.

## **C. Real-Time Balancing Market**

The primary purpose of the Real-Time Balancing Market is to centrally dispatch online resources to balance real-time supply and demand. The benefit of this market is to match supply and demand at the lowest total production costs.

The Real-Time Balancing Market is similar to today's EIS Market in that Market Participants submit offers to supply electricity and SPP, based on these offers and the limitations of the transmission system, clears the market and sends out dispatch instructions every five minutes. However, because of several key differences, SPP is not simply modifying the EIS Market, but, rather, is replacing it entirely with the Real-Time Balancing Market.

Two key differences between the EIS Market and the Real-Time Balancing Market involve settlements. First, the EIS Market is settled on an hourly basis, while the Real-Time Balancing Market will be settled every five minutes. Second, the point of comparison for calculating settlements is different. In the EIS Market, the amount of electricity settled is the difference between actual meter readings and scheduled amounts. In the Real-Time Balancing Market, the amount of electricity settled will be the difference between actual meter readings and the amounts cleared in the Day-Ahead Market.

## **D. Operating Reserves Procurements**

Another major feature of the Integrated Marketplace design is the competitive procurement of reserves. Resources will compete to provide reserves to SPP, and only those resources that can provide reserves effectively and at the lowest cost will be selected. The benefit of this change is to lower total costs to ratepayers while maintaining reliability.

Market Participants will be able to buy and sell reserves in the Day-Ahead and Real-Time Balancing Markets. They may do so by submitting offers to sell reserves along with their offers and bids for energy. Reserve products include regulation (up and down), spinning reserve, and supplemental reserve.

There are two areas to highlight about reserve procurement in the Integrated Marketplace. First, reserves will now be procured by SPP for its entire footprint. Before, each of the fifteen balancing authorities carried their own regulation and the Reserve Sharing Group carried spinning and supplemental reserves to ensure reliability. Now, SPP will become the sole balancing authority. SPP will procure enough reserves to meet its region-wide reserve requirements, while also ensuring that reserves will be deliverable to load points within its system.

Second, reserves will be “co-optimized” with energy. Co-optimization means that SPP will determine the lowest total cost of energy and reserves together. Instead of having one market for energy and another for reserves, SPP combines all bids and offers for energy and all offers for reserves, and then finds the lowest total cost solution to meet both load and reserve requirements. This results in SPP’s resources being used in the most efficient manner possible and producing the lowest total cost.

Competitive procurement of reserves may also encourage additional investment in and participation by, demand response resources. Statistics suggest that demand response resources have been adept at providing reserves in other markets.<sup>8</sup> The lack of competitive procurement of reserves may partly explain why demand response resource participation in SPP has lagged behind that of the other RTOs.<sup>9</sup>

## **E. Auction Revenue Rights/Transmission Congestion Rights**

The Integrated Marketplace will also change the way the cost of transmission congestion is managed. Congestion occurs when the amount of energy flowing over a transmission line

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<sup>8</sup> For example, demand response resources provided 7.80% of total synchronized reserves in CAISO in 2009, despite accounting for just 3.60% of total installed capacity, and 6.12% of total synchronized reserves in PJM in 2009, despite accounting for only 4.40% of total installed capacity there. See 2010 ISO/RTO Metrics Report at Page 60 and Page 285, found here: <http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/2010%20ISO-RTO%20Metrics%20Report.pdf>.

<sup>9</sup> See 2010 ISO/RTO Metrics Report, which shows that SPP’s “Demand Response Capacity as Percentage of Total Installed Capacity” for 2009 was 1.53% (Page 344). The other RTOs’ statistics were as follows: CAISO 3.60% (Page 43); ISO-NE 5.34% (Page 94); Midwest ISO 3.78% (Page 161); NYISO 6.60% (Page 220); and PJM 4.40% (Page 278).

reaches an upper limit. Congestion can cause prices in one area to differ from prices in another area, and transmission congestion (and its costs) can be unpredictable. Transmission customers need tools to protect themselves from congestion costs while maintaining their rights to service on the grid.

Today, Market Participants use physical transmission rights to protect themselves from paying for congestion. As long as it follows its schedule, a Market Participant is protected from real-time congestion costs.

The Integrated Marketplace will introduce ARRs and TCRs as new, financial congestion cost management tools. Like today's physical transmission rights, TCRs and ARRs are designed to protect ratepayers from paying for congestion. Unlike today, however, TCRs and ARRs will allow Market Participants to easily sell their rights to other Market Participants.

ARRs are provided to those customers who now use and rely on the grid for firm transmission service. TCRs are financial rights to the transmission system, which can either be held by a transmission customer or sold to other participants in periodic auctions. Together, ARRs and TCRs will allow customers to retain their current rights to protection from congestion costs while introducing an option to sell those rights to other Market Participants.

### **III. ANALYSIS OF MAJOR FEATURES OF THE INTEGRATED MARKETPLACE PROPOSAL**

#### **A. Transmission Congestion Cost Management**

##### **1. Primer**

No transmission system can deliver an unlimited amount of electricity. Sometimes the limits are related to the physical capability of facilities like transmission lines and transformers. More often, limits are driven by the need to plan for contingencies. That is, put simply, a transmission line or other facility is kept below its physical limit so that, if an unexpected outage of another transmission line or a power plant occurs, there will be room to take on new power flow. Transmission congestion occurs when limits such as these are reached.

In wholesale markets, transmission congestion is revealed most notably through differences in LMPs at one location on the transmission system as compared to another. Indeed, the difference in LMPs *is* the presumed price of congestion.<sup>10</sup> Since the causes of congestion can be unpredictable, the extent and price of transmission congestion is uncertain and can make electricity prices volatile.

As expected, load-serving entities want to protect ratepayers from congestion costs and price volatility. Today, in the SPP real-time energy market, that protection comes with physical transmission rights. With the proposed Integrated Marketplace proposal, the protection will be changed to financial transmission rights. Both the existing physical and proposed financial transmission rights are explained in what follows.

##### **2. SPP's Current Approach**

As noted, SPP now uses physical transmission rights in the EIS Market. These physical transmission rights, in the form of schedules, serve to protect Market Participants from paying congestion costs. Specifically, these schedules give load-serving entities physical rights to transmission between their specified supply and load. Load-serving entities will be insulated from paying congestion if (a) their schedules are not curtailed and (b) they do not deviate from their schedules. For example, say Market Participant One schedules 100 MWh from Generator A to Load B. Further, assume that the LIP at Generator A is \$40/MWh and the LIP at Load B is \$50/MWh. If Generator A actually produces 100 MWh in real-time and Load B consumes 100 MWh in real-time, then the Market Participant will be shielded against paying the \$10/MWh of congestion costs (\$50 minus \$40). However, if Load B had actually consumed 110 MWh then Load B would have to pay for the additional 10 MWh at \$50/MWh. So, in the EIS Market, a Market Participant is exposed to congestion costs to the extent that it deviates from its schedules.

##### **3. SPP's Proposed Integrated Marketplace Approach**

SPP's Integrated Marketplace replaces the existing physical transmission rights with financial transmission rights. These financial transmission rights are provided to Market

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<sup>10</sup> When the LMPs are calculated ignoring losses.

Participants through Transmission Congestion Rights (TCRs) and Auction Revenue Rights (ARRs). Like physical transmission rights, TCRs and ARRs are designed to protect ratepayers from paying for congestion. What is new is that, unlike physical transmission rights, TCRs and ARRs allow holders of those rights to easily sell them to other Market Participants.

**a. ARRs**

In initially allocating transmission rights, SPP will provide users of the transmission system with rights based on their historical usage. SPP will allocate these rights in the form of ARRs. ARRs simply entitle the holder to revenues from the TCR Auctions for the corresponding transmission paths. An ARR holder has two options. It can hold onto the ARR until the TCR Auction and receive the revenue collected by SPP for the sale of the TCR for the same path in the TCR Auctions. Alternatively, the holder can self-convert the ARR to a TCR and therefore have a hedge against day-ahead congestion costs along that path. A TCR entitles the holder to a refund of the congestion component of the Day-Ahead LMP.

In the Annual TCR Auction (to be held each May), SPP will make available both monthly and seasonal TCR products; these products are also further broken down into peak and off-peak time periods as flow patterns can be drastically different on- and off-peak. The Annual TCR Auction is conducted in a single round process with Market Participants providing bids for specific transmission paths and SPP calculating LMPs, similar to how it does for the current EIS Market. In this annual auction, SPP will make available 100% of the transmission system for June, 90% for July through September, and 60% for the Fall, Winter, and Spring.

In the Monthly TCR Auctions (held each month), SPP will make available TCRs for any remaining transmission capability. The products auctioned in the Monthly TCR Auctions are Monthly TCRs (no seasonal TCRs) and they are also broken down into on- and off-peak products.

ARRs are provided *only* to those entities that have firm transmission service on the SPP system; that is, they must take Network Integrated Transmission Service (Network Service) and/or firm Point-to-Point Service. If an entity does not have firm transmission service it will not receive any ARRs.

SPP distributes ARRs through its Annual ARR Allocation process in April of each year. In this allocation process, SPP makes 100% of its transmission system capability available through a three-round process. Transmission customers with Network Service and/or firm Point-to-Point Service can request or nominate Candidate ARRs along specific transmission paths consistent with their firm transmission reservations. However, because of the limits to the transmission system, each customer has an ARR nomination cap based on its historical peak load and its existing firm transmission rights. SPP will then allocate the portion of the nominated ARRs that are simultaneously feasible given SPP's transmission system.

