UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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| **Uplift Cost Allocation and Transparency** | ) | |
| **in Markets Operated by Regional** | ) | **Docket No. RM17-2-000** |
| **Transmission Organizations and** | ) | |
| **Independent System Operators** | ) | |

# COMMENTS OF POTOMAC ECONOMICS, LTD.

Potomac Economics respectfully requests permission to submit comments out-of-time on the above-captioned Notice of Proposed Rulemaking initiated by the Federal Energy Regulatory Commission (the "Commission").[1] The Commission is proposing rules (the "Proposed Rules") in RTO/ISO[2] wholesale markets related to two issues.

The first involves allocating real-time "uplift costs" and transparency associated with these costs, including posting these costs and the out-of-market resource commitments that are often the source of these costs. The second issue involves transparency related to transmission-

1 Pursuant to the notice published in the Federal Register, 82 Fed. Reg. 9539 (Feb. 7, 2017), comments on the NOPR were due on April 10, 2017. Potomac Economics requests permission, pursuant Rule 2008 of the Commission's Rules of Practice and Procedure, to submit these comments seven days out of time. Due to market monitoring issues requiring its resources, Potomac Economics was unable to submit these comments on time. Potomac Economic agrees to accept the record in this proceeding as developed to date. Accepting Potomac's late comments will not disrupt the proceedings in any way or prejudice any party.

2 "RTO" is Regional Transmission Organization and "ISO" is Independent System Operator. Both entities operate the transmission networks and the centralized wholesale markets to which the price reforms are to be applied. Because there are no substantive differences between RTOs and ISOs in this context, for ease of exposition, we will refer to them both as RTOs.

constraint penalty factors, including how they are used to set locational prices and the procedures for changing them. We have long advocated for efficient rules in these two areas and we support the Commission's effort to define these rules.

Potomac Economics is the Independent Market Monitor for Midcontinent ISO ("MISO"), the Market Monitoring Unit for the New York ISO ("NYISO"), and the External Market Monitoring Unit for ISO New England ("ISO-NE"). In these roles, we are responsible for monitoring and evaluating the performance of each RTO's energy and operating reserve markets. We also recommend market design changes to improve the performance of the markets and evaluate design changes proposed by the RTOs or market participants.

The NOPR would require each regional transmission organization and independent system operator (collectively "RTO") that currently or in the future allocates the costs of real-time uplift to deviations to allocate such real-time uplift costs only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs. The proposed rules would also add reporting requirements for real-time uplift costs, out-of-market unit commitment, and transmission constraint relaxation parameters for greater transparency for market participants to ultimately reduce the need for uplift.

## I. NOTICE AND COMMUNICATIONS

All communications, correspondence, and documents related to this proceeding should be directed to the following persons and such persons should be placed on the official service list maintained by the Commission's Secretary for this proceeding:

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## II. COMMENTS

Our Comments are divided into two parts, corresponding to the two main issues raised in the rulemaking. The first part addresses allocation of uplift costs, and the second part addresses the transmission-constraint penalty factors (or more accurately described as transmission-demand-curve parameters).

### A. Uplift Cost Allocation

The Commission's Proposed Rules on uplift cost allocation are confined to "real-time uplift costs." In the Commission's formulation, real-time uplift costs are defined as "uplift payments to resources committed after the close of the day-ahead market, including any uplift associated with reliability commitments…."[3] This definition covers most real-time uplift costs that can be linked to participant deviations and we support this approach. However, as we discuss in more detail below, uplift costs associated a subset of the reliability commitments that are cleared in the day-ahead market are costs that should logically fall under the Commission's Proposed Rules, even though such costs are considered day-ahead uplift.

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3 Proposed Rules at para 4, footnote 2.

The Commission's Proposed Rules pertain only to real-time uplift costs that are allocated to deviations, i.e., allocated based on a participant's actual real-time positon relative to its day-ahead schedule. The Commission is not requiring uplift costs to be allocated based on deviations if the RTO does not already allocate costs based on deviations.

Overall, we very much support the Commission's Proposed Rules in these areas. We have worked with the various RTOs that we monitor to apply these principles, especially in MISO. If implemented as proposed, we believe the Commission's rules will generally improve the process of uplift cost allocation and create incentives to reduce overall uplift. However, there are changes in the rules that would improve their effectiveness and generate more efficient incentives. We address the various Commission's Proposed Rules in the following subsections.

**1. Applicability**

One main issue we have with the Proposed Rules is the Commission's intention to limit their applicability to RTOs that currently allocate based on deviations. Our concern with this limitation is that deviations often do cause RTOs to make out-of-market commitments that generate uplift costs. To the extent that this is true, developing an uplift allocation that recognizes the effect of deviations will improve participants' incentives and the efficiency of RTO day-ahead market outcomes. Hence, we believe that the Commission should extend the Proposed Rule to require all RTOs to allocate uplift costs based on deviations to the extent costs are caused by deviations. Failure to do so undermines the very purpose of the Commission's Proposed Rules. Requiring all RTOs to allocate uplift costs to those that cause the costs will provide incentives to avoid such cost-causing activities and, thereby, reduce the overall level of uplift costs and improve overall price formation.

### 2. Definition of Deviation

*General Definition*. The Commission is inviting comments on the proposed definition of deviations. We are in general agreement with the definition the Commission proposes:

> We propose that deviations are megawatt hour differences between a market participant's scheduled deliveries or receipts at particular points cleared in the day-ahead market and those amounts actually delivered or received at those points in real-time that are not related to real-time economic or reliability-related operator dispatch instructions.[4]

Although we generally agree with this definition, there are a variety of qualifications we discuss below.

*Energy versus Capacity*. The Commission proposes that deviations be measured as the difference between day-ahead schedules and final real-time positons. While this measure of deviations is straightforward for most types of deviations (e.g., load, virtual trades, etc.), it is not necessarily appropriate for generation resources. When a generation resource deviates, it may create the need for additional capacity in excess of its schedule. For example, consider a 200 MW unit committed day ahead with a 100 MW schedule. If that unit does not start or takes an outage, the schedule deviation is 100 MW. However, the system actually loses 200 MW of capacity, which is a need the operators may have to meet with out-of-market commitments. In this case, the net deviation is 200 MW. MISO accomplishes this by treating unscheduled "headroom" as a helping deviation. Therefore, in the MISO framework, when the 200 MW unit in our example does not start, its net deviations go up by 200 MW: 100 MW reduction in helping deviations and 100 MW harming deviation for the day-ahead schedule. In its final rule, the Commission should adjust its definition to accurately account for these facts.

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[4] Proposed rule at para 37.

*Notification Deadline*. The Commission seeks comment on whether there should be advanced notification requirements in determining helpful deviations.[5] In other words, will a schedule deviation that in theory helps the operator avoid an out-of-market commitment (for example, a unit that raises its maximum generation level) be announced too late to actually help the operator? The question of such a notification deadline may vary from RTO to RTO. Some RTOs with plenty of quick-start units may be able to commit additional units up to very close to real time, justifying a relatively short deadline. Other RTOs may not have many quick-start units and have to make most of their out-of-market commitments two or more hours in advance, which makes any helping deviation close to real-time immaterial to the RTO's commitment decisions. In such a case, a reasonable deadline could be hours before real time. Hence, any deadline should be adopted in light of the flexibility of the RTO's portfolio of resources available in real time.

*Operator Instructed Deviations*. The Commission seeks comment on its proposal to exempt operator-instructed deviations from a participant's net deviations.[6] We support the Commission's rule because such deviations are not decisions made by the participants. The cost allocation rules are based on the theory that participant deviations that cause costs should be allocated such costs in order to create incentives to avoid the associated deviations. Operator-instructed deviations are not participant decisions. Hence, it would not be reasonable to allocate costs to such deviations nor to use them in any netting process. In fact, allocating costs to such deviations would provide incentives for participants to disregard RTO instructions.

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5 Proposed Rule, para 50.

6 *Id*.

*Helping and Harming Deviations and Cost Causation.* There is often confusion regarding when a deviation is helping (likely to be reducing uplift) versus harming (likely to be increasing uplift). For example, capacity-related uplift costs arise when operators must commit additional resources out-of-market to meet load and reserve requirements and these additional resources do not fully recover their commitment and energy production costs under prevailing market prices. These are *direct* uplift cost effects that result from supply-*decreasing* deviations that contributed to the need for these commitments. There can also be secondary or *indirect* uplift cost effects that are generally in the opposite direction of the direct effect. For example, the supply-*decreasing* deviations whose direct effect is to increase uplift may, *ceteris paribus*, also raise market clearing prices. The higher resulting prices may reduce the uplift payments that are needed to ensure that the resources committed by the operator are revenue adequate. We have argued that the cost allocation methodologies adopted by RTOs should be based exclusively on the *direct* effects of the deviations. Providing any credit in the cost-allocation methodology for indirect effects would reward participants for incurring deviations that ultimately require RTOs to take out-of-market actions.

