Southwest Power Pool

PRICE FORMATION TASK FORCE MEETING

February 10, 2016

Conference Call

• M I N U T E S •

Agenda Item 1 — Call to Order, Proxies, Agenda Discussion

Matt Moore (GSEC) called the meeting to order at 9:00 a.m. The attendance was recorded (*Attachment 1 - PFTF Attendance February 10 2016*).

The group reviewed the agenda (*Attachment 2 - PFTF Agenda for February 10 2016*).

Agenda Item 2 — Review Charter

Jared Greenwalt (SPP) reviewed the Price Formation Task Force (PFTF) 2016 Charter (*Attachment 3 - PFTF Charter*). Jared explained the reasons why it is important to first define "market efficiency" before the group begins to list concerns and propose solutions *(Attachment 4 – PFTF Charge)*. Jared concluded by describing the four goals of proper price formation as directed by FERC *(Attachment 5 - 153 FERC ¶ 61,221)*.

1. Maximize market surplus for consumers and suppliers;
2. Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability;
3. Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and
4. Ensure that all suppliers have an opportunity to recover their costs.

Agenda Item 3 — Process for Receiving the List of Concerns

The PFTF discussed possible categories by which to group concerns and the proper format to communicate those concerns to be included in a survey. The format will include (1) a description of the problem or issue with the current design, (2) an explanation of how the issue relates to price formation, and (3) potential solutions the submitter would find acceptable or unacceptable. The third item is optional. Jared Greenwalt (SPP) was assigned an action item to draft a template and send to the PFTF members. The PFTF will begin discussing the definition of "market efficiency" before this survey is sent out to the MWG exploder and the MOPC exploder. Cliff Franklin (Westar) asked SPP staff to research a method for identifying cost causation of make-whole payments and the extent to which they recover costs; SPP staff took an action item to explore a methodology for doing this. Participants asked for review sessions on various topics, and SPP staff took an action item to summarize some specific training topics related to pricing that is currently available. Cliff took an action item to draft a definition for "market efficiency for wholesale electric markets" and send to PFTF members before the March 10th meeting.

Agenda Item 4 — PFTF Meeting Schedule

The next meeting will be held on March 10, 2016 from 9:00 – 12:00 a.m. by conference call. The PFTF will meet face-to-face at AEP in Dallas on April 18, 2016 from 1:00 – 5:00 p.m.

<u>Agenda Item 5 – Adjournment</u>
Matt Moore (GSEC) adjourned the meeting at 11:00 a.m.

Action Items:

- **Agenda Item 3:** Jared Greenwalt (SPP) will create a template for concerns and send it to PFTF members for review.
- **Agenda Item 3:** SPP Staff will research a method for identifying cost causation of make-whole payments and the extent to which they recover costs.
- **Agenda Item 3:** SPP staff will summarize some specific training topics related to pricing that is currently available.
- **Agenda Item 3:** Cliff Franklin (Westar) will draft a definition for "market efficiency for wholesale electric markets" and send to PFTF members by the March 10th meeting.

Future Agenda Items:
Define "market efficiency" – March

Future Meetings:
March 10, 2016 (9:00 a.m. – 12:00 p.m.)
Location: Conference Call

April 18, 2016 (1:00 p.m. – 5:00 p.m.)
Location: AEP Office – Dallas, TX
Room: 8th Floor

Respectfully Submitted,

Debbie James
Secretary

Attachments
Attachment 1 - PFTF Attendance February 10 2016
Attachment 2 - PFTF Agenda for February 10 2016
Attachment 3 - PFTF Charter
Attachment 4 – PFTF Charge
Attachment 5 - 153 FERC ¶ 61,221

X	= In Person	PFTF			
P	= By Phone	February 10, 2016			
*	= By Proxy	Conference Call			
Day 1	Full Name	Company	E-mail	Business Phone	Other Phone
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Southwest Power Pool

PRICE FORMATION TASK FORCE

February 10, 2016

Conference Call

• A G E N D A •

9:00 a.m. – 11:00 a.m.

1. Call to Order, Proxies, Agenda Discussion .... Matt Moore
2. Review Charter .... Jared Greenwalt
3. Process for Receiving the List of Concerns .... Jared Greenwalt
4. PFTF Meeting Schedule .... Jared Greenwalt
5. Adjournment .... Matt Moore

Southwest Power Pool
Price Formation Task Force
Charter
January 19, 2016

Purpose

The Price Formation Task Force 2016 (PFTF 2016) is a task force established by the Market Working Group (MWG) to evaluate the efficiency and transparency of Energy and Operating Reserve pricing.

Scope of Activities

In carrying out its purpose, the PFTF 2016 will:

1. Define "market efficiency" and determine how to measure it.

2. Determine what pricing is for reliability purposes as opposed to economic purposes.

3. Review/Analyze concerns expressed with current pricing methodologies.

4. Report findings to the MWG and recommend prioritization of development of the market design changes to the MWG.

5. Evaluate any proposed market design change related to the items listed above and make a recommendation to MWG.

Representation

PFTF 2016 membership consists of up to five members, including a chair, as appointed by the MWG chair with due consideration of the various types and expertise of members and their geographic locations. A member of SPP staff shall be the secretary for the task force.

Duration

The PFTF 2016 is temporary and is expected to complete its tasks by the end of 2016.

Reporting

The PFTF 2016 reports to the MWG.

PFTF Charge

February 10, 2017

Jared Greenwalt
jgreenwalt@spp.org
501.688.8314

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future

Why Define Market Efficiency?

- If we don't know where we are going, how do we know…
  - How to get there?
  - When we're lost?
  - How close we are?
  - When we have arrived?

Why Define Market Efficiency?

- To measure how well the market is designed
  - Can it be improved?
  - How much can it be improved?
- To provide market design direction
  - How can it be improved?
  - What pieces need improvement?
  - What do we change to improve it?
- To measure the benefit of a proposed design
  - Is the change fixing it or making it worse?

Why Are We Operating a Market?

- RTO facilitated markets account for the energy sales while setting a mutually agreeable price
- Wholesale energy markets are designed to emulate competitive demand and supply markets
  - Economic Pricing
  - Reliability Pricing

Equal in Magnitude, Opposite in Direction

- Economic Pricing
  - Driven by supply and demand
    - Flexible demand (competition) is simulated through
      - Offer Cap
      - Mitigated Offers
- Reliability Pricing
  - Accounts for the obligation to serve and keep the lights on
    - NERC standards
    - Keeping the lights on

Timeline

- Define “market efficiency”
- Send out template for areas of concern
- Review and prioritize list of concerns
- Resolve the top concerns
- All recommendations to MWG by January 2017

Lighthouses: Goals of Proper Price Formation

1. Maximize market surplus for consumers and suppliers;
2. Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability;
3. Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and
4. Ensure that all suppliers have an opportunity to recover their costs.

153 FERC ¶ 61,221 at 2

153 FERC ¶ 61,221
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators — Docket No. AD14-14-000

ORDER DIRECTING REPORTS

(Issued November 20, 2015)

TABLE OF CONTENTS

Paragraph Numbers

1. In this order, we direct each regional transmission organization (RTO) and independent system operator (ISO) to publicly provide information related to certain price formation issues. Specifically, we seek information in a report from each RTO/ISO regarding five price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. We direct each RTO/ISO to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions contained herein within 75 days of the issuance of this order. Following the submission of the RTOs'/ISOs' reports, the Commission will allow for public comment. The Commission will use the reports and comments to determine what further action is appropriate.

2. To evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs, the Commission initiated a proceeding in this docket on June 19, 2014. The Commission stated that the goals of proper price formation are to: (1) maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.[1] Each RTO/ISO ideally would not need to commit any additional resources beyond those resources scheduled economically through the market processes and market prices would thus reflect the value of electricity consumption without the need to involuntarily curtail load or increase resource commitments out-of-market.

3. We are directing the RTOs/ISOs to submit reports addressing five areas of price formation in RTO/ISO markets. Specifically, this order focuses on pricing of fast-start resources, resource commitments to manage multiple contingencies, look-ahead modeling, uplift allocation, and transparency because each of these five areas has a potential for reform to improve price formation in the RTOs/ISOs consistent with the goals of the price formation initiative. In particular, identifying best practices for these

[1] *See* Notice Inviting Post-Technical Workshop Comments, Docket No. AD14-14-000, at 2 (Jan. 16, 2015); Notice, Docket No. AD14-14-000 (June 19, 2014).

five areas should provide incentives to maintain reliability, to facilitate accurate and transparent pricing, to reduce uplift, and for market participants to operate consistent with dispatch signals. We have selected these areas because the discussion at the price formation workshops and the comments received after the workshops suggest that a number of RTOs and ISOs have sufficient experience with these areas such that we may be able to discern best practices and understand unintended consequences. Further, because these issues are complex, inter-related market features, the effects of any one change on the price formation process may not be readily apparent. By obtaining information on these five issues, the Commission, RTOs/ISOs, and stakeholders will be able to compare practices across markets. Such comparisons will illustrate the benefits and drawbacks of any particular practice as well as illuminate potential unintended consequences from potential reforms. Through these reports, we also seek further information regarding current practices for each issue and any reforms already planned. The Commission seeks this information not only to answer technical questions regarding how each RTO/ISO addresses these topics, but also to understand the reasons why each RTO/ISO has made its set of policy choices.

4. The first three areas of potential reform — pricing of fast-start resources, commitments to manage multiple contingencies, and look-ahead modeling — involve processes already developed by some RTOs/ISOs. These processes are highly technical and their features are unique to each marketplace. Information on the technical features of each process, as well as the reasons for RTOs/ISOs choosing a particular design for each process, would develop a sufficient record for the Commission to consider any potential reforms in these areas.

5. As explained further in the following sections, improvements in the pricing of fast-start resources, commitments to manage multiple contingencies, and look-ahead modeling should assist in meeting several price formation goals. For example, making block-loaded fast-start units eligible to set locational marginal prices (LMPs) could yield market-clearing prices more representative of the cost of the marginal resource.[2] Including multiple contingency planning in the market model, either as a modeled constraint or through a special reserve product, could allow more resources to be committed within the market-clearing process and result in prices that reflect the

[2] *See* Calpine Comments at 10; Entergy Nuclear Power Marketing Comments at 4-5; Exelon Comments at 16; GDF SUEZ Comments at 7-8; ISO-NE Comments at 16, 18-19; Joint Trade Associations Comments at 1; Vitol, Inertia Power, and DC Energy Comments at app. A. 16-18; NYISO Comments at 8-9; PJM Utilities Coalition Comments at 9; Potomac Economics Comments at 6-7; Western Power Trading Forum Comments at 9; Xcel Comments at 4.

operational constraints of reliably operating the system.[3] Moreover, improving the use of look-ahead modeling in real-time commitment and dispatch could improve efficiency of dispatch and unit commitment by better anticipating needs for ramping.[4]

6. The last two areas of potential reform — uplift allocation and transparency — are aspects of price formation that affect the incentives for market participants to take actions that reduce uplift costs. Allocation of uplift costs to market participants whose transactions contribute to uplift could improve the incentive to those participants to change their bidding and operational behavior and potentially reduce uplift as a result.[5] Improved transparency of the reasons for incurring uplift costs could help limit market uncertainty as well as improve participant understanding and confidence in them. A better understanding of the drivers of uplift could, itself, elicit a market response to address system needs when a price signal fails to do so. Further, improved transparency could facilitate stakeholder discussions about market rule reforms.[6] However, the rules for allocating uplift costs are complex and the process for improving transparency is not straightforward. Information on the tradeoffs between different uplift allocation rules, as well as on the concerns about and feasibility of improving transparency, would, again, develop a sufficient record for the Commission to evaluate any potential reform in these areas.

7. The need for these reports is based in the Commission's statutory mandate to ensure that rates and the practices affecting such rates are just, reasonable, and not unduly discriminatory or preferential. For the foregoing reasons, and as discussed below, we direct each RTO/ISO to file a report that provides an update on its current practices in the identified topic areas, that describes the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions contained herein within 75 days of the

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[3] *See, e.g.*, CAISO, *Contingency Modeling Enhancements Issue Paper*, Mar. 11, 2013, *available at* http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

[4] *See* Uplift Workshop Tr. 47:7-17, 223:21-25.

[5] *See* PJM Comments at 17; Potomac Economics Comments at 29-30.

[6] EEI Comments at 6-7; Energy Storage Association Comments at 2; Financial Marketers Coalition Comments at 8-9; Xcel Comments at 3; Operator Actions Workshop Tr. 204:3-6 ; Uplift Workshop Tr. 228:1-8; Susan L. Pope, FTI Consulting, Price Formation in ISOs and RTOs, Principles and Improvements, Docket No. AD14-14-000, at 63 (Oct. 29, 2014).

issuance of this order.[7] Public comment in response to the RTO/ISO reports may be submitted within 30 days of the filing of the reports.

I. Discussion

8. Each of the following discussion sections is arranged as follows: (1) background, which explains the issue; (2) comments, which summarizes certain comments from the workshops and post-workshop comments regarding the issue, as well as what individual RTOs/ISOs already do and recommendations regarding individual RTOs/ISOs; and (3) scope of reporting requirements, which contains the questions each RTO/ISO must respond to on a given issue in its report.