**b. TCRs**

TCRs are purely financial instruments that entitle their holders to payments for day-ahead congestion charges between two points on the system. We say they are *financial* instruments

because they are completely independent of actual power flows on the system, and they are independent of fees associated with transmission service reservations. As already explained above, the congestion charges between the two points are calculated as the difference between the Day-Ahead LMP at the end of the transmission path and the Day-Ahead LMP at the start of the transmission path.<sup>11</sup>

To show how TCRs will work, consider the following, simple day-ahead example.<sup>12</sup> Let's assume that a load-serving entity pays for its load at Point B. Let's also assume that the load-serving entity holds a TCR from Point A to Point B, representing its right to receive power from a generator at Point A over that path. At settlement, load pays for its 100 MWh at \$30, \$5 of which represents the cost of congestion. Because it holds a TCR on the path from Point A to Point B, however, the load-serving entity receives a payment for its TCR for \$5. On net, the load-serving entity pays \$2,500 (100 MWh times \$30 less the TCR payment of 100 MWh times \$5). Had it not held the TCR, the load-serving entity would have paid \$3,000. The \$500 difference was the cost of congestion that the TCR protected the load-serving entity from paying.

Note that TCRs also can be liabilities because they are directional. In the example above, the TCR was for power that is flowing from Point A to Point B. Therefore, if the LMP at Point B turned out to be lower than the LMP at Point A, the load-serving entity would have to pay money to SPP rather than collect money.

Market Participants have several options for obtaining TCRs: they can (a) self-convert ARR to TCRs, (b) purchase them in the Annual TCR Auction, (c) purchase them in one of the Monthly TCR Auctions, (d) obtain them in conjunction with certain transmission service requests, or (e) purchase them through the secondary, bilateral market. The total number of TCRs sold is limited to the capability of the SPP transmission system.

#### **4. Critique of SPP's Proposal**

##### **a. What We Can Support**

We support SPP's overall proposal regarding the management of congestion and its costs. Financial transmission rights are not new and so the Board can have confidence they can work. TCRs have been around since 1998 when they were first successfully implemented in PJM. Since then, Midwest ISO, NYISO, ISO-NE, and CAISO have implemented financial transmission rights proposals. The experience of other RTOs will assist SPP in software and market protocol development.

##### **i. Maintains current benefits**

Introducing financial transmission rights will not require current customers to sacrifice the rights they currently enjoy from their physical transmission rights. SPP's proposal ensures that customers that rely on the transmission grid for firm service will be allocated continued access to the grid through the allocation of ARRs. SPP's proposal also ensures that customers

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<sup>11</sup> Assuming no losses.

<sup>12</sup> The example assumes no transmission losses.

that seek protection from paying congestion costs have a tool by which to do so – namely, TCRs.

**ii. Adds new benefits**

In addition to maintaining current benefits of physical transmission rights, SPP’s financial transmission rights proposal will introduce new benefits. First, TCRs are independent of actual physical energy flow, so they allow Market Participants to be protected from paying congestion costs along a path whether or not their resource is committed by SPP in the Day-Ahead Market. This facilitates optimal unit commitment because it encourages Market Participants to participate in the Day-Ahead Market.

Another benefit is that TCRs allow the transmission right to be used by those entities that value them most. Because TCRs are independent of physical schedules and power flows, TCRs are easily auctioned and traded among parties. With TCRs, any Market Participant can buy and sell TCRs on any path. This allows load-serving entities to sell their TCRs if they choose to so those who value the rights most can have them.

**iii. Open to all creditworthy entities**

Similar to the other RTOs, SPP also appropriately proposes to open its TCR Auctions and markets to any Market Participant that is creditworthy, including non-asset owning, financial participants. More competition in the TCR auctions means better prices for load-serving entities that choose to sell their TCRs. Meanwhile, the strict credit requirements (discussed below) will ensure that the ratepayers are protected from defaults by a Market Participant.

**iv. Tried and true mechanics**

The mechanics of TCRs and ARR in SPP’s proposal are also similar or identical to the other RTOs. For example, TCRs in SPP will be settled identically to how they are settled in the other RTO markets, *i.e.*, as the difference in Day-Ahead LMPs between two points (ignoring losses). SPP will allow ARR nominations in a similar manner to PJM and Midwest ISO. In PJM, network customers may nominate 100% of their contribution to historical peak load, and point-to-point customers can nominate up to their associated historical firm reservation amounts on each path. SPP’s similar approach (up to 103% of historical peak load for network customers, full amount of any firm reservations) ensures fairness to ratepayers by allowing for transmission customers to be fully hedged for their historical usage of the system.

**v. TCRs will not be oversold**

The amount of TCRs that can be awarded is limited by the size of the grid, and SPP will appropriately use what is referred to as a “simultaneous feasibility test” to determine if the grid can physically support a set of awarded TCRs. This will also help ensure that SPP remains “revenue-neutral,” meaning that the congestion costs it collects from customers equals the amount of TCR revenues it pays out to TCR holders.

## **b. What Concerns Us**

The TCR market can be substantial in size; currently, the nationwide value of the TCR market amounts to roughly several billion dollars.<sup>13</sup> TCRs and ARRs introduce new revenue and cost streams to Market Participants, and thus may introduce new incentives for anti-competitive or economically-irrational behavior by some participants. In some cases, possession of TCRs can enhance a participant's market power. Further, opening the SPP markets to non-asset owning, financial participants may expose SPP members to additional counterparty default risk. None of these risks are unique to SPP; rather, they are inherent in any market that features TCRs and ARRs. It is important to note that we believe these risks, and the others highlighted below, are outweighed by the benefits that TCRs and ARRs provide. Further, all of these risks can be mitigated with proper safeguards in place.

### **i. Market power**

TCRs, on their own, cannot be used to manipulate energy market results. A holder of a TCR cannot withhold the TCR in order to raise energy prices. That feature contrasts favorably with physical transmission rights, which, when withheld, can produce higher energy prices.

A Market Participant with generation on both sides of a transmission constraint already has an incentive to increase generation on the export side to cause congestion; the benefit would be a higher price on the constrained, import side. With TCRs, that incentive increases if the higher LMP on the constrained side also increases the value of a TCR held by that Market Participant. This concern can be addressed by specific vigilance by the SPP MMU.

### **ii. Credit**

One risk that has been evidenced in other RTO markets is the risk that a participant in the TCR market will default, leaving losses on its TCR positions to be absorbed by other RTO members. In December of 2007, PJM members faced this exact problem when a participant in its TCR markets, Power Edge, LLC (Power Edge), defaulted on \$51.7 million in TCR obligations. Power Edge was one of eight affiliated companies doing business in the PJM markets, five of which were transacting in the TCR markets. The default spawned an investigation by FERC regarding possible market manipulation against Power Edge and its affiliates. While the investigation turned up insufficient evidence of fraudulent behavior by Power Edge and its affiliates, the Power Edge default and subsequent investigation identified PJM's collateral requirements for participation in its TCR market as "grossly inadequate." As PJM is a revenue-neutral organization – just like SPP – PJM members were forced to pick up the socialized bill of Power Edge's default.

FERC responded to this newly highlighted problem and the 2008 credit crisis by initiating a rulemaking proceeding that resulted in Order No. 741, issued on October 21, 2010, which addressed credit requirements in RTO markets. Order No. 741 establishes important

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<sup>13</sup> See "Testimony of Chairman Jon Wellinghoff, Federal Energy Regulatory Commission, Before the Energy and Environment Subcommittee Of the Committee on Energy and Commerce, United States House of Representatives, Impacts of H.R. 3795, the Over-the-Counter Derivatives Markets Act of 2009, on Energy Markets" (December 2, 2009).

credit requirements that will be necessary for SPP to adopt with the introduction of TCRs and virtual bidding, each of which attracts non-asset owning, financial participants. While participation by such entities is largely beneficial – as explained above and elsewhere in this Report – their participation must be contingent on strict credit requirements that protect SPP’s members and ratepayers from default risk of these parties.

FERC’s Order No. 741 requires SPP to make a number of changes to its credit requirements (*e.g.*, cap the unsecured credit in each market to no more than \$50 million per Market Participant and no more than \$100 million per corporate family). SPP must meet these reforms by June 30, 2011. Most notably for the TCR markets going forward, FERC disallows SPP and other RTOs to accept unsecured credit for TCR positions. FERC acknowledged that TCRs are an important risk management tool and does not intend to discourage their use, but noted that the risk and effects of TCR defaults warrant full credit support.

### **iii. Long-term transmission rights**

With the implementation of the Integrated Marketplace, SPP is likely to be considered an “organized electricity market,” as defined by FERC in its Order on long-term transmission rights, Order No. 681. In that Order, FERC required transmission providers to provide Market Participants with the ability to obtain long-term transmission rights to manage their exposure to congestion costs over the life of their long-term power purchase agreements. FERC specifically exempted SPP, stating that “SPP is not subject to this Final Rule because its *current* market design does not fit within the definition of organized electricity market that we adopt at this time.” (Order No. 681 at Paragraph 32. *Emphasis added.*) FERC defined “organized electricity market” as “an auction-based *day-ahead* and real-time wholesale market...” (Order No. 681 at Paragraph 30. *Emphasis added.*)

With the implementation of a Day-Ahead Market, it appears that SPP will become an organized electricity market as defined by FERC. As such, SPP will now be subject to the requirements of FERC Order No. 681 to provide participants with conforming long-term transmission rights.