Nonetheless, the Commission raised questions on this issue when MISO filed to exempt helping deviations that occur after MISO's post-notification deadline from uplift allocations.[7] Prior to this filing, MISO's methodology treated helping deviations occurring in the post-notification deadline as harming. FERC speculated that the indirect price effects of these helping deviations could increase uplift by lowering prices. To address this question, Potomac Economics conducted a study to estimate the direct and indirect effects of post-notification-deadline supply-increasing deviations. This study was discussed in an Affidavit filed by Dr.

7 See MISO Filing in Docket No. ER16-213, filed October 30, 2015.

Robert Sinclair filed by MISO in that proceeding and attached to these comments as Attachment I.

The study demonstrates conclusively that the direct effects of these post-notification deadline deviations far exceeded the indirect effects. For deviations occurring before the notification deadline, the direct effects should be even more dominant because they are fully known by the operator.

Some may argue that cost causation is difficult to establish and offer examples of cases where a helping deviation may raise uplift or a harming deviation may lower uplift. Most of these examples are anomalous cases where the indirect effect exceeds the direct effect, which is not typically the case and should not influence the Commission's final rule. It is economically efficient to allocate costs based on their expected effects on uplift. If this is the Commission's objective, its proposed methodology that is based only on the direct effects of deviations is a sound and reasonable methodology.

### 3. Recognizing Regional Differences

The Commission requested comment on whether the Proposed Rules should recognize regional flexibility with regard to uplift categories.[8] We believe the Commission is correct in proposing the two categories of uplift cost that would be subject to the deviations-based cost allocation: system-wide capacity-based uplift and congestion-management-based uplift. We believe these categories are the ones to which deviation-based cost allocation would be most effective because the connection between the participant action and costs it causes is most clearly linked. Additionally, as we explain below, good cost classification is critical in order to avoid comingling these costs because different deviations affect constraints than affect system-wide

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8 *Id*., at para 44.

capacity. For example, virtual load is a helping deviation for system-wide capacity, but can be a harming deviation on a constraint.

The Commission should recognize that RTOs address capacity requirements in different ways. For example, NYISO incurs uplift associated with reliability commitments in the day-ahead market in accordance with its forecasted load requirement. This essentially allows day-ahead reliability commitments to clear the day-ahead market instead of being committed through a reliability commitment process after the day-ahead market closes. These day-ahead commitments would be out-of-market commitments after the day-ahead market in other RTOs. The additional uplift costs in NYISO from the forecast-load commitments are allocated based on principles consistent with those underlying the Commission's Proposed Rules. For example, such uplift in NYISO is allocated to virtual supply, which would be allocated to real-time uplift under the Commission's Proposed Rules if such commitments had been made after the day-ahead market. Hence, it is important that the Commission recognize that RTOs have different processes for making commitment to satisfy their capacity and reliability needs. These difference will affect how uplift costs are generated and how the Commission's proposal should be applied to each RTO.

### 4. Cost Classification

The Commission seeks comment on the method for classifying costs between system system-wide capacity commitments and congestion management commitments.[9] MISO has significant experience on methods to classify costs between capacity-related costs and congestion-related costs. MISO generally relies on operator logs to determine the primary reason the operator committed the unit. Because the primary reason is by far the most important,

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[9] *Id*., at para 56.

it would be reasonable to categorize all the uplift costs under that reason. However, MISO's method recognizes that commitment for one reason (e.g., transmission congestion), may address general capacity needs, thus it divides the cost between congestion uplift and system-capacity uplift. MISO accomplished this split by empirically examining historical out-of-market commitments to determine how they may satisfy joint needs. Although we do not believe this is necessary, we believe the MISO's approach is reasonable.

### 5. Netting Deviations

The Commission is also seeking comment on the process for netting of transactions and deviations.[10] Like the classification of costs, we believe MISO methodology is a best practice in this area. Deviations are netted for two reasons under MISO's methodology. First, all deviations are netted market-wide to determine whether the market-wide deviations are harming on net or helping on net.[11] For capacity-related uplift costs, for example, net supply-decreasing deviations will create the potential need for out-of-market commitments. If the market-wide effect is *supply increasing*, then no capacity-related uplift costs are allocated to deviations for that period.

If the market-wide net effect is harming, then the magnitude of the net harming deviation relative to the quantity of the out-of-market commitments determines that share of the costs allocated to deviations. Once this total allocation is determined, the deviations are netted on a participant level so that the uplift can be allocated to those participants that exhibit net harming deviations. In other words, once it is determined in the first step that the market-wide deviations contributed to out-of-market commitment costs, then each participant is allocated a share of

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10 *Id*.

11 MISO utilizes a notification deadline. After the deadline, a participant's harming deviations cannot be offset by helping deviations because post-notification helping deviations may or may not actually have helped if operators were not aware of them at the time they made out-of-market commitments. Therefore, the netting described in this section includes pre-notification helping and harming deviations, and post-notification deadline harming deviations.

those costs in proportion the net harming deviations of its own portfolio. We believe this approach is a best practice that should be adopted in the final rule.

### 6. Transparency of Uplift

The Commission invited comments on its transparency requirements.[12] In general, we support transparency requirements in the markets we monitor because transparency tends to allow participants to take efficient actions in response to market conditions. However, transparency is less important when it involves uplift cost allocation because uplift cost allocation is a settlement process, and immediate release of information concerning the source and allocation of uplift costs will not improve participants' ability to take economic actions that lower overall costs. There are legitimate concerns regarding releasing uplift payment information and supply offers with a minimal lag because it could allow for tacit or explicit collusion among suppliers. It is well understood such collusion is much more difficult and unlikely when competitors cannot observe each others' conduct. The Commission is proposing a 20-day lag, which we conclude is still likely too short to ensure that competition will not be adversely affected. Given that the value of transparency does not diminish substantially by delaying the release of information, but that the risk to competition does diminish, we see no reason to accelerate the release of unit-specific information on a 20-day lag. We would recommend at least a three-month lag.

### 7. Transmission Outages and Network Model

The Commission has also invited comments on additional reporting of transmission outages.[13] We support the Commission's Proposed Rules on additional transmission outage reporting. When market participants have more information about system conditions, they can

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[12] *Id.*, at para 83.

[13] *Id.*, at para 100.

make better economic decisions in the day-ahead and real-time markets, which contribute to market efficiency.

### B. Transmission Constraint Penalty Factors

As the Commission notes in its Proposed Rule, we have been proponents of transparency in the process of setting and posting transmission-constraint penalty factors. These penalty factors are referred to as *transmission constraint demand curves* by MISO and as *graduated transmission demand curves* by NYISO. Referring to them as demand curves is intuitive and conveys an important principle. i.s., the size of the violation matters from a reliability perspective. Violating a transmission constraint by one percent generally raises substantially lower reliability concerns than violating a constraint by 20 percent. Utilizing a transmission constraint demand curve allows an RTO to distinguish between a relatively small violation and a substantial violation. Therefore, we recommend that the Commission encourage RTOs to file curves that reflect this principle rather than single penalty factors that remain static regardless of the size of the violation. For simplicity, we will refer to these as “transmission constraint penalty factors” for the balance of these comments.

*Filing the Transmission Constraint Penalty Factors*

Transmission constraint penalty factors play a pivotal role in LMP markets. These factors represent the maximum redispatch cost that the RTO will incur to resolve congestion on a constraint, and are generally used to set the congestion components of the LMPs when a constraint is in violation. Because these factors both set prices in some circumstances and can affect the dispatch solutions in others, we have been arguing for years that these factors (or demand curves) should be filed as tariff provisions, and reviewed and approved by the Commission. When RTOs have operated without having filed these penalty factors, we have observed the RTOs changing the values for a variety of reasons.

RTOs sometimes increase transmission constraint penalty factors during real-time operations because they are seeking additional relief that may be available at a higher price. There are two primary explanations for this:

1. The violation is raising more serious reliability concerns than normal for this constraint. This can be the case, for example, if the constraint has been in violation for an extended period, which can make the violation more serious for a thermal limit because a line will become hotter the longer the flow exceeds the limit. This can also be necessary if the RTO is using a single penalty factor and the violation is relatively large because larger violations raise more serious reliability concerns. Using a transmission constraint demand curve solves this particular problem.
2. The initial penalty factor was set too low and did not reflect the reliability cost or risk of violating the constraint. In this case, the penalty factor should be permanently increased.

We have also observed RTOs sometimes lowering these factors in real time. The only reason for lowering the penalty factor in real time is to reduce the real time congestion pricing for a constraint that is in violation.