A. Pricing of Fast-Start Resources

1. Background

9. In RTOs/ISOs, inflexible resources[8] typically cannot set LMPs because the market pricing software does not treat these resources as dispatchable or as able to meet the next increment of load. Nonetheless, some inflexible resources, such as certain natural gas-fired or diesel generators, can start up quickly in real-time to address system needs. These resources are generally referred to as block-loaded[9] fast-start resources, and RTO/ISO markets apply different methods to allow these resources to set LMPs.

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[7] The Federal Power Act (FPA) authorizes the Commission to obtain this information. FPA section 301(b) provides that the Commission shall at all times have access to, and the right to inspect and examine all accounts and records of public utilities, which includes RTOs and ISOs. 16 U.S.C. § 825(b) (2012). FPA section 309 grants the Commission the authority to "perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary and appropriate to carry out the provisions of [the FPA]." 16 U.S.C. § 825h (2012).

[8] An inflexible resource generally refers to a resource that may not be able to physically operate much below its maximum output and therefore cannot be dispatched up or down. For this reason, the energy supply offer parameters for these resources may stipulate that they be dispatched either to zero or to a minimum level that is at (or close to) their maximum output, but not in between.

[9] A block-loaded resource is a resource whose economic minimum operating limit is equal to its economic maximum output.

10. While certain exceptions exist, only resources that can be dispatched up or down in response to changes in system conditions are eligible to set LMPs. This presents a problem when fast-start resources are called upon to meet system needs in real-time because the majority of fast-start resources are block-loaded (i.e., non-dispatchable). As a result, these resources cannot set prices without a modified pricing treatment in the market software. Typically, this is accomplished by treating block-loaded fast-start resources as dispatchable in a pricing algorithm (i.e., pricing run) separate from the dispatch algorithm (i.e., dispatch run). The pricing run relaxes the minimum operating level of a resource so that the resource is seen as dispatchable by the market software and eligible to set price.

11. Enhanced pricing logic for block-loaded fast-start resources allows energy prices to better reflect the cost of wholesale electricity, reduces uplift, and enhances incentives for all resources to perform during periods of system stress. Pricing fast-start resources helps to better reflect the cost of production in LMPs because it allows inflexible resources that are used to serve load to set the LMP. It helps to reduce uplift by ensuring the block-loaded fast-start resources are paid through an LMP that reflects their cost (including potentially start-up and no-load costs) and also by increasing LMPs and thus reducing the need for make-whole payments to cover other resources' bid costs. Moreover, pricing improvements that better enable fast-start resources to set prices mean that all resources will perceive stronger financial incentives to perform when fast-start resources operate (which tends to be during stressed system conditions, when the performance of all resources is paramount).

12. All RTOs/ISOs have incorporated some form of pricing logic into their pricing algorithms that allows block-loaded fast-start resources to appear dispatchable to the pricing software, making them eligible to set LMPs. Approaches vary across RTOs/ISOs because fast-start pricing logic involves various decisions, each with its own set of tradeoffs. Among other things, these decisions include: (1) whether to account for commitment costs, such as start-up and/or no-load costs of block-loaded fast-start resources, in LMPs; (2) how to handle potential over-generation issues and generator incentives to deviate from RTO/ISO dispatch signals due to the relaxation of the economic minimum operating limit; (3) whether fast-start pricing should be applied exclusively to block-loaded fast-start resources; and (4) whether to allow offline resources to set the clearing price.[10]

13. Given the generally brief dispatch period for block-loaded fast-start resources, one can argue that commitment costs like start-up and no-load costs are appropriately viewed

[10] For example, resources that are not currently online are eligible to set LMPs in certain circumstances under MISO's Extended LMP process.

as incremental variable costs that should be included in LMP.[11] Further, including commitment costs can minimize the use of uplift or make-whole payments. However, incorporating commitment costs into LMPs raises questions about how to appropriately apportion those costs across the intervals during which a resource is dispatched — for example, over a resource's minimum run time or some other time period.

14. Allowing block-loaded fast-start resources to set LMPs through fast-start pricing logic can give flexible generators that are backed down an incentive to generate energy in excess of their dispatch signal to capture the higher LMP, which can lead to over-generation.[12] To keep total generator output balanced with load system-wide, it may then be necessary to offset any such over-generation with "regulation down" signals to other generators providing regulation service. Possible approaches to over-generation include penalizing uninstructed deviations and compensating resources that are backed down with their incurred opportunity costs.

15. Typically, fast-start pricing logic applies to block-loaded fast-start units. However, fast-start pricing logic could be extended to other resources, such as dispatchable fast-start units, that are not able to set LMPs when dispatched at their minimum operating limit.[13] For example, PJM contends that extending the pricing logic

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[11] The Commission previously found that MISO's Extended LMP methodology, which allows commitment costs to affect prices, leads to prices that better capture the costs considered in committing and dispatching resources. *See Midwest Indep. Sys. Operator, Inc.*, 140 FERC ¶ 61,067, at P 39 (2012).

[12] This happens because flexible resources may have to be dispatched down to accommodate the output of a block-loaded fast-start resource. In such cases, the RTO/ISO may ask a given resource to reduce its output when the price is increasing. *See, e.g.*, FERC, *Operator-Initiated Commitments in RTO and ISO Markets*, Docket No. AD14-14-000, at 27 (Dec. 2014) *available at* https://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf.

[13] In contrast to block-loaded fast-start units, dispatchable fast-start units provide a dispatch range over which the units can be dispatched. There are instances when dispatchable fast-start units are committed at their minimum operating level to meet load and cannot set price. This can occur when an online resource is dispatched down to accommodate a fast-start resource that is economically dispatched at its minimum output level, and the fast-start resource's minimum output level exceeds the additional output that is required to meet load. In this case, the dispatchable fast-start resource is not the marginal unit and cannot set the LMP. Extending the fast-start pricing logic to dispatchable fast-start units would allow LMPs to reflect the cost of these units needed to meet load when dispatched at their minimum operating levels.

to other resources allows LMPs to reflect the costs of other resources operating to meet demand.[14] MISO argues that not extending the fast-start pricing logic to fast-start resources other than block-loaded fast-start resources could create an incentive for dispatchable fast-start resources to offer in as block-loaded resources, potentially reducing system flexibility.[15] Nonetheless, extending fast-start pricing logic to categories of resources other than block-loaded fast-start resources could further expand concerns regarding over-generation.[16]

16. Commenters have varying opinions regarding whether offline fast-start resources should be allowed to set LMPs. Some commenters contend that allowing offline resources that are economic to set the clearing price in the interval while they are starting up can improve price signals by allowing prices to more accurately reflect the cost of meeting demand.[17] However, after MISO's Independent Market Monitor expressed concerns about the practice, MISO delayed its planned implementation of its fast-start pricing logic, Extended LMP. MISO proposed revisions, which the Commission accepted, regarding which offline fast-start resources were eligible to set the LMP.[18] The following section discusses comments and workshop discussions on fast-start pricing, including details of each RTO's/ISO's fast-start pricing approach. Given the differences in fast-start pricing logic across RTOs/ISOs, it appears that RTOs/ISOs have taken different approaches to address the tradeoffs involved in pricing block-loaded fast-start resources.

2. <u>Comments</u>

17. Workshop panelists and commenters provide information about each RTO's/ISO's current approach to pricing block-loaded fast-start resources and discuss the tradeoffs that arise with different approaches. There was no consensus on the best approach to fast-start pricing logic. Commenters also share their perspectives regarding whether the Commission should take action regarding fast-start pricing logic.

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[14] PJM Comments at 10.

[15] MISO Comments at 13-14.

[16] APPA and NRECA Comments at 35-36; CAISO Comments at 16; NYISO Comments at 10.

[17] *See* MISO Comments at 16; Potomac Economics Comments at 9.

[18] *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,143 (2015).

18. Multiple commenters discuss each RTO's/ISO's current fast-start pricing logic. RTOs/ISOs discuss some, but not necessarily all, of the four aforementioned fast-start pricing decisions: whether to account for commitment costs; how to handle potential over-generation; whether to apply fast-start pricing exclusively to block-loaded fast-start resources; and whether to allow offline resources to set the clearing price. ISO-NE states that under the fast-start pricing methodology that ISO-NE currently uses, supply offers from fast-start resources generally do not set the market price even when they are the highest-cost resources supplying power in the system.[19] ISO-NE's current fast-start logic allows commitment costs to be incorporated in LMPs, but only during the resource's initial commitment interval.[20] Currently, ISO-NE handles imbalanced power dispatch resulting from the fast-start pricing logic through regulation service.[21] ISO-NE's fast-start pricing logic is not limited to block-loaded fast-start resources, and offline resources are not eligible to set LMP.[22] ISO-NE contends that revisions to its fast-start pricing methodology, which the Commission recently approved, would allow real-time energy market pricing algorithms to enable committed fast-start resources to participate in energy price-setting when their energy production is considered "economically useful" for meeting real-time energy and reserve requirements.[23]

19. NYISO's "hybrid pricing" methodology,[24] relaxes the minimum operating limits of certain fast-start, block-loaded resources in order to permit them to set LMPs.[25]

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[19] On September 24, 2015, ISO-NE proposed to modify its fast-start pricing logic in Docket No. ER15-2716-000; the changes were accepted by delegated letter order on October 19, 2015, with an effective date of March 31, 2017. *ISO New England, Inc.*, Docket No. ER15-2716-000 (Oct. 19, 2015) (delegated letter order).

[20] ISO-NE filing, Revisions to Fast-Start Resource Pricing and Dispatch, Testimony of Matthew White, Chief Economist, on Behalf of ISO-NE, Docket No. ER15-2716-000, at 37 (Sept. 24, 2015).

[21] *Id.*

[22] ISO-NE Comments at 19.

[23] ISO-NE explains that a fast-start unit's energy production is considered "economically useful" when the power system's total production costs would be higher without the fast-start unit's service. ISO-NE Comments at 16.

[24] NYISO, NYISO Market Administration Tariff, §17.1.2.1.2 (12.0.0).

[25] NYISO Comments at 8.

NYISO states that its hybrid pricing methodology ensures that block-loaded resources are ineligible to set price when they are not economic. NYISO notes that it does not see a need to extend its hybrid pricing methodology to resources other than block-loaded fast-start resources.[26] With regard to offline resources, NYISO states that offline, 10-minute start-up gas turbines can set LMPs under certain circumstances. NYISO expresses concern that including start-up and no-load costs in prices could undermine market efficiency.[27] However, NYISO states that its hybrid pricing methodology accounts for start-up costs of offline, fast-start resources when such resources are committed and economic to serve load in real-time.[28]

20. PJM states that it relaxes the minimum operating limits of block-loaded fast-start resources, including combustion turbines and demand side resources, when these resource types bid into the day-ahead market.[29] PJM explains that it does not incorporate start-up and no-load costs into LMPs because this can result in prices that incentivize resources not to follow dispatch instructions.[30] Also, in order to avoid power balance concerns, PJM limits the degree of relaxation of the minimum operating limit to 10 percent. PJM's fast-start pricing logic does not allow for offline resources to set LMPs.[31]

21. MISO's Extended LMP methodology relaxes the minimum operating limits in the pricing run of its market model.[32] MISO explains that Extended LMP is performed in an ex-post process for pricing only while its dispatch software is used for physical dispatch.[33] At the Uplift Workshop, the MISO panelist explained that MISO's Extended

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[26] *Id.* at 10.

[27] *Id.*

[28] *Id.* at 11.

[29] PJM Comments at 9. *See also* PJM, PJM Manual 11, Energy & Ancillary Services Market Operations, § 2.3.4.

[30] PJM Comments at 10-11.

[31] PJM Comments at 11.

[32] MISO Comments at 13. *See also* MISO, FERC Electric Tariff, Schedule 29A, ELMP for Energy and Operating Reserve Market: Ex-Post Pricing Formulations, (36.0.0).

[33] MISO Comments at 13.

LMP process allows certain non-committed offline resources to participate in price-setting, and incorporates start-up and no-load costs of certain resources committed in real-time.[34] MISO also states that Extended LMP is not limited to block-loaded fast-start resources.[35]

22. Similarly, CAISO relaxes the minimum operating levels in its market model's pricing run.[36] However, CAISO states that it limits this relaxation to resources that have minimum operating levels that are very close to their maximum operating levels to limit concerns with over-generation.[37] CAISO also states that including commitment costs in LMPs can make the market solution complex and lead to operational challenges; thus, CAISO does not currently include start-up and no-load costs in LMPs.[38]

23. SPP states that its fast-start logic allows market participants to submit a physical minimum and maximum operating limit instead of a block-load approach.[39] SPP explains that its approach allows fast-start resources to include start-up and no-load costs in the energy offer and it also allows offline resources that meet certain fast-start criteria to set the LMP.[40] At the Operator Action Workshop, the SPP panelist stated that SPP is looking into developing products that will allow fast-start units better access to the market.[41] Golden Spread argues that insufficient cost recovery for fast-start units is a serious issue in SPP.[42]

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[34] Uplift Workshop Tr. 175:20-176:7.

[35] MISO Comments at 13-14.

[36] CAISO, CAISO eTariff, § 27.7.3 Constrained Output Generators in the IFM (1.0.0), § 27.7.5 Constrained Output Generators in the Real-Time Market (3.0.0).

[37] CAISO Comments at 16.

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

[39] SPP Comments at 3.