FERC has provided transmission providers with significant latitude in meeting its requirements in Order No. 681, and it is possible that SPP’s TCR and ARR proposals already meet FERC’s requirements. For example, FERC requires a minimum long-term transmission right of ten years. However, that does not mean that SPP will need to develop a 10-year TCR. FERC noted:

We will adopt guideline (4) with a modification to indicate a 10-year minimum term that transmission organizations must be able to offer. Transmission organizations and stakeholders will have substantial latitude to determine how to achieve long-term coverage through combinations of transmission rights of specific terms and renewal rights along with transmission planning and expansion procedures that support long-term rights. (Order No. 681 at P 255)

Other RTOs have met the “10-year minimum” requirement without implementing 10-year TCRs. PJM offers TCRs with a maximum length of three years, but allows load-

serving entities significant rollover rights related to those TCRs. The rollover rights effectively allow load-serving entities to hedge their congestion exposure for ten years and beyond. SPP, therefore, may be able to meet FERC's long-term transmission rights requirements given their current proposal. There are other requirements in Order No. 681, however, and we would recommend that SPP review its TCR and ARR rules with an eye toward Order No. 681's requirements if it has not already done so.

#### **iv. Ad hoc adjustments to ARR nomination cap**

SPP proposes to limit Network Service customers' access to ARRs in the annual ARR allocation process. The cap itself is appropriate, as it is high enough to allow customers to be protected from congestion costs while not over-allocating, and capping ARR nominations is done in PJM, Midwest ISO, *etc.* However, our concern is with language in Section 5.1.3(1) of the proposed Integrated Marketplace Market Protocols, which states that the nomination caps may be adjusted "as required" to account for load migration between customers.

Providing for adjustments to the ARR nomination amounts makes sense. A transmission customer's load may grow or migrate during the year, and it would be unfair to not allow that customer to adjust its ARR nomination to protect itself from paying congestion costs. Our concern, however, is that SPP's proposed case-by-case, approach, in FERC's eyes, may provide SPP with too much discretion in determining the allocation of ARRs. We recommend that SPP develop specific language to explain how and when it will adjust the ARR nomination values. As an example of this, we point to section 36.8.5 of the CAISO tariff, titled "Load Migration Between [Load-Serving Entities]," which states that adjustments to allocations of congestion rights will be made "in proportion" to the amount of load gained or lost from the time of the original allocation. SPP would seem to benefit from a similar, clearly-explained approach.

#### **c. Recommendation**

We recommend that the Board approve the proposal to address transmission congestion costs by introducing TCRs and ARRs, and that it direct SPP to (a) ensure vigilant market monitoring in the TCR markets; (b) comply with FERC's credit requirements in Order No. 741; (c) address FERC's requirements in Order No. 681 regarding long-term transmission rights; and (d) develop specific language to address load migration in adjusting ARR nomination caps.

### **B. Transmission Losses**

#### **1. Primer**

When transporting electricity from one point on a transmission system to another, a portion of the electricity is lost through the dissipation of heat. These losses of electricity are commonly referred to as transmission losses. There are a few key characteristics of transmission losses worth noting. First, total transmission losses increase when power is transported greater distances. Therefore, supplying 50 MWh at Load A will require more power to be generated from a resource that is located 60 miles from the load than a resource that is only 10 miles away. Second, as more power is added to a transmission line, average transmission losses increase. For

example, the electricity lost per MWh is greater when transporting 100 MWh across a line than transporting just 20 MWh across that same line. Third, total transmission losses decrease when transported at higher voltages. This is the reason high-voltage lines are used to transport electricity great distances.

Because of transmission losses, more power must be provided by generation resources than is consumed by customers. Specifically, generators must supply enough electricity to cover load plus what is lost in transit. This results in a mismatch in which a generator may be paid, for example, for 100 MWh while load receives and pays for 95 MWh. This mismatch requires SPP or any other RTO to have a method for (a) accounting for transmission losses when dispatching the system and (b) incorporating the cost of losses into LMPs. The two main methods used in RTOs are the average loss method and the marginal loss method (or marginal loss pricing). Before discussing the details of these two methods, it is useful to understand the relationship between average and marginal losses.

Average losses on a transmission line can be computed as the total losses incurred divided by the total number of MW of flow on the transmission line. This tells us the average energy lost for every MW on the transmission line. Marginal losses for a transmission line can be computed as the amount of transmission losses incurred for *an incremental increase* in loading on the line. Because, as discussed above, average transmission losses increase as more power is added to a transmission line, marginal losses will always be greater than average losses.<sup>14</sup> And, as we will explain later, it is this relationship between average and marginal losses that leads to over-collection for losses when marginal losses are reflected in LMPs.

## **2. SPP's Current Approach**

SPP currently uses the average loss method in operating the EIS Market. This method can be best explained by discussing how SPP accounts for transmission losses in dispatch and how transmission losses are included in prices.

To account for transmission losses in dispatch, SPP estimates total system losses based on load forecasts and models these losses as an additional load input to the system. SPP then runs the dispatch model on a “lossless” network because losses are already accounted for as additional load. Therefore, the dispatch model dispatches enough generation to meet demand requirements (load plus the power lost in transmission). However, it is worth noting one major deficiency in SPP's current method. Because the system is modeled as a lossless network, resources far from load are treated the same as those that are located near load. This is despite the fact that in order to serve a given load, resources farther away must generate more electricity than resources close by. This results in a less efficient dispatch solution and higher total production costs.

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<sup>14</sup> This is the relationship between average and marginal when measuring anything, not just transmission losses. To see this, consider a room with ten people in it, and we calculate the average height to be 5 feet 8 inches. Then consider an eleventh person walks in, and we recomputed the average height to be 6 feet. Because the average increased, we know for sure the eleventh person was taller than the old average – that is, we know for sure the “marginal” person was above the previous average height.

As for including the cost of losses in prices, SPP's current system does so indirectly. As stated above, SPP models transmission losses as an additional load, which increases the demand requirements for the system. This in turn requires additional, more expensive power to be utilized resulting in all LIPs being increased. Therefore, SPP's average loss method results in loads paying a proportional share of system losses. There is no over-collection of revenues using the average loss method and therefore no method is needed for redistributing excess revenues.

### **3. SPP's Proposed Integrated Marketplace Approach**

SPP has proposed to use the marginal loss method for the Integrated Marketplace. As with the average loss method, the marginal loss method can best be explained by discussing how SPP will account for transmission losses in dispatch and how transmission losses will be included in price.

#### **a. A Hypothetical Example**

To account for transmission losses in dispatch, SPP will use a "dynamic loss" network dispatch model. This means that instead of modeling estimated total transmission losses as an additional load on a lossless network, the software automatically accounts for transmission losses. To show how the software accomplishes this, a hypothetical example is useful. Say there are two generators, Gen A and Gen B (each with a minimum operating level of 100 MW), and a single 100 MWh load, Load C. Further, assume that Gen A is located 50 miles from Load C while Gen B is located at Load C. Finally, say Gen A's offer price is \$28/MWh and Gen B's offer price is \$30/MWh. Using the average loss method Gen A would be turned on and dispatched to meet Load C's requirements because it has the lowest offer price. However, under the marginal loss method, Gen B could be dispatched to serve Load C if transmission losses from Gen A to Load C are high enough.

For example, if Gen A actually had to produce 110 MWh to serve the 100 MWh at Load C then Gen B would be dispatched even though it has a higher offer price than Gen A. We can see this by comparing the total production costs of serving Load C with Gen A and with Gen B. The total production costs for Gen A would be \$3,080 (\$28/MWh times 110 MW), while the total production costs for Gen B would be just \$3,000 (\$30/MWh times 100 MW). In order to be able to make these calculations, the dispatch software will have a database that includes loss coefficients for all transmission lines. These loss coefficients are used to calculate the transmission losses incurred in transmitting power from one point to another on the system. This marginal loss method functionality results in a more efficient unit commitment and dispatch of SPP's resources and, in turn, lower transmission losses and lower total production costs.

#### **b. Refunding Over-collections**

To account for transmission losses in LMPs, SPP plans to include the marginal cost of transmission losses directly in the LMP calculation. LMPs are calculated as the cost of supplying the next or marginal MW of power at a specific location on the grid. As explained above, the dispatch software will be able to include the costs of transmission losses in the total cost of supplying load. So, when calculating the cost to supply the next MW at any point on the

system, the cost of losses is included in the LMP at that location. This means that LMPs can diverge across the SPP system even without congestion. More importantly, it also means that LMPs at load points are generally higher than those at generators. And because the LMPs reflect marginal losses, rather than average losses, this price divergence causes there to be an over-collection of revenue by SPP. That is, SPP will receive more revenue from load than it pays out to generators. SPP is revenue-neutral so it must refund this over-collection back to Market Participants.

SPP currently plans to distribute over-collected loss revenues using a complex method involving what SPP calls “loss pools.” The overall idea of the SPP loss pool method is to provide a fair and equitable distribution of loss revenues that complies with FERC precedent. To do so, SPP will form a loss pool for each Asset Owner in SPP. Participants with more than one Asset Owner would have the option to create one loss pool that includes all of its Asset Owners. Each loss pool will be made up of all generation and load settlement locations for that Asset Owner(s). Using these loss pools, SPP will carry out a series of complex calculations to determine the allocation of transmission loss revenues.