In both cases, whether increasing or decreasing the penalty factors, these actions can have a profound effect on the RTO's LMPs, unit commitments, dispatch levels, and reliability. Because they play such a pivotal role in market outcomes, we do not believe that RTO's should be modifying such parameters without FERC oversight. Hence, we support the Commission's proposal to require that RTO's file these values, as well as the provisions to allow RTOs to adjust them. However, we recommend that the Commission strengthen its requirement by requiring the RTO's to file multi-point demand curves rather than single penalty values

We also recommend that the Commission clarifying that the values should correspond to the reliability concerns that arise when the constraints are violated. This is important because these values will prevent the market from managing the flow on a constraint if flow relief is more costly than the penalty value. This should only occur when the reliability cost of violating the constraint is lower than the commitment and/or dispatch cost of managing it. While we recognize it would be difficult in many circumstances to precisely estimate the reliability value of a transmission constraint, reasonable values can be established that reflect the relative reliability concern associated with violating different constraints.[14] For example, constraints on high-voltage facilities that carry a large flow and whose failure could endanger the stability or security of the system and lead to cascading loss of load should be priced highest. Alternatively, low-voltage facilities often have low-cost post-contingency action plans that allow a transmission operator to manage the system reliability if the contingency occurs, which would justify a relatively low penalty factor.

*Using Penalty Factors or Transmission Demand Curves to Set LMPs*

Additionally, the Commission proposed requiring the RTO's to explain whether they are used to set LMPs. We strongly recommend that the Commission strengthen this requirement to require RTOs to use these values to set LMPs when a constraint is in violation. This is the only way to ensure that efficient economic signals are established to provide incentives for participants to help resolve the violation. This is not only important in the real-time markets where the violations occur, but likely just as important for the day-ahead market that will respond to the congestion observed in real-time and lead the RTO to a more efficient commitment of its resources.

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[14] To date, the penalty factors or transmission constraint demand curves have ranged from $500 per MW to $4000 per MWh.

To understand why this is both economic and efficient, consider the following example. If an RTO has set its penalty factor to $1000, it will utilize all redispatch up to $1000 to manage the constraint. If the last redispatch needed to manage the constraint has a marginal cost of $999, the congestion components of the LMPs will reflect this shadow cost. Because the effects of generation and load at different locations vary, this would produce nodal congestion prices generally ranging from $40 to $200 per MWh.[15] However, when the constraint becomes violated, some RTOs "relax" the constraint to set a shadow cost less than the penalty factor, which reduces the resulting congestion reflected in the LMPs. It is easy to recognize that this will distort the LMPs because conditions in this scenario are unambiguously worse – the constraint is violated and reliability is diminished – but the congestion that is priced in the LMPs will be reduced. In the first scenario, the congestion will be determined by the $999 shadow price. In the second scenario, the "relaxed" shadow price will determine the price and this shadow price may be well below the penalty factor.

For example, for years after its start-up, MISO relaxed its violated internal constraints using a software algorithm inherited from PJM. We recommended for five years that MISO discontinue use of this algorithm because it severely distorted the congestion pricing in MISO. In more than one quarter of the intervals with a violation, the algorithm relaxed the shadow price to zero, eliminating entirely the congestion associated with the violated constraint. In these years, the algorithm eliminated over $300 million in annual unpriced real-time congestion costs. MISO discontinued use of this algorithm in 2012 on its internal constraints, but not on its market-to-market constraints because PJM opposes this change. Further, because PJM is similarly situated to MISO and uses the same algorithm, we believe PJM's LMPs likely contain

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15 These variable effects at different locations is reflected in "shift factors" that indicate the portion of the injections and withdrawals of electricity at each location that will flow over the constraint.

distortions comparable to the distortions in MISO's LMPs prior to 2012. Therefore, we recommend that the Commission not just require an explanation of how the penalty factors contribute to setting LMPs in its final rule, but require the penalty factors (or demand curves) set the shadow prices for the violated constraints.

One possible exception from this requirement would be RTOs whose software does not currently allow them to set efficient penalty factors. NYISO, for example, can currently only set one demand curve for all of its constraints and has filed a curve that is set over most of its range at $4000 per MW of flow. This value is unreasonably high for many of NYISO's constraints so a constraint relaxation algorithm could be reasonable for these constraints until NYISO can improve its software to utilize transmission demand curves that vary by constraint. But for this exemption, allowing the reliability value of violated constraints to appear in RTOs' LMPs is a critical improvement for their price formation and is consistent with the Commission's expressed objectives for shortage pricing (transmission violations are "transmission shortages") and its price formation objectives more broadly.

**C. CONCLUSION**

We strongly support the main elements of the Commission proposals in this rulemaking and believe they will lead to better price formation, improved incentives, and ultimately lower costs in the RTO markets. The uplift allocation rules will improve participants' incentives in the RTOs' day-ahead markets, leading to more efficient market outcomes and lower uplift costs. Likewise, the reforms proposed for transmission-constraint penalty factors improve these values and their use by the RTOs, which will ultimately improve the RTOs' price formation in periods when one or more constraints are violated.

We have made several recommendations that are intended to help ensure an even greater improvement in economic efficiency, and we respectful request the Commission consider these recommendations.

Respectfully submitted,

*/s/ David B. Patton*

David Patton
President
Potomac Economics, Ltd.

April 17, 2017

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 17th day of April 2017 in Fairfax, VA.

*/s/ David B. Patton*

**<u>Attachment I:</u>**

**Affidavit of**
**Dr. Robert Sinclair**

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| Midcontinent Independent System | ) | |
| Operator, Inc. | ) | Docket No. ER16-___-000 |

# Affidavit of Robert A. Sinclair, Ph.D.

## I. Qualifications

1. My name is Robert A. Sinclair. I am an economist and Vice President of Potomac Economics. Our offices are located at 9990 Fairfax Boulevard, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets. Potomac Economics currently serves as the Independent Market Monitor for the Midcontinent Independent System Operator, Inc. (MISO) as well as the Market Monitoring Unit for the New York Independent System Operator, Inc. and the External Market Monitor for the ISO New England, Inc. In these engagements, we are responsible for assessing the competitive performance of the markets, including assisting in the implementation of market monitoring plans to identify and remedy market design flaws and abuses of market power. We also provide recommendations regarding market power mitigation measures and other market rules.
2. I have worked as an energy economist for more than twenty years, focusing primarily on competition policy in the electric utility and natural gas industries. I have provided expert testimony and analysis regarding competition in the electric utility industry, including market power analysis, ratemaking, open-access transmission policies, market design, and merger policy. I have filed expert testimony and reports to the Federal Energy Regulatory Commission, state regulatory commissions, U.S. courts, and regulatory authorities in Canada.
3. I hold a Ph.D. in Economics from the University of Pittsburgh and a B.A. in Economics from Indiana University of Pennsylvania.

## II. Purpose and Summary

4. The purpose of this affidavit is to support MISO's proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) concerning Revenue Sufficiency Guarantee (RSG) payments. RSG payments are made by MISO to participants outside the ordinary day-ahead and real-time market clearing settlements in order to help ensure resources committed by MISO do not operate at a loss in responding to the MISO commitment instructions. In particular, resources that are committed by MISO for capacity or for congestion management after the day-ahead market receive a real-time RSG payment if their as-offered costs are not recovered through the real-time energy market prices. The costs of these RSG payments are allocated to market participants in accordance with certain formulas.

5. I address a proposed Tariff change involving the allocation of real-time RSG costs. A main factor determining how some of these costs are allocated is whether or not a participant deviated from its day-ahead schedule in a manner that contributed to the need to make the associated real-time RSG-related commitments. The proposed change would exempt from RSG cost allocation certain participants that have deviated from their day-ahead schedule close to real time if the deviations tend to increase real-time supply, known as "supply-increasing" or "helping" deviations. The supply-increasing deviations in question are those made during the "Post-Notification Deadline" (PNDL) period, which is the four hour period just prior to the real-time operating hour.

6. On August 7, 2013, MISO submitted this proposal to the Commission in Docket No. ER13-2124-000, as part of several Tariff revisions regarding the allocation of RSG costs. In an order issued on March 7, 2014, the Commission rejected the proposal

without prejudice because it deemed that MISO had not submitted adequate evidence to justify this change. *Midcontinent Independent Sys. Operator, Inc*., 146 FERC ¶ 61,165 at P 42-45 (2014) ("March 7, 2014 Order"). In particular, the Commission asked how these supply-increasing deviations also contribute to higher RSG costs because they will tend to decrease real-time market clearing prices and decrease output of dispatched units, thereby potentially causing the need for higher RSG payments to participants unable to fully recover their production costs due to the lower prices and reduced output. *Id*. at P 42-43. In addition, the Commission asked why the "hypothetical" RSG savings from PNDL supply-increasing deviations should be taken into account for cost allocation purposes. *Id*. at P 44 and n.83. In order to address the Commission's concerns, we produced an empirical analysis that estimates the RSG cost impact of supply-increasing deviations, taking into account both decreased commitment costs and the increase of RSG costs from changes in prices and dispatch based on actual data.