[40] SPP Comments at 3. *See also* SPP Tariff, Attachment AF §§ 3.2.E(3), 3.3.F(3) (10.0.0); Market Protocols for SPP Integrated Marketplace, Appendix G § 6.4 Energy Offer Curve for Quick Start (effective date Aug. 4, 2015).

[41] Operator Actions Workshop Tr. 157:25-158:2.

[42] Golden Spread Comments at 14.

24. Other commenters also discuss the tradeoffs involved in different fast-start pricing logic policy choices. Multiple commenters detail the advantages and disadvantages of incorporating start-up and no-load costs into LMPs.[43] Many commenters support incorporating such costs,[44] while others oppose including start-up and no-load costs.[45] Wisconsin Electric states that no-load costs should be incorporated into LMPs for committed resources, and RTOs/ISOs should include start-up costs over the period the resource is needed. EPSA states that appropriate pricing of fast-start resources in the real-time markets is necessary to incentivize investments of these resources in the correct areas of the RTO/ISO region. PJM argues against including the start-up costs in prices, because it must make assumptions regarding the duration of the resource's runtime, which can introduce pricing errors.[46] PJM states that no-load costs are not a significant contributor to uplift, and incorporating them would provide little benefit in reducing uplift.[47]

25. Some commenters note that pricing block-loaded fast-start resources can create differences between price and dispatch signals, and could incent flexible market participants to disregard dispatch signals, leading to over-generation.[48] To address this, commenters propose a few solutions, such as paying resources their opportunity cost when dispatched down, or imposing a penalty for not following dispatch instructions.[49]

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[43] Potomac Economic Comments at 9; NYISO Comments at 10-11.

[44] Brookfield Comments at 3-4; Entergy Nuclear Power Marketing Comments at 4; GDF SUEZ Comments at 8; Joint Trade Associations Comments at 2; PJM Utilities Coalition Comments at 9; Wisconsin Electric Comments at 7; Uplift Workshop Tr. 133:22-134:4; Uplift Workshop Tr. 215:16-215:21; Wartsila Comments at 2.

[45] PJM Comments at 10-11; SCE Comments at 3.

[46] PJM Comments at 10.

[47] *Id.* at 11.

[48] APPA and NRECA Comments at 35-36; CAISO Comments at 15-16; Exelon Comments at 18; GDF SUEZ Comments at 7; ISO-NE Comments at 17; New York Transmission Owners Comments at 8; PJM Comments at 9-10; Wisconsin Electric Comments at 7; Potomac Economics Comments at 8; NYISO Comments at 8; MISO Comments at 13.

[49] Brookfield Comments at 4; Exelon Comments at 18; GDF SUEZ Comments at 7; ISO-NE Comments at 17-18; Potomac Economics Comments at 8.

26. Commenters disagree about whether fast-start pricing logic should be applied to resources other than block-loaded fast-start resources. PJM notes that it has made changes to its dispatch and pricing software that relax minimum operating levels on resources other than block-loaded fast-start units. PJM states that it has made this change in order to provide resources that are operating to control transmission constraints the maximum opportunity to reflect their costs in both day-ahead and real time LMPs.[50] MISO states that fast-start pricing logic should not be limited to block-loaded fast start resources because, if only block-loaded fast-start resources are eligible to set the price, dispatchable fast-start resources may have an incentive to submit block-loaded offers, which reduces system flexibility.[51] Other commenters state that fast-start pricing logic should only apply to block-loaded fast-start resources for reasons including the concern of over-generation.[52]

27. Commenters also offer varying opinions about whether offline block-loaded fast-start resources should ever set LMP, with several commenters stating that offline resources should set LMP under certain conditions, such as if they are economic and can start up quickly.[53] For example, Potomac Economics asserts that if either of these conditions is not true, offline resources that set prices will artificially depress real-time prices and undermine price formation.[54] Other commenters state that allowing offline resources to set LMPs could lead to price distortion.[55] PJM, for instance, contends that allowing offline resources to set LMPs would create inconsistent signals that do not reflect actual operating conditions because these signals would incorporate resources that are not online.

28. Several commenters support the pricing of block-loaded fast-start resources, but urge the Commission to allow continuation of regional efforts between stakeholders and

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[50] PJM Comments at 10; PJM Utilities Coalition Comments at 9-10.

[51] MISO Comments at 13-14.

[52] APPA and NRECA Comments at 35-36; CAISO Comments at 16; NYISO Comments at 10.

[53] Exelon Comments at 17; New York Transmission Owners Comments at 8; PJM Utilities Coalition Comments at 10; Potomac Economics Comments at 9-10; Wisconsin Electric Comments at 7-8; NYISO Comments at 9; GDF SUEZ Comments at 9.

[54] Potomac Economics Comments at 9-10.

[55] ISO-NE Comments at 19; PG&E Comments at 4; PJM Comments at 11.

RTOs/ISOs, and to limit any directive in this proceeding to a requirement that RTOs/ISOs share best practices.[56] Some commenters recommend that the Commission monitor the performance of the various approaches to determine the merits of the different designs, and allow collaboration between RTOs/ISOs and their stakeholders to determine which approach is best within their respective markets.[57] ISO-NE conducted an extensive survey of approaches to pricing block-loaded fast-start resources and concluded that, while approaches vary considerably across RTOs/ISOs, there is no best approach to pricing these resources, and that more than one approach can produce reasonable results.[58]

3. <u>Scope of Reporting Requirements</u>

29. Little consensus exists on the best approach to pricing block-loaded fast-start resources. Also, not all RTOs/ISOs explained how they weighed the tradeoffs involved and the costs and benefits associated with their current fast-start pricing logic. In addition, the operating practices of each RTO's/ISO's fast-start pricing logic are not necessarily detailed fully in tariffs and manuals. Recognizing that there may be no single best practice for dispatching and pricing these resources, we seek further information regarding the different fast-start pricing approaches and associated tradeoffs. As such, we direct each RTO/ISO to submit information related to its fast-start pricing practices, as discussed below.

1. Generally, the fast-start pricing logic consists of a dispatch run and a pricing run that relaxes the minimum operating limit of block-loaded fast-start resources such that these resources can set the LMP.

   a. Please explain during what period fast-start pricing logic is applied to block-loaded fast-start resources. For example, does fast-start pricing logic apply during a resource's initial commitment period or during its actual run time?
   b. Please explain the order in which the various fast-start pricing logic processes are executed. Specifically, are the dispatch run and pricing run executed separately or integrated into one process?

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[56] APPA and NRECA Comments at 36-38.

[57] *Id.*; Exelon Comments at 17; ISO-NE Comments at 17; PG&E Comments at 4-5.

[58] ISO-NE Comments at 14-15 & 19.

c. Some RTOs/ISOs relax the minimum operating limit of a resource only in the pricing run, but some RTOs/ISOs currently also relax the minimum operating limit in the dispatch run.[59] Does the fast-start pricing logic relax the minimum operating limit of a resource in the dispatch run, the pricing run, or both? Please explain why the RTO/ISO chose the specific approach.
d. When a fast-start resource sets the LMP under the RTO's/ISO's fast-start pricing logic, how does the RTO/ISO ensure that the minimum operating limits of block-loaded fast-start resources are satisfied in dispatch?
e. CAISO, ISO-NE, NYISO, and MISO currently relax the minimum operating limit of eligible block-loaded fast-start resources to zero, while PJM relaxes the minimum operating limit by 10 percent. Please explain the reasons for the specific approach used to relax minimum operating limits. For SPP, please explain whether minimum operating limits are relaxed to zero or not, and the reasons for the chosen approach.

2. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, related to fast-start pricing logic and why those changes are being pursued. What tradeoffs, in terms of costs and benefits, are the RTO/ISO and/or stakeholders considering during this process? Please provide a qualitative discussion of whether and how enhancements to existing fast-start pricing logic could potentially reduce overall uplift.

3. Please explain the following regarding the RTO's/ISO's fast-start pricing logic eligibility:

a. What type of resource (e.g., combustion turbine) may be considered a fast-start resource and what are the eligibility requirements (e.g., start-up time and/or notification time)? Are resources other than block-loaded fast-start resources eligible to set the LMP under the fast-start pricing logic? Can a fast-start resource choose not to be included in the fast-start pricing logic?
b. Can commitment-related start-up and/or no-load costs be accounted for in the LMP? If so, please explain how and provide numerical examples to illustrate how these costs are included in LMP.
c. Can offline block-loaded fast-start resources set the LMP? If so, please explain how and provide numerical examples to illustrate how such resources set the LMP.

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[59] PJM Comments at 9-10. ISO-NE filing, Revisions to Fast-Start Resource Pricing and Dispatch, Testimony of Matthew White, Chief Economist, on Behalf of ISO-NE, Docket No. ER15-2716-000, at 22 (Sept. 24, 2015).

4. Based on the definition in the RTO/ISO tariff, how much block-loaded fast-start capacity (in MWs) is available? How much fast-start capacity is not block-loaded? Please provide as seasonal capability (i.e., summer capability) and include only capacity that is currently in service and can participate in the market.

5. As previously discussed, fast-start pricing logic can result in over-generation or in resources not following dispatch instructions.

a. Please discuss the extent to which fast-start pricing logic has resulted in over-generation or resources otherwise not following dispatch instructions.
b. Please describe the current approach, if any, used to address over-generation or the incentive to not follow dispatch instructions, and discuss the benefits to this approach versus other potential approaches to address this problem. For example, approaches include paying resources their opportunity costs, or penalizing them for deviating from dispatch instructions.

6. For those RTOs/ISOs that apply fast-start pricing logic only to the real-time market, please explain why this methodology is not applied to the day-ahead market.

7. Certain RTOs/ISOs argue that expanding the fast-start pricing logic to resources other than block-loaded fast-start resources is not needed. However, this limits the amount of fast-start resources that are able to set LMP. Please explain the advantages or disadvantages of allowing fast-start resources that are not block-loaded but that have a limited operating range to set the LMP, and please explain whether it is appropriate to allow the commitment-related start-up and no-load costs of such resources to affect prices.

B. Commitments to Manage Multiple Contingencies

1. Background

30. In addition to N-1 contingencies,[60] RTOs/ISOs also make commitment and dispatch decisions to address certain N-1-1 or N-2 contingencies (collectively, multiple contingencies).[61] These decisions are generally driven by the requirements of North

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[60] An N-1 contingency is the loss of a single generator or transmission element.

[61] An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by

(continued ...)

American Electric Reliability Corporation (NERC) Reliability Standards.[62] There are several different ways that RTOs/ISOs can model multiple contingencies. For example, RTOs and ISOs can establish reserve zone boundaries so that existing contingency reserve products are able to provide capacity to address multiple contingencies. For smaller areas, RTOs/ISOs could also implement a local reserve product to clear capacity in addition to normal contingency reserves to address a multiple contingency. RTOs/ISOs could also implement forward reserve clearing to provide a longer-term capacity commitment to address multiple contingencies. Finally, RTOs/ISOs could consider implementing changes to locational marginal pricing algorithms to more explicitly model and price a multiple contingency as a constraint in the algorithm.

31. The commitment and dispatch of resources to address N-1-1 and N-2 contingencies may result in committing a resource at its operating minimum for an extended period of time and thus result in significant uplift payments as a resource's commitment and dispatch costs are not recovered through payments for energy and ancillary services. By incorporating constraints into market models that reflect the need to commit and dispatch resources to address multiple contingencies or ensuring that reserve products can address multiple contingencies, RTOs/ISOs may be able to better reflect the marginal cost of supply in each area. Prices that better reflect the marginal cost of supply would, in turn, reduce the need for uplift payments to resources committed to address such contingencies. Based on the record developed during the price formation proceeding, RTOs/ISOs appear to address multiple contingencies in the day-ahead and real-time markets in varying ways. We are concerned that these types of contingencies might not be sufficiently or transparently reflected in market models, increasing uplift.

32. Determining whether and how to address multiple contingencies is a complex decision. Addressing multiple contingencies can introduce additional complexity to existing market models. On the other hand, adding reserve products or a constraint to market models can better represent the marginal cost of serving load at a given location, which in turn provides greater transparency, provides more accurate price signals, and enhances consumers' ability to hedge. However, if there is only one resource owner or,

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another loss of a single generator or transmission element. An N-2 contingency is the simultaneous loss of two transmission elements or generators.

[62] *See, e.g.*, Reliability Standard TOP-007-WECC-1a (Western Electricity Coordinating Council regional standard requiring, *inter alia*, that that at no time shall the power flow for a Transmission path exceed the System Operating Limit for more than 30 minutes); Reliability Standard TOP-004-2 (Continent-wide standard requiring, *inter alia*, that each Transmission Operator shall operate within Interconnection Reliability Operating Limits and System Operating Limits).

in the extreme, one resource that can be committed and dispatched to address a multiple contingency, the benefits of competitively procuring capacity to address the multiple contingency through the day-ahead or real-time market may be reduced. In addition, unforeseen events such as facility outages or de-ratings resulting in short-term multiple contingency concerns will still likely need to be addressed through manual commitment. Thus, even if reserve products or constraints are added to market models to address persistent multiple contingency concerns, there will still likely be a need to use manual commitments in certain instances.

2. Comments

33. Workshop panelists and commenters note the steps individual RTOs/ISOs have already taken to address multiple contingency commitments, highlight shortcomings in individual RTOs'/ISOs' current practices, and debate suggestions for improving multiple contingency commitments. Workshop panelists and commenters generally differ on the circumstances under which multiple contingencies should be included in market models and how they should be modeled.

