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BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF ENTERGY TEXAS, INC.
FOR APPROVAL TO TRANSFER OPERATIONAL CONTROL OF
ITS TRANSMISSION ASSETS TO THE MISO RTO

DIRECT TESTIMONY OF RICHARD DOYING

ON BEHALF OF MISO

JULY 6, 2012

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A. INTRODUCTION

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND BUSINESS ADDRESS.

A. My name is Richard Doying. I am the Vice President of Operations for the Midwest Independent Transmission System Operator, Inc. ("MISO"), a Regional Transmission Organization ("RTO"). My business address is 701 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received my Bachelor of Arts in Geography from the University of California, Los Angeles in 1991 and my Masters of Arts of Public Affairs from the University of Minnesota in 1993. Starting in 1993, I was an Associate with ICF Resources Incorporated, becoming a Senior Associate in 1995. In 1997, I was made a Project Manager for ICF Resources Incorporated. In 1997, I became a manager in the Market Assessment division of PG&E National Energy Group, where I was made Director of the same division in 1999. In 2001, I was named the Director of the Strategy and New Initiatives division of PG&E National Energy Group. In December 2002, I became Director of the Market Analysis and Development department of MISO. In October 2005, I was made Director of the Forward Markets department of MISO and I was promoted to Executive Director of Forward Markets in 2006. In September 2006, I was promoted to Vice President of Market Operations and have occupied my current position as Vice President of Operations since May 2010.

Q. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying on behalf of MISO.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS PROCEEDING.

A. My primary responsibilities at MISO are oversight of operations of both MISO's reliability functions and market administration, and associated supporting activities. Those functions include the Real-Time Market, Day-Ahead Market, Reliability Assessment Commitment, Auction Revenue Rights ("ARR") / Financial Transmission Rights ("FTR") Market, Resource Adequacy, Outage Coordination, Tariff and Scheduling, Market and Tariff Settlements, and Application Information Services. I am also responsible for MISO's market analysis and development of all the MISO markets, from the conceptual design through delivery of market systems for implementation. I am also responsible for oversight of MISO's stakeholder process as it relates to reliability and market issues. I also participated in the development of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Q. HAVE YOU SPONSORED ANY OTHER TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. Yes. I have submitted prepared testimony before the Federal Energy Regulatory Commission ("FERC") involving matters specific to MISO, as well as testimony before the Missouri Public Service Commission and before the Kentucky Public Service Commission. More recently, I submitted prepared testimony before the Arkansas Public

Service Commission in support of Entergy Arkansas, Inc.'s pending request for authority to integrate into MISO and before the Louisiana Public Service Commission in support of the Joint Application of Entergy Louisiana, L.L.C. and Entergy Gulf States Louisiana, L.L.C for approval to integrate into MISO. I also submitted prepared testimony before the Mississippi Public Service Commission in support of the Joint Application of Entergy Mississippi, Inc. and MISO for Transfer of Functional Control.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to support the Application of Entergy Texas, Inc. filed in this docket and to explain why approval of the Application is in the public interest and is the best alternative. My testimony provides an overview of the existing markets administered by MISO, the actual workings of the markets, FTRs, ARRs, management of inadvertent interchange, the guiding principles of MISO with regard to FTR and ARR processes, the existence of hedges for load pocket generation, and the status within MISO of FTR funding.

Additionally, my direct testimony addresses issues concerning MISO's Joint Operating Agreement ("JOA") with the Southwest Power Pool ("SPP"); MISO's current interconnection with SPP; transmission capacity sharing concerns; and other issues pertaining to the potential integration of the Entergy Operating Companies into MISO. Each of these issues is addressed below. I will also describe the historic firm flow rights and firm service entitlements of each party to the JOA as determined using the Congestion Management Process ("CMP"), the technical document that is a part of the JOA. My testimony then describes how MISO, PJM, and SPP honor, and coordinate, their respective historic firm flow rights. Finally, I will describe in greater detail the mechanisms and benefits of market-to-market redispatch as a congestion management tool.

B. OVERVIEW OF PUBLIC INTEREST

Q. IS APPROVAL OF ENTERGY'S APPLICATION IN THE PUBLIC INTEREST?

A. Approval of Entergy's application is in the public interest. As discussed below, and in the testimony of MISO witnesses Wayne Schug and Jennifer Curran, the transfer of operational control to MISO will yield benefits to Entergy's customers in terms of reliability, availability, and cost of service.

In fact, the overwhelming consensus of opinion appears to be that Entergy joining an RTO would itself be a welcomed, positive development ushering in significant, potential benefits.

Q. IS THERE A BETTER ALTERNATIVE THAN TRANSFERRING OPERATIONAL CONTROL OF ENTERGY'S TRANSMISSION ASSETS TO THE MISO RTO?

A. No. Entergy's choice of MISO stands out as the best alternative for both Entergy and Texas ratepayers for a number of reasons, several of which are highlighted in my testimony and in the testimony of other MISO witnesses.

First, MISO has mature, competitive markets in place today, the implementation cost of which will be nearly fully depreciated by the proposed date Entergy would join MISO. In contrast, SPP still looks forward to completing the development, implementation, testing and roll out of a new Day-Ahead Market, centrally-dispatched Real-Time Market, ancillary services markets, and a congestion revenue rights market (collectively SPP's "Integrated Markets"), all of which today already exist and are fully established in MISO. The implementation of these complex markets is an inherently difficult task, involving stakeholder approval of all aspects of market design, development of market rules and procedures, regulatory approvals, market application software development and testing, determination of hardware requirements and configurations, customer training, participant registration, and full market testing. It is essential that all elements of this process are fully and successfully performed. Given the billions of dollars of ratepayer money at stake, there are no shortcuts. The difficulty of successfully navigating such a complex process and of anticipating and overcoming inevitable obstacles, has lead other currently operating RTO markets to experience launch delays and cost overruns. The reality is that no one can predict with certainty the date on which SPP will complete its transition to the fully operational, tested and proven, mature markets that MISO already is experienced in operating. Factoring in the risk of any delay or increased cost is critical, however, because estimated quantified benefits from an alternative "join SPP" option assume SPP will have implemented its planned Day 2 market by March 2014.

In the meantime, MISO continues to improve its already well-functioning markets. For example, in April 2012, MISO implemented a new Look Ahead Commitment tool to be used in conjunction with its Security-Constrained Economic Dispatch (SCED) engine. This new online tool allows for power grid operators to more efficiently plan near-term resource commitments in the Real-Time Market for improved operational efficiencies and reduced wholesale power costs. The tool could save the existing MISO region (11 states and Manitoba, Canada) upwards of $2 million per year and that is a conservative estimate. Using this new Look Ahead Commitment tool, MISO will be able to better identify upcoming changes and more efficiently commit resources to meet those needs. The Commission's support of ERCOT's "Look Ahead" SCED development echoes the importance of this added capability.

Second, MISO's larger scale creates greater efficiencies and delivers greater cost savings because expenses are more widely spread across a larger number of members. The impact of the scale of MISO's operations and membership on cost savings is addressed in greater detail in the testimony of Wayne Schug.

Third, MISO's commitment to the engagement of an Independent Market Monitor ("IMM") is a key consideration distinguishing membership in MISO from membership in SPP. SPP's internal market monitoring unit ("MMU"), for administrative purposes, reports to SPP's Chief Compliance Officer, and otherwise reports to the Oversight Committee of the SPP Board of Directors. MISO's IMM is Potomac Economics, the same entity that functions as ERCOT's IMM. Potomac Economics reports directly to the MISO Board of Directors.

The SPP MMU has observed that the lack of concentration in the current SPP footprint makes it unlikely that a market participant today could be successful in exercising market power by withholding capacity. Potomac Economics, however, is experienced in the investigation of market power abuse concerns, including price impacts from suspected unit withholding in ERCOT. Moreover, physical withholding of capacity is far from the only type of potential market manipulation that must be monitored and mitigated. As described more fully below, MISO's IMM continuously monitors the operation of the Real-Time Market and immediately mitigates any attempt to engage in market manipulation. SPP may be satisfied with an internal market monitoring organization given the composition of its markets today, but the Commission may decide that the advantages of an external monitor are overwhelmingly obvious. An external monitor, with its extensive experience in oversight of the industry's established and functioning energy markets such as the MISO and ERCOT markets and its reputation in the industry-at-large necessarily at stake, in my opinion, may be more committed to objective and critical reporting than an internal group of employees.

While SPP's use of its internal organization may currently be less expensive from an administrative cost perspective, this is not an area in which corners can be cut. MISO is committed to the greater benefits offered by engagement of an IMM. MISO's historic reliance on an external monitor offers a clear advantage to state regulators and consumers alike.

