UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

RESPONSES OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP
TO STAFF QUESTIONS

Pursuant to the January 16, 2015 Notice Inviting Post-Technical Workshop Comments[1] and February 9, 2015 Notice Granting Extension of Time,[2] the Transmission Access Policy Study Group ("TAPS") comments on the price formation questions posed by Commission Staff.

TAPS identifies overarching concerns that are pertinent to all of Staff's questions, and provides more detailed responses on certain issues. We support the goal of proper price formation in RTOs with Day-Two energy and ancillary services markets, which generally work well today. While there is always room for improvement, the additional cost, complexity, and potential for adverse side-effects (including additional opportunities to exercise market power) caused by new electricity products and market design changes must be weighed against potential efficiency gains. Such determinations cannot be made on a generic basis. Because RTOs differ, and each RTO's markets have many moving parts, the impacts of any given reform will not be the same in every RTO. Efficiency gains that look promising in theory may, in practice, be either *de minimis*, or

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[1] eLibrary No. 20150116-3050.

[2] eLibrary No. 20150209-3029.

swamped by unintended interactive effects on the RTO's other markets. Reforms that seem benign in one RTO might significantly increase market power problems or opportunities for gaming and manipulation in another. Such changes could dramatically increase price volatility and consumer costs without providing any meaningful price signal or financial incentive for desired investment—an outcome inconsistent with the Commission's statutory obligation to set rates that result in the lowest reasonable cost to consumers.

TAPS therefore urges against generic action. Rather than requiring that all RTOs expend their limited resources on particular reforms that may provide little return in some RTOs, each region should be permitted to focus on the issues most pressing for that region, based on the assessment by the RTO and its stakeholders of potential gains, costs, and unintended consequences.

INTEREST OF TAPS

TAPS is an association of transmission-dependent utilities ("TDUs") in more than 35 states, promoting open and non-discriminatory transmission access.[3] Representing load-serving entities ("LSEs") entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS has supported the Commission's initiative to form truly independent regional transmission organizations to foster efficient investment in transmission and generation, and to provide non-discriminatory transmission access. As discussed below, TAPS members view RTO energy and

[3] Tom Heller, Missouri River Energy Services, chairs the TAPS Board. Jane Cirrincione, Northern California Power Agency, is the TAPS Vice Chair. John Twitty is the TAPS Executive Director.

ancillary services