34. Various workshop panelists and commenters state that RTOs/ISOs currently address multiple contingencies in a variety of ways. For example, CAISO states that it is working with stakeholders to develop a mechanism to procure and price capacity needed to address post-contingency re-dispatch in order to bring the system within operating limits within 30 minutes (i.e., N-1-1 contingencies).[63] CAISO states that these modeling enhancements will commit resources through the day-ahead market to meet N-1-1 contingency needs that had been met through out-of-market dispatches.[64] The CAISO panelist estimated that in 2012, roughly 21 to 77 percent of exceptional dispatches were used to meet post-contingency needs, resulting in roughly $47 million out of $101 million paid in uplift.[65] Calpine and EPSA state that CAISO currently uses the Minimum Online Commitment constraint, which ensures that, in a given geographic region (e.g., the Los Angeles Basin), there is sufficient generation on-line to prevent voltage collapse after a series of transmission (often N-1-1) contingencies.[66]

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[63] CAISO Comments at 36; Uplift Workshop Tr. 209:2-211:5.

[64] CAISO Comments at 43.

[65] Uplift Workshop Tr. 210:24-211:5.

[66] Calpine Comments at 17; EPSA Comments at 33.

35. In contrast, NYISO addresses multiple contingencies primarily through adjusting reserve requirements for specific reserve zones. Specifically, NYISO states that its network model currently includes certain N-1-1 constraints, including local N-1-1 thermal requirements in New York City.[67] NYISO states that the New York City load pockets of the day-ahead market ensure sufficient generation capacity is available in those load pockets to be able to meet N-1-1 criteria.[68] NYISO also states that it has established two operating reserve zones (East of Central-East and Long Island) and is in the process of establishing a third (southeastern New York) to address N-1-1 contingencies.[69]

36. PJM addresses multiple contingencies based on factors specific to each situation. The PJM panelist stated that it conducts planning studies and builds transmission facilities years ahead of time based on reliability criteria; however the PJM panelist noted that, if a planned reliability fix has not been made, and an issue materializes in the operating time horizon, it adds in an N-1-1 contingency in real-time.[70] The PJM panelist stated that one example of a contingency that continues to be a concern is the Cleveland Interface.[71] The panelist noted that PJM monitors and operates the Cleveland Interface because of the historical concerns in that area dating from the 2003 blackout where PJM had an N-1-1 criteria for scheduling units in that area.[72] The PJM panelist contended that in all the other situations where PJM schedules and operates units for an N-1-1 contingency, it tends to be because of a discussion between PJM and the transmission owner for an increased reliability concern or local area concern. In that case, the PJM panelist asserted that PJM will actually schedule units based on an N-1-1 contingency and generally will charge the transmission owner for that expense.[73] PJM also states that

[67] NYISO Comments at 20.

[68] Operator Actions Workshop Tr. 81:8-15.

[69] NYISO Comments at 17.

[70] Operator Actions Workshop Tr. 74:15-24.

[71] The "Cleveland Interface" is one of several post-contingency voltage constraints that can limit the amount of energy that can be imported from and through portions of the PJM RTO. PJM Manual 3: Transmission Operations, Section 3.8, *available at* http://www.pjm.com/~/media/documents/manuals/m03.ashx.

[72] Operator Actions Workshop Tr. 75:1-13.

[73] *Id.* at 75:14-21.

under certain conditions it will operate to N-2 conditions by modifying contingency sets in the day-ahead and real-time market model.[74]

37. The SPP panelist stated that the manner in which SPP incorporates N-1-1 contingencies depends upon the consequences of experiencing an N-1-1 contingency. For example, the panelist argued that in the vast majority of cases, SPP can readily manage a constraint that exceeds its system operating limit for a period of time. However, the SPP panelist contended that constraints in New Mexico and the Texas Panhandle are more of an N-1-1 concern because they affect the transient stability of a fairly large area of the SPP footprint.[75]

38. Unlike other RTOs/ISOs, ISO-NE purchases operating reserves to address multiple contingencies on a forward basis. The ISO-NE panelist stated that when ISO-NE tries to operate to N-1-1 contingencies that are longer-term issues, it wants to make sure that there is a price signal. Therefore, ISO-NE noted that it implemented its locational forward reserve market which identifies the amount of 30-minute reserves needed in an area so the market can respond to that signal.[76] Potomac Economics notes that ISO-NE's implementation of 30-minute reserve zones corresponds with N-1-1 reliability requirements.[77]

39. Some commenters also highlight shortcomings or suggest areas in which an individual RTO/ISO can improve its approach to commitments to manage multiple contingencies. Potomac Economics argues that local reserve zones should be created whenever the RTO/ISO must have capacity in a specific area in order to respond to certain system contingencies and argues that MISO has two notable areas with N-1-1 requirements in its South region that would benefit substantially from the creation of a local 30-minute reserve product.[78] In addition, Potomac Economics notes that while NYISO has a number of local reserve zones, it has some areas subject to N-1-1 requirements that have not yet been defined as local reserve zones.[79] Potomac

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[74] PJM Comments at 20.

[75] Operator Actions Workshop Tr. 76:4-18.

[76] *Id.* at 78:8-17.

[77] Potomac Economics Comments at 15.

[78] Potomac Economics Comments at 14-15.

[79] *Id.* at 15.

Economics argues that establishing a reserve zone to address N-1-1 contingencies and procuring 30-minute reserves allows the market to select the least expensive units for such reserve commitments and provides valuable incentives for investment in quick-start capacity.[80] Calpine and EPSA state that when the Minimum Online Commitment binds in the CAISO day-ahead market, capacity is generally uneconomically committed to Pmin,[81] resulting in LMPs that reflect a marginal cost of resources with dramatically lower costs than those of units committed under Minimum Online Commitment.[82] Calpine and EPSA state that they support reserves-like products to address such contingencies and specifically, CAISO's efforts to develop a capacity payment for suppliers to offset the price suppression due to Minimum Online Commitments.[83]

40. Some commenters also suggest improvements to multiple contingency commitment practices across all RTOs/ISOs. Commenters differ on the circumstances under which constraints to address multiple contingencies should be included in market models and how such constraints should be modeled. For example, several commenters express general agreement that reliability constraints, including persistent multiple contingency constraints, should be incorporated into market models to the extent possible.[84] Calpine, for example, states that all persistent constraints should be resolved through market-clearing processes and not through out-of-market actions by the system operator.[85] New York Transmission Owners contend that, in general, RTOs/ISOs should include constraints in their market models only if those constraints can be reasonably well approximated using flow-based constraints.[86] PJM states that RTOs/ISOs should

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[80] *Id.*

[81] Pmin is defined as the minimum normal capability of the generating unit. *See generally*, CAISO, Glossary of Terms and Acronyms, *available at* https://www.caiso.com/Pages/glossary.aspx.

[82] Calpine Comments at 17-18; EPSA Comments at 33.

[83] Calpine Comments at 17-18; EPSA Comments at 33.

[84] Calpine Comments at 17; Direct Energy Comments at 11; Entergy Nuclear Power Marketing Comments at 7; MISO Comments at 27; NCPA Comments at 9; New York Transmission Owners Comments at 15-16; PJM Comments at 18; PJM Utilities Coalition Comments at 17.

[85] Calpine Comments at 17.

[86] New York Transmission Owners Comments at 15-16.

include in their market models constraints that cause significant congestion costs and are likely to be sustained over time, but the types of constraints that are of a lower priority for inclusion in the market model and could be handled by manual commitments are those that are unlikely to be repetitive or sustained over time.[87] Similarly, at the Operator Actions Workshop, the NRG/Boston Energy Trading & Marketing panelist stated that, while manual commitments are appropriate for situations where outages may cause transient reliability issues, defining a locational reserve requirement or reserve product would be appropriate where multiple contingency issues are present on a consistent basis.[88]

41. MISO argues that incorporating N-1-1 constraints into the day-ahead market is likely too conservative, unless there is a known load pocket issue.[89] MISO contends that incorporating N-1-1 constraints in addition to outages can result in seeing congestion that is unlikely to occur in real-time.[90] MISO further argues that in the case of a load pocket, the transmission system is weakly interconnected to the pocket, and N-1-1 constraints need to be utilized to reliably commit enough generation to serve the load inside the pocket.[91]

42. SCE, however, cautions that adding more constraints, such as N-1-1 constraints, to the market model would not necessarily improve the efficiency of price formation or the markets. SCE argues that the inclusion of N-1-1 constraints may, among other things, make market prices less transparent and make price discovery more difficult, because the price formation is too complicated to understand.[92] SCE contends that relying instead on occasional "targeted" solutions, even if expensive at the time of use and implemented in a specific and targeted fashion, is likely a more efficient, lower-cost market solution over time.[93]

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[87] PJM Comments at 18.

[88] Operator Actions Workshop Tr. 299:4-300:3.

[89] MISO Comments at 27.

[90] *Id.* at 28.

[91] *Id.*

[92] SCE Comments at 5-6.

[93] *Id.* at 6.

3. Scope of Reporting Requirements

43. While commenters generally agree that RTOs/ISOs should and often do include multiple contingencies in the market model where practical, it remains unclear to what extent in practice each RTO/ISO incorporates multiple contingencies in its day-ahead and real-time market. Moreover, it remains unclear how units are committed in the day-ahead and real-time market to address multiple contingencies and what proportion of the revenue these units receive through uplift payments rather than payments for energy and ancillary services. As such, we direct each RTO/ISO to submit information related to its commitments to manage multiple contingencies, as discussed below.

> **1.** Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, to incorporate the costs of multiple contingencies into clearing prices for energy and ancillary services. This description should include estimated costs and a timeline for implementation.
>
> **2.** Please explain whether constraints or reserve products are used to address multiple contingencies in the day-ahead and real-time energy and ancillary services markets and, if so, how such constraints or reserve products are incorporated in market models. Specifically, describe (1) the criteria for determining what constraints or reserve products are included in the day-ahead or real-time market model to address multiple contingencies, and (2) provide a detailed description of how constraints or reserve products to address multiple contingencies are included in both the day-ahead and real-time market model.
>
> **3.** If resources are manually committed (i.e., committed outside of security constrained unit commitment processes) to address multiple contingencies, please describe the criteria used to determine whether a manual commitment will be made and how the RTO/ISO determines what resources are committed. If resources are manually committed to address only some subset of multiple contingencies, please describe what criteria the RTO/ISO uses to determine whether a manual commitment will be made.
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> **4.** For each month during the twelve month period between October 1, 2014 and September 30, 2015, please provide: (1) an estimate of the number of resource commitments made in real-time or day-ahead to address multiple contingencies. This estimate should be broken down by geographic area (e.g., reserve zone or load zone), if possible; and (2) an estimate of the dollar amount of uplift paid to resources committed to address multiple contingencies.
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> **5.** Describe whether and how incorporating additional multiple contingency constraints or using reserve products in day-ahead or real-time market models would improve price formation. If taking additional steps to incorporate multiple contingency constraints or using reserve zones in day-ahead or real-time market

models is unnecessary, impracticable, or would negatively affect price formation, please explain why.

C. Look-Ahead Modeling

1. Background

44. In RTO/ISO market operations, look-ahead modeling generally refers to tools that assess near-term[94] unit commitment and dispatch needs. When evaluating commitment and dispatch decisions, look-ahead modeling optimizes such decisions over the projected trajectory of load, variable energy resource output, and other system conditions in the near future. Look-ahead modeling may provide benefits by pre-positioning resources in anticipation of near-term system needs, including ramping needs, and by optimizing the near-term commitment of fast-start generators, possibly improving price formation and increasing operational efficiency. In this regard, using look-ahead modeling to make actual commitment and dispatch decisions rather than solely as an advisory tool for operators could reduce the need for out-of-market[95] operator actions and consequently could reduce the need for uplift payments in the real-time market. There may also be the potential for look-ahead modeling to introduce unintended market consequences. For instance, we seek to understand whether look-ahead modeling could create interval prices that reflect the costs associated with managing anticipated future interval system needs that later turn out to be inconsistent with actual system conditions.

2. Comments

45. Workshop panelists and commenters discuss look-ahead modeling, detail RTOs'/ISOs' current practices, and generally highlight the benefits of look-ahead modeling in enabling the RTO/ISO to commit sufficient ramp capability. Each RTO/ISO uses some form of look-ahead modeling in its real-time unit commitment and dispatch

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[94] "Near-term" in this context typically corresponds to a period of one or more hours. *See, e.g.*, NYISO Market Administration and Control Area Services Tariff § 4.4 (17.0.0) (NYISO's real-time commitment includes look-ahead functionality that provides commitment information for a two and a half hour period); CAISO eTariff § 34.5.1 (0.0.0) (CAISO's real-time economic dispatch produces binding dispatch instructions for the next dispatch interval, and advisory dispatch instructions for multiple future intervals through at least the next trading hour).