The first series of calculations aims to determine a proxy for how much the load in each loss pool contributed to the total over-collected transmission loss revenues. SPP does this by first assuming that all injections within a loss pool serve the load (withdrawals) within that same loss pool. If there are not enough injections to cover the withdrawals, SPP will assume the remaining load is served by an SPP exchange that is made up of injections that exceeded withdrawals from other loss pools. Next, in order to estimate how much each load contributed to the over-collections, SPP will multiply the load amounts for each loss pool by the difference between the marginal loss LMP component of the load and either (a) the generation-weighted average marginal loss LMP component of all generation resources in the respective loss pool or (b) the generation-weighted average marginal loss LMP component of the exchange, whichever is appropriate. The result of these calculations is an estimate of how much each loss pool contributed to the total over-collected revenue; these calculations are completed for every hour. Next, using these estimates, SPP will calculate loss rebate factors that are used to determine what portion of the total over-collection is allocated to each Asset Owner.

#### **4. Critique of SPP’s Proposal**

##### **a. What We Can Support**

Overall we support SPP’s proposal to implement the marginal loss method for several reasons. First, the marginal loss method is a tried and true market design feature that is currently utilized by all the other RTOs in the United States. Given that the other RTOs use the marginal loss method, the software needed for implementation is readily available and tested with years of operation in multiple RTOs.

Second, FERC has supported the use of the marginal loss method in other RTOs so there is good reason to believe FERC will also support SPP’s proposal. FERC, in an Order that conditionally approved CAISO’s marginal loss proposal, stated: “We conditionally accept the CAISO’s proposal to reflect marginal losses in its calculation of LMP, because doing so sends

more accurate price signals and assures least-cost dispatch.”<sup>15</sup> Further, in an Order related to Midwest ISO’s marginal loss proposal the Commission stated: “We have supported the use of marginal losses in LMP in prior Midwest ISO orders because it leads to a least-cost dispatch that reflects the true costs of transmission.”<sup>16</sup>

Third, and most important to us, the marginal loss method can achieve a more efficient dispatch. This results in lower transmission losses and lower total production costs for ratepayers. In its Frequently Asked Questions regarding the Integrated Marketplace, SPP estimates that this will save roughly \$5-\$25 million per year.<sup>17</sup> Other RTOs also forecasted significant savings for their marginal loss pricing proposals. PJM, for example, estimated that switching from average losses to marginal losses would save about \$100 million per year.<sup>18</sup>

### **b. What Concerns Us**

While we recommend going forward with the marginal loss method because of its potential benefits to SPP’s ratepayers, we do have a concern with the proposed methodology for allocating over-collected loss revenues. The magnitude of these over-collections can be significant, so how this money is distributed is crucial.

As explained above, SPP has proposed a complex method using loss pools for allocating over-collections. After reviewing this method, we believe that it may be unnecessarily complex. This complexity concerns us for several reasons. First, it would be extremely difficult, if not impossible, for Market Participants to perform shadow settlement calculations to ensure that they are receiving the correct allocation of loss revenues. A more transparent methodology could be replicated. Second, because so much money is being distributed, SPP must be careful that the method chosen does not allow for gaming opportunities. For example, in PJM, revenues from over-collection are distributed on a *pro rata* basis to those participants that contribute to paying for the fixed costs of the transmission system. In an effort to game PJM’s allocation methodology, some participants attempted to purchase additional transmission service in hopes of profiting from a larger distribution of over-collected loss revenues. That is, they hoped that the additional loss revenues received would more than cover the cost of the additional transmission service. While SPP proposes a different method that would not be open to such behavior, other behaviors could be used if the distribution is not designed correctly. Third, with such a complex method for allocating loss revenues, we would be concerned that there would be a greater chance of a less than equitable allocation of funds among parties.

We understand that one reason SPP’s proposed method is so complex is that FERC has explicitly stated that over-collected loss revenues should not be directly reimbursed to those that contributed to the over-collections. FERC has stated that directly reimbursing those participants

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<sup>15</sup> *California Independent System Operator Corporation*, 116 FERC ¶ 61,274 at Paragraph 90 (2006).

<sup>16</sup> *Midwest Independent System Operator, Inc.*, 108 FERC ¶ 61,163 at Paragraph 71 (2004) (Midwest ISO Losses Order).

<sup>17</sup> Southwest Power Pool, SPP Future Markets Design Frequently Asked Questions, Last Updated: 10/15/10 at Page 3-13.

<sup>18</sup> *Atlantic City Electric Company, et al. v. PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,132 at Paragraph 6 (2006) (PJM Order).

that paid for the losses would undermine the purpose of LMP pricing. For example, in an Order regarding marginal losses in PJM, FERC stated the following:

Of course, a method needs to be determined for disbursing the over collected amounts. Customers, however, are not entitled to receive any particular amounts through disbursement of the over collections, since the price they are paying (based on marginal losses) is the correct marginal cost for the energy they are purchasing. In fact, the Commission has made clear that the method for disbursing the amounts of any over collections should not directly reimburse customers for their marginal loss payments, as such a collection would interfere with the goal of basing prices on marginal losses:

We further stated that “[r]efunding excess loss revenues to the participants who incurred the losses would undermine the usefulness of including marginal losses in the LMP calculations.” Refunding the excess LMP revenues to those who paid would result in those purchasers no longer paying the marginal cost for energy – the basic foundation of LMP.<sup>19</sup>

Further, in the Midwest ISO Losses Order, FERC stated:

As we requested in the Declaratory Order, Midwest ISO and stakeholders have developed a method for refunding marginal loss surplus that does not refund losses on a transactional basis and thus mute the loss price signal.<sup>20</sup>

We believe that FERC’s concerns may be misplaced and recommend that SPP Staff request a meeting with FERC Staff to discuss the possibility of allowing direct refunds or another simplified method such as a *pro rata* allocation based on load ratio share. We believe FERC’s concerns are misplaced because the largest benefit of implementing marginal loss pricing results from a more efficient dispatch of the system with lower transmission losses and lower total production costs. These benefits are not erased if the surplus revenues are directly refunded to those participants that paid for marginal losses. Furthermore, FERC states that implementing direct refunds would “mute” the loss price signal. We disagree. To start, we do not believe that customers are able to effectively respond to “loss” signals. Moreover, the “response” to loss price signals is achieved automatically through dispatch – that is, the dispatch computer takes account of marginal losses and dispatches less often the generators that are farther from load. Discussing the reasons with FERC and working to implement a simpler method, if possible, for over-collected loss revenues would be beneficial to all parties involved.

### **c. Recommendation**

We recommend that the Board approve the proposal to implement marginal loss pricing, and that it direct SPP to work with FERC to implement a simpler approach to the distribution of over-collected loss revenues.

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<sup>19</sup> PJM Order at Paragraph 24.

<sup>20</sup> Midwest ISO Losses Order at Paragraph 239.

## **C. Virtual Bidding**

### **1. Primer**

Virtual bids are purely financial offers to buy or sell energy in the Day-Ahead Market. A virtual *supply offer* is an offer to sell a stated quantity of energy for a specified location at a stated price in the Day-Ahead Market. A virtual *demand bid* is an offer to buy a stated quantity of energy for a specified location at a stated price in the Day-Ahead Market. From a market-clearing perspective, virtual bids are similar to physical bids in that both types of bids can “clear the market” and can set prices. Virtual bids, however, are not linked to any physical resource and thus do not carry with them any obligation to inject or withdraw energy. Instead, virtual bids that clear the market are automatically reversed and liquidated in real-time.

To illustrate, consider the example of a virtual purchase of 10 MWh in the Day-Ahead Market at an SPP pricing node. This virtual purchase in the Day-Ahead Market commits the participant to a parallel, price-taking offer to sell 10 MWh of energy in real-time at that same location. The Market Participant will pay the day-ahead price at that SPP pricing node for its 10 MWh purchase, then, will be paid the real-time price at that same location for its 10 MWh sale. If the day-ahead price is lower than the real-time price, this participant will receive a net payment at settlement. If the day-ahead price is higher than the real-time price, then the participant will be required to pay that difference.

For example, assume the day-ahead price is \$30 per MWh and the real-time price is \$35 per MWh. In the Day-Ahead Market, \$300 ( $\$30 \times 10$  MWh) would be paid by the purchaser. In the Real-Time Balancing Market, \$350 ( $\$35 \times 10$  MWh) would be paid to the seller. Thus the Market Participant who made the 10 MWh virtual purchase would gain a net \$50.

### **2. SPP’s Current Approach**

SPP currently has just a real-time, EIS market, so it does not employ, nor have any need, for virtual bidding.

### **3. SPP’s Proposed Integrated Marketplace Approach**

SPP’s proposal to introduce virtual bidding to its Integrated Marketplace is similar to virtual bidding designs in other established RTO markets. Market Participants will be able to submit virtual bids and offers at all Settlement Locations, including trading hubs. This high level of granularity is similar to that in PJM, ISO-NE, and CAISO. And, as in other RTOs, virtual bids and offers are eligible to set LMPs. Further, in addition to asset-owning Market Participants, SPP proposes to allow non-asset owning entities to participate in the virtual market. All participants will be subject to credit requirements and postings of collateral. Market Participants will also be subject to a transaction fee for all submitted virtual bids and offers.

SPP also proposes to subject virtual bidders to uplift costs. Specifically, virtual bidders will be required to share in the allocation of uplift costs related to make-whole payments in both the Day-Ahead Market and RUC. SPP proposes to allocate a proportional share of the make-whole uplift payments to all participants with cleared virtual bids and/or offers.