7. Our analysis of the actual historical commitment costs finds that PNDL supply-increasing deviations will result in RSG cost savings that substantially exceed any increase in RSG costs that may arise due to lower real-time clearing prices from these deviations. Hence, in accordance with cost causation principles, it is not reasonable to allocate RSG costs to PNDL supply-increasing deviations.

## III. Proposed RSG Cost Allocation Exemption

8. MISO's August 7, 2013 filing aimed to reform the RSG process to align more closely the allocation of the real-time RSG costs to the participants causing the need for unit commitments that result in the costs.

9. The Commission's March 7, 2014 Order accepted the various MISO proposals, except the one regarding the RSG exemption of PNDL supply-increasing deviations. The Commission concluded MISO did not provide sufficient evidence and explanation to adopt the previously-proposed exemption. In this section, I provide evidence and analysis to support the proposed RSG exemption for supply-increasing deviations.

### A. Background

10. As we indicated above, real-time RSG costs are paid outside the normal day-ahead and real-time market-clearing settlements and the cost of these payments are allocated to participants based on a variety of factors. In general, these costs should be allocated as efficiently and equitably as possible. This was the motivation for the August 2013 filing by MISO to allocate these costs to participant conduct that cause them.

11. Units become eligible for real-time RSG payments when MISO must commit resources after the day-ahead market for three main reasons: (1) to meet overall capacity needs (capacity-related RSG costs); (2) to manage transmission congestion (congestion-related RSG costs); and (3) to manage voltage and local reliability (VLR-related RSG costs). MISO categorizes real-time RSG costs based on one of these three commitment reasons (although a fourth, smaller category includes commitments for miscellaneous reasons that do not fit one of the three specific categories). By classifying these costs into the four categories, MISO is able to allocate them to the actions by participants that caused them.

12. The subject of MISO's proposal discussed herein concerns commitments made for capacity-related needs (RSG category (1) above) that give rise to real-time capacity-related RSG costs. The discussion that follows is confined to real-time capacity-related RSG costs (which we will simply refer to as "RSG costs").

13. As explained in more detail below, MISO had proposed to exempt supply-increasing deviations that occur after the PNDL from being allocated RSG costs because they do not directly cause them. Capacity-related RSG costs arise when operators must commit additional units to meet load requirements and these additional units are unable to recover their commitment and energy costs under prevailing market prices. These are *direct* RSG cost effects and can be the result of supply-*decreasing* deviations that cause the need for these additional commitments. There are also secondary or *indirect* RSG cost effects that arise from deviations that can reduce the energy price. A supply-increasing deviation, *ceteris paribus*, can cause an increase in supply and, as a result, cause lower clearing prices in the real-time markets. The lower resulting prices mean RSG-eligible units committed for capacity may need higher RSG payments to make them revenue adequate. We recognized this secondary, indirect effect in our supporting comments to MISO's 2013 proposal and concluded this effect is minor compared to the direct effect from additional commitments. The Commission found, however, that as of then, an empirical analysis had not been conducted to support our conclusion.

14. As the Commission explained:

> [W]e find that MISO has not provided sufficient evidence that these [supply-increasing] deviations do not cause the incurrence of real-time RSG costs. MISO and its Independent Market Monitor concede that these deviations can cause real-time RSG costs by reducing real-time prices and rendering some production costs unrecoverable. Further, MISO has not addressed the extent to which supply-increasing deviations that occur after the notification deadline could cause MISO to dispatch other resources downward, potentially reducing the revenues received by other resources and causing the incurrence of real-time RSG costs (March 7, 2014 Order at P 42).

### B. MISO's Proposal

15. The notion of a schedule "deviation" is a central concept in MISO's present RSG cost allocation proposal. A deviation is the difference between day-ahead and real-time schedules, i.e., the difference between what a participant commits to do in the day-ahead market and what it actually performs in real time. Deviations arise after schedules are established in the day-ahead market. After that point in time, participants can submit "supply-decreasing" deviations or "supply-increasing" deviations.

16. Both schedules to supply resources as well as schedules to consume power can create deviations. With regard to resources supplying the system, a *supply-decreasing* deviation occurs when a participant's day-ahead schedule is not fully met in real time due to a change in the participant's ability or willingness to participate in the real-time market clearing. For example, a participant can lower its maximum generation parameter and thereby "derate" the physical capacity available in real time. A participant may also decrease an import schedule or increase an export schedule. Or a participant may be deficient and simply not satisfy its physical schedule in real time even if it did not change its day-ahead schedule. This is known as "deficient energy." With regard to schedules that consume power, e.g., load and exports, a supply-decreasing deviation occurs when a participant's real-time schedule is higher than its day-ahead schedule. This is a supply-decreasing deviation because additional supply is needed to meet the higher load.

17. A supply-increasing deviation is the opposite of a supply-decreasing deviation. In particular, a supply-increasing deviation may occur when participants increase real-time supply (or decrease real-time demand) by: (1) changing the physical parameter on a

generator; (2) increasing an import schedule; (3) decreasing an export schedule; or (4) withdrawing less load in real time than is forecast.

18. When supply-decreasing deviations are substantial and not offset by supply-increasing deviations, MISO may have to commit additional resources in the operating horizon and incur RSG costs for these commitments. The MISO RSG process identifies these RSG costs and allocates them to participants in proportion to both their supply-decreasing deviations and, in some circumstances, to supply-increasing deviations.

19. MISO's original proposal focused on how RSG costs should be allocated between supply-decreasing and supply-increasing deviations. One element of MISO's proposal involved revising the RSG cost allocation in relation to the four-hour "notification deadline" prior to the real-time operations (i.e., the PNDL introduced above). Under the current Tariff provisions, the allocation of (real-time capacity-related) RSG costs is different depending on when a deviation occurs relative to the notification deadline. Participants that change schedules prior to the notification deadline are charged RSG costs based on their net supply-decreasing deviations (any charges are applied only if the net supply-decreasing deviations are greater than zero). This netting results in participants being allocated RSG costs only if they are decreasing supply on a net basis (and only if there is a net supply-decreasing deviation on a market-wide basis).

20. In the PNDL timeframe, both supply-decreasing deviations and supply-increasing deviations are charged for the RSG costs -- there is no netting. In fact, the supply-increasing deviations are added to the supply-decreasing deviations even though the supply-increasing deviations may help to avoid RSG costs. As a result, PNDL schedule

changes are charged RSG costs whether the schedule change increases available supply or decreases it.

21. MISO's proposed change to the RSG allocation rules are intended to exempt PNDL supply-increasing deviations from being charged RSG costs. The rationale for this exemption is that most RSG costs are the result of real-time commitments made by MISO operators in response to supply-*decreasing* deviations. Supply-increasing deviations do not cause (and often help avoid) such commitments, regardless of when they occur. However, it is possible that supply-increasing deviations may sometimes increase RSG costs indirectly by lowering real-time prices. Our study was intended to quantify and compare these two effects of PNDL supply-increasing deviations. The results of the study are presented in the following section.

### C. Empirical Study Methodology

22. To address the concerns expressed in the March 7, 2014 Order, we developed an empirical analysis of RSG costs to compare how PNDL deviations directly contribute to RSG costs by causing or avoiding the need for commitments, and how they indirectly affect RSG costs by increasing or decreasing supply and changing LMPs.

23. Our empirical analysis is based on historical supply, demand, deviations, and RSG cost data from 2013 and 2014 MISO operations and settlements.[1] We estimate the RSG cost impacts from an illustrative, marginal 200 MW PNDL deviation in each of the historical hours in the two-year period. The basic idea is to quantify the expected RSG cost impact

[1] We use 2013 and 2014 data with one exception. The one exception is data on the division of post-notification deadline deviations between supply-increasing deviations and supply-decreasing deviations. The determination of how deviations split between the two types was based on a 2012 MISO study. This is the most recent data available on the categorization of deviations and we believe it is representative of the split during the study timeframe.

from an incremental deviation in each hour of the historical period. This provides a basis for using actual commitment costs to estimate the extent to which supply-increasing deviations directly reduce RSG commitment costs, and how such cost reduction compares to increase of RSG costs due to resulting reduction in real-time prices from supply affects. The data and analysis serve as an empirical basis for the proposal to exempt PNDL supply-increasing deviations from RSG cost allocation.