[95] Out-of-market commitments are resource commitments made by the RTO/ISO outside of the market-clearing process (e.g., out-of-market commitments to satisfy local reliability issues that are not included in the market model).

processes.[96] In some instances, RTOs/ISOs use look-ahead modeling solely as an advisory tool for operators; in other instances, RTOs/ISOs use look-ahead modeling to produce actual commitment/dispatch decisions for the next period (typically treating the results for later periods as advisory).[97]

46. Multiple commenters assert that look-ahead modeling can help to ensure sufficient ramping capability in real-time, and further assert that certain RTOs/ISOs currently use look-ahead modeling to manage ramping capability.[98] At the Uplift Workshop, the MISO panelist indicated that MISO uses look-ahead modeling to help operators optimize real-time commitment decisions.[99] The Potomac Economics panelist argued that when RTOs/ISOs use look-ahead modeling, operators may make fewer uneconomic out-of-market decisions in real-time, thereby reducing the need for uplift payments.[100] At the Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, the NYISO panelist explained that one reason NYISO uses look-ahead modeling is to anticipate upcoming system events.[101] The PJM panelist stated that PJM uses an intermediate-term look-ahead modeling tool which is primarily responsible for unit commitment.[102] At the Operator Actions Workshop, the NYISO and CAISO panelists asserted that their look-

[96] FERC, *Operator-Initiated Commitments in RTO and ISO Markets,* Docket No. AD14-14-000, at 19-21 (Dec. 2014), *available at* http://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf.

[97] *Id. Compare, e.g.*, MISO, MISO FERC Electric Tariff Module C, § 40.1.A (30.0.0) (MISO using an algorithm in its Look-Ahead Commitment process to "*recommend* Resource commitments and decommitments" (emphasis added)) *with* NYISO, NYISO Market Administration and Control Area Services Tariff § 4.4.2.1 (17.0.0) (NYISO's real-time dispatch will produce a "*binding* schedule for the next five minutes" and "*advisory* schedules for the remaining four time steps of its bid-optimization horizon" (emphasis added)).

[98] *See* NYISO Comments at 14-15; Potomac Economics Comments at 11; PJM Comments at 14.

[99] *See* Uplift Workshop Tr. 223:21-223:25.

[100] *See id.* at 47:7-47:17.

[101] *See* Scarcity and Shortage Pricing, Offer Mitigation, and Offer Caps Workshop Tr. 44:3-44:8.

[102] *See id.* at 31:3-31:7.

ahead models optimize the commitment of fast-start resources.[103] Additionally, the NYISO panelist argued that its look-ahead models enhance efficiency with respect to interface scheduling.[104] The CAISO panelist also stated that CAISO's look-ahead models assist with managing operating configurations at combined cycle generating plants.[105]

47. Only a few commenters highlight shortcomings or suggest areas in which individual RTOs/ISOs can improve look-ahead approaches. PSEG Companies argue that the look-ahead model used in PJM's intermediate dispatch process[106] contains problematic features related to shortage pricing. PSEG states that, if PJM's intermediate dispatch process does not see a shortage in advance of at least three 15-minute intervals, the shortage is not communicated to PJM's real-time dispatch system. PSEG states that this creates a "deadband" for reserve shortage events.[107] In addition, MISO explains that it is currently evaluating initiatives to enhance its existing look-ahead modeling capability.[108]

3. Scope of Reporting Requirements

48. We seek further information regarding the current state of look-ahead modeling implementation across RTOs/ISOs. Additionally, we seek further information regarding the full range of potential benefits from using look-ahead modeling to make actual commitment, dispatch, and pricing decisions rather than solely as an advisory tool for operators. We appreciate that there may be unintended consequences associated with using look-ahead modeling to make actual commitment, dispatch, and pricing decisions.

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[103] *See* Operator Actions Workshop Tr. 96:10-97:8, 98:21-99:9.

[104] *See id.* at 96:20-97:8.

[105] *See id.* at 98:21-99:9.

[106] PJM's refers to its intermediate dispatch process as the "Intermediate Security Constrained Economic Dispatch" (IT SCED). PJM's IT SCED performs multiple functions over a one-to-two hour look-ahead period, including: resource commitments for energy and reserves, calculation of energy dispatch trajectories for use in real-time dispatch, forward determination of reserve shortages, and execution of the Three Pivotal Supplier Test for energy. *See* PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 76 at 29 (effective Aug. 3, 2015).

[107] PSEG Companies Comments at 31.

[108] MISO Comments at 3-4.

As such, we direct each RTO/ISO to submit information related to look-ahead modeling, as discussed below.

1. Please describe any RTO/ISO and/or stakeholder initiatives or plans, if any, related to look-ahead modeling. For any look-ahead modeling enhancements that the RTO/ISO and/or its stakeholders are currently considering, please discuss any evaluation of the costs and/or complexities of look-ahead modeling relative to its potential benefits, and the estimated time frame for implementation of any look-ahead modeling enhancements.

2. Please list all of the unit commitment and dispatch processes that execute after the close of the day-ahead energy market, up to and including all unit commitment and dispatch processes used in the real-time market. Please indicate whether each process uses look-ahead modeling. With respect to each process that uses look-ahead modeling, please address each of the topics listed below and include examples where possible.

a. Please indicate whether the process uses look-ahead modeling solely as an advisory tool for operators or, alternatively, whether the process uses look-ahead modeling to make actual commitment, dispatch, and pricing decisions. What is the time horizon considered by the look-ahead model?[109] What are the commitment/dispatch intervals considered by the look-ahead model?[110] How frequently does the model execute throughout the operating day (e.g., every 15 minutes, every 30 minutes)?

b. Please discuss whether and how look-ahead modeling affects real-time price formation and/or operational efficiencies (especially with respect to the commitment and pre-positioning of fast-start and flexible resources).

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[109] As explained in the December 2014 Staff Report, the time horizon is the period of time included in the forward look-ahead. FERC, *Operator-Initiated Commitments in RTO and ISO Markets*, Docket No. AD14-14-000, at 20 (Dec. 2014), *available at* http://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf.

[110] For example, according to NYISO, its real-time dispatch looks ahead over a time horizon of approximately 60 minutes on a five-minute interval basis, and its real-time commitment looks ahead over a 150-minute time horizon in 15-minute increments. *See* NYISO Comments 9 n.12, 10. At the Uplift Workshop, the PJM panelist explained that PJM's short-term unit commitment process commits units over a time horizon of 120 minutes on a 15-minute basis. *See* Uplift Workshop Tr. 180:13-180:20.

i. Please explain whether and how the RTO's/ISO's look-ahead model pre-positions the dispatch of resources in anticipation of system needs, especially with respect to expected near-term needs for ramping capability. Please explain whether and how the RTO's/ISO's look-ahead model optimizes the commitment of resources in anticipation of system needs.

ii. If the RTO/ISO uses look-ahead modeling to make unit commitment decisions, how far in advance of real-time does the operator issue commitment instructions? Does this time period for issuing commitment instructions differ by resource characteristics, such as start-up time?

iii. Please explain whether and how look-ahead modeling affects real-time prices. In this regard, please explain whether and how the look-ahead model calculates actual real-time prices, and whether and how constraints in future periods affect price formation.

iv. Please discuss whether and how look-ahead modeling can reduce out-of-market commitments by operators.

v. Please explain whether and how look-ahead modeling provides greater benefits when used to make actual market decisions rather than solely as an advisory tool for operators.

vi. Please discuss any other potential or actual benefits from look-ahead modeling.

3. Please discuss the complexities and limitations of look-ahead modeling, as well as any potential unintended consequences that could arise from the implementation or enhancement of look-ahead modeling tools.

a. Are there any features of existing look-ahead models that could adversely affect price formation (for instance, are there any instances in which existing look-ahead model designs could lead to inaccurate price signals)? If so, please describe these features in detail and discuss whether any improvements are warranted.

b. Please describe any other challenges, complexities, or practical limitations associated with look-ahead modeling. Where possible, please provide quantitative examples.

D. Uplift Allocation

1. Background

49. In RTO/ISO energy and ancillary services markets, uplift refers to payments that RTOs/ISOs make to resources whose commitment and dispatch resulted in a shortfall between the resource's offer costs and the revenue earned through market clearing prices.[111] RTOs/ISOs fund uplift payments through charges to market participants. Reforms to the uplift drivers discussed in the previous sections have the potential to reduce overall levels of uplift. However, the Commission understands that uplift is an inherent element of centralized wholesale energy and ancillary services markets such that we will never be able to eliminate uplift payments. As a result, RTOs/ISOs need to have some method to allocate uplift costs.

50. The tariff provisions that govern the allocation of uplift charges vary across RTOs/ISOs. In some cases, current allocation methodologies may not allocate these charges to the market participants that either cause the uplift charges to be incurred or that benefit from the underlying action, and might not create incentives for market participants to change their behavior in ways that will reduce uplift.

51. Uplift cost allocation is a contentious stakeholder issue. Reducing uplift allocated to some market participants is generally thought to require increasing the amount of uplift allocated to others. Thus, RTOs/ISOs may need direction from the Commission to make meaningful progress on any reform of uplift allocation. However, we do not have enough information to determine at what point the incremental improvement involved in making uplift allocation more consistent with cost causation might be outweighed by complexities and potential unintended consequences associated with adjusting uplift allocation. As commenters in the price formation proceeding have indicated, uplift allocation influences market behavior[112] and allocating uplift to the market participants that cause uplift can encourage behavior that leads to reductions in uplift levels.[113]

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[111] FERC, *Staff Analysis of Uplift in RTO and ISO Markets*, Docket No. AD14-14-000, at 1-2 (Aug. 2014), *available at* https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.

[112] PJM Comments at 17; Potomac Economics Comments at 29-30; Potomac Economics Comments at 16; PG&E Comments at 9; APPA and NRECA Comments at 42-43.

[113] EPSA Comments at 31-32; Exelon Comments at 20.

2. Comments

52. Workshop panelists and commenters discuss the details of individual RTO/ISO uplift allocation approaches, critique those approaches, or comment on the potential burden of Commission action in this area. Commenters also propose a range of uplift allocation methodologies. Most commenters generally support allocating uplift charges based on cost-causation principles[114] or contend that uplift should be allocated such that there is an incentive for market participants to change their behavior to avoid or reduce uplift charges.[115] In this regard, some commenters argue that MISO's current uplift allocation methodology aligns with cost causation principles and represents an industry-best practice,[116] while others argue that none of the RTOs'/ISOs' current uplift allocation methodologies represent a best practice.[117] Some commenters assert that certain uplift charges should be allocated in proportion to deviations between market participants' day-ahead and real-time schedules.[118] In addition, multiple commenters contend that RTOs/ISOs should create allocation categories that relate to the underlying causes for various types of uplift.[119] Other commenters discuss the impact of uplift allocation on

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[114] Potomac Economics Comments at 16-17; APPA and NRECA Comments at 42-43; Brookfield Comments at 6; California State Water Project Comments at 4-6; CAISO Comments at 31; Calpine Comments at 16; Direct Energy Comments at 10; EPSA Comments at 31-32; Exelon Comments at 20; Financial Marketers Coalition Comments at 12-15, 24; GDF Suez Comments at 6; MISO Comments at 26; NYISO Comments at 19-20; New York Transmission Owners Comments at 15; NCPA Comments at 8-9; PG&E Comments at 9; PJM Comments at 17; PJM Utilities Coalition Comments at 16; PSEG Companies Comments at 25; SCE Comments at 5; SPP Comments at 5; Wisconsin Electric Comments at 12-13.

[115] Potomac Economics Comments at 16; PG&E Comments at 9; APPA and NRECA Comments at 42-43.

[116] Potomac Economics Comments at 18; Financial Marketers Coalition Comments at 26.

[117] PJM Comments at 17; PJM Utilities Coalition Comments at 16.

[118] Potomac Economics Comments at 17-18; APPA and NRECA Comments at 43; Calpine Comments at 16; Direct Energy Comments at 10.

[119] Potomac Economics Comments at 17-18; Financial Marketers Coalition Comments at 13; MISO Comments at 26-27; NYISO Comments at 19-20.

virtual bidding,[120] or suggested approaches for allocating uplift with respect to virtual transactions.[121]

53. Many commenters discuss individual RTOs'/ISOs' current uplift allocation practices. MISO contends that its current real-time uplift allocation methodology aligns closely with cost-causation principles and includes allocation categories based on: (1) commitments for system-wide capacity needs; (2) actions taken for congestion management; and (3) commitments for voltage and local reliability reasons.[122] Potomac Economics and Financial Marketers Coalition suggest that MISO's uplift allocation methodology aligns with cost-causation principles and represents a best practice among RTOs/ISOs.[123] At the Operator Actions Workshop, the Potomac Economics panelist asserted that MISO is the only RTO that attempted to identify the causes of uplift and to allocate uplift in a way that creates incentives for people to change their behavior in a way that minimizes uplift.[124] Additionally, the MISO panelist stated that costs related to highly localized constraints that address controlling for voltage in a very small regional area are allocated locally.[125]

54. NYISO asserts that its current uplift allocation methodology allocates uplift costs relating to statewide reliability to all loads across the New York Control Area, and uplift costs relating to local reliability issues to the load within the applicable transmission area for which the reliability actions were taken.[126] Similarly, at the Uplift Workshop, the NYISO panelist asserted that NYISO attempts to allocate local costs to the local region in which such costs are incurred, rather than distributing them across a broader area.[127] At

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[120] *See, e.g.*, Vitol, Inertia Power, and DC Energy Comments at Attachment A, at 21; Financial Marketers Coalition Comments at 18.

[121] Financial Marketers Coalition Comments at 20-21.