Unlike physical bids, virtual bids have no underlying cost basis. Accordingly, virtual bids will not be eligible for SPP's bid cost recovery provision. SPP proposes a provision that would require the MMU to monitor for uneconomic virtual bids and offers. Specifically, the MMU will monitor the divergence between day-ahead and real-time prices, and determine if any particular Market Participants caused such divergence by its virtual bidding and offering activity. SPP proposes specific thresholds for determining "excessive" divergence, which, if met, will allow SPP to impose a three-month suspension on any virtual bidder deemed to have caused the divergence.

#### **4. Critique of SPP's Proposal**

##### **a. Expected Ratepayer Benefits**

We recommend that the SPP Board approve going forward with virtual bidding. Virtual bidding should provide benefits to ratepayers, and SPP's design, with our recommended changes below, should protect against undesirable market outcomes. We believe that SPP's virtual bidding proposal can confer ratepayer benefits of two sorts: (a) risk management for load and supply and (b) convergence between day-ahead and real-time prices.

##### **i. Example of risk management benefits**

To illustrate how virtual bidding can protect ratepayers from real-time price spikes, consider the following example. There is a Market Participant with load to serve that is forecasted to be 100 MWh on the following day. However, this load-serving entity is concerned that if its actual, real-time demand exceeds 100 MWh, the load-serving entity (and its ratepayers) would be subject to real-time price risk. That is, the load-serving entity is concerned that additional real-time demand, coupled with a real-time price spike, could expose its customers to the risk of paying high prices for power.

Virtual bidding allows that load-serving entity to protect its ratepayers from such price spikes. To do so, the load-serving entity submits a virtual bid to buy 20 MWh of power in the Day-Ahead Market, along with its 100 MWh physical demand bid to serve its physical load. If the day-ahead price is \$30/MWh, the load-serving entity is charged (a) \$30 for 100 MWh of physical demand, or a total of \$3,000, and (b) \$30 for 20 MWh of virtual demand, or \$600. In all, the load-serving entity's net charge is \$3,600 for Day-Ahead Market activities.

In real-time, assume that the load-serving entity does indeed experience greater demand than it forecasted day-ahead, seeing 110 MWh of real-time demand. As such, the load-serving entity is required to purchase the additional 10 MWh at whatever price clears the Real-Time Balancing Market. Assume also that the real-time price that the load-serving entity must pay is indeed higher than the day-ahead price, clearing at \$35/MWh. The load-serving entity must pay, therefore, \$350 for the additional 10 MWh of physical demand.

However, the load-serving entity cleared a 20 MWh virtual demand bid in the Day-Ahead Market and it must reverse it by selling 20 MWh in real-time. This means that the load-serving entity is *paid* the real-time price of \$35 for its virtual 20 MWh, or \$700. In all, the load-serving

entity's net real-time position is a credit of \$350. Combining the day-ahead charge of \$3,600 and the real-time net credit of \$350 means the load-serving entity in this example pays a total of \$3,250 to serve its load.

Had there been no virtual bidding available, the load-serving entity would have paid more. The load-serving entity would have paid \$3,000 for its day-ahead power and \$350 for its 10 MWh of real-time demand, or a total of \$3,350. In this single example, virtual bidding produced \$100 of savings for this load-serving entity.

In our example, the load-serving entity guessed right about its real-time load and real-time prices – both were higher than in day-ahead. If the load-serving entity guessed wrong and the real-time price was lower than day-ahead, it would have lost money. Surely the entity will see a mix of results and no one can guarantee a net positive position. However, virtual bidding could be of value even if the entity lost money on a net cash basis. The larger benefit of virtual bidding is its role as insurance against significant price spikes. If, for example, a forced outage had caused the real-time price to spike to \$200/MWh, the load-serving entity would be fully protected from paying the much higher price thanks to its virtual position. In this sense, virtual bidding provides insurance against significant price spikes and this insurance benefit may be its most important risk management effect.

## **ii. Price convergence benefits**

For two reasons, it is generally thought that it is better for ratepayers if load-serving entities bid in the Day-Ahead Market rather than in the Real-Time Balancing Market. The first reason is that the optimal unit commitment is more likely to be achieved if most load is bid in the Day-Ahead Market. The second is that the Day-Ahead Market should be less volatile so ratepayers are better protected against swings in prices.

If Day-Ahead Market prices are persistently higher than those in real-time, load-serving entities will have an incentive to bid load in real-time. Virtual bidding mitigates against this because it helps day-ahead prices converge with real-time prices. In addition, virtual bidding allows a load-serving entity to bid its full physical load day-ahead, but still attempt to gain financial advantage when it expects prices to spike in real-time.

Note that virtual bidding has been shown to cause price convergence between day-ahead and real-time prices in other RTO markets. In Midwest ISO's 2007 State of the Market Report, Midwest ISO's independent market monitor noted that "virtual supply and demand participation in the Day-Ahead Market to arbitrage the price differences has contributed to the good price convergence in [Midwest ISO]."<sup>21</sup> The 2009 State of the Market Report for PJM shows that, in 2009, day-ahead prices were almost identical on average to real-time prices, averaging just a 0.2% difference.<sup>22</sup>

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<sup>21</sup> See "2007 State of the Market Report for the Midwest ISO," at Page vi, found here: [https://www.midwestiso.org/Library/Repository/Communication%20Material/Stakeholder/2007%20MISO%20SO%20Report\\_Final%20Text.pdf](https://www.midwestiso.org/Library/Repository/Communication%20Material/Stakeholder/2007%20MISO%20SO%20Report_Final%20Text.pdf).

<sup>22</sup> See Page 95 of Volume 2 of the 2009 State of the Market Report for PJM, found here: [http://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2009/2009-som-pjm-volume2-sec2.pdf](http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec2.pdf).

## **b. What We Can Support**

Turning to the specifics of SPP's proposal, we believe SPP's overall design is sound and should deliver the purported benefits of virtual bidding to Market Participants and ratepayers. SPP has followed the designs of most of the other RTOs and, thus, is using a proven market design. The proposed mechanics of SPP's virtual bidding – cleared virtual bids and offers that are reversed in real-time – are inherent to every virtual bidding design.

### **i. Granularity**

SPP's decision to allow virtual bidding at every Settlement Location will allow virtual bidding to be as effective a tool as possible for participants. In our example of the load-serving entity above, we assumed that the load-serving entity could submit virtual bids at the exact location of its physical load. This allowed load to be perfectly protected for the full amount of the load-serving entity's virtual bid. However, if virtual bidding was only allowed in aggregations of Settlement Locations (*e.g.*, a zone), the settlement prices for the virtual bid and the physical bid would likely be different, and thus would provide imperfect protection to load. The nodal virtual bidding proposed here is employed in mature virtual bidding markets such as PJM and ISO-NE.

### **ii. Financial participants**

SPP's proposal to open virtual bidding to non-asset owning entities can have benefits. So-called "financial participants" provide additional competition in SPP's markets that helps achieve the benefits of virtual bidding, including insurance against real-time price spikes and price convergence. In our load-serving entity example above, the load-serving entity's ability to protect its ratepayers from high real-time prices could benefit from the presence of financial participants. Financial participants would compete to provide this "price insurance" to load-serving entities, and through this competition, this insurance would be available at the lowest possible cost. Financial participants also help converge day-ahead and real-time prices. They do this by discovering predictable price patterns and competing them away, thus giving physical participants incentive to schedule in the Day-Ahead Market.

There are risks to allowing participation in the virtual market by non-asset owning entities. However, it is important to point out that the goals of the non-asset owning entities can be aligned with those of their physical participant counterparts, much in the same way insurance companies can make profits selling protection to property owners and businesses. Financial participants can be successful in speculating on differences in day-ahead and real-time prices while also providing load-serving entities with ratepayer protection from real-time price spikes.

Virtual bidding is not new, as it has been around in PJM since 2000, in NYISO since 2001, in ISO-NE since 2003, and in Midwest ISO since 2005. During that time, financial participants have been participating without any incidents of sanctionable behavior by the FERC. Midwest ISO's independent market monitor noted in its 2007 State of the Market Report that "virtual losses that warrant further investigation have been rare, and none have warranted a

referral to the Commission.”<sup>23</sup> In a recent ISO-NE presentation to the CAISO on virtual bidding, ISO-NE noted that the profit achieved by virtual bidders is typically under \$100,000 per day in a market that clears \$25,000,000 worth of activity per day.<sup>24</sup> Concerns about non-asset owner participation should be assuaged by the experience gleaned from the operation of other RTOs.

### **iii. Bid cost recovery**

Virtual bids have no cost basis, and, thus, SPP’s proposal to *not provide* virtual bids and offers with guaranteed bid cost recovery is appropriate.

#### **c. What Concerns Us**

##### **i. Virtual bidding and TCRs**

SPP’s proposal will allow all entities to be active participants in both the TCR market and as virtual participants in the Day-Ahead Energy Market. Because of this, TCR holders may have an incentive to use virtual bidding to cause day-ahead congestion to impact the value of their TCRs. Specifically, higher day-ahead congestion can increase the value of some TCRs. When executed properly, the participant loses money on its virtual bids (because the day-ahead price is increased relative to the real-time price), but more than makes up for that loss with a gain in the value of the TCR.

The behavior we would seek to prevent is “uneconomic” virtual bidding by a participant that had a material impact on the value of a TCR held by that participant. SPP proposes to give the MMU the authority to monitor for uneconomic virtual bidding and, if certain thresholds are met, allows SPP to suspend participants from submitting virtual bids and offers for three months. While this may be sufficient authority to prevent uneconomic bidding to impact TCR values, it may be worthwhile to develop a specific rule in the Integrated Marketplace Market Protocols that explicitly allows for a claw-back of revenue from this behavior.