24. It is reasonable to measure the effect of a deviation on the margin under a wide array of market conditions to estimate the representative changes in RSG caused by PNDL deviations. We chose a 200 MW deviation because it a reasonable size for capturing the most likely effects of a deviation. It is large enough to affect resource commitments without being so large that it would not be representative of the PNDL supply-increasing deviations actually observed. For each hour, we calculated:

- The direct effects of supply-increasing deviations on the RSG costs related to the commitments these deviations allow MISO to avoid; and
- The indirect effects of PNDL deviations on RSG costs related to price effects of the additional supply.

25. We present our estimates in the next two sections. First we address the direct and indirect RSG cost effects from PNDL supply-increasing deviations and then the RSG cost effects of PNDL supply-decreasing deviations.

26. The March 7, 2014 Order stated that MISO previously did not explain why "hypothetical" RSG cost savings should have a role in the allocation of actually incurred RSG costs. In particular, the Commission asked why "…the RSG benefits that [MISO] describes – the hypothetical avoidance of RSG costs that are never actually incurred or

allocated – should be considered when allocating other RSG costs that are actually incurred."[2]

27. Our empirical analysis of PNDL supply-increasing deviation uses actual commitment cost in each hour to estimate the cost savings from a supply-increasing deviation. These are not "hypothetical" costs, but are based on the actual cost incurred by MISO in each hour to commit RSG-eligible units. PNDL supply-increasing deviations reduce the commitment of RSG-eligible units, while supply-decreasing deviations increase them. Accordingly, our study evaluates the extent to which PNDL supply-increasing deviations increase or decrease actual RSG costs. Ultimately, the goal is to establish an allocation of RSG costs that is fully consistent with cost causation. An allocation that reflects the fact that supply-increasing deviations reduce RSG costs, supports this goal.

## IV. Direct RSG Cost Savings from PNDL Supply-Increasing Deviations

28. We estimate the direct cost savings from avoided commitments due to PNDL supply-increasing deviations based on the actual historical conditions in each hour. Using the historical hourly system conditions, we can determine the extent to which operators could avoid commitments and save RSG costs when a 200 MW supply-increasing deviation occurs within the four-hour PNDL period.

29. To the extent that the PNDL supply-increasing deviations are known before operators make RSG-eligible commitments, the PNDL supply-increasing deviations can result enable operators to avoid additional commitments and thereby reduce RSG costs. Our analysis is rooted in two key empirical facts: (1) a large portion of RSG-eligible

[2] March 7, 2014 Order at P 44.

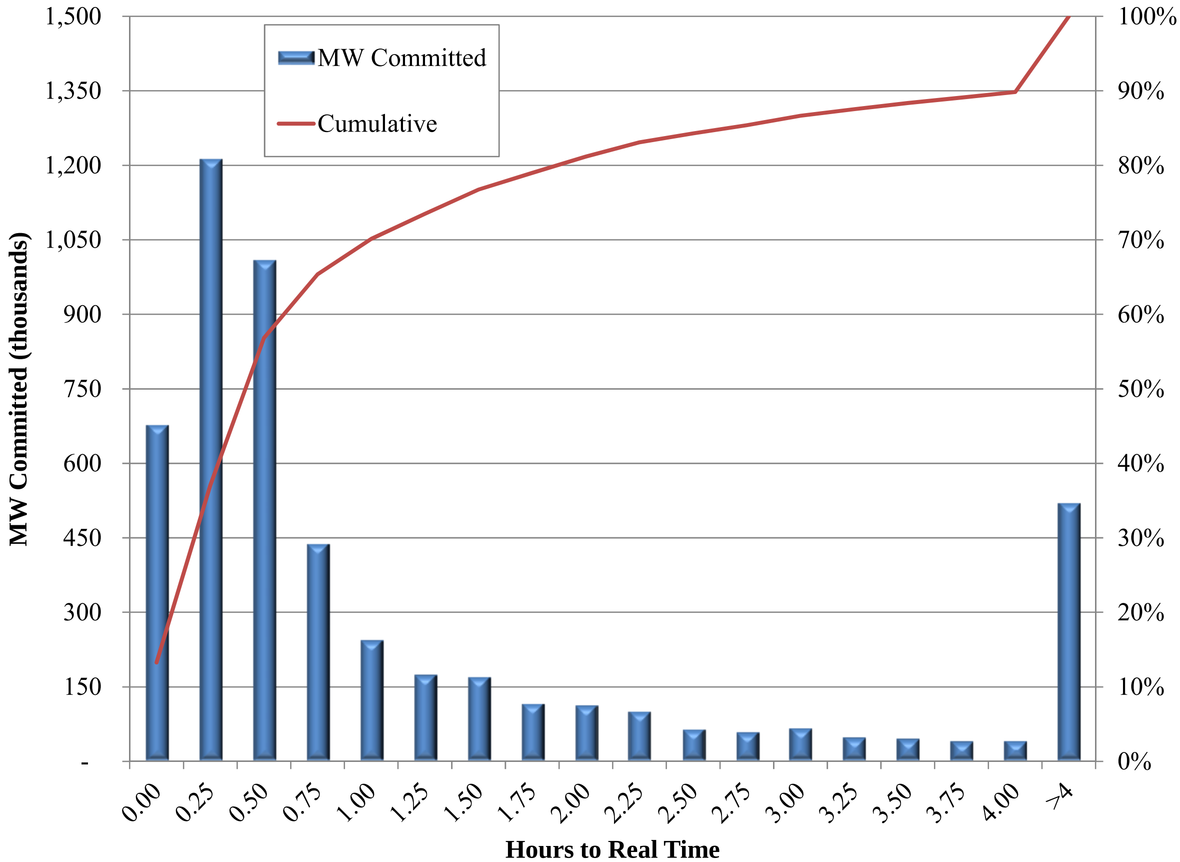
commitments are made well into the PNDL period (very close to real time) and (2) operators are aware of a signification portion of PNDL supply-increasing deviations by the time they make RSG-eligible commitments.

### A. Timing of RSG-Eligible Commitments

30. Figure 1 supports the first key fact. This figure shows the time distribution of RSG-eligible commitments.[3] Each bar shows the quantity of RSG-eligible commitments made during a particular 15-minute period prior to real time. For example, the first bar represents commitments made in the last 15-minute period before real time. The second bar represents RSG-eligible commitments made between 15 and 30 minutes before real time. The last bar represents all RSG-eligible commitments made earlier than the PNDL.

**Figure 1: Timing of RSG Commitments**

[3] Our overall analysis is based on 2013-2014 operating data, except for the timing of RSG commitment shown in Figure 1. The data in the figure is based on a 2012 MISO study. We are not aware of more recent data of this type and believe that it remains representative of current commitment patterns.




31. The figure shows that most of the RSG-eligible commitments are made very close to the operating hour. In fact, 70 percent of commitments are made within one-hour of real time. This is not surprising because large shares of the real-time commitments are made based on recommendations from the Look-Ahead Commitment (LAC) model that runs every 15 minutes. When the LAC recommends a commitment, operators will tend to act on those that must be made because of the start-time of the unit. For example, if LAC recommends the commitment of a unit with a 30 minute start time 2 hours prior to real time, the operator will generally wait for confirmation of this commitment recommendation by later LAC results. If the LAC recommends such a commitment 30

minutes prior to real time, the operator will generally act on the recommendation at that time.

### B. Types and Timing of PNDL Supply-Increasing Deviations

32. The fact that most commitments occur so close to the real-time operating hour makes a second key empirical fact very important – the timing of the PNDL deviations. To the extent that operators make the vast majority of the commitments that generate real-time RSG costs well into the PNDL period, then operators will likely be aware of a large portion of PNDL supply-increasing deviations prior to making their commitments, which will inform their decisions to commit resources for capacity.

33. The MISO data indicates that a large portion of PNDL supply-increasing deviations are known to operators by the time they make most of their commitments. This can be seen in Table 1, which summarizes the various types of supply-increasing deviations derived from a study MISO conducted on PNDL deviations from 2012. We classified the data between supply-increasing and supply-decreasing deviations as explained in Appendix 1.

**Table 1: PNDL Supply-Increasing Deviations**

| Category of Deviations | Volume (MWh) | Percentage of Total |
|---|---|---|
| Resources | | |
| Must Run | 7,015,615 | 29% |
| Dispatch Deviation | 240,181 | 1% |
| Non Dispatchable | 4,653,729 | 20% |
| Load | 9,630,520 | 40% |
| Interchange | | |
| Import | 1,946,133 | 8% |
| Export | 330,732 | 1% |
| Total | 23,816,911 | 100% |

1. Must-Run Deviations (29 percent of total)

34. The "must-run" category contains deviations that are the result of: a) increases in the minimum of the dispatch level for online units, and b) self-commitment of units that were previously offline. These two types of must-run deviations have very different effects. Increasing the minimum dispatch level (i.e., the Hourly Economic Minimum Limit) of an online unit does not affect commitments because it has no effect on the total capacity available to satisfy the system's needs. However, self-committing a resource can affect operators' decisions to commit resources for capacity if the operators are unaware of the self-commitment sufficiently in advance.