[122] MISO Comments at 26-27.

[123] Potomac Economics Comments at 18; Financial Marketers Coalition Comments at 26.

[124] *See* Operator Actions Workshop Tr. 273:8-13.

[125] *See* Operator Actions Workshop Tr. 34:18-23.

[126] NYISO Comments at 19-20.

[127] *See* Uplift Workshop Tr. 35:1-6.

the Operator Actions Workshop, the NYISO panelist explained that NYISO allocates uplift costs statewide when such costs are related to voltage support, but that out-of-market costs related to local constraints on the 138 kV transmission network in New York City are allocated locally.[128] At the Uplift Workshop, the Potomac Economics panelist contended that NYISO is one of the few RTOs/ISOs that has evaluated whether deviations increase or reduce uplift, though to a lesser extent than MISO.[129]

55. SPP states that uplift should be allocated based on cost causation only to the extent that cost causation can be determined and insofar as process costs are outweighed by the benefits of using cost causation. SPP also notes that resource commitments above its load forecast plus reserves are performed under the category of "headroom" and that SPP's stakeholder groups periodically discuss the philosophy and results of this approach.[130] In the Operator Actions Workshop, the SPP panelist stated that the costs associated with commitments to address persistent voltage issues on the transmission system (for instance, going in and out of the Texas Panhandle) are allocated regionally.[131]

56. CAISO notes that it plans to discuss cost causation-based uplift allocation with its stakeholders on an ongoing basis, and argues that the Commission should weigh the benefits of more efficient uplift allocation against the potential for overly-complex market rules.[132]

57. PJM asserts that its current uplift allocation methodology mutes investment signals, that a PJM stakeholder group is currently examining uplift allocation, and that it would be beneficial if the Commission provided direction on the guiding principles for uplift allocation.[133] At the Uplift Workshop, the PJM panelist stated that in PJM there are a small number of units receiving very large amounts of uplift, and that the two broad reasons this occurs are (1) to support the "PJM-ConEd Wheel," and the inflexible nature of the units involved; and (2) reactive power payments, driven in large part by relative

[128] *See* Operator Actions Workshop Tr. 34:11-17.

[129] *See* Uplift Workshop Tr. 171:17-21.

[130] SPP Comments at 5.

[131] *See* Operator Actions Workshop Tr. 33:8-20.

[132] CAISO Comments at 30-32.

[133] PJM Comments at 17.

gas and coal prices.[134] Additionally, the PJM panelist asserted that real-time exigent circumstances can lead to conservative operations being reflected in uplift payments, and that while rare, such cost are allocated to load in real-time.[135] At the Uplift Workshop, PJM's Independent Market Monitor stated that PJM carved out reactive power costs from overall uplift and then effectively allocated the costs to zonal load.[136]

58. At the Uplift Workshop, the ISO-NE panelist stated that real-time uplift allocation does impact performance, and that ISO-NE tries to incorporate uplift as part of portfolio planning.[137] At the Operator Actions Workshop, the ISO-NE panelist also stated that ISO-NE allocates market-wide those uplift costs resulting from LMPs that do not cover the costs of commitments made through the market process. Additionally, the ISO-NE panelist explained that costs associated with manual dispatch in a local area because of an outage or un-modeled constraint could be allocated to the local participating transmission owner, while costs associated with low voltage are spread across the system as a whole.[138]

59. Commenters offer a range of views on appropriate approaches to allocating uplift charges not specific to any RTO/ISO. Many commenters generally support allocating uplift charges based on cost-causation principles.[139] A number of commenters argue that RTOs/ISOs should allocate uplift charges in ways that are predictable and can inform

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[134] *See* Uplift Workshop Tr. 30:8-25.

[135] *See id.* at 138:4-8.

[136] *See Id.* at 32:5-13.

[137] *See id.* at 136:4-6.

[138] *See* Operator Actions Workshop Tr. 34:24-36:17.

[139] Potomac Economics Comments at 16-17; APPA and NRECA Comments at 42-43; Brookfield Comments at 6; California State Water Project Comments at 4-6; CAISO Comments at 31; Calpine Comments at 16; Direct Energy Comments at 10; EPSA Comments at 31-32; Exelon Comments at 20; Financial Marketers Coalition Comments at 12-15 & 24; GDF Suez Comments at 6; MISO Comments at 26; NYISO Comments at 19-20; New York Transmission Owners Comments at 15; NCPA Comments at 8-9; PG&E Comments at 9; PJM Comments at 17; PJM Utilities Coalition Comments at 16; PSEG Companies Comments at 25; SCE Comments at 5; SPP Comments at 5; Wisconsin Electric Comments at 12-13.

market participant decisions,[140] or in ways that give market participants the incentive to change their behavior such that uplift charges are avoided or reduced.[141] Multiple commenters assert that RTOs/ISOs should create allocation categories that relate to the underlying causes for various types of uplift;[142] further, some commenters assert that certain uplift charges should be allocated in proportion to deviations between market participants' day-ahead and real-time schedules.[143] Brookfield argues that ISO-NE should accelerate its schedule to implement an uplift cost allocation project.[144]

60. Several commenters discuss the appropriateness of broad-based allocation of uplift charges (i.e., allocating uplift charges across broad categories such as cleared load and export transactions). Some commenters argue that it is reasonable to allocate uplift to load when causation is difficult to determine.[145] However, Wisconsin Electric contends that broad-based allocation of uplift charges to load leads to increased uncertainty for load, and PJM argues that broad-based allocation of uplift charges suppresses information about locational system issues.[146] GDF SUEZ argues that uplift should not be allocated to load that is self-supplied by a load-serving entity.[147]

61. Commenters also discuss the specific details of uplift allocation methodologies. SCE argues that uplift should be allocated to variable energy resources to the extent deviations by variable energy resources cause uneconomic adjustments to dispatch.[148]

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[140] EPSA Comments at 31-32; Exelon Comments at 20.

[141] Potomac Economics Comments at 16; PG&E Comments at 9; APPA and NRECA Comments at 42-43.

[142] Potomac Economics Comments at 17-18; Financial Marketers Coalition Comments at 13; MISO Comments at 26-27; NYISO Comments at 19-20.

[143] Potomac Economics Comments at 17-18; APPA and NRECA Comments at 43; Calpine Comments at 16; Direct Energy Comments at 10.

[144] Brookfield Comments at 7.

[145] Western Power Trading Forum Comments at 14; Calpine Comments at 16.

[146] Wisconsin Electric Comments at 12-13; PJM Comments at 17.

[147] GDF SUEZ Comments at 16.

[148] SCE Comments at 5.

PG&E argues that variable energy resources should receive uplift charges based on cost causation, in order to provide incentives to reduce the impacts that such resources have on the grid.[149] GDF SUEZ argues that uplift charges should be allocated to the hours in which the uplift was incurred.[150] The Potomac Economics panelist stated that the Commission could ask all the RTOs/ISOs to look at whether existing uplift allocation rules are consistent with cost causation, and that such a request could lead to improved day-ahead commitment.[151]

62. Several commenters discuss uplift allocation in the context of virtual transactions. Financial market participants argue for reducing or removing the allocation of uplift to virtual transactions, contending that virtual transactions promote price convergence between day-ahead and real-time markets.[152] In this regard, financial market participants argue that allocation of uplift charges to virtual transactions is counterproductive and can impede price convergence.[153] Financial Marketers Coalition asserts that best practices for uplift allocation in RTOs/ISOs include: (1) allocating to virtual transactions a share of uplift charges associated with the day-ahead market, but not allocating to virtual transactions any uplift charges associated with the real-time market; and (2) market-wide netting of virtual demand and virtual supply for purposes of uplift allocation.[154] NCPA argues that virtual bidding in CAISO[155] is a source of real-time congestion offset costs,

[149] PG&E Comments at 9.

[150] GDF SUEZ Comments at 6-7.

[151] *See* Uplift Workshop Tr. 170:24-171:25. The panelist argued that allocating uplift charges based on cost causation could improve day-ahead commitment by reducing perverse incentives. The panelist stated that in some cases congestion is appearing in real-time but not in the day-ahead market, and that the normal market response is to buy more in the load pocket, which would lead to more day-ahead commitments. The panelist argued that this market response is “getting dinged” with uplift charges.

[152] Financial Marketers Coalition Comments at 15-18; Vitol Inc., Inertia Power, LP, and DC Energy, LLC (Vitol, Inertia Power, and DC Energy) Comments at Attachment A, at 21.

[153] Vitol, Inertia Power, and DC Energy Comments at Attachment A, at 21; Financial Marketers Coalition Comments at 18.

[154] Financial Marketers Coalition Comments at 20-21.

[155] In CAISO, virtual bidding is referred to as “convergence bidding.”

and that CAISO should change its market rules to allocate some of these costs to virtual bidders.[156] PJM Utilities Coalition states that virtual transactions cause uplift.[157]

63. At the price formation workshops, several panelists discussed the impact of uplift allocation methodologies on virtual bidders' participation in RTO/ISO energy markets. At the Uplift Workshop, the Financial Marketers Coalition panelist argued that uplift allocation methodologies have a profound impact on the amount of virtual transactions in markets, and suggested that MISO's uplift allocation methodology is more equitable than PJM's.[158] In this regard, the Financial Marketers Coalition panelist asserted that 41 percent of all the virtual transactions in the PJM footprint are settling against someone else's virtual transaction, thus having no impact on the power balance, unit commitment, or dispatch, but still paying uplift charges that such transactions have no possibility of causing.[159] The panelist also contended that uplift allocation "killed" virtual transactions in ISO-NE.[160]

3. Scope of Reporting Requirements

64. While there is general consensus that uplift allocation should follow cost-causation principles, questions remain about: how to define appropriate cost-causation categories for uplift; whether any RTOs/ISOs currently have a best practice for allocating uplift charges; the extent to which uplift charges should be allocated to virtual transactions; and the benefits of improved uplift allocation relative to the complexity of market rules involved. As such, we direct each RTO/ISO to submit additional information related to its uplift allocation methodologies, as discussed below.

1. Please provide a high-level overview of the RTO's/ISO's existing framework for allocating uplift charges (e.g., briefly explain the principles that guide the RTO's/ISO's allocation of uplift charges and summarize at a high level how these principles are applied in the day-ahead and real-time energy and ancillary services markets).

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[156] NCPA Comments at 8-9.

[157] PJM Utilities Coalition at 16.

[158] *See* Uplift Workshop Tr. 141:8-15.

[159] *See id.* at 142:25-143:6.

[160] *See id.* at 146:1-2.

2. Please identify any specific areas where the RTO/ISO believes that its existing uplift allocation methodology needs improvement. Please discuss these areas, along with any RTO/ISO and/or stakeholder initiatives or plans aimed at improving uplift allocation.

a. Please identify any specific transaction types, resource types, schedule deviations, or other uplift drivers that cause uplift on a regular basis, but do not receive an allocation of uplift charges under current market rules.

b. Please discuss the complexity of re-designing existing market rules and settlement systems to better align uplift allocation with cost-causation principles. Please provide a qualitative assessment of whether and how the potential benefits of improved uplift allocation outweigh the cost and complexity of implementation and application.

c. Commission staff's 2014 paper on uplift noted that a small number of resources receive the majority of uplift payments in every RTO/ISO.[161] Additionally, PJM asserts that existing uplift allocation rules likely mute investment signals due to lack of clarity regarding where uplift payments are being received, and asks the Commission to provide guidance on principles for uplift allocation.[162] Please identify any specific areas where the RTO's/ISO's current uplift allocation methodology could potentially mute investment signals.

3. Please explain the methodology by which the RTO/ISO allocates day-ahead and real-time energy and ancillary services market uplift, including an explanation of whether and how the allocation rules follow cost-causation principles.[163] In this regard, please explain the following (referencing specific charge codes to the extent that it is practical):

a. Explain whether and how day-ahead and real-time energy and ancillary services market uplift is allocated to transactions that cause the commitment of resources that receive uplift payments;

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[161] FERC, *Staff Analysis of Uplift in RTO and ISO Markets*, Docket No. AD14-14-000, at 7-8 (Aug. 2014), *available at* https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.

[162] *See* PJM Comments at 17.

[163] Please include in this response a discussion of virtual transactions.

b. Explain whether and how the RTO/ISO allocates real-time energy and ancillary services market uplift to market participants' deviations from day-ahead schedules, and whether and how deviations that increase the need for actions that cause uplift (harming deviations) are netted against deviations that reduce the need for actions that cause uplift (helping deviations);

   i. explain whether and how uplift related to real-time resource commitments for transmission constraint management is allocated to schedule deviations;

   ii. explain whether and how uplift related to real-time resource commitments for system reliability is allocated to schedule deviations;

c. Explain the locational granularity with which this uplift is allocated (e.g., RTO-wide, zonally);

   i. explain whether and how uplift related to real-time resource commitments for voltage and local reliability is allocated to local transmission areas or zones;

d. Explain whether day-ahead and real-time energy and ancillary services market uplift is allocated on an hourly, daily average, or another basis;

e. Discuss and explain whether there are certain components of day-ahead and real-time energy and ancillary services market uplift that cannot be allocated consistent with cost-causation principles, and if so explain how these are allocated;

f. Explain the conditions under which the RTO/ISO exempts from the allocation of each charge any market participants, transactions, or schedule deviations that would otherwise receive an allocation, and explain the rationale for such exemptions.

g. Finally, list and explain the categories of transactions, or schedule deviations to which the RTO/ISO allocates day-ahead and real-time energy and ancillary services market uplift charges.[164] For the period spanning October 1, 2014 through September 30, 2015, report the share of day-ahead

[164] For example, if an RTO/ISO allocates uplift charges to transactions and/or schedule deviations by generators, load zones, imports, exports, virtual supply, and virtual demand, it should list and explain these categories in its response to this question.

energy and ancillary services market uplift (in percentage terms) allocated to each category. Similarly, report the share of real-time energy and ancillary services market uplift allocated to each category over the same time period. Do not identify any specific market participants.