PJM, ISO-NE, and CAISO all have this type of rule explicitly found in their tariffs. For example, in PJM, the market monitor evaluates each participants overall benefits from its TCR positions and virtual activity, and is allowed to recover “inappropriate benefits from the subject activity” if the amount lost on the virtual transactions is “less than the benefit derived” by the TCR holder. We would recommend a similar approach be considered by SPP.

##### **ii. Credit**

As we noted in the Congestion Cost Management section above, the Power Edge incident and the 2008 credit crisis highlighted the need for sound RTO credit policy, and FERC has responded with additional and more stringent credit requirements with which SPP will have to comply. We just want to note here that the standards required by FERC in Order No. 741, such as limits on unsecured credit, also will help protect ratepayers from the increase in default risk with virtual bidding.

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<sup>23</sup> See “2007 State of the Market Report for the Midwest ISO,” at Page 39.

<sup>24</sup> See “California ISO Presentation: Convergence Bidding – New England Experience,” presented by Ronald Coutu of ISO-NE, at Slide 10, found here: <http://www.caiso.com/1fb9/1fb9eb329740.pdf>.

### iii. Bid limits

Based on the implementation in the new CAISO market design, we raise a concern here about an unlimited number and scale of virtual bids. Put very simply, in CAISO, the software vendor raised concerns that with unlimited virtual bidding, computer systems would not consistently be able to come to a final market solution.<sup>25</sup> Because of this, we suggest that SPP should have the right to impose limits on virtual bids if, in consultation with the vendor it chooses, such limits are found to be needed to avoid implementation problems like that in CAISO.

Many of the other RTOs apply limitations on virtual bidding. PJM, for example, has the ability to impose daily limits on the number of virtual bids and offers that can be submitted by individual Market Participants, and may also limit the amount of MW of virtual bids it will accept at certain locations to allow the Day-Ahead Market to reach a solution. Midwest ISO has the option to impose a daily limit on total MW of virtual bids and offers, while NYISO has the ability to limit the total virtual bids and offers at a particular location. CAISO – the most recent RTO to introduce virtual bidding – has a transitional mechanism that limits each participant’s total exposure at individual pricing points. SPP’s proposal to impose a per-bid transaction fee on virtual bids may implicitly serve to limit bid volumes while also helping recover administrative costs. However, SPP has no explicit limitations on virtual bid volumes.

### iv. Uplift cost allocation

SPP proposes to allocate a portion of the uplift costs associated with make-whole payments to virtual bidders. While some allocation of uplift costs to virtual bidders is appropriate, we are concerned that SPP is not following cost causation in allocating uplift costs.

In the Day-Ahead Market, virtual *supply offers* may displace physical supply offers. Because of this, additional physical supply may be required to be procured in the RUC process. Virtual supply is purely financial and the RUC process will add physical resources to assure that sufficient physical resources are online to meet demand. All of this added RUC capacity is entitled to make-whole payments that can cause uplift. Since virtual *supply offers* can cause additional RUC uplift, we agree that cleared virtual supply offers should be allocated a proportional share of the RUC make-whole payments.

Similarly, in the Day-Ahead Market, virtual *demand* can increase the total amount of physical supply that is committed in the Day-Ahead Market. This added physical supply is entitled to Day-Ahead make-whole payments. Thus, if there is a need for any day-ahead make-whole payments, cleared virtual demand has contributed to the need for that uplift, and should share in the costs.

Our concern is that SPP’s proposal imposes uplift on both virtual supply and virtual demand regardless of the source of the uplift. We recommend that SPP consider applying (a) RUC uplift to only virtual supply and (b) day-ahead uplift only to virtual demand. We believe

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<sup>25</sup> The Siemens/CAISO paper can be found at: <http://www.caiso.com/240a/240a7ace60860.pdf>.

that, without this distinction, SPP overcharges virtual bidders and that overcharge could serve to raise a barrier to participation in SPP's market by virtual bidders. The higher the barrier to entry, the lower the amount of virtual participation, and the more limited the benefits to virtual bidding become. FERC's most recent Order on RTO virtual bidding confirms our stance on this issue.<sup>26</sup>

#### **d. Recommendation**

We recommend that the Board approve the proposal to implement virtual bidding, and that it direct SPP to (a) develop a specific rule to "claw back" any TCR revenues created by uneconomic virtual bidding; (b) comply with FERC's credit requirements in Order No. 741; (c) consider additional limitations on virtual bidding that are used in other RTOs; and (d) apply a share of Day-Ahead Market uplift costs to virtual demand only and RUC uplift costs to virtual supply only.

### **D. Must-Offer Requirement and Manual Dispatch**

#### **1. Primer**

A "Must-Offer Requirement" is an obligation for supply resources to offer all of their capacity in the Day-Ahead and Real-Time Balancing Markets. Must-Offer Requirements have two purposes. First, the Must-Offer Requirement can help reliability by ensuring that all resources will be available in the Day-Ahead and Real-Time Balancing Markets. Second, Must-Offer Requirements help prevent suppliers from withholding their capacity in the Day-Ahead Market to drive up prices – that is, they are added mitigation against market power abuse.

Typically, resources that are subject to Must-Offer Requirements are compensated for agreeing to offer their capacity. Payment for "capacity" – standing ready to deliver power – can come from having an asset in rate base, from being paid a capacity payment in a bilateral contract, or from a capacity price paid in an RTO capacity market. Capacity payments help ensure long-term resource adequacy by providing incentives for new investment.

"Manual Dispatch" is an out-of-market instruction issued by the system operator to a resource to start-up and/or provide energy. Manual Dispatches are different than market dispatches because they come from the system operator's staff rather than the market software solution. Manual Dispatches provide "backstop" capacity service for the system operator. If emergency conditions arise that require the system operator to seek additional capacity that the market did not procure, the system operator can issue a Manual Dispatch instruction to a resource to address the emergency condition.

#### **2. SPP's Current Approach**

SPP does not currently have a Must-Offer Requirement. Participation in the EIS Market is voluntary.

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<sup>26</sup> *California Independent System Operator Corporation*, 133 FERC ¶ 61,039 at Paragraphs 22-69 (2010).

SPP does have the ability to issue manual dispatches. Under Section 9.2.2 of its current protocols, SPP may dispatch any resource through Manual Dispatch instructions when necessary to resolve emergency conditions that the EIS Market dispatch cannot resolve. When manually dispatched, resources are paid EIS Market revenues and are exempted from any uninstructed deviation penalties.

### **3. SPP's Proposed Integrated Marketplace Approach**

SPP's Must-Offer Requirement proposal has been in flux. Market Working Group's proposal to MOPC on October 12<sup>th</sup> included a Must-Offer Requirement for *all* resources. This Must-Offer Requirement would obligate every resource to submit day-ahead and real-time offers for all of its capacity. All resources would be required to submit (a) offers for energy and (b) offers for all ancillary services that the resource is qualified to provide. Exceptions to the Must-Offer Requirement would be made for resources on outage.

MOPC did not approve this Must-Offer Requirement proposal and directed the Market Working Group to discuss further whether the Must-Offer Requirement should apply to non-Designated Resources in the Day-Ahead Market. Since then, Market Working Group has taken up this issue again and has modified the Day-Ahead Must-Offer Requirement. Instead of applying the Day-Ahead Must-Offer Requirement to all resources, the new Must-Offer Requirement only requires Market Participants with load obligations to offer enough capacity to cover their individual load and reserve obligations.

We note that neither of these two Must-Offer Requirement proposals from Market Working Group included an additional payment for resources subject to the Must-Offer Requirement.

SPP also proposes to retain its authority to manually dispatch resources in emergency conditions. Proposed section 4.4.2.4 of the Integrated Marketplace Market Protocols allows SPP to issue "reliability directives" via Manual Dispatch to any online resource to resolve emergency conditions. SPP proposes to continue to allow manually-dispatched resources to collect energy market revenues, and will allow them to collect any necessary make-whole payments. However, no additional capacity payment is required.

### **4. Critique of SPP's Proposal**

#### **a. What We Can Support**

We support the use of a Must-Offer Requirement. Again, the Must-Offer Requirement has two main benefits: (a) it helps ensure short-term resource adequacy, which means that SPP will have enough capacity online to meet customer needs; and (b) it prevents needed suppliers from withholding capacity to increase market prices. All other RTOs require some or all of their resources to offer their capacity in the Day-Ahead and Real-Time Balancing Markets. However, for SPP, we only support applying the Must-Offer Requirement to Designated Resources, and we will discuss this limited application below.

We also support SPP's Manual Dispatch authority and real-time payment provisions. Like every other RTO, SPP needs access to all resources in emergency conditions to prevent load shedding. However, we would recommend development of a new capacity payment to manually-dispatched, non-Designated Resources. That issue is also discussed below.

## **b. What Concerns Us**

### **i. Applying Must-Offer Requirement to non-Designated Resources**

SPP should limit the Must-Offer Requirement to Designated Resources, which are defined in the SPP tariff as generation resources that are owned, purchased, or leased by a transmission customer to serve load in SPP. Doing so will bring SPP in line with the other RTOs. In the other RTOs, a Must-Offer Requirement is applied to resources that are deemed "needed" for reliability – a concept similar to SPP's Designated Resource. The process by which the RTO determines which resources are needed differs. In PJM, ISO-NE, and NYISO, centralized capacity markets allow suppliers to win capacity obligations in which they are paid for being available to provide energy and reserves for a specified period of time. In Midwest ISO and CAISO, resource adequacy targets for load-serving entities are set by either the ISO or the states, which provide for contracting between load-serving entities and "needed" supply resources.

A common principle in the other RTOs is that suppliers are compensated for agreeing to be subject to the Must-Offer Requirement. By applying the Must-Offer Requirement to Designated Resources only, SPP would live up to this principle. We can presume these Designated Resources receive some form of capacity payment because the capacity asset is put into rate base or a capacity payment is required under a long-term contract.

In addition, applying the Must-Offer Requirement only to Designated Resources would help ensure long-term resource adequacy in SPP. To maintain resource adequacy, it is important that SPP's Integrated Marketplace provides incentives for investment in new resources. To do so, SPP's Integrated Marketplace must provide *access* to "fixed cost" recovery, which is recovery of costs above a resource's day-to-day operating costs.

In SPP, as already noted, fixed cost recovery is accessible in Designated Resource contracts.<sup>27</sup> Suppliers have the ability to negotiate a capacity-type payment in exchange for agreement to become a Designated Resource and be subject to the Must-Offer Requirement. Non-Designated Resources, however, do not have this leverage to gain access to fixed cost recovery. It would be unfair to require non-Designated Resources to provide the same capacity-type service as Designated Resources – that is, to be subject to the Must-Offer Requirement – without providing a similar capacity payment for that service.

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<sup>27</sup> SPP does not have, nor is it proposing, a centralized, forward capacity market. The Regional State Committee has authority over long-term resource adequacy. Capacity markets are controversial, and implementing a market likely involves ceding jurisdiction to FERC, as confirmed in a recent D.C. Court of Appeals decision affirming FERC's jurisdiction over New England's installed capacity requirement when it involves interstate transmission. See *Connecticut Department of Utility Control v. FERC*, No. 07-1375 (D.C. Cir. June 23, 2009).

We recommend, therefore, that SPP apply a Must-Offer Requirement only to Designated Resources. Non-Designated Resources should be exempted from the Must-Offer Requirement.

### **ii. Manual Dispatch of non-Designated Resources**

SPP will still have the right to call upon non-Designated Resources in emergency conditions to provide “reliability” services. We agree that SPP should have the authority to call upon these non-Designated Resources. However, we also believe that such resources should be compensated for this reliability service. When a non-Designated Resource is called upon to provide reliability services in emergency conditions, the non-Designated Resource is providing the same reliability services as that of a Designated Resource. The reliability service that the non-Designated Resource is providing justifies a payment similar to that earned by Designated Resources. Otherwise, SPP is enjoying a free service from these non-Designated Resources. Failure to compensate non-Designated Resources for their reliability services may chill investment in long-term resource adequacy by not providing resources with adequate fixed cost recovery for the services they provide.

### **iii. A relevant FERC precedent from CAISO**

A recent FERC Order on CAISO’s market design shows FERC support for paying all resources for capacity services.<sup>28</sup> We must first explain the CAISO approach to capacity services to show the relevance of the CAISO Manual Dispatch Order.

CAISO has a state-run resource adequacy program. Load-serving entities procure capacity one year in advance with resources designated as “Resource Adequacy” resources. The CAISO originally proposed a Must-Offer Requirement for *all* resources – Resource Adequacy resources and non-Resource Adequacy resources. FERC initially accepted this proposal in 2004,<sup>29</sup> but later found that the CAISO Must-Offer Requirement was “discriminatory” against non-Resource Adequacy resources that were providing the same services to the CAISO grid as Resource Adequacy resources, and should be paid accordingly.<sup>30</sup> From this directive, the CAISO introduced a series of voluntary, backstop capacity mechanisms, each of which allowed CAISO to request a resource to sign a 30-day or more contract for capacity at a FERC-approved price.

Still, a need persisted for the CAISO to issue manual dispatches to resources for reliability services in emergency conditions. FERC scrutinized this practice in 2008 and 2009 and ultimately found that non-Resource Adequacy resources that were manually dispatched by the CAISO should be compensated similarly to (a) those services provided by Resource

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<sup>28</sup> *California Independent System Operator Corporation*, 126 FERC ¶ 61,150 (February 20, 2009) (CAISO Manual Dispatch Order).

<sup>29</sup> *California Independent System Operator Corporation*, 108 FERC ¶ 61,022 (July 8, 2004).

<sup>30</sup> *Independent Energy Producers Association v. California Independent System Operator Corporation*, 116 FERC ¶ 61,069 (July 20, 2006).

Adequacy resources and (b) those resources procured through the voluntary backup capacity mechanism.<sup>31</sup>

To comply with FERC's finding, the CAISO now provides non-Resource Adequacy resources that are manually dispatched for reliability reasons with the option of obtaining a short-term capacity contract. FERC found that this option provides non-Resource Adequacy resources with access to adequate fixed cost recovery.

We believe that the CAISO example is instructive. From it, it can be gleaned that FERC may find that SPP's proposal to subject some or all non-Designated Resources to the Must-Offer Requirement is unjust and unreasonable. It is also possible that FERC will find SPP's proposal to be able to call upon non-Designated Resources for reliability purposes during emergency conditions, without the provision of explicit fixed cost recovery, to be discriminatory.

### **c. Recommendation**

We recommend that a Must-Offer requirement be set for Designated Resources. Further, we recommend that non-Designated Resources be compensated for the capacity services they provide when called upon in an emergency. Because this is a resource adequacy issue, we recommend that the Regional State Committee spearhead this effort.

## **E. Combined-Cycle Modeling**

### **1. Primer**

A natural gas-fired, combined-cycle power plant produces electricity twice with the same fuel. First, natural gas fuels electricity production in a combustion turbine. Second, the hot exhaust heat from the combustion turbine is used to produce steam; that steam is then used in a steam turbine to produce electricity a second time. By using the same fuel twice, combined-cycle power plants use fuel very efficiently.

Many combined-cycle power plants have multiple combustion turbines and steam turbines. Because of their multiple generating units, combined-cycle resources can have multiple operating configurations. For example, a combined-cycle resource with two gas-fired combustion turbines and one steam turbine can have at least three configurations: (1) gas unit one plus the steam unit; (2) gas unit two plus the steam unit; and (3) gas units one and two, plus the steam unit. Each of these configurations is like a separate resource in that they can have different costs and output and operating limitations. This makes combined-cycle resources advantageous to system operators because they are more flexible than most other resources.

However, the increased efficiency and flexibility of combined-cycle resources can only be fully accessed if the market can recognize and efficiently choose from their many

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<sup>31</sup> CAISO Manual Dispatch Order. *See, e.g.*, FERC at Paragraph 145: "The Commission accepts the CAISO's compensation proposal because it provides non-resource adequacy resources with an opportunity to recover the fixed costs associated with any capacity-type services procured by the CAISO through Exceptional Dispatch."

configurations. This capability is known as Combined-Cycle Modeling. In order for a market to use Combined-Cycle Modeling, the combined-cycle owners must provide offer curves and other operating parameters for each configuration to the market operator and the market software must be able to take this information and determine which configuration is optimal to the system given current and forecasted conditions. Furthermore, the market software must also recognize that each configuration is mutually exclusive of the other configurations. That is, while the software can pick from the configurations as if they are different resources, it cannot pick more than one configuration at a time.

Adding to this complexity is the fact that, because of their multiple generating units, combined-cycle resources have “transition phases.” Transition phases are specific ranges of output at which combined-cycle resources cannot stably operate. Combined-cycle generators can only be transitioned through these phases to a different level of output at which it can stably operate. As a result, the market software must also be able to take account of this information when dispatching the resource and when asking the resource to switch from one configuration to another.

Therefore, while Combined-Cycle Modeling can tap into the full benefits of combined-cycle resources, additional information from resource owners and more complex modeling software are required to successfully implement this feature.

## **2. SPP’s Current Approach**

SPP does not currently have any modeling capabilities or tariff provisions that are specific to combined-cycle resources. A combined-cycle resource can submit just one offer curve for its entire resource, just like other resources.

## **3. SPP’s Proposed Integrated Marketplace Approach**

SPP proposes to include Combined-Cycle Modeling capability in its Integrated Marketplace design in order to capture the full benefits of its combined-cycle resource fleet. To do so, SPP will allow an owner of a combined-cycle resource to submit separate offers for each configuration of their resource. In addition, SPP’s market software will be able to recognize each configuration as a separate, mutually exclusive generator with its own costs and operating limitations and pick the most economic configuration given market and system conditions. The software would also avoid dispatching a combined-cycle at an output level at which it cannot stably operate.

## **4. Critique of SPP’s Proposal**

### **a. What We Can Support**

We support the concept behind SPP’s proposal. The language SPP has proposed for its Integrated Marketplace Market Protocols is not problematic, and the benefits that would be delivered from successfully implementing Combined-Cycle Modeling capability could be significant. Today, for example, an owner of combined-cycle resource may submit an offer curve with a price that is higher than its incremental cost in order to protect itself in case it is

dispatched in one of its transition phases. However, if the Combined-Cycle Modeling proposed by SPP was successfully implemented, the combined-cycle owner could submit separate offer curves for each configuration that reflected the true incremental cost of each. SPP could then dispatch the most economic of those configurations, and, furthermore, the resource would never be dispatched at a level at which it cannot operate.

For combined-cycle resource owners, this modeling capability could mean higher profitability and a higher return on investment for the unique capabilities of those resources. For ratepayers, this modeling capability could mean lower total costs, as cheaper configurations could displace more expensive generation that would have been dispatched without that modeling capability. Roughly 17% of SPP's generation fleet is combined-cycle, so these benefits could be substantial.<sup>32</sup>

### **b. What Concerns Us**

Our concern with SPP's proposal is the very high level of difficulty in implementing combined-cycle modeling. Introduction of combined-cycle modeling results in significant amounts of new data and registration requirements that may directly hinder the performance of SPP's market software. SPP itself admits that combined-cycle modeling represents a "high system risk" for both development and testing of the system and model.<sup>33</sup> Our concern is that the difficulty in developing and implementing this feature could result in cost overruns and even delay implementation of the entire Integrated Marketplace.

Experience from other RTOs provides evidence of our concern. Throughout our Report, we have pointed to the experience of other RTOs as solace for the Board and SPP ratepayers that the Integrated Marketplace proposal is not re-inventing the wheel. For combined-cycle modeling, however, this is not the case. Only two RTOs have attempted to develop and implement this modeling capability, and both RTOs faced performance issues that delayed implementation, increased costs, and ultimately resulted in scaled-back versions of the original design.

ERCOT began development of combined-cycle modeling in 2007. During testing phases, ERCOT faced numerous performance issues. To combat this, ERCOT cut back on the complexity of its combined-cycle modeling design. While this adjustment improved the performance of the market software, it also reduced the effectiveness of the modeling capability and thus the benefits ERCOT's market would enjoy. After numerous delays, ERCOT finally implemented a scaled-back version of combined-cycle modeling in December 2010.

CAISO is the only other RTO to attempt to introduce combined-cycle modeling. CAISO had planned to include combined-cycle modeling capability in its Day-Ahead Market, which was launched in 2009. Like ERCOT, however, adding this capability to the market software harmed the software's performance. As a result, CAISO has delayed implementation of this feature multiple times.

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<sup>32</sup> See SPP's "Pre-MOPC Education Session on Future Markets" at Slide 66 (January 12, 2010).

<sup>33</sup> See SPP's "Pre-MOPC Education Session on Future Markets" at Slide 67 (January 12, 2010).

### **c. Recommendation**

We recommend that the Board defer SPP's proposal to include Combined-Cycle Modeling in the Integrated Marketplace design. We believe that the risk of delays and cost overruns are too great at this time. Development and testing will likely be difficult and expensive, with no guarantee that the modeling capability will not harm the performance of the market software. SPP has enough work to do as its Integrated Marketplace is already an ambitious undertaking. Furthermore, the Combined-Cycle Modeling capability is not essential for the success of the core elements of the Integrated Marketplace.

However, because of the potential benefits of the Combined-Cycle Modeling functionality, we recommend that the Board direct SPP to turn back to the Combined-Cycle Modeling effort once the Integrated Marketplace is successfully operating. That way, SPP can avoid the risks of this functionality causing a delay in market implementation. Also, by that time, SPP may be able to glean further lessons from ERCOT and CAISO.

## **F. Settlements**

### **1. Primer**

RTOs such as SPP serve as brokers to facilitate trades of electricity between willing buyers and sellers. They collect money from those Market Participants that consumed or bought electricity and distribute money to those Market Participants that generated or sold electricity. To do so, RTOs must define a settlement interval or time interval for settlement with Market Participants. For each of these settlement intervals, RTOs must calculate an electricity quantity and an associated price in order to determine the settlement amounts. Currently, all RTOs settle their Day-Ahead Markets on an hourly basis, and all RTOs, except for NYISO, CAISO, and ERCOT settle their real-time markets on an hourly basis. NYISO, CAISO, and ERCOT settle their real-time market on a five-minute basis, ten-minute basis, and fifteen-minute basis, respectively.

### **2. SPP's Current Approach**

SPP currently has only one market, the EIS Market. The EIS Market is *dispatched* every five minutes. This means that every five minutes SPP's dispatch computer calculates prices and sends out instructions to resources letting them know at what level they should operate. While dispatch occurs every five minutes, *settlements* are only done on an hourly basis. To get an hourly LIP, SPP calculates the simple average of the twelve, five-minute interval prices from the EIS Market. To get an hourly electricity value, SPP calculates the difference between *actual* metered data and *scheduled* data. So, for example, if a resource scheduled 100 MWh for Hour 5 of the operating day but actually produced 105 MWh, then that resource would have 5 MWh (105 minus 100) settled in the EIS Market. To calculate the settlement amount, or in this case how much the generator is paid, this 5 MWh would be multiplied by the simple average of the twelve interval prices for Hour 5 of the operating day. If the resource's LIP for Hour 5 was

\$100/MWh, then the resource would be paid \$500 for its electricity. A calculation like this is performed for every settlement location in SPP and for every hour of each day.

### **3. SPP's Proposed Integrated Marketplace Approach**

SPP is proposing two separate settlement processes for its Day-Ahead and Real-Time Balancing Markets. For the Day-Ahead Market, SPP will clear the market for each hour of the following day and communicate both a LMP and MWh amount to each settlement location. SPP will also settle with Market Participants on an hourly basis. Therefore, if a generator is awarded 50 MWh in Hour 6 of the following day and has an LMP of \$100/MWh then that generator is paid \$5,000 for that settlement interval.

For the Real-Time Balancing Market, and similar to today's EIS Market, SPP will clear the market and send dispatch instructions to resources every five minutes. However, instead of settling each hour with Market Participants, SPP proposes to settle every five minutes. The price that will be used for settlement is simply the LMP calculated for that five-minute interval. The amount of electricity settled in the Real-Time Balancing Market will be the difference between a settlement location's actual meter reading and the amount cleared in the Day-Ahead Market.

### **4. Critique of SPP's Proposal**

#### **a. What We Can Support**

We support SPP's proposal to implement a Day-Ahead Market with hourly settlements. All RTOs in the United States settle their Day-Ahead Markets on an hourly basis, and we have heard no major complaints from stakeholders regarding this part of SPP's proposal.

While we do *not* support SPP's five-minute settlements proposal for the Real-Time Balancing Market, we do recognize that there are potential benefits to this proposal and believe it is useful to discuss these briefly here. As explained above, prices for the Real-Time Balancing Market will be calculated every five minutes. Under the five-minute settlements approach, these market prices can be used directly for settlements. However, under the hourly settlements approach, these prices must be averaged or rolled up to hourly prices. The five-minute settlements approach brings with it several benefits as a result of not requiring prices to be averaged or rolled up.

First, the electricity generated and consumed by Market Participants would be more accurately priced for settlements under the five-minute method. For example, say real-time prices were low during the first part of an hour and much higher during the second part of an hour due to an outage. Under the hourly method, the price for that hour would be an average of the twelve, five-minute prices and would fall somewhere between the low prices of the first part of the hour and the high prices of the second part of the hour. This would result in the electricity for the first part of the hour being overpriced and the electricity for the second part of the hour being underpriced. This would not be the case under a five-minute settlements approach because more granular prices (five-minute prices) would be used.

Second, settling on a five-minute basis rather than an hourly basis would result in stronger incentives for Market Participants to follow SPP's dispatch instructions. This relationship can be shown through a simple example. Let's again assume that the prices in the first part of an hour are low and the prices in the second part of an hour are high due to an outage. Say a generator was not dispatched by SPP for the first part of the hour when prices were low but was dispatched for the latter half of the hour when prices increased. Under a five-minute settlements approach, the generator would be paid a price that fully accounts for the outage on the system. However, under an hourly settlements approach, the generator would be paid a lower, average price for its generation. It is even possible that this average price could be lower than the generator's offer price. As a result, this generator will have a weaker incentive to follow SPP's dispatch instructions under the hourly settlements approach.

Third, under the five-minute settlements proposal there would be no make-whole payments stemming from the hourly-averaging of LMPs. As seen in the example above, there are instances when averaging LMPs can cause generators to earn less market revenues than their costs. Therefore, this additional type of make-whole payment is sometimes needed under the hourly settlements method, but is not needed under the five-minute settlements method.

#### **b. What Concerns Us**

While we recognize the purported benefits of five-minute settlements, we do *not* support SPP's five-minute settlements proposal for the Real-Time Balancing Market. We believe the risks of this proposal outweigh the potential benefits.

Specifically, we have concerns with the complexity it introduces. Implementing five-minute settlements would substantially increase the amount of data required for settlements. Specifically, settling on a five-minute basis rather than an hourly basis effectively increases the amount of data required by about a factor of twelve. All of this additional data must be fully vetted, saved on SPP's systems, and sent to Market Participants. This will increase the administrative burden for SPP. Furthermore, five-minute settlements are in no way vital for the success of the Integrated Marketplace proposal. In fact, SPP's proposal is already extremely complex and substantive and will require an immense amount of work to achieve successful implementation. As such, we do not believe this added complexity is warranted, and removing it is one efficient way to simplify SPP's proposal.

Moreover, as already noted, only NYISO settles its real-time market on a five-minute basis. Other RTOs have operated successful markets for years without five-minute settlements.

#### **c. Recommendation**

We recommend that the Board approve the proposal to implement hourly settlements for the Day-Ahead Market. However, we recommend that the Board reject the proposal to implement five-minute settlements for the Real-Time Balancing Market, and instead direct SPP to opt for hourly settlements. Finally, because five-minute settlements creates stronger incentives to follow dispatch than does hourly settlements, we recommend that the Board direct the Market Working Group to look into methods to increase the incentives for participants to

follow dispatch instructions under the hourly settlements approach. These methods could include strengthening or altering the uninstructed resource deviation provisions in the proposed Integrated Marketplace Market Protocols.