35. In order to determine when the self-commitments occurred relative to the operators' commitment decision, we evaluated offer data and the Look-Ahead Commitment tool (LAC). Operators rely on LAC to inform their commitments in a prospective two-and-a-half-hour horizon. LAC forecasts system conditions based on a variety of inputs, including real-time load, online generation, and interchange data. Hence, to the extent the must run deviation is reflected in LAC online generation data, then it is known to operators.

36. Our evaluation of must-run deviations indicated:

- 55 percent of the must-run deviations were increases in the Hourly Economic Minimum Limit of units that were online prior to the notification deadline. These deviations have no effect on operator decisions as described above.

- The remaining 45 percent of must-run deviations are associated with self-commitments during the PNDL period. Of these, 82 percent are known more than one hour before real time (i.e., 37 percent of all must-run deviations), information that was available for operators to use to reduce RSG-eligible commitments.

- In total, therefore, 92 percent of all must-run deviations do not materially affect operators' decisions to commit resources for capacity, either because they do not change the total online capacity or because they are known well in advance of when operators are deciding to commit resources for capacity.

2. Dispatch Deviations (1 percent of total)

37. Supply-increasing Dispatch Deviations (called excessive energy) occur when the resource over-performs its day-ahead schedule. These deviations are observed in real time when units exceed their dispatch instructions. However, these deviations do not affect commitments for two reasons. First, they do not change the quantity of online capacity so, even if they had been known, they would not have affected the operators' determinations on the need to commit resources. Second, they are very small, totaling only one percent of the PNDL supply-increasing deviations.

3. Load and Non-Dispatchable Deviations (60 percent of total)

38. The categories of load and non-dispatchable deviations are associated with forecast errors. A supply-increasing load deviation occurs when the anticipated load at the PNDL period is less than the actual load in real time. These load deviations are categorized as supply-increasing deviations even though they are demand-reducing deviations in reality.

39. Non-dispatchable deviations involve units that have to forecast their output, primarily wind units. To the extent that there is uncertainty regarding wind speeds, the units may produce more than scheduled and constitute a supply-increasing deviation.

40. While the final accounting of forecast deviations occurs after real time, operators will be aware of a large portion of these deviations at the time they are making commitments. Operators continuously monitor system conditions and update their forecasts between the PNDL and the real-time operating timeframe. To the extent that forecast errors fall after

the PNDL, these supply-increasing deviations reduce the quantity of commitments made by operators.

41. To gain some insight on what portion of these forecast errors were likely known by the operators when making reliability commitments, we examined MISO's forecast data from its intra-day commitment tools, i.e., the LAC (1 hour prior to real time) and the Intra-day Reliability Assessment and Commitment (IRAC) process (4 hours prior to real time). By comparing these two forecasts to the real-time load, we found that the LAC one-hour-ahead load forecast error is over 30 percent lower than the IRAC four-hour-ahead load forecast. This means 30 percent of the supply-increasing load deviations are known prior to the timeframe when the operators make most of their commitments.

42. We do not have a comparable forecast error analysis for the other forecast deviations (Non-Dispatchable deviations). However, we believe operators will benefit from comparable improvements in these forecasts as the real time horizon nears. Nonetheless, to be conservative, we assume that none of these deviations are known by operators when they make commitments.

4. Import and Export Deviations (9 percent of total)

43. Raising the quantity of an import schedule or reducing the quantity of an export schedule results in a supply-increasing deviation. Similarly, reducing the quantity of an import schedule or raising the quantity of an export schedule results in a supply-decreasing deviation. We examined tag data on interchange schedules and found that 66 percent of the supply-increasing schedule changes are made prior to the last hour before real time.

### C. Summary of Supply-Increasing Deviations Known by Operators

44. As a result of the empirical analysis described above, we find that a substantial portion of the supply-increasing deviations are known to operators by the time they make commitments in the last hour of the PNDL period. Hence, they would tend to directly reduce RSG costs by causing operators to make fewer commitments.

45. The portion of the PNDL supply-increasing deviations that would directly reduce RSG costs are those that are:

- Known more than one hour in advance of real time; and
- Would reduce the amount of capacity commitments the operators would have otherwise made.

46. Based on the percentage of each type of supply-increasing deviation that meet these criteria (as described above), the aggregate portion of the PNDL deviations that would reduce RSG costs would range from 29 percent to 49 percent. The low end of this range is based on the assumption that none of the non-dispatchable deviations are known. In reality, the operators have processes that would allow them to be aware of some portion of these deviations. The high side of this range is based on the assumption that all of the non-dispatchable deviations are known. However, this range is based on the deviations that occurred throughout 2012. During any particular period going forward, the PNDL supply-increasing deviations that may directly reduce RSG costs may be lower or higher than this range. Therefore, our analysis presented in the following section quantifies the estimated RSG effects for a range of 25 percent to 75 percent.

### D. Estimated Direct RSG Cost Effects of PNDL Supply-Increasing Deviations

47. As discussed in the previous subsection, the data indicates that 70 percent of RSG-eligible commitments are made one hour prior to real time (see Figure 1). Therefore, we estimate the avoided commitment costs of supply-increasing deviations under a range of assumptions about what portion of deviations are known one hour before real time.

48. In particular, in hours when there were historical RSG costs incurred, we measure the marginal value of a supply-increasing deviation in the historical hour by modeling a 200 MW deviation under multiple scenarios that vary according to what portion of the deviation is reflected in the operators' commitments. We use three scenarios. One where the portion of the deviations that are known is 75 percent, one where it is 50 percent, and one where it is 25 percent.

49. When 75 percent of the supply-increasing deviations can be observed by operators, then operators are able to reduce the RSG commitments by 150 MW (75 percent of 200 MW). Our estimate of avoided commitments is capped at the amount of commitments that actually occur in the last hour of the PNDL period. This is because operators can only mitigate commitments that are made in the latter part of the PNDL period. Therefore, if the commitments in the last hour were 90 MW in this example, then the estimated avoided commitments are estimated at 90 MW, not 150 MW.

50. Likewise, for the 50 percent scenario, it is assumed that operators can reduce commitments by 100 MW, capped at the actual commitments (90 MW in this example). For the 25-percent scenario, 25 percent of the 200 MW deviation can be avoided (50 MW).

51. The avoided cost associated with these avoided commitments is estimated by using actual RSG commitment costs for each hour. If all commitments are avoided, then the total RSG commitment costs for commitments in that hour represent the estimated avoided commitment costs. When only a portion of the RSG commitments are avoided in a given hour, then we assume the most expensive commitment costs incurred in the hour are the ones that would be avoided because MISO's operators commit less expensive units ahead of more expensive units.

52. Table 2 shows the range of avoided costs corresponding to the various scenarios regarding the portions of the deviations that are known to operators.

**Table 2: Estimates of Avoided Cost from 200 MW Supply-Increasing Deviation**
Dollars per MW of Deviation

| Portion of Deviations Known One Hour before Real Time | RSG Cost (Savings) |
|---|---|
| 75 Percent | ($5.25) |
| 50 Percent | ($3.76) |
| 25 Percent | ($2.04) |

53. Because supply-increasing deviations allow the operators to avoid commitments and save commitment costs in many hours, the greater the portion of deviations that operators know in advance, the greater the cost savings.

## V. Indirect RSG Cost Effects from Supply-Increasing Deviations

54. The direct avoided commitment costs evaluated in the previous subsection are an important component of the impact of supply-increasing deviations on RSG costs. However, as the Commission emphasized in its March 7, 2014 Order, supply-increasing deviations can potentially increase RSG costs indirectly by lowering energy prices and

increasing the RSG payments needed for the committed units to recover their costs fully. We call this the "price effect" and we estimate it in this subsection.

55. We estimate the price effects on RSG costs based on the effect that a supply-increasing deviation has on the energy prices in each historical hour. Having estimated these price effects, we then can calculate any change in RSG payments that would be necessary to cover the as-bid costs of the RSG-eligible units.

### A. Methodology for Estimating Price Effects from Deviations

56. The price effects from deviations will occur in all hours of the year when at least some RSG costs are being paid. It will also occur in hours when RSG costs are not being paid but an RSG-eligible unit becomes revenue inadequate because of a lower price from the supply-increasing deviations. For historical hours when RSG costs were being paid, a supply-increasing deviation will increase RSG costs to units receiving RSG payments by the change in price times the output of the unit in question.

57. For historical hours when there was no RSG costs being paid, we checked to ensure that RSG-eligible resources were earning their as-offered cost after the price effect of the supply-increasing deviation. We find that in these hours, there were some revenue-adequate units that were eligible for RSG payments (committed by MISO), but became revenue inadequate as the result of the price decrease resulting from the supply-increasing deviation. In such cases, the increased RSG costs are the amount of revenue each unit requires in order to remain revenue-adequate under the revised energy price.