4. Some commenters suggest that MISO's uplift allocation methodology matches cost-causation principles and represents an industry best practice.[165]

a. Please discuss the advantages and disadvantages of MISO's approach, and discuss whether it represents an industry best practice.

b. Please discuss whether other RTOs/ISOs should create allocation categories that relate to the underlying causes of uplift, and how these categories should be defined. Discuss the types of uplift costs that can be assigned to cost-causation categories. What types of uplift costs, if any, cannot be readily assigned such categories? Why are such uplift costs difficult to categorize in accordance with cost-causation?

5. Please discuss other potential approaches to allocating uplift charges based on cost-causation, and explain the potential advantages and disadvantages of such approaches.

6. Some commenters argue that allocating uplift charges to virtual transactions reduces the volume of such transactions, thereby impeding the convergence of day-ahead and real-time energy prices, while other commenters argue that RTOs/ISOs should allocate a portion of uplift charges to virtual transactions.[166]

a. Please discuss whether and how the RTO's/ISO's uplift allocation methodology nets virtual transactions or other deviations from day-ahead schedules for purposes of allocating uplift charges. Please discuss the advantages and disadvantages of such practices in the context of cost causation and the convergence of day-ahead and real-time prices.

b. Please discuss the advantages and disadvantages of allocating to virtual transactions a portion of the uplift charges associated with the day-ahead

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[165] *See* Potomac Economics Comments at 18; Financial Marketers Coalition Comments at 26.

[166] *Compare* Vitol, Inertia Power, and DC Energy Comments at Attachment A, at 21; and Financial Marketers Coalition Comments at 18; *with* NCPA Comments at 8-9.

market alone (and not allocating to virtual transactions any uplift charges associated with the real-time market), and whether such an approach is consistent with cost-causation principles.

E. Transparency

1. Background

65. Transparency into the process by which prices are developed in energy and ancillary service markets supports the functioning of efficient markets by enhancing predictability, facilitating investment decisions, and identifying and raising awareness about system needs. Predictability enables resources to plan their operations better, such as daily fuel acquisition. Transparency about the price formation process is critical to hedging, investment, and resource entry and exit decisions. Investors seek information regarding the pricing of market services in order to assess the prospective value of potential investments. Without sufficient transparency, market participants may not have the tools necessary to critically analyze and discuss problems and identify potential solutions to market inefficiencies.

66. There are numerous causes of uplift and operator actions that affect market outcomes, some of which might not be transparent to the market. Failure to identify, communicate, and price such causes can distort prices, undermine the effectiveness of market signals and efficient system utilization, and mute investment signals. Frequent and timely reporting that specifies the location of and reasons for uplift and operator actions and communicates changes in market models (e.g., changes in the underlying constraints that are used to calculate clearing prices) may help incentivize a market response to a system need. In contrast, reporting that is aggregated such that it lacks information regarding the reason for, or location of, uplift or operator actions, or that is reported too late or infrequently, may be of limited use to market participants and fail to encourage economic investment decisions. There may not always be enough information regarding uplift, operator actions, and market models available to market participants to enable them to understand the actions that lead to uplift, understand how market clearing prices respond to market fundamentals, and effectively participate in RTO/ISO stakeholder processes.

67. Some RTOs/ISOs break down uplift charges into broad categories specifying, for example, whether uplift was incurred during day-ahead market commitment, reliability unit commitment, or real-time dispatch; these categories, however, often fail to specify the underlying cause of uplift (e.g., local, voltage constraints). Some RTOs/ISOs report uplift on an aggregated RTO-/ISO-wide basis, thus precluding market participants from

determining the location where uplift was incurred.[167] As discussed in the Uplift Staff Report, a review of RTO/ISO and market monitoring unit routine data postings indicated that only PJM's market monitoring unit and NYISO and its market monitoring unit report uplift at a zonal level.[168]

68. Despite the benefits of transparently sharing information regarding uplift, operator actions, and market models, some commenters have expressed concern that care must be taken when sharing such data to ensure that commercially sensitive information is not disclosed.[169] For example, multiple commenters argue that information disclosed on uplift and operator actions should not reveal payments to individual resources.[170] While acknowledging these comments, we note that sellers with market-based rate authority are currently required to file public Electronic Quarterly Reports with the Commission that include uplift payments received by day and by resource location. This unit-specific uplift information does not specify uplift drivers. Given the public disclosure of this data, commenters' concern may lie more with the timing of disclosure than the content.[171] Additionally, releasing certain information about constraints within the market models could potentially lead to market power abuse or otherwise result in certain market participants earning inappropriate amounts by exploiting such information.

69. Balancing the need for transparency about uplift, the market models, and operator actions with the need to preserve the confidentiality of market participants' proprietary information is not always straightforward. As explained below, RTOs/ISOs currently aggregate their uplift data to some degree (e.g., by driver/cause or location), or delay the

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[167] FERC, *Staff Analysis of Uplift in RTO and ISO Markets*, Docket No. AD14-14-000, at 27 (Aug. 2014).

[168] *Id.*

[169] *See* PJM Comments at 7-8; APPA and NRECA Comments at 34; ISO-NE Comments at 12; MISO Comments at 10-11; NYISO Comments at 5; PG&E Comments at 4; SPP Comments at 2.

[170] MISO Comments at 10-11; PJM Utilities Coalition Comments at 8; PSEG Companies Comments at 10; Western Power Trading Forum Comments at 8.

[171] *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, Order No. 768, FERC Stats. & Regs. ¶ 31,336, at P 157, 163 & 166 (2012); *orders on reh'g and clarification*, Order No. 768-A, 143 FERC ¶ 61,054 (2013); *and order on reh'g*, Order No. 768-B, 150 FERC ¶ 61,075 (2015); *Revisions to Electric Quarterly Report Filing Process*, Order No. 770, FERC Stats. & Regs. ¶ 31,338 (2012).

release of information, thereby preventing the disclosure of commercially sensitive information. However, given uncertainty regarding what information constitutes commercially sensitive information, some RTOs/ISOs might aggregate data or delay its release beyond what is needed to protect commercially sensitive information. For example, PJM notes that a PJM Operating Agreement provision restricts sharing information deemed commercially sensitive; PJM may only share such commercially sensitive information online approximately four months after the bid or offer data was submitted and at a location no lower than the zonal level. Nonetheless, PJM and PJM's Independent Market Monitor contend that some information currently categorized as commercially sensitive might not be commercially sensitive or could benefit the market if disclosed.[172] For example, if a resource is routinely committed out of market to resolve a local voltage issue, it may be beneficial to release information on the uplift associated with using such a resource in order to alert market participants about the local voltage issue and potentially incent other market participants to undertake investments that could resolve the local voltage issue more efficiently (e.g., install additional capacitors).

2. <u>Comments</u>

70. Workshop panelists and commenters discuss the ways in which RTOs/ISOs already share information on uplift and operator actions, critique those practices, and suggest areas for improvement. Many commenters highlight the importance of increased transparency and generally indicate that transparency about uplift and operator actions could be improved by sharing information more promptly or more frequently and by providing better information about the location of and drivers of uplift.[173]

71. Multiple workshop panelists and commenters discuss how RTOs/ISOs already communicate information on uplift and operator actions. At the Operator Actions Workshop, panelists representing RTOs and ISOs described data they share publicly about operator actions, the detail of which varies by RTO/ISO.[174] In addition,

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[172] PJM Comments at 7-8; Uplift Workshop Tr. 31:12-32:3; *see also* Monitoring Analytics, 2013 State of the Market Report for PJM at 123 (Mar. 13, 2014), *available at* http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013/2013-som-pjm-volume2.pdf.

[173] *See* Xcel Comments at 3; EEI Comments at 6-7; Energy Storage Association Comments at 2; Financial Marketers Coalition Comments at 8-11; Operator Actions Workshop Tr. 204:3-6; Susan L. Pope, FTI Consulting, Price Formation in ISOs and RTOs, Principles and Improvements, Docket No. AD14-14-000, at 63 (Oct. 29, 2014); Uplift Workshop Tr. 228:1-8.

[174] *See* Operator Actions Workshop Tr. 118:2-130:9.

RTOs/ISOs generally post reports on their websites that contain publicly available information about market operations, including discussions about uplift and operator actions.[175]

72. At the Uplift Workshop, the Connecticut Municipal Electric Energy Cooperative panelist indicated that ISO-NE publishes useful information in its morning report and monthly operations report.[176] The Financial Marketers Coalition panelist praised MISO for flagging the reason MISO has committed each unit that causes uplift.[177] The Calpine panelist indicated that CAISO has begun to report how the Minimum Online Commitment Constraint, a source of uplift, affects prices.[178] The Monitoring Analytics panelist noted that by identifying uplift associated with reactive power support and carving it out of overall uplift, PJM has raised awareness of the cause and location of this category of uplift.[179] The Con Edison panelist lauded NYISO for increasing transparency about commitments that cause uplift.[180] Similarly, PSEG Companies believe that NYISO's information disclosure represents a best practice because it discloses, *inter alia*, (1) all operator-initiated out-of-market actions in the daily operational announcements as the actions are taken, (2) which units are involved, (3) the level of the individual unit commitments, and (4) the time of the out-of-market actions.[181]

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[175] *See, e.g.*, CAISO, *Bulletins, Reports and Studies*, *available at* http://www.caiso.com/informed/Pages/BulletinsReportsStudies/Default.aspx; ISO-NE, *Markets and Operations*, *available at* http://www.iso-ne.com/markets-operations; NYISO, *Reports and Information*, *available at* www.nyiso.com/public/markets_operations/market_data/reports_info/index.jsp; PJM, *Energy Market*, http://www.pjm.com/markets-and-operations/energy.aspx; MISO, *Market Reports*, *available at* https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx; and SPP, *Reports*, *available at* https://marketplace.spp.org/web/guest/reports.

[176] *See* Uplift Workshop Tr. 118:20-119:23.

[177] *Id.* at 165:18-166:10.

[178] *Id.* at 111:21-112:1.

[179] *Id.* at 32:4-13.

[180] *Id.* at 167:7-15.

[181] PSEG Companies Comments at 9.

73. Commenters also highlight shortcomings or suggest areas in which individual RTOs/ISOs might improve information sharing practices. Although PSEG Companies believe that NYISO's information disclosure represents a best practice, they argue that NYISO could improve its practice by disclosing uplift drivers.[182] PSEG Companies also contend that PJM's dispatch and commitment decisions are largely opaque to market participants because market participants do not know *inter alia*: (1) which units are consistently called for out-of-merit commitment; (2) whether PJM really needed the units committed out-of-market; (3) the level of costs that were not captured in the clearing price, and (4) whether an alternative dispatch or different dispatch methodologies would have been available to meet reactive power requirements through efficient price signals.[183] Xcel believes there is inadequate transparency regarding: (1) real-time generator substitutions between energy and ancillary services (particularly in SPP); (2) reasons for disqualifying generators that may result from inadequate modeling (also in SPP); (3) use of temporary flowgates; and (4) sources of revenue insufficiency leading to uplift and the basis for uplift allocation.[184] Golden Spread expresses concern regarding the transparency and efficiency of headroom procurement decisions and the uplift that results.[185] Golden Spread suggests that SPP post the percentage of headroom procured within two days of procurement.[186]

74. Commenters also offered perspectives on improving transparency across all RTOs/ISOs. Many commenters and panelists at the Uplift and Operator Actions Workshops highlight the importance of increased transparency to better understand the reasons behind uplift and operator actions and to develop market-based solutions to reduce uplift and operator actions. Commenters generally indicate that transparency around uplift and operator actions could be improved by sharing information more

[182] *Id.* at 10.

[183] *Id*. at 8-9.

[184] Xcel Comments at 3-4.

[185] Golden Spread notes that headroom in SPP is excess generation capacity procured by the SPP Central Balancing Authority over and above what is needed for load and operating reserves to address the market's ramping needs.

[186] Golden Spread Comments at 13-15.

promptly or more frequently and with better information about the location and drivers of uplift.[187]

75. Generators and other market participants recommend greater transparency regarding the reasons why units were committed for uplift or operator actions.[188] Calpine, for instance, notes that each RTO/ISO may have different uplift and operator action drivers but data disclosure should expose repeated and avoidable non-market dispatch.[189]

76. Several commenters discuss the importance of locational information regarding uplift and operator actions. Financial Marketers Coalition highlights the importance of transparency concerning locational information, noting that near-term transparency regarding the location and reasons for out-of-market operator actions allows financial market participants to understand when operators are taking out-of-market actions and to refrain from bidding accordingly.[190] PJM notes that its public uplift information is aggregated at a high enough level that market participants cannot see where uplift is created and why. According to PJM, this aggregation protects market participants' confidential information but fails to provide information granular enough to provide an accurate market signal. PJM suggests that a revised approach would involve releasing uplift data on a zonal level, which will permit better market signals without allowing a

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[187] *See* Xcel Comments at 3; EEI Comments at 6-7; Energy Storage Association Comments at 2; Financial Marketers Coalition Comments at 8-11; Operator Actions Workshop Tr. 204:3-6; Susan L. Pope, FTI Consulting, *Price Formation in ISOs and RTOs, Principles and Improvements*, Docket No. AD14-14-000, at 63 (Oct. 29, 2014); Uplift Workshop Tr. 228:1-8.