MISO's decision to use an IMM also is markedly more consistent with the Texas Legislature's preference as expressed in PURA § 39.1515, which requires that an independent organization's wholesale market monitoring activities be performed by an Independent Market Monitor. PURA Section 39.152, likewise, "authorized the Commission to select an independent market monitor to detect and prevent market manipulation strategies, market rule violations, and market power abuses in the ERCOT wholesale electric market."

C. OVERVIEW OF EXISTING MISO MARKETS

Q. PLEASE PROVIDE AN OVERVIEW OF THE EXISTING MARKETS ADMINISTERED BY MISO.

A. MISO currently administers the following markets: Day-Ahead Energy and Operating Reserve Market, Real-Time Energy and Operating Reserve Market, Annual and Monthly FTR Auctions, and a Month-Ahead Voluntary Capacity Auction.

The Day-Ahead Energy and Operating Reserve Market ("Day-Ahead Market") is a forward market in which energy and operating reserves are procured prior to the operating day, *i.e.*, the day the energy is going to be used. For market participants, the Day-Ahead Market provides the opportunity to preschedule generation output and load and gain price certainty for generation and load cleared in the Day-Ahead Market. The Day-Ahead Market also aids MISO in ensuring that sufficient resources are online and available to meet the anticipated demand in the Real-Time Energy and Operating Reserve Market ("Real-Time Market"). Hourly prices are calculated on a simultaneously co-optimized basis for each hour of the next operating day based on offers by market participants and bids for energy and offers for the sale of operating reserves. Market participants purchase and sell energy and operating reserves in the Day-Ahead Market at financially binding day-ahead prices. These prices are based on cleared bids and offers and reflect transmission operating limits. Prices may vary by location and are referred to as Locational Marginal Prices ("LMP") for energy, and Market Clearing Prices ("MCP") for operating reserves. Two of the market processes that will run in the Day-Ahead Market to commit and dispatch resources are Security Constrained Unit Commitment and Security Constrained Economic Dispatch, which are defined below.

The Day-Ahead Market's unit commitment is a process of committing resources to be on-line for the following day. It utilizes a simultaneously co-optimized Security-Constrained Unit Commitment ("SCUC") algorithm to commit sufficient reserves to meet the fixed demand bids, cleared price sensitive demand bids, scheduled exports, cleared virtual demand bids, forecasted zonal market-wide regulating reserve requirements and forecasted zonal and market-wide contingency reserve requirements on an hourly basis. The objective of the SCUC is to minimize costs over the entire commitment period while simultaneously enforcing physical constraints and reliability requirements.

The Day-Ahead Market's economic dispatch utilizes a simultaneously co-optimized security-constrained economic dispatch ("SCED") algorithm to dispatch resources to meet demand bids, scheduled imports, cleared virtual demand bids, forecasted zonal and market-wide contingency reserve requirements on an hourly basis. The objective of SCED is to minimize total hourly costs while simultaneously enforcing all physical constraints and reliability requirements. The SCED process produces Day-Ahead Market LMPs and MCPs. Any generation offers or demand bids submitted in the Day-Ahead Market are financially binding.

Q. WHAT IS THE REAL-TIME MARKET AND HOW DOES IT WORK?

A. The Real-Time Market is a continuous process for least cost balancing of supply and demand while recognizing current operating conditions. Total costs to be minimized in this process include energy costs and reserve availability costs. MISO uses a network model to accurately dispatch resources to match the short-term demand forecast and operating reserve minimum requirements, and to manage congestion. The process uses SCED to balance injections and withdrawals, manage congestion, and set Real-Time Market LMPs and MCPs. The SCED program runs every five minutes during the operating hour to establish the dispatch instructions for generators to meet load for the next five-minute period.

Market participant activities in the Real-Time Market include submitting offers and physical schedules for use in the Real-Time Market clearing processes. In the Real-Time Market, resource offers can be submitted that differ from the Day-Ahead Market resource offers. Market participants can also submit physical schedules. Demand bids, financial schedules, and virtual transactions do not participate in the Real-Time Market. The SCED program produces resource dispatch targets, and Real-Time Market LMPs and MCPs. The Real-Time Market utilizes the same network model that is used in the Day-Ahead Market, adjusted to reflect actual real-time network configuration and all constraints determined from most recent State Estimator results.

Q. WHAT ARE THE BENEFITS IN TERMS OF RELIABILITY, AVAILABILITY AND COST OF SERVICE ASSOCIATED WITH MISO'S MARKETS TO ENTERGY'S MEMBERS AND CUSTOMERS?

A. MISO's markets provide a wide range of benefits to MISO members and market participants. Many of these benefits have been quantified as part of an ongoing analysis performed through a cooperative effort between MISO and stakeholders. Quantifiable benefits include improved reliability and transmission system availability through MISO's broader regional view, state of the art tools to evaluate and respond to potential threats to system reliability, and enhanced training systems and processes that exceed NERC requirements. In addition to increased reliability, MISO's market reduce customer cost through increased generation and transmission availability, reduced energy and operating reserves costs, and reduced required planning reserves. MISO has identified approximately $500 million in benefits if all the Entergy Operating Companies join MISO, with 80% of that increase going to the Entergy region. In addition, MISO has identified net annual benefits for the existing MISO footprint of between $2.1. and $2.7 billion based on the existing MISO Value Proposition.

Even entities outside, but adjacent to the MISO markets, enjoy benefits. First, the market can be readily accessed by those wishing to purchase from or sell into the market. Second, the market provides transparent price signals to enable better decision making about how and when to take advantage of the market. Third, the overall lower energy cost within the MISO market region lowers the cost of purchased power by external market participants. Although these benefits exist to external entities, to capture the full benefits of MISO requires being fully within the market. Several companies to the west (i.e., Iowa) and south (i.e., Kentucky) of MISO have recently evaluated those benefits and elected to join MISO.

Finally, MISO continually seeks to enhance its market services and the value of those services in the region. MISO's market participants include traditional, integrated utilities; municipalities; cooperative and other public entities; alternative retail suppliers; independent power producers; energy marketers and others. The competitive energy markets operated by MISO ensure that those entities serving load can cost-effectively procure wholesale power and pass on resulting savings to their customers. Accordingly, MISO's energy markets will help enhance the value of Texas retail electric energy services.

D. INDEPENDENT MARKET MONITOR

Q. CAN THIS COMMISSION BE ASSURED THAT MISO'S MARKETS ARE AND WILL REMAIN COMPETITIVE? WHAT IS THE ROLE OF THE INDEPENDENT MARKET MONITOR?

A. MISO's energy markets include safeguards to ensure that it remains competitive under all conditions. As discussed above, MISO has an independent market monitor ("IMM") that monitors, reports and mitigates potential or actual attempts to exercise market power or any inappropriate manipulation, gaming or abuse of MISO's markets. The IMM has the authority to limit the maximum allowable offers to ensure market prices reflect competitive market outcomes. The market monitoring and mitigation measures employed by MISO's IMM include constant monitoring and immediate mitigation, when warranted, thereby removing the ability to exercise market power and assuring that the market remains competitive.

Further, MISO's tariff requires that the IMM not only monitor and mitigate, but also report to FERC instances of potential market power abuse. FERC may refer such conduct to its enforcement staff for further investigation and punitive action based either on the IMM's reports or upon complaints received from market participants. In addition, the IMM and MISO's analysts, in concert with stakeholder efforts, continually evaluate MISO's various markets to identify opportunities to enhance performance or increase the efficiency of those markets. MISO makes FERC filings when such enhancement opportunities are identified during these ongoing evaluations.

E. ARRs AND FTRs

Q. DOES THE MISO SYSTEM OF AUCTION REVENUE RIGHTS ALLOCATION AND VALUATION PROCESS PROVIDE THE BEST PROTECTION FOR USERS OF THE ENTERGY TRANSMISSION SYSTEM TO MINIMIZE ANY ADVERSE FINANCIAL IMPACTS OF TRANSMISSION CONGESTION IN A DAY 2 MARKET?

A. Yes. That protection is provided through the use of financial transmission rights ("FTRs") and auction revenue rights ("ARRs").

Q. WHAT ARE ARRs AND FTRs AND HOW DOES MISO ADMINISTER THE FTR MARKET?

A. MISO's market for financial transmission rights includes ARRs, allocated to MISO's market participants based on firm historical usage of the transmission network, and FTRs, which can be bought and sold in annual and monthly FTR auctions. ARRs are financial instruments that entitle their holders to a share of the revenue generated in the annual FTR auction. Because ARRs entitle their holders to a share of the revenue generated in the annual FTR auction, ARRs can be used to offset or "hedge" the cost of obtaining FTRs in the annual FTR auction. It is also possible to directly convert ARRs into FTRs through self-scheduling in the annual FTR auction. FTRs are financial instruments whose values are determined by the transmission congestion charges that arise in the Day-Ahead Market, leading to differences in the Marginal Congestion Components ("MCCs") of Day-Ahead LMPs at different locations. Both ARRs and FTRs are defined as between specified locations, for a specified MW quantity, in a specified direction and for a specified period of time. FTRs may be used to provide a financial hedge to manage the risk of congestion cost in the Day-Ahead Market. For example, a market participant who holds FTRs can offset congestion charges for scheduled injections (*e.g.*, generation, bilateral purchases, etc.) at one location, and withdrawals (*e.g.*, load, bilateral sales) at a different location in the Day-Ahead Market.

The ARR annual allocation and FTR auction process occurs in the first several months of each year. To the extent that an incoming Transmission Owner integrates prior to the established timelines for participation in the next annual ARR allocation, MISO will conduct a partial year FTR allocation that will provide the Load Serving Entities within the new Transmission Owner system with congestion hedges for the remainder of the year leading up to the next full year allocation period. As for all Load Serving Entities, FTRs allocated during this partial year process will be based on paths representing their historical transmission usage.

For example, if a Transmission Owner integrates in September, the partial year FTR allocation would include three seasons (Fall, Winter and Spring) for both peak and off-peak periods. Consistent with the ARR allocation process, the partial year allocation of FTRs to market participants will be capped at their annual peak network load and the volume of Transmission Service Requests ("TSRs") for point-to-point transmission service. Any allocated partial year FTRs are financially binding for their entire term. The partial year FTR allocation process is contained in Module C of the MISO Tariff.

Q. HOW DO FTR AUCTIONS WORK, AND WHEN DO THEY OCCUR?

A. MISO conducts FTR auctions on an annual and monthly basis. These auctions are held to facilitate the buying and selling of FTRs. MISO conducts *annual* FTR auctions to allow the conversion of ARRs received in the annual allocation process to FTRs, and to facilitate the buying, selling and reconfiguration of existing FTRs between market participants. The annual FTR auction is conducted immediately following the annual ARR allocation and consists of eight independent auctions for the peak and the off-peak periods for the four seasons.

MISO conducts *monthly* FTR auctions to facilitate the buying and selling of FTRs. The monthly FTR auction consists of two independent auctions: one for the peak period and one for the off-peak period. All FTRs sold in monthly FTR auctions have a term of one month beginning on the first day of the month following the FTR auction and are associated with either the peak or the off-peak period. Auction results are made available before the start of the subject month.

Q. WHAT IS THE STATUS OF FUNDING FTRs AND ARRs?

A. FTR funding for the current allocation / auction period, has been slightly above target levels, meaning that there will be FTR revenue remaining at the end of the annual allocation / auction period to be distributed to all MISO FTR holders. In prior years, FTR funding had been below target levels. Based on in-depth analysis, including analysis by outside experts, MISO has made changes to the FTR auction process to increase FTR funding.

Long-term transmission rights ("LTTRs"), more fully discussed below, are guaranteed full funding. Several processes and tariff settlement provisions ensure this outcome. First, a simultaneous feasibility test is performed to ensure that the transmission system can support the subscribed set of allocated ARRs during normal system conditions, including defined transmission contingencies and outages. Second, any costs associated with LTTRs that are found to be infeasible in the simultaneous feasibility test are funded by all LTTR holders. Amounts remaining from the Annual FTR Auction after all Stage 1A ARRs have been funded are distributed to ARR holders *pro rata* based on the difference between the nomination cap and the total MWs of ARRs owned (including infeasible ARRs). Finally, to the extent that FTRs are less than fully funded through congestion revenues in any settlement period, shortfalls are allocated to FTR holders in proportion to their FTR target revenues (*i.e.*, the total value of FTRs held by each market participant) for that period.

Q. WHAT IS THE BASIS FOR THE ALLOCATION OF ARRs TO PARTICULAR MARKET PARTICIPANTS?

A. ARRs are allocated to market participants based on historical firm transmission service usage. Such transmission service is "firm" in the sense that it is given greater priority and protection from curtailment (*i.e.*, reduction or interruption) that may be necessary due to emergency or other reliability-related conditions. Firm historical transmission service is the basis for entitlements to ARRs ("ARR Entitlements"). ARR Entitlements can be nominated for the allocation of ARRs during the annual allocation process described above. ARRs can also be allocated to market participants based on the additional transmission capability created by network upgrades that they directly fund.

The MISO Tariff includes a special category of ARRs, Long-Term Transmission Rights ("LTTR"), to allow load serving entities to obtain long term hedges. LTTRs are provided in the form of ARRs granted, based on nominated ARR Entitlements, during the first of three ARR allocation stages (called "Stage 1A"), giving load serving entities an opportunity to acquire congestion hedges for eligible LTTR MW amounts for at least 10 years. LTTR eligibility is based on the qualification of LTTR generation resources (called "Reserved Source Points" or "RSPs," with a capacity factor of at least 50 percent, and in which the market participant has an ownership or contractual right of at least 5 years) for inclusion in a set of eligible base load resources (called the "Baseload Reserved Source Set" or "BRSS"). ARRs that do not qualify as LTTRs can be nominated and allocated in a second step (called "Stage 1B") of the annual allocation process.

Q. PLEASE DISCUSS HOW MISO ALLOCATES ARRs.

A. The eligibility to request ARRs is determined during the ARR registration process. This process identifies historical firm transmission service that is eligible to receive an allocation of ARRs. The process results in a defined set of ARR Entitlements. Market participants are able to select, within limits, the entitlements for which they are found eligible, and that they wish to convert into ARRs.

The ARR allocation process includes a simultaneous feasibility test, which is a mechanism to protect the full funding of ARRs. The process of requesting ARRs in the allocation is called "nomination." The amount nominated for a particular ARR Entitlement becomes a candidate ARR. Candidate ARRs are ARR Entitlement nominations submitted by market participants to be considered throughout the annual ARR allocation process.

The simultaneous feasibility analysis is performed for two stages of the ARR allocation process: Stage 1A and Stage 1B. The ARR allocation process also includes a final stage ("Stage 2"), which consists of an allocation to market participants of residual FTR auction revenue based on the market participants' unallocated, eligible megawatts. Stage 1A, as described above, is for the allocation of LTTR based ARR Entitlements associated with base load resources or point-to-point services with a historical scheduling factor greater than or equal to fifty percent (50%), relative to a reference period.

In Stage 1A, market participants can nominate up to: fifty percent (50%) of their total point-to-point entitlement in megawatts (from eligible entitlements) and; fifty percent (50%) of their forecasted network integration transmission service peak load (from entitlements sourcing from base load resources). Rules for Stage 1A serve to maximize the feasibility of requested LTTRs and are founded on the current set of long-term rights.

In Stage 1B, market participants are eligible to nominate candidate ARRs up to one hundred percent (100%) of the sum of their forecasted network integration transmission service peak load, less ARRs allocated in Stage 1A for network integration transmission service.

Q. DOES MISO'S TARIFF ENSURE A SUFFICIENT ALLOCATION OF FTRS/ARRS FOR EACH MARKET PARTICIPANT?

A. MISO's FTR/ARR process is designed to provide each eligible load serving entity with an opportunity to obtain FTRs or ARRs to meet its reasonable needs in fulfilling its obligation to serve its loads, subject to the requirements of simultaneous feasibility, and the availability of congestion and auction revenues.

The ARR registration process described above enables all market participants to identify firm transmission service that qualifies as ARR Entitlements that will be the basis for their ARR nominations. The ARR allocation process allows eligible market participants to acquire LTTRs in Stage 1A, as supplemented by a restoration process that uses counterflows to minimize the curtailment of nominated LTTRs that would otherwise be infeasible without counterflows. Other ARRs (*i.e.*, those that are not LTTRs) can also be obtained in Stage 1B; and residual auction revenues are distributed in Stage 2 to mitigate the effects of ARR nominations that were not granted. FTRs can be acquired by converting ARRs to FTRs through self-scheduling of ARRs in the annual FTR auction, by purchasing them in FTR Auctions, or through the secondary market. Market participants of new Transmission Owners joining MISO in the midst of an ARR allocation cycle can also acquire FTRs through a partial-year allocation as described above. ARRs can also be allocated to market participants that directly fund network upgrades.

For purposes of LTTRs, MISO's Tariff identifies the level of reasonable need with base load usage, which is defined as one-half of peak usage or of point-to-point transmission service. Priority is given to entities serving native load, although ARRs can also be made available to entities that agree to pay a share of the transmission system's embedded costs on a long-term basis to support external load.

Q. WHAT ARE THE REMEDIES FOR ANY INSUFFICIENT ALLOCATION OF FTRS/ARRS FOR EACH MARKET PARTICIPANT?

A. Within the framework of the ARR allocation process, any insufficient allocation of LTTRs in Stage 1A can be remedied through the restoration process (*i.e.*, using counterflows to increase the number of feasible LTTRs); or through participation in Stage 1B. The non-granting of ARR nominations in Stage 1A or Stage 1B can also be mitigated through the distribution of residual auction revenues in Stage 2. Beyond the allocation process, a Market Participant may also invoke dispute resolution procedures under the MISO Tariff to contest particular ARR allocations.

Tariff revisions may also be sought to improve the ARR allocation process, or to accommodate reasonable needs associated with the integration of new Transmission Owners. For example, MISO filed Tariff revisions, which FERC accepted, to adjust the configuration of ARR Zones in a manner that recognized certain features of Dairyland Power Cooperative ("Dairyland") when it integrated with MISO (*i.e.*, some of Dairyland's resources and load were already part of ARR Zones of other existing Transmission Owners before Dairyland's integration). MISO already has initiated stakeholder processes to address any unique circumstances in connection with Entergy's integration into MISO, including the needs of Qualified Facilities.

F. RESOURCE ADEQUACY

Q. PLEASE EXPLAIN MISO'S APPROACH TO RESOURCE ADEQUACY AND DESCRIBE THE VOLUNTARY CAPACITY MARKET?

A. MISO utilizes a long term resource adequacy mechanism that allows a Load Serving Entity ("LSE") to use its own resources or procure capacity bilaterally in order to meet its Planning Reserve Margin Requirement. This is an approach that has been successfully used in NERC regions and load sharing groups for decades. MISO performs both a yearly study to determine the Planning Reserve Margin Requirement for each LSE for the upcoming year and a study for years 2-10 to help gauge future reserve requirements. This MISO Resource Adequacy Review ("RAR") mechanism was developed through close collaboration with the Organization of MISO States ("OMS") and our other stakeholders.

As for current resource adequacy requirements, MISO's mechanism was designed to build upon and complement established state regulatory processes. MISO has and continues to rely on established state processes for resource planning, load forecasting, demand response, and energy efficiency investment decisions. Module E of the MISO Tariff outlines this mechanism and requires LSEs to have adequate resources to meet their forecasted load, plus a planning reserve margin. If an LSE fails to meet its Planning Reserve Margin Requirement it will be assessed an administrative deficiency charge equal to the "cost of new entry" ("CONE"), which takes various physical factors into account and is calculated annually with the Independent Market Monitor.

All load serving entities are required to submit annual resource plans to demonstrate their ability to satisfy the MISO resource adequacy planning reserve margin requirement. Load serving entities are also required to submit month-ahead plans, demonstrating compliance with the reserve adequacy requirement for the upcoming month. Load serving entities that wish, may elect to offer to sell or bid to buy resources through a voluntary capacity auction. The Voluntary Capacity Market is a month-ahead auction that allows resource owners to offer to sell capacity and for load serving entities to acquire any incremental capacity needed to meet the month-ahead resource adequacy requirement. Participation by both loads and suppliers is voluntary.

MISO has recently filed to enhance certain elements of the resource adequacy provisions contained in Module E of MISO's FERC tariff to better meet the needs of load-serving entities and to comply with various FERC requirements associated with the provisions of Module E. The two primary enhancements include: 1) evaluation of inter-regional transmission constraints to ensure deliverability within MISO of planning resources; and 2) changing the resource adequacy compliance period from monthly to annually to better align with the annual reserve margin planning period. The current capacity auction will continue to be available on a voluntary basis for the sale and purchase of incremental capacity for the upcoming annual planning period.

Q. HAS FERC ACTED ON MISO'S RESOURCE ADEQUACY FILING?

A. Yes. FERC accepted MISO's resource adequacy proposal subject to a compliance filing, which is due July 12, 2012. *See* Order on Resource Adequacy 139 FERC ¶ 61,199 (June 11, 2012) ("MISO's resource adequacy proposal is hereby accepted, effective October 1, 2012, subject to a compliance filing, as discussed in the body of this order."). The order accepted the enhancements described above that align the MISO planning period to the resource adequacy evaluation period (i.e., moving from a monthly to an annual process) and evaluating transmission constraints that may limit the deliverability of resources within the MISO region.

Q. CAN AN ACCURATE COMPARISON BE MADE BETWEEN "CAPACITY-MARKET COSTS" BETWEEN MISO AND SPP?

A. Any comparison of "capacity-market costs" is not possible because, among other reasons, SPP's Integrated Markets tariff filing does not address resource adequacy and does not include a capacity market. Moreover, SPP's markets have not yet launched and how any later proposed resource adequacy mechanism and associated markets might evolve is uncertain. MISO's market design, for example, adhered to an "energy only" principle at introduction, and its current resource adequacy approach is decidedly different than the centrally procured "capacity market" approach taken in some other RTO markets. The distinction is borne out by SPP's recent Integrated Markets presentation at the PUCT's Open Meeting on May 18, 2012. On a slide comparing approaches by RTOs, SPP identified PJM as operating a capacity market and ERCOT as including Reliability Must

Run, but neither MISO nor SPP was identified as adopting a capacity market as the key component of the approach used to ensure resource adequacy. Moreover, it is important to note, that participation in MISO's capacity auction is voluntary. Entergy, or any other market participant, may choose to supply its own resource, whether owned or bilaterally contracted to fulfill MISO's resource adequacy requirements. There is no financial exposure to capacity market clearing prices to the extent an entity choses to self- supply.

G. CURRENT INTERCONNECTION BETWEEN MISO AND ENTERGY

Q. WHAT IS THE CURRENT TRANSMISSION SYSTEM INTERCONNECTION BETWEEN MISO AND ENTERGY?

A. Entergy's transmission system has a high-voltage interconnection with MISO's Transmission System via Entergy Arkansas, Inc.'s ("EAI") transmission facilities. The physical interconnection is located in New Madrid, Missouri where Ameren, Associated Electric Cooperative, Inc. and EAI share the capacity of five 345 KV transformers. The direct contiguous tie capability between EAI and Ameren is approximately 1,000 MW of the 1,500 MW total capability of the interconnection. Ameren is a transmission-owning member of MISO. Entergy has announced that the contractual arrangement supporting this interconnection has been extended for an additional twenty (20) years.

Q. WILL THE SHARING OF TRANSMISSION CAPACITY CREATE RELIABILITY RISKS TO THE ELECTRIC SYSTEM?

A. No. As explained below, the JOA provides the processes and mechanisms for the safe, reliable operation of the electric system between MISO and SPP. Today, these processes and mechanisms are in place and operating on a daily basis. Those processes and mechanism have been enhanced at the seam between MISO and PJM by adding market-to-market redispatch to ensure transmission congestion is managed both reliably and at least cost. Market-to-market congestion management between MISO and PJM has operated successfully since 2005. Currently MISO and SPP perform market-to-non-market coordination. Both market-to-market and market-to-non-market processes will operate to ensure the reliable and efficient operations continue with Entergy's integration into MISO.

H. JOINT OPERATING AGREEMENT (JOA)

Q. IS SHARING OF TRANSMISSION CAPACITY UNIQUE TO THE JOA BETWEEN MISO AND SPP?

A. No. MISO has similar agreements with its neighboring systems. For instance, MISO has a nearly identical JOA with PJM. The transmission capacity sharing arrangement with PJM allows MISO's load-serving entities located in Michigan to transact business with the rest of MISO over a transmission grid that is largely owned by PJM members. Likewise, PJM's load-serving entities located in Chicago are able to transact business with the rest of PJM in excess of PJM's actual physical transmission capabilities due to this sharing arrangement. Moreover, transmission capacity sharing occurs daily under the existing JOA between MISO and SPP. One of the JOA's key features is that it provides reliable management of congestion along the current market-to-non-market seam between MISO and SPP.

Q. SPP AND OTHERS HAVE CONTENDED IN PUBLIC FILINGS THAT CAPACITY SHARING IS A CONFISCATION OF TRANSMISSION CAPACITY WITHOUT COMPENSATION. WHAT IS MISO'S POSITION?

A. Coordinated use and management of jointly impacted facilities is not a confiscation of transmission service. Loop flows or unscheduled interchange are a reality of integrated bulk power facilities. They occur because electricity flows are governed by the laws of physics and are the results of interregional transfers as well as traditional service of network or "native" load. Most unscheduled flows occur over uncongested elements of the transmission network and, as such, create no incremental costs on the network. In fact, disallowing these economic transfers, as some have proposed, would actually increase the costs of service loads in the combined regions.

It is true that unscheduled flows can contribute to congestion that may occur along a seam between neighboring regions, so operating agreements like the JOA between MISO and SPP were created to provide reliable coordinated operation for congestion management on jointly impacted facilities as well as appropriate compensation for the cost of redispatch to manage transmission constraints at the seam. Coordinated operations under the JOA make available reliability and efficiency benefits that accrue to members of both RTOs. Thus, capacity sharing cannot rationally or reasonably be described as confiscation of service.

I have read and agree with Entergy witness Michael Schnitzer who indicates that compensation due to flows across SPP's system will only be due to SPP under the JOA when transmission congestion necessitates generation re-dispatch and if MISO market flows would exceed MISO's share of the JOA flow gates as determined in advance through the CMP process.

Q. WILL THE APPLICATION OF THIS TRANSMISSION CAPACITY SHARING ALLOW MISO/ENTERGY TO "USE" CAPACITY ON THE SPP SYSTEM THAT IS CURRENTLY AVAILABLE TO OTHER SPP MEMBERS?

A. No. Transmission capacity sharing occurs today between Entergy, MISO, SPP and neighboring utilities, such as TVA. It is due to the interconnected nature of the network transmission system. Flows from SPP member generation to SPP member load "use" MISO, Entergy and TVA transmission facilities. Likewise flows from generation to load within MISO "use" transmission on the Entergy, SPP and TVA systems. Absent a JOA, transmission capacity sharing is not monitored and "use" of one system's transmission capacity by another entity is managed through an inefficient Transmission Loading Relief process that physically rations limited transmission capacity without compensation for the cost to mitigate the congestion.

The capacity sharing provisions of the MISO-SPP JOA provide for more effective monitoring of transmission flows, from whatever source, and more efficient management of congested transmission facilities at the seam between MISO and SPP. The sharing provision allows both RTOs to pursue available economic transfers without imposing artificial constraints on dispatch. When congestion management is required on a jointly-impacted facility, the JOA defines the firm use rights of both RTOs on the facility and apportions the management of non-firm flows among the RTOs. The capacity sharing provision of the JOA does not alter the firm rights to use the facility. As a result, it would not be accurate to describe the capacity sharing provision as allowing the use of capacity that rightfully belongs to another party.

Q. IS IT TRUE THAT ENTERGY'S INTEGRATION INTO MISO MAY INCREASE THE AMOUNT OF UNSCHEDULED INTERCHANGE OR "LOOP FLOW" OVER THE SPP SYSTEM?

A. No study has been presented in this docket that demonstrates an increase in loop flows as a result of Entergy's integration to MISO. In fact, changes in transmission flows are far more likely to occur within the Entergy footprint than they are to occur between Entergy and the existing MISO footprint. Internal Entergy region flows are likely to change more significantly as all of the assets in the area are considered in a single, centralized commitment and dispatch pool. In any event, as discussed above, any change in unscheduled interchange on either the MISO or SPP systems as a result of Entergy's integration into MISO would be effectively and efficiently managed pursuant to the provisions contained in the MISO-SPP JOA.

Q. SPP HAS PUBLICLY CLAIMED THAT ENTERGY'S INTEGRATION INTO MISO MAY REQUIRE TRANSMISSION UPGRADES TO ACCOMMODATE INCREASED POWER FLOWS ACROSS THE SYSTEM. IS THIS TRUE, AND DOES IT HAVE AN IMPACT ON TEXAS RATEPAYERS?

A. No. Currently, Entergy system load is met through dispatch of generation within and nearby (imports into) the Entergy region. Transmission constraints require that the dynamic balancing of supply and demand is done within the operating limits of the transmission system. The same transmission system will exist in Entergy the day before and the day of the integration of the Entergy system into the MISO market. What will change is the population of units available to serve load within Entergy's system and the optimization of the commitment and dispatch of those units to meet the expanded MISO-wide demand while honoring the operating limits of the transmission system. Delivered energy cost will decline under MISO market commitment and dispatch, but the existing transmission system within Entergy is adequate for the benefits of market participation to be realized.

Importantly, MISO planning processes will study actual and forecasted flows and consider upgrades that may be needed for reliability or that are beneficial in terms of increasing economic efficiency. Although new transmission will not be needed to integrate Entergy in the MISO market, the market will identify opportunities to further reduce cost to end users by adding transmission to increase the ability to move power from low cost generation to load. These planning processes already include cross-border collaboration with SPP in its planning processes. Compliance with FERC Order 1000, as discussed in the testimony of Ms. Curran, will lead to enhanced transmission coordination across existing planning regions, including the seam between MISO and SPP. MISO looks forward to increasing planning collaboration with all of its neighbors, including SPP.

Q. FERC's ORDER INTERPRETING THE JOA IN MISO'S FAVOR NOTED THAT THE PROVISIONS OF THE JOA PROVIDE AN OPPORTUNITY FOR SPP AND MISO TO RENEGOTIATE, WHEN AND IF NECESSARY. IS MISO WILLING TO RENEGOTIATE THE JOA AND, IF SO, WHAT STEPS HAVE BEEN TAKEN IN THIS PROCESS?

A. Yes, MISO is agreeable to negotiating improvements to the JOA. The current JOA provides benefits to both RTOs through the coordinated operation of the jointly-impacted facilities per the procedures under the JOA that are in place and operating effectively today. Those processes and procedures can and should be continually evaluated and enhanced when opportunities to do so are identified. The FERC order interpreting the JOA recognizes the practical need for MISO and SPP to continue to work together on potential revisions to the JOA that would improve the economic efficiency of the operations across those regions. MISO agrees that the continued operation of the JOA is important and necessary to ensure operational efficiency that ultimately leads to increased customer benefits.

MISO will continue to work with SPP to study and review the JOA in order to address any provisions that could be improved. In fact, shortly after the FERC's order was issued, MISO reached out to SPP to initiate such discussions to determine what operational issues SPP felt needed to be addressed. MISO has always maintained that it is in both (and all) parties' best interests to continue to improve operational efficiencies, which ultimately increase customer benefits.

As a result of the testimony provided in the earlier Arkansas Public Services Corporation proceeding, MISO has coordinated meetings with SPP, its members and Entergy to discuss the issues raised by SPP and a subset of its members regarding the operation of the JOA. Meetings have been held on September 28, 2011, November 4, 2011, December 2, 2011, April 20, 2012, and May 22, 2012.

Q. ARE THERE EVENTS THAT MIGHT CAUSE BOTH PARTIES TO NEGOTIATE CHANGES TO THE JOA?

A. Yes. One such event would be the rollout of SPP's Day-2 market. Once SPP implements its Day-2 market, it would be beneficial to enable market-to-market coordination instead of the market-to-non-market coordination operating now. This would significantly increase dispatch efficiency at the seam between MISO and SPP and address concerns regarding fair compensation for the actual costs of managing congestion associated with inter-regional energy flows. MISO's JOA with PJM contained market-to-non-market congestion management procedures prior to MISO's Day 2 Market implementation in 2005 to address operations between the PJM market and MISO prior to the implementation of its Day 2 Market. Upon the implementation of MISO's Day 2 Market, MISO and PJM adopted market-to-market congestion management and settlement processes that have been implemented to effect redispatch at the seam between MISO and PJM. MISO anticipates market-to-market congestion management procedures similar to those approved by FERC in the JOA between MISO and PJM will be beneficial to incorporate in the JOA between MISO and SPP.

As noted earlier, another such item might be to improve current collaborative transmission processes. MISO is openly and actively working on both fronts, especially considering the recent issuance of FERC Order 1000.

Q. WHAT ARE THE EFFECTS OF THE RECENT FERC ORDER REGARDING THE JOA BETWEEN SPP AND MISO?

A. FERC's order confirms that the transmission capacity sharing, as currently implemented under the JOA, will continue to apply if EAI/all Entergy operating companies join MISO. This order confirms that the assumption contained in Entergy's Evaluation Report of May 12, 2011 was conservative. The CRA study results, augmented by Entergy's May 2012 report, reflected an assumption that only 1,000 MW of physical transfer capability would be available between the current MISO region and the current region created by the integration of Entergy into MISO. The CRA study also noted that the identified benefits would be greater if energy transfers were not limited to 1,000MW. FERC's ruling confirms that the extent of benefits quantified in the CRA study understates the benefits that will likely be realized by the Entergy region upon integration into MISO.