58. As for our estimation of the avoided commitment costs described in the previous section, we measure the price effect in each hour by modeling a 200 MW supply-increasing deviation. Our basic approach is to reconstruct the actual hourly supply curve and the

market clearing point and shift the supply curve to model the marginal increase in supply. We assume the supply-increasing deviations come at a zero offer price cost and displace high-cost units on the supply curve, thereby causing a lower-cost unit to set price.

59. In measuring the marginal price impact of a supply-increasing deviation in a given hour, we must recognize that in some of these hours a deviation avoids a commitment. These avoided commitments will tend to partially offset the reduction in energy prices. In other words, the net additional supply will not be the entire supply-increasing deviation, but rather the deviation amount minus the quantity of avoided commitments. In fact, the net change in supply can sometimes result in an *increase* in energy prices. Indeed, as we explain below, if operators know at least 50 percent of the PNDL deviations, then the clearing-price effect actually results in higher prices and lower RSG costs.

### B. Types of Supply-Increasing Deviations

60. In estimating the indirect effects of supply-increasing deviations, it is important to recognize that not all supply-increasing deviations will cause price effects. As shown above in Table 1, there are six types of supply-increasing deviations.

61. Some of these deviations will have price effects because they affect the total supply available to the real-time market or otherwise change the supply that will clear. These deviations include:

- Must-run deviations associated with units self-committed after the PNDL, because these deviations increase the total supply;
- Must-run deviations associated with suppliers increasing the Minimum Generation level that results in higher output from a unit whose costs exceed the LMP – because these are uneconomic must-run deviations that increase the total supply;

- Dispatch deviations, because these displace higher-cost marginal supply; and
- Supply-increasing Interchange deviations.

62. When the above-listed deviations occur, they affect the supply that will clear by displacing other higher-cost supply. In other words, if the deviation had not occurred, the market would clear on a higher portion of the supply curve. Taken together, these deviations constitute 34 percent of all of the PNDL supply-increasing deviations.

63. However, other deviations relating to forecast errors ("Load" and "Non-Dispatchable" deviations) do not affect the supply that will clear the real-time market. These deviations are associated with errors in forecasting real-time conditions, but do not change the real-time conditions (supply or demand). These forecasts generally improve over the PNDL timeframe. Nonetheless, even if the forecasts had been perfectly accurate, the real-time supply and demand would be the same. Hence, there is no possible price effect associated with these types of deviations. Therefore, these types of deviations are not used in estimating the price effect. Additionally, must-run deviations associated with units that are committed prior to the PNDL are not included because they do not increase the total quantity of real-time supply. Taken together, these deviations constituted 66 percent of all of the PNDL supply-increasing deviations.

64. In summary, for purposes of estimating the price effects of supply-increasing deviations, we assume that 34 percent of the PNDL supply-increasing deviations affect MISO's real-time energy prices (i.e., 68 MW of the 200 MW deviation simulated).

65. The 34 percent level assumed likely overestimates the portion of supply increasing deviations that have a price impact. This is because some of the categories of deviations assumed to affect energy prices would in reality not affect the energy prices. Interchange

deviations is one such category. It includes both imports and exports that may partially offset and, therefore, will not all affect energy prices. For example, an increase in an import schedule can be offset by an increase in an export schedule. In this case, the price would not be affected. Therefore, the 34 percent assumption parameter used in estimating the effect of supply-increasing deviations on the clearing price is a conservative value and is likely lower in reality.

### C. Estimated Effects of Supply-Increasing Deviations on RSG Costs

66. To estimate the clearing-price effect, we model the real-time supply and demand using actual market offers and outcomes from the historical hours in 2013 and 2014. The basic idea is to calculate a price change due to the increase in supply from the deviations. We build the supply curve using offers of all committed resources for that operating hour and place the dispatched resources on top of the supply curve. In other words, the supply-increasing deviations are placed in the supply curve at zero marginal cost.

67. For each hour, we adjust the supply curve in two ways to reflect the impact of the supply-increasing deviation:

- First, we adjust the supply to account for the portion of the supply-increasing deviation that would affect energy prices;
- Second, we reduce the supply to account for any commitments that would be avoided due to the deviations.

68. In some hours, as noted above, the commitment effect could be greater than the dispatch effect and result in a higher price and a decrease in RSG costs. Because supply-increasing deviations have two effects on price (the commitment effect and the dispatch effect), the net effect will depend on the portion of deviations that are known to operators prior to making commitments (see Table 2). The higher the portion of deviations known

to operators, the greater the avoided commitment effect and thus, the lower the net effect on prices.

69. The Commission hypothesized that a supply-increasing deviation could cause some online units to produce less energy and, in doing so, might cause MISO to have to make higher RSG payments to the unit.[4] The basic idea is that a RSG-eligible unit on the margin may be redispatched to a lower output level and cause a decline in its net revenues, thereby requiring more RSG costs to maintain its revenue adequacy. This "output" effect on RSG costs is generally very small for the following reasons:

- The units that will reduce output because of the supply-increasing deviation are those that are on the margin (whose energy cost equals the LMP at its location). Hence, only RSG-eligible units on the margin will be affected by the hypothesized output effect. But RSG-eligible units are rarely on the margin.
- Even for those RSG-eligible units on the margin, their reduced output from the deviation will have marginal production costs that are roughly equal to the energy prices. Therefore, there is little or no loss in net revenue associated with this output effect. In other words, if a unit offering at $25 per MWh is on the margin, its LMP will be $25 per MWh. If its output goes down, its production cost will decline by the same amount as its market revenue. Therefore, its net revenues do not change so its RSG payments will not change.

70. In other words, the "output" effect on RSG costs is probably more hypothetical than actual. Nonetheless, we calculate our price effects in a manner that will tend to over-estimate the price effect and more than cover any potential output effect. This is the case because we assume no output reduction of RSG-eligible units. Therefore, the reduced production costs from reducing output are ignored and our indirect price effect from supply-increasing deviations will include the additional RSG payment needed to recover the costs of producing the uneconomic energy at the higher original output level. For this

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[4] March 7, 2014 Order at P 24, fn. 83.

reason, our estimates of the potential for indirect increases in RSG costs caused by the PNDL supply-increasing deviations will always be overestimated.

## VI. Summary of the Aggregate Direct and Indirect RSG Cost Effects

71. Table 3 shows the total effect on RSG costs from supply-increasing deviations based on what operators know at the time of commitment. The estimates show that the clearing effect is smallest when the deviation known is the highest. The second column shows the direct RSG cost effects of deviations which are associated with avoided commitments and were first shown above in Table 2. The third column shows the indirect clearing-price RSG cost effects. The final column on the right shows the sum of the direct and indirect results.

**Table 3: Total Effect on RSG Costs from Supply-Increasing Deviation**
**Dollars per MW of Deviation**

| Portion of Deviations Known One Hour before Real Time | RSG Cost (Savings) | | RSG Costs (savings) from Clearing-Price Effect | | Total Change in RSG Costs | |
|---|---|---|---|---|---|---|
| | 2013 | 2014 | 2013 | 2014 | 2013 | 2014 |
| 75 Percent | ($5.25) | ($4.24) | ($0.36) | ($0.06) | ($5.61) | ($4.30) |
| 50 Percent | ($3.76) | ($3.08) | ($0.06) | $0.18 | ($3.82) | ($2.89) |
| 25 Percent | ($2.04) | ($1.68) | $0.25 | $0.41 | ($1.79) | ($1.27) |

72. Overall, the table shows that on the margin, supply-increasing deviations that occur after the PNDL would reduce RSG costs on a net basis in all scenarios. Hence, the current regime that allocates RSG costs to these PNDL deviations is in direct conflict to the cost-causation principle that is the basis of MISO's RSG cost allocation framework. In fact, one could argue that such deviations should receive a credit rather than a charge.

Nonetheless, the MISO proposal in this docket is conservative in that it simply proposes an exemption for the PDNL supply-increasing deviations.

## VII. Incentive Effects of MISO Proposal

73. While the March 7, 2014 Order mainly noted the absence of an empirical analysis that would support exempting PNDL supply-increasing deviations from RSG cost allocation, there are other incentive effects that support MISO's proposal. Additionally, the Commission raised other questions related to these incentive effects that we address in this subsection.

### A. Improved Incentives to Avoid Supply-Decreasing Deviations

74. The MISO proposal will improve participants' incentives to follow dispatch instructions. When RSG costs are allocated to deviations that do not cause RSG-eligible commitments, a smaller amount of costs are allocated to those deviations that do cause the RSG-eligible commitments. Approval of the MISO proposal will increase the allocation of costs to deviations that cause RSG-eligible commitments, and this would strengthen the disincentive to cause these types of deviations. Ultimately, reducing these supply-decreasing (or load-increasing) deviations will improve the performance of the day-ahead market and reduce RSG costs.