[188] APPA and NRECA Comments at 34; California State Water Project Comments at 3; Calpine Comments at 7-8; EEI Comments at 2; Energy Storage Association Comments at 2; Entergy Nuclear Power Marketing Comments at 6; EPSA Comments at 16-17; Joint Trade Associations Comments at 2; PG&E Comments at 4; PJM Utilities Coalition Comments at 7-8; PSEG Companies Comments at 10; Xcel Comments at 3-4.

[189] Calpine Comments at 7-8.

[190] Financial Marketers Coalition Comments at 8-9.

competitor to infer particular resource offers.[191] PJM Utilities Coalition also supports sharing data at a zonal or regional level.[192]

77. Regarding the timing and frequency for releasing information, several commenters support reporting uplift and operator actions information shortly after the close of a market.[193] Western Power Trading Forum states that stakeholders should have access to any information that is available in real-time regarding out-of-market activity, while PJM and the CAISO panelist at the Operator Actions Workshop, however, express concerns about, respectively, the feasibility of releasing uplift and all out-of-market information in real-time.[194] Powerex contends that some operator interventions are not disclosed until long after the intervention occurs, if ever.[195] In terms of frequency of reporting, the Entergy panelist at the Uplift Workshop suggested that RTOs/ISOs should regularly provide granular information about the causes of uplift.[196] PJM Utilities Coalition similarly emphasizes the importance of regular periodic reporting on uplift drivers.[197] Energy Storage Association believes that RTOs/ISOs should be required to provide daily summary uplift data, including reasons for uplift,[198] while PJM Utilities Coalition recommends monthly reports on uplift categories.[199] To address problems associated with committing uneconomic units, Calpine argues that RTOs/ISOs should disclose whether uneconomic units were committed: (1) during the multi-day commitment

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[191] PJM Comments at 7.

[192] PJM Utilities Coalition Comments at 8.

[193] Calpine Comments at 9; EPSA Comments at 26 (citing Susan L. Pope, FTI Consulting, Price Formation in ISOs and RTOs, Principles and Improvements, Docket No. AD14-14-000, at 34 (Oct. 29, 2014)); Uplift Workshop Tr. 169:15-170:9.

[194] Western Power Trading Forum Comments at 7; PJM Comments at 7; Operator Actions Workshop Tr. 129:9-19.

[195] Powerex Comments at 17.

[196] Susan L. Pope, FTI Consulting, Price Formation in ISOs and RTOs, Principles and Improvements at 63; Uplift Workshop Tr. 169:15-170:9.

[197] PJM Utilities Coalition Comments at 7.

[198] Energy Storage Association Comments at 2.

[199] PJM Utilities Coalition Comments at 16-17.

process, (2) in the day-ahead market, (3) after the day-ahead market but before real-time, or (4) in real-time.[200]

78. Multiple commenters highlight the need to balance transparency with concerns regarding confidentiality and market power.[201] PJM argues that all non-commercially sensitive and non-Critical Energy Infrastructure Information should be shared publicly; however, PJM states that information that is truly commercially sensitive should not be shared.[202] Several commenters oppose revealing bids and offers or payments to specific resources.[203] For instance, PSEG Companies recommend that RTOs/ISOs never provide unit-specific information about bidding levels, but instead provide uplift cost information categories that both are narrow enough to be useful and broad enough that individual unit profiles cannot be discerned.[204]

79. Some commenters recommend solutions that would reduce uncertainty around operator actions or changing modeling assumptions. Direct Energy notes that unexpected operator actions, when needed, should be made pursuant to predictable protocols that are known to market participants.[205] Calpine contends that models or algorithms used to determine operator actions, as well as any non-market changes to model inputs or results, should be transparent and publicly disclosed.[206] Powerex suggests the Commission require that market operators establish a formal process for independent technical experts

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[200] Calpine Comments at 8-9.

[201] APPA and NRECA Comments at 32-35; ISO-NE Comments at 12; MISO Comments at 10-11; NYISO Comments at 5; PG&E Comments at 4; PJM Comments at 6; SPP Comments at 2.

[202] PJM Comments at 7-8.

[203] MISO Comments at 10-11; PJM Utilities Coalition Comments at 8; PSEG Comments at 10; Western Power Trading Forum Comments at 8. Though resource owners must report resource-specific uplift payments in the Electric Quarterly Report, it is possible that the commenters' concern relates more to the timing of the information's release rather than its content.

[204] PSEG Companies Comments at 10; *see also* Western Power Trading Forum Comments at 8.

[205] Direct Energy Comments at 5.

[206] Calpine Comments at 7.

to review the appropriateness of market models and the parameters applied to them.[207] Western Power Trading Forum and Calpine add that information should be provided concerning transmission outages, quantity of renewables that clear the day-ahead market, and operator modifications to load forecast and import schedules.[208] Calpine also recommends that with each instance of uneconomic unit commitments RTOs/ISOs report the number of units, the hourly MW, and the duration of the uneconomic dispatch.[209]

3. Scope of Reporting Requirements

80. Sufficient information regarding uplift drivers, charges and operator actions may be lacking for market participants to participate efficiently in RTO/ISO markets. Specifically, there appears to be a lack of clarity regarding what uplift RTOs/ISOs should report according to specific drivers, and the feasibility of and appropriate limits to releasing information more frequently, more promptly, and with additional geographic granularity. We also appreciate that there may be unintended consequences associated with increasing transparency. As such, we direct each RTO/ISO to submit information related to the transparency of its practices, as discussed below.

1. Please provide an up-to-date description of the RTO's/ISO's efforts or plans, if any, to address any RTO/ISO-specific transparency shortcomings. Are there any RTO/ISO and/or stakeholder initiatives to improve the transparency of data released publicly about uplift, operator actions, and other changes to the market parameters that can affect market clearing prices? If so, please describe any plans and related timelines.

2. Please describe how and the degree to which the RTO/ISO reports the specific reasons for uplift and operator actions. Please also respond to the following:

  a. Are there particular uplift or operator action categories that could be refined or disaggregated to improve transparency about the underlying reasons for uplift? If so, please describe.

  b. Please also describe the tradeoffs involved in refining uplift categories.

  c. Calpine recommends that RTOs/ISOs report the hourly MW and the duration of the uneconomic dispatch each time a resource is committed out-

[207] Powerex Comments at 19-20.

[208] Calpine Comments at 8; Western Power Trading Forum Comments at 8.

[209] Calpine Comments at 9.

of-market.[210] Please report on whether sharing each element (hourly MW and duration of uneconomic dispatch, to the extent known) is feasible shortly after uneconomic unit commitments are made; and if it is not feasible, please explain the existing barriers.

3. PJM notes that certain information that is currently considered commercially-sensitive by market participants may not actually be commercially sensitive. Under section 18.17 of its Operating Agreement, PJM can only post non-aggregated commercially-sensitive offer data approximately four months after bid and offer data were submitted and at a locational level no more granular than zonal.[211] Are there any RTO/ISO tariff provisions that restrict the release of uplift category information (location, speed, frequency, or driver) beyond what is needed to protect confidential information?

4. How frequently should categories of incurred uplift charges be shared with market participants? How promptly should categories of incurred uplift be shared with market participants?

a. Is it feasible to disclose uplift or operator actions (including MWs and expected duration), as soon as or shortly after the commitment is made (whether in real-time, if the commitment of uneconomic units is made in real-time, or shortly after the close of the day-ahead market, if the commitment is made day-ahead), while disclosing the reason for that uplift or operator action at a later time once the RTO/ISO has been able to determine the cause?[212] Is releasing this information feasible while protecting confidential information? What protections are required?

b. If it is feasible to release this information as soon as it is known in real-time, is it also feasible to release the information at a zonal level in real-time? Does reporting real-time zonal information address concerns about protecting confidential information? More specifically, please respond to the following questions:

i. Is zonal reporting of individual uplift categories feasible and is zonal reporting the appropriate geographic level for uplift reporting? If

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[210] *Id.*

[211] PJM Comments at 8-9 (citing PJM, Operating Agreement, § 18.17.1(e)).

[212] *See* Operator Actions Workshop Tr. 129:4-130:2.

not, what is the appropriate geographic granularity for reporting uplift categories?

ii. Can zonal reporting of each uplift category be accomplished without revealing proprietary information?

iii. Are there any uplift categories for which zonal reporting would not send a sufficiently granular signal? (For example, is zonal reporting sufficiently granular for uplift related to local voltage support?)

c. PSEG Companies recommend that RTOs/ISOs never provide unit-specific information about bidding levels, but instead provide uplift cost information categories that are both narrow enough to be useful and broad enough that individual unit profiles cannot be discerned.[213] To what degree is that principle (adjusting the dissemination of uplift information, as needed, to protect confidential information), one which can be applied in real-time or immediately after the close of a market in order to adjust regular reporting requirements?

5. PSEG Companies suggest that NYISO's specific uplift reporting practice may represent a "best practice." This reporting includes: (1) all operator-initiated out-of-market actions in the daily operational announcements that are released as the actions are taken; (2) which units are involved; (3) the level of the individual unit commitment; and (4) the time of the actions.[214] Are the speed, level of unit-specific detail (excluding payment information), and geographic granularity of this uplift reporting simultaneously feasible in other RTOs/ISOs? If not, to what degree could the RTO/ISO improve the speed and granularity of its out-of-market commitment and operator action reporting to approach NYISO's level of transparency in reporting real-time uplift?

6. Direct Energy contends that unexpected operator actions, when needed, should be made pursuant to predictable protocols that are known to market participants.[215] Calpine argues that models or algorithms used to determine operator actions, as

[213] PSEG Companies Comments at 10; *see also* Western Power Trading Forum Comments at 8.

[214] PSEG Companies Comments at 9-10.

[215] Direct Energy Comments at 5.

well as any non-market changes to model inputs or results, should be transparent and publicly disclosed.[216]

a. Please explain the RTO's/ISO's process for releasing changes to market models (such as revising assumptions about constraints or adding new closed-loop interfaces). What factors does the RTO/ISO consider when determining whether or not to release information about changes to market model inputs?

b. Does the RTO/ISO release this information to all market participants?

c. What limits are necessary prior to disseminating changes to the RTO/ISO market model?

The Commission orders:

The RTOs/ISOs are hereby directed to file reports, as discussed in the body of this order, within 75 days of the date of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[216] Calpine Comments at 7.

APPENDIX A: List of Short Names/Acronyms of Commenters

Short Name/Acronym	Commenter
APPA and NRECA	American Public Power Association and National Rural Electric Cooperative Association
Brookfield	Brookfield Renewable Energy Marketing LP
California State Water Project	California Department of Water Resources State Water Project
CAISO	California Independent System Operator Corporation
Calpine	Calpine Corporation
Con Edison	Consolidated Edison Company of New York, Inc.
Direct Energy	Direct Energy Business Marketing, LLC, Direct Energy Business, LLC and affiliated companies
EEI	Edison Electric Institute
EPSA	Electric Power Supply Association
ELCON	Electricity Consumers Resource Council
Energy Storage Association	Energy Storage Association
Entergy Nuclear Power Marketing	Entergy Nuclear Power Marketing, LLC
Exelon	Exelon Corporation
Financial Marketers Coalition	Financial Marketers Coalition
GDF SUEZ	GDF SUEZ North America, Inc.
Golden Spread Electric Cooperative, Inc.	Golden Spread Electric Cooperative, Inc.
ISO-NE	ISO New England, Inc.
Joint Trade Associations	Joint Trade Associations (Electric Power Supply Association, Edison Electric Institute, Natural Gas Supply Association, Nuclear Energy Institute, America's Natural Gas Alliance)
MISO	Midcontinent Independent System Operator, Inc.

NYISO	New York Independent System Operator, Inc.
New York Transmission Owners	New York Transmission Owners (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Power Supply of Long Island, New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation)
NCPA	Northern California Power Agency
NRG/Boston Energy Trading & Marketing	NRG/Boston Energy Trading & Marketing
OMS	Organization of MISO States
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, L.L.C.
PJM Utilities Coalition	PJM Utilities Coalition (American Electric Power Service Corporation, the Dayton Power and Light Company, FirstEnergy Service Company, Buckeye Power, Inc., and East Kentucky Power Cooperative)
Potomac Economics	Potomac Economics, Ltd.
Powerex	Powerex Corp.
PSEG Companies	PSEG Companies (Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC)
SCE	Southern California Edison Company
SPP	Southwest Power Pool, Inc.
Vitol, Inertia Power, and DC Energy	Vitol Inc., Inertia Power, LP, and DC Energy, LLC
Wartsila	Wartsila North America, Inc.
Western Power Trading Forum	Western Power Trading Forum
Wisconsin Electric	Wisconsin Electric Power Company
Xcel	Xcel Energy Services Inc.