Q. SPP HAS PUBLICLY RAISED CONCERNS REGARDING THE INTEGRATION OF ENTERGY INTO MISO, AND THE POTENTIAL FLOW IMPACTS ON ITS SYSTEM. DO YOU AGREE THIS IS A VALID CONSIDERATION?

A. No. As noted above, current market-to-non-market processes address current flow impacts between MISO and SPP and will address any potential flow impacts upon Entergy's integration in MISO. And the expected future implementation of market-to-market coordination will enhance the management of any potential flow impacts. All of the contiguous RTOs and other entities who share seams with their neighbors regularly assess and review the impacts they have upon one another's systems and operations. This type of coordinated effort is essential for the smooth daily operation of a reliable interconnected grid. As discussed above, flow impacts noted by SPP are part of daily reality and, as such, the flow issue has been and continues to be worthy of focus. In fact, MISO and SPP have worked collaboratively across industry groups, including the Market Flow Task Force under the Congestion Management Process Council ("CMPC") to focus on seams management process and methods to review and enhance seams coordination processes.

Q. SPP HAS ALSO MADE SEVERAL PUBLIC STATEMENTS REGARDING MISO'S CALCULATIONS OF MARKET FLOWS. DOES MISO AGREE WITH SPP'S COMMENTS?

A. MISO has been, and is, working with SPP and PJM on this issue since the end of 2009, by participating in the Market Flow Task Force formed under Congestion Management Process Council to address SPP's concerns. SPP's representations about energy flows due to "large highly fluctuating amounts of wind in MISO . . ." have not been supported by the analysis of the Market Flow Task Force. Also, MISO disagrees with SPP's assertion that "large amounts of market flow from MISO's operations . . . are not reported to the IDC [Interchange Distribution Calculator] as a result of the manner in which MISO calculates their market flows." Based on the study performed, MISO (as well as PJM) has been calculating the market flows as per the procedures defined in the JOA between MISO and SPP.

Subsequent to the completion of the work by Market Flow Task Force, MISO and SPP have recently initiated an effort to collect data and develop an analysis that can be used to assess the accuracy of market flow calculations. Both parties have also agreed to evaluate alternative methods to calculate market flows to the extent the analysis suggests such an evaluation would be beneficial. Although neither SPP nor MISO have been able to identify market flow calculation errors, at a meeting on May 22, 2012, MISO invited SPP to undertake a further review of detailed market flow data MISO offered to make available.

Q. ASSUMING THAT LOOP FLOWS REGULARLY OCCUR ACROSS THE TRANSMISSION SYSTEM COVERED BY MISO'S OPEN ACCESS TRANSMISSION TARIFF (OATT), WHAT ACTIONS DOES MISO BELIEVE WOULD BE APPROPRIATE REMEDIES OR COMPENSATION FOR THE USE

OF THE TRANSMISSION SYSTEM? PLEASE DESCRIBE THOSE REMEDIES OR COMPENSATIONS IN AS MUCH DETAIL AS POSSIBLE.

A. Studies conducted by MISO indicate that SPP parallel flows regularly appear on the MISO transmission system. Those flows are effectively and efficiently managed pursuant to the market-to-non market provisions of the MISO-SPP JOA and the cost of MISO redispatch required to manage congestion due to those flows represents a small price for the benefits of operating in an interconnected system. Compensation for parallel flows in neighboring systems is governed by the FERC's policy. That policy does not permit compensation unless the parallel flow "diminishes the entity's ability to utilize its system in the most economical manner." *N. Ind. Pub. Serv. Co. v Midwest Indep. Transmission Sys. Operator, 116 FERC ¶61,006 at P 11 (2006) (citing E. Ky. Power Coop., 114 FERC ¶ 61,035 at P 40 & n. 29 (citing Am. Elec. Power Serv. Corp., 49 FERC ¶ 61,377 at 62,381 (1989)); E. Ky. Power Coop., 114 FERC ¶ 61,035 at P 40 (2006) (*denying TVA's request for compensation from loop flows absent "specific evidence that the loop flow jeopardizes the reliability of TVA's system or diminishes TVA's ability to utilize its system in the most economical manner").

Rather than attempting to monetize the impact of loop flows on each other's system, the JOA between MISO and SPP, for example, controls the effects of parallel flows by allocating firm flow rights on critical flowgates, and requires each RTO to provide relief on congested flow gates by reducing its flows to the previously established allocation levels. (*See* CMP document attached to and made part of the JOA.[1]) The

[1] MISO-SPP JOA and CMP can be found at:
https://www.midwestiso.org/Library/Repository/Tariff/Rate%20Schedules/Rate%20Schedule%2006%20-%20Midwest%20ISO-SPP%20JOA%20and%20CMP.pdf

procedure for reducing loop flow in neighboring transmission systems is defined in the NERC reliability standard "IRO-006-4 – Reliability Coordination – Transmission Loading Relief", which is being followed by all of the Transmission Service Providers in the Eastern Interconnection. This ensures that parallel flows do not rise to the level of interference that would support compensation under FERC's loop flow precedent.

Once SPP's Day Two energy market is operating, SPP will benefit by adopting the market-to-market redispatch protocol now used between the MISO and PJM markets. This method of dealing with parallel flows allows the parties to provide redispatch to jointly manage congestion on the flowgates. During real time congestion, parties with market-to-market protocol exchange cost information automatically and the RTO with the least cost redispatch provides market flow relief to ease congestion on a flowgate.

A compensation mechanism has been established to determine which RTO should bear/compensate the cost of the redispatch provided. This is largely dependent on whether or not the loop flow owner's flow on the flowgate exceeded its firm flow entitlement on that same flowgate determined based on the historic configuration (pre-market) using procedures defined in Sections 4 and 5 of the CMP. This not only provides for least cost transmission constraint management, but also effectively provides a form of price transparency as to the value of relieving the impact of parallel flows that would otherwise interfere with an owner's use of its system. (*See* CMP attachment C.[2])

Q. WILL ENTERGY JOINING MISO INCREASE CONGESTION ON THE SPP SYSTEM?

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[2] *Id.*

A. No. The Congestion Management Process ("CMP") describes the process and rules by which transmission capacity is allocated among Reciprocal Entities (that is, signatories to a seams agreement that manage congestion using the CMP) and third parties who have not adopted the CMP as a congestion management tool. Reciprocal Entities are expected to follow the rules and processes designated in the agreement to ensure that contract path and parallel flows are recognized and controlled in a manner that ensures system reliability and equity among the Reciprocal Entities. In the forward processes, such as the selling of transmission service on OASIS through the MISO Day-Ahead Market, all Reciprocal Entities, including MISO, limit the parallel flow placed upon another provider's system by respecting that neighbor's firm flow entitlements as calculated by the rules in the CMP. In real time, all Reciprocal Entities have the ability to maximize the utilization of the bulk electric system, sometimes above their own firm flow entitlement, in order to serve load at the least possible cost. If congestion occurs, Reliability Coordinators have the ability to manage congestion per NERC rules, which can result in Reciprocal Entities reducing their flows on another provider's system to return to each Reciprocal Entity's firm flow limit.

Q. WHAT OTHER OPERATING ENTITIES USE THE CMP?

A. Multiple transmission providers have signed a seams agreement using the CMP, including RTOs and Non-RTO transmission providers. MISO has even incorporated the CMP into its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") making the process available to neighboring systems who want to use this tool.

Q. IS THE CMP A PART OF SEAMS COORDINATION?

A. Yes. The baseline CMP is the basis for congestion management processes followed by all signatories to seams agreements in the Eastern Interconnection. All of MISO's Joint Operating Agreements (including the agreements with SPP, PJM and Manitoba Hydro) and MISO's Module F customers follow the principles and rules defined in the CMP. Where a neighboring Transmission Service Provider operates an energy market (e.g., PJM) the market-to-market process provides a more precise tool for allocating the costs of congestion and addressing parallel flows.

Q. HOW DOES THE CMP ALLOCATE FLOWGATE CAPACITY?

A. Section 6.4 of the CMP describes the process for allocating transmission capacity to Reciprocal Entities. With the signing of the CMP, all Reciprocal Entities agreed to use transmission reservations and generation dispatch order as of the Freeze Date that coincided with ComEd and AEP's integration into PJM. This timing was agreed upon to reflect, and protect, the firm transmission usage of non-market entities as the first energy markets were implemented.[1] Pursuant to the process, the historical information related to transmission reservations and generation dispatch order is used to allocate firm flow rights for each Reciprocal Entity on all Reciprocally Coordinated Flowgates.

Q. IS ENTERGY ENTITLED TO FIRM FLOW ALLOCATIONS TODAY?

A. No, only Reciprocal Entities that have signed an agreement to use the CMP are entitled to receive an allocation of firm flow entitlements on flowgates. Firm Flow impacts on flowgates resulting from Entergy, AECI, CLECO, and even Southern Company, however, are determined on flowgates today,[2] and Reciprocal Entities subtract these flows before they allocate the remaining flowgate capacity between themselves. In this

[1] Sec. 6.4 of CMP
[2] CMP Sec. 6.6 Step 8

manner, the firm flows of non-signatory transmission providers are respected in MISO's forward operating processes today.

Q. WOULD ENTERGY'S FLOWGATE IMPACTS CHANGE IF IT ADOPTED THE CMP?

A. Yes. Entergy's adoption of the CMP would result in the historic firm flows on flowgates being specifically modeled and allocated to it as a Reciprocal Entity transmission provider. Section 6.6 Step 8 of the CMP identifies the process by which firm flows are determined for non-signatory transmission providers. Third party flows are subtracted from the remaining flowgate capacity, but only if they are equal to or greater than 5% of the flows observed. A third party non-signatory who has only 4% of the flows on a given flowgate, for example, would not be considered in that calculation, and would not be recognized by the other entities. The 5% threshold applied derives from the NERC process for issuing TLRs. The remaining capacity is then allocated under the CMP to the affected Reciprocal Entities. A Reciprocal Entity is allocated more flowgate capacity (down to 0% remaining, if sufficient capacity remains) on all Reciprocally Coordinated Flowgates. Based on this rule set and the topology of the transmission system in the region, I would expect Entergy's historic firm flows on all flowgates, including those in SPP, TVA, and MISO, to be more accurately identified and allocated specifically to Entergy. This would result in the firm flow allocations of SPP, TVA, and MISO decreasing. Entergy's decision to join an RTO would effectively add Entergy's firm flow entitlements as a Reciprocal Entity to those of the RTO that they propose to join.

Q. HOW DOES MISO MANAGE CONGESTION WITH NEIGHBORING SYSTEMS?

A. MISO coordinates with all Reciprocal Entities to follow the forward process in the CMP to limit the sales of transmission service that would exceed the known available capacity of Coordinated Flowgates. MISO clears its Day-Ahead Market with a Security Constrained Economic Dispatch so that its firm flow entitlements on these flowgates will not be exceeded in real time, thus minimizing parallel flow impacts on neighboring systems.[3]

MISO utilizes the NERC TLR process and market-to-market coordination, specified in Attachment 3 of the MISO-PJM JOA, to manage congestion when it occurs in real time. MISO reports the energy flows on flowgates resulting from MISO generation serving MISO native load to the NERC Interchange Distribution Calculator ("IDC"). The NERC IDC is utilized by Reliability Coordinators across the entire Eastern Interconnection to monitor energy flows on flowgates. MISO utilizes TLR to manage flows on flowgates with SPP. If a Reliability Coordinator calls a TLR, the IDC assigns the MW amount of flow that MISO must reduce in order to maintain reliability. This value is passed through to MISO's Security Constrained Economic Dispatch system where generation is redispatched every 5 minutes to reduce the flow on the flowgate for the prescribed MW amount from the IDC.

MISO and PJM have implemented a market-to-market congestion management process, which is the Interregional Coordination Process ("ICP") as defined in Attachment 3 of the MISO-PJM JOA. Using this approach, MISO and PJM jointly redispatch both markets in order to reduce MW flows on the constrained flowgates at the lowest combined production cost possible, with usage-entitlement comparison based financial settlements to address equity. Comparing to the TLR approach employed with

[3] Sec. 5.3 of the CMP

SPP, the market-to-market process is a faster and more economic solution to address congestion in real time, with equity based financial settlements.

Q. WHAT IS MARKET-TO-MARKET CONGESTION MANAGEMENT?

A. Market-to-Market Congestion Management is a set of procedures that allows transmission constraints that are significantly impacted by generation dispatch in the MISO and PJM markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of transmission constraints near the market borders provides a more efficient transmission congestion management solution, lowering consumer costs, while also providing coordinated pricing at the market boundaries. The market-to-market process builds upon the procedures identified in the CMP. In real time, the firm flow rights of MISO and PJM on flowgates eligible for market-to-market congestion management do not impact the physical dispatch of the system; the firm flow rights are used to ensure appropriate compensation based on comparison of the actual market flows to the firm flow entitlements. It effectively allows each energy market the ability to maximize the economic dispatch for each system and provides a payment mechanism for the cost of relieving congestion by the market exceeding its firm flow rights. Together, both RTOs use of the market-to-market process yields lower production cost for load in both markets as compared to the TLR procedure.

Q. HOW DOES MARKET-TO-MARKET RESULT IN THE LOWEST COST DISPATCH?

A. The market-to-market process takes advantage of generation redispatch options in both MISO and PJM's market to reduce flows on a transmission constraint. Market-to-market achieves the lowest redispatch cost possible because it considers the Shadow Price of a constraint calculated by each market. The Shadow Price relative to a specific constraint is the cost each market would incur to redispatch generation to meet the prescribed MW reduction in flow required to mitigate the constraint. When utilizing market-to-market congestion management on a constraint, MISO and PJM exchange their Shadow Prices and the market with the lowest Shadow Price redispatches its generation which results in the least cost redispatch to manage congestion. This process continues in an iterative manner until the physical flow on the flowgate has been reduced to below its safe operating limit.

Q. HOW DOES MARKET-TO-MARKET COMPARE TO TLR?

A. The market-to-market process is superior to the NERC TLR process because it allows much more efficient use of the regional transmission system. TLRs are slow to implement, generally requiring up to 30 minutes to provide congestion relief, which usually requires one RTO to redispatch their generators to ensure reliability. Market-to-market coordination can provide effective relief within 5-10 minutes. Also, because TLR prescribes a MW reduction amount to each Transmission Provider, it can result in the curtailment of a large amount of transactions on one Transmission Provider's system to provide a small amount of relief on an affected flowgate; whereas, under a market-to-market process, both markets work together to provide the most reliable and economic option to reduce the physical flow on a constraint. The CMP is designed to avoid, to the greatest extent possible, getting into a TLR situation in the first place by planning and limiting system use in the day ahead time frame. The market-to-market process is a real time tool that avoids the need to curtail transactions, even if the CMP is unable to avoid congestion. Instead of curtailments, the two entities using market-to-market redispatch simply determine which of them can relieve the congestion at the least cost, and then settle financially to compensate the entity that performed the redispatch.

Q. DID THE INTEGRATION OF COMMONWEALTH EDISON INTO PJM RESULT IN PJM FLOWS ACROSS THE MISO SYSTEM?

A. It did, and sometimes MISO produced flows across the PJM system. As I mentioned previously, in the forward processes, MISO plans its use of the transmission system to be within its firm flow entitlements. In real time, MISO and PJM, as well as others, have the ability to economically dispatch their markets in order to maximize the use of the transmission system. When congestion occurs, MISO and PJM utilize the market-to-market process to provide the most reliable and lowest cost redispatch to manage congestion.

Q. DOES MISO INCUR COSTS TO REDISPATCH FOR THE PJM MARKET?

A. Yes. MISO incurs costs during the market-to-market process when MISO is identified with the lower cost to redispatch its generation to provide relief on a constraint in PJM. As I described previously, there is an after the fact settlement between MISO and PJM to determine who should pay for the redispatch. The settlement is not based directly on the incurred production cost, but rather on the comparison between the loop flow and firm flow entitlement of the market that does not have functional control on the constraint, in this case MISO. It is important to understand that the settlement's purpose is to address the equity between two markets when both markets' flows cause the congestion on a flowgate. There are situations that will require MISO to redispatch for PJM Market and still owe PJM during the settlement, and vice versa. It is because the non-owning market has over-used their firm flow entitlement in the neighboring market's facilities and they are responsible to reduce the flow during the congestion and still pay the neighboring RTO if they cannot reduce their flow under its entitlement.

Q. CAN YOU DESCRIBE HOW MISO DISTRIBUTES AND COLLECTS THE REVENUE NEEDED FOR MARKET-TO-MARKET SETTLEMENT?

A. Payments received by MISO or paid by MISO for market-to-market redispatch are distributed or assessed to MISO market participants on a load ratio share basis. This broad-based approach to financial settlement reflects the broad distribution of the benefits of the market-to-market process in terms of lower consumer costs across the MISO market region.

The market-to-market process is used extensively by both MISO and PJM; market-to-market redispatch actions occur on a daily basis between MISO and PJM. In 2011, MISO paid a total of around $10 million to PJM and PJM paid MISO around $85 million, which resulted in a net payment to MISO for around $75M dollars.

Q. IS MARKET-TO-MARKET A FORM OF PAYMENT FOR LOOP FLOWS?

A. No. Although the market-to-market settlements can be thought of as monetizing the impact of parallel flows on flowgates in an interconnected system when they result in congestion, the market-to-market process is more than that. It is a method to utilize generation in adjoining energy markets to achieve the lowest production cost *in each market*, when using redispatch to manage a congested flowgate. As I noted earlier, MISO and PJM limit the parallel flows placed on external systems in their respective forward operations processes. This allows for all entities to use the flowgate capacity in real time in the same way as they have historically. However, in real time, if some parties are not fully utilizing the transmission system, the parties to the JOA have agreed that it is prudent to maximize the use of the transmission system in order to provide the most economic generation mix to serve load.

As noted above, firm flow entitlements are based on historical usage, including usage of systems owned by others (loop flow), and not on payments for transmission service. Firm flow entitlement holders were not required to pay for historical usage for loop flow and are not required to pay for current usage for loop flow. In addition, firm flow entitlement holders may exceed their firm flow entitlement limit in real time, including the portion of the firm flow entitlement established by historical loop flow, without payment for those flows. Financial settlement under the market-to-market process occurs only when transmission congestion occurs and then only to the extent necessary to compensate for the cost of redispatch when appropriate.

Q. HOW DOES MISO MANAGE CONGESTION ON THE SPP SEAM TODAY?

A. MISO manages congestion on the SPP seam in three timeframes: when granting requests for firm transmission service, in forward (primarily ARR/FTR and Day-Ahead Market) processes, and in real time operations.

When selling transmission service, MISO and SPP include each other's flowgate limits to ensure no transmission service is granted that may cause an overload on one another's facilities. In addition, for Firm transmission service requests, there is a check against each RTOs firm flow rights to ensure those are not exceeded. This is a practice that all signatories have been following since the beginning of CMP processes in 2005. To prevent a situation where this practice may limit selling transmission service when the flowgate is not congested, there is a provision in CMP to allow sharing of unused allocation between reciprocal entities on the flowgate. Both MISO and SPP enjoy these benefits; the 2010 CMP Annual Report (latest available, appoved by SPP) illustrated that there are 369 instances (per flowgate, per transmission service request) that MISO borrowed SPP allocations to approve Firm transmission service requests and 943 instances SPP borrowed MISO allocations to approve Firm transmission service requests.

In the Day-Ahead Market, MISO limits its flows on SPP's facilities by utilizing MISO's firm flow entitlements for that day. This ensures MISO does not plan the approaching generation dispatch in a way that would exceed MISO's firm flow entitlements. These processes are set out in the highly technical provisions of the CMP.

In real time, MISO and SPP utilize the NERC TLR procedures to manage congestion on flowgates. Under the TLR procedure, both MISO and SPP report their market flows on each Coordinated Flowgate to the IDC which is available to all Reliability Coordinators. These calculated market flows are consistent with the criteria identified in the CMP. If a Reliability Coordinator observes high loading on a flowgate, a TLR is called wherein the necessary reduction in MW flow is entered into the IDC by the RC. The IDC uses the MW flow reduction amount to calculate market flow reductions and E-Tag curtailments. Any MISO TLR obligation is then passed to MISO's SCED process where generation is redispatched to relieve flows on the congested flowgate.

As described earlier, TLR is a slower process, and in this case (because MISO and SPP have not adopted the market-to-market ICP process) does not utilize the generation in MISO and SPP to identify the lowest cost generation redispatch. As a consequence, both SPP and MISO must redispatch their own generation or take other measures to reduce flows, without regard to lower cost alternatives available with market-to-market coordination.

Q. DO MISO MARKET FLOWS EXCEED ITS FIRM FLOW ENTITLEMENTS ON SPP FLOWGATES UNDER THE CURRENT JOA?

A. As permitted by the CMP process, each Reciprocal Entity is allowed to sell transmission in real time to take advantage of available capacity in the transmission system, regardless of the allocated firm flow rights. In real time, MISO SCED will attempt to utilize any available transmission facility capacity, which would not be currently utilized by another Reciprocal Entity, in order to minimize the cost of generation to serve load. But if congestion occurs in real time, the entity making use of the idle capacity must redispatch generation or otherwise curtail transmission service to reduce its flows to meet TLR obligations assigned to it by the IDC. Maximizing the use of the transmission system in real time, to reduce the cost of serving load, is a core tenant of the JOA.

Q. DO SPP MARKET FLOWS EVER EXCEED SPP FIRM FLOW ENTITLEMENTS ON MISO FLOWGATES?

A. Yes. As a signatory to the JOA and CMP process, SPP is a Reciprocal Entity with the same right to deploy transactions on MISO flowgates that exceed SPP's firm flow entitlements. As noted in my previous answer, though, the same restrictions apply to force reductions in those flows if congestion occurs in real time. This permits a much more efficient use of the transmission system, benefiting customers in the long run, while protecting reliability in real time by using the pre-arranged rules and processes of the CMP. From MISO's perspective, there are times when SPP will rightly maximize it use of the transmission system (by exceeding its firm flow entitlements) and we expect this to continue along the expanded seam with Entergy's footprint.

Q. DO YOU KNOW WHETHER SPP HAS A SIMILAR SEAMS MANAGEMENT PROCESS IN PLACE TODAY, WITH ENTERGY?

A. It is my understanding that there is some coordination between Entergy and SPP, but not as much coordination as between MISO and SPP, described under the JOA/CMP. It appears that SPP and Entergy do consider some of each other's flowgates when selling transmission service; but the criteria for including flowgates is not clear and it is not as stringent as the criteria for Coordinated Flowgate identification in Sec. 3.2.1 of the CMP. It is unclear what limits are respected on flowgates when SPP and Entergy plan their operating days in the day ahead environment. To manage congestion in real time, SPP uses the NERC TLR procedures whereas Entergy uses a combination of NERC TLR and internal generation redispatch.

Q. HOW WILL THE SEAM BETWEEN SPP AND ENTERGY CHANGE AFTER ENTERGY INTEGRATES INTO MISO?

A. Immediately upon Entergy's integration, the seam between SPP and Entergy would become part of the processes and procedures described in the CMP already in place between SPP and MISO. Of course, the location of the seam will remain unchanged, but management of the seam will be enhanced by the application of the CMP. MISO recently completed an analysis to estimate the additional flowgates that may be required to be included in the MISO and SPP processes as described in Sec. 3.2.1 of the CMP. Our results show that with Entergy in MISO, MISO would become a Reciprocal Entity on 17 new SPP flowgates and SPP would become a Reciprocal Entity on 56 flowgates.

What's striking is that this indicates a need for increased coordination between the existing Entergy footprint and SPP because the number of flowgates in Entergy's footprint impacted by SPP, using the methodology in the CMP, is greater than the number of Entergy flowgates currently included in SPP's AFC calculation process.

MISO anticipates two other enhancements to Seams coordination with SPP. Today, there is an opportunity for MISO and SPP to enter into a generation redispatch agreement. Module F of the MISO Tariff identifies a process by which MISO and SPP could agree on generation redispatch options to manage congestion on specific flowgates. It includes financial settlement language so that at a minimum, the party providing a redispatch request for another is held harmless. This opportunity exists today, regardless of the Entergy decision or timeline, and would provide MISO and SPP nearly the same level of efficiency as the market-to-market process described earlier. (The economic results are the same, but the process would likely be manual for Module F redispatch, whereas MISO and PJM have automated much of the market-to-market process for ease of implementation and more accurate settlements.)

Even before the implementation of SPP's Day 2 Market, MISO and SPP could begin a Market-to-Market process like that in place between MISO and PJM. During the SPP stakeholder meetings recently attended by MISO to address the concerns about Entergy joining MISO, SPP confirmed that its existing imbalance market is compatible with the ICP market-to-market process.

Q. HOW DOES THE CMP ADDRESS A CHANGE IN REGIONAL FLOWS WHEN NEW TRANSMISSION FACILITIES ARE CONSTRUCTED?