75. Together with MISO, we described this benefit in our Post Technical Conference comments:

> [A]llocating the RSG costs to a much large number of deviations by including Post-Notification Deadline supply-increasing deviations will substantially reduce the incentive for participants to fully schedule the system's needs in the day-ahead market. This will, in turn, reduce the efficiency of the day-ahead commitment and ultimately raise overall costs to MISO's customers. The RSG cost allocation plays a

> key role in minimizing the [supply-decreasing] harming deviations that require MISO to resort to out-of-market actions that result in RSG costs. (Post Technical Conference Comments of MISO and its IMM, at p. 10, December 3, 2014).

76. While the Commission did not disagree with this benefit, it indicated that the market effects of under-allocating RSG costs to supply-decreasing deviations should be evident because this flaw currently exists.[5] In reality, it is difficult to isolate the impact of this allocation flaw from all other factors that influence day-ahead market scheduling. However, increasing the allocation of real-time RSG costs to supply-decreasing (which include load-increasing deviations) will increase the economic incentives to schedule load in the day-ahead market. If load is under-scheduled, allocating cost to load-decreasing deviations will deter such deviations and this will improve the efficiency of the day-ahead market because it facilitates day-ahead commitments that will satisfy MISO's full real-time requirements.

77. Therefore, the most relevant evidence of adverse effects of the current allocation would be a persistent under-scheduling of net load in the day-ahead market. Net load in this context is defined as physical load plus virtual load minus virtual supply in the peak hour of each day. In general, the system demands in the peak hours drive MISO to commit additional resources and incur RSG costs. Table 4 shows the peak-hour net load scheduled in the day-ahead market as a percent of the actual real-time load.

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[5] March 7, 2014 Order at P 44.

**Table 4: Net Load Scheduling in Peak Hours in the Day-Ahead Market**

| Year | Share of Real-Time Load Scheduled Day Ahead |
|---|---|
| 2013 | 99.1% |
| 2014 * | 99.8% |
| 2015 ** | 98.9% |

*Notes*:
* Excludes January due to anomalous supply conditions during the "polar vortex."
**Includes January 1 - July 31, 2015.

78. The table shows that net load scheduled in the day-ahead market in the peak hour of each day has been under-scheduled on average over the past three years. Although it is difficult to isolate the effects of the current flaw in RSG cost allocation, these results are consistent with our expectations. When the RSG rate charged to supply-decreasing deviations (or under-scheduled load) is understated, one would expect more of these deviations and lower net-load scheduling in the day-ahead market. Scheduling less than 100 percent of the peak load in the day-ahead market leads to sub-optimal commitments of MISO's generating resources and increases the frequency with which MISO must rely on higher-cost units committed in real time to satisfy the system's needs.

79. In approving most of MISO's proposed RSG cost allocation reforms last year, the Commission recognized the benefits of aligning the allocation of RSG costs with the actions that cause the costs. The economic justification for this proposed change is no different.

## B. Potential Adverse Incentives from MISO's Proposal

80. The Commission also suggested that the MISO proposal could create inefficiencies:

> MISO also does not address whether the proposed exemption could instead cause market inefficiencies. For example, MISO does not address whether, by exempting certain supply-increasing deviations from the allocation of real-time

RSG costs, MISO would remove an implicit penalty for deviating from resources' dispatch instructions. (March 7, 2014 Order at P 44.)

81. When one considers the types of supply-increasing deviations that would be exempted under MISO's proposal, it becomes clear that there is no substantial concern that the proposal will cause market inefficiencies. The following is a discussion of the potential efficiency implications of MISO's proposal for each class of PNDL supply-increasing deviation that would be exempted from the RSG cost allocation:

- <u>Dispatch deviation</u>: This includes generators producing more energy than requested by MISO, which appears to be the subject of the Commission's concern. These deviations accounted for only 1 percent of the supply-increasing deviations in our data. MISO has never had a material issue with over-production, which only generally occurs when generators are asked to ramp down quickly and are responding more slowly than requested. The LMP itself and uninstructed deviation settlement rules are the preferred means to motivate suppliers to follow MISO's dispatch instructions, and we deem RSG charges to be unnecessary for that purpose.

- <u>Must-Run and Import/Export deviations</u>: Self-commitments and changes in physical transactions generally occur in response to economic signals. As such, in addition to reducing RSG costs, they will produce market efficiencies when implemented consistently with MISO's prices. There is no value in penalizing this conduct to discourage it. These deviations account for 39 percent of all PDNL supply-increasing deviations.

- <u>Load and Non-Dispatchable deviations</u>: These deviations are caused by forecast errors and do not ultimately change the dispatch. Additionally, the forecasts continue to improve as MISO moves toward the operating hour. There is no benefit in penalizing these deviations since participants already have incentives to forecast well and MISO supplements the participants' forecasts. These deviations account for 60 percent of the PDNL supply-increasing deviations.

82. Therefore, this evaluation of the incentive effects and justifications for the proposal also supports the approval and adoption of MISO's proposal.

83. This concludes my Affidavit.

## Appendix 1 – Disaggregation of PNDL Deviations

1. The quantities of supply-increasing and supply-decreasing deviations used in our empirical analysis were derived from aggregated deviation data from 2012. Table A1 below shows our division of the aggregated data between the two types of deviations.

2. Column (2) is the aggregated data for each category. Column (3) and (4) are our allocation of the volumes in Column (2) between supply-increasing and supply-decreasing deviations, respectively. The purpose of this Appendix is to explain the division of these deviations between columns (3) and (4).

**Table A1 Post Notification Deadline Deviations**

| Sub Category | Mwh/Year | Supply Increasing | Supply Decreasing |
|---|---|---|---|
| Load | 19,261,040 | 9,630,520 | 9,630,520 |
| Non Dispatchable | 9,307,458 | 4,653,729 | 4,653,729 |
| Must Run (Min↑) | 7,015,615 | 7,015,615 | |
| Import | 6,277,848 | 1,946,133 | 4,331,715 |
| Export | 1,066,879 | 330,732 | 736,147 |
| Derate (Max ↓) | 5,799,972 | | 5,799,972 |
| Dispatch Deviation | 436,693 | 240,181 | 196,512 |
| Total | 49,165,505 | 23,816,911 | 25,348,594 |

3. The table is sorted according to the total deviations. The largest category is **Load**. We divide this between supply-increasing and supply-decreasing deviations equally. We do this because in general MISO schedules 99 percent of the day-ahead load. That means that, on average, day-ahead load is 99 percent of actual real-time load. Consequently, deviations in real-time load from day-ahead load will tend to be equally over and under scheduled.

4. The second category in the table is deviations from **Non-Dispatchable** resources. These deviations are associated with units that have to forecast their output, primarily wind units. These forecasts may not be accurate relative to the final schedules and so, in real

time, the unit may produce more or less than scheduled. Like the load forecast error, we divide these equally between supply-increasing and supply-decreasing deviations. Ongoing improvements in MISO wind forecasting accuracy also supports an equal split between supply-increasing and supply-decreasing deviations because this will tend to alleviate a bias toward under or over forecasting. A small forecast bias supports an equal split between forecast errors because a small bias means the forecasts tend to be equally over- and under forecasted.

5. The "**Must Run**" sub-category contains deviations that are the result of increases in the minimum of the dispatch range, which might include a change from 0 MW (which is a self-committed unit). These deviations are categorized solely as supply-increasing because they can only increase supply and not decrease it. The analogous category to must-run deviations for supply-decreasing deviations is the **Derate** category. A derate is a decrease in the maximum generation level for a resource. It can only result in a supply decrease. Accordingly, all derates are classified as supply-decreasing deviations.

6. Next in the table are interchange deviations, **Imports** and **Exports**. We examined actual interchange schedules for each hour in 2013 and 2014. We found that 69 percent of the PNDL interchange schedule changes were supply-decreasing ones (either a reduction in an import schedule or an increase in an export schedule) and 31 percent were supply-increasing ones (either a reduction in an export schedule or increase in an import schedule).

7. **Dispatch Deviations** (called excessive energy and deficient energy) occur when the resource over-performs or underperforms its day-ahead schedule. We found that supply-increasing deviations make up 55 percent of this total.

ATTESTATION

I am the witness identified in the foregoing Affidavit of Robert A. Sinclair. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Robert A. Sinclair, Ph.D.

Subscribed and sworn before me this 30 day of October, 2015

MATTHEW JAMES CARRIER
NOTARY PUBLIC
REG. #7233763
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES NOVEMBER 30, 2017

Notary Public

My commission expires: November 30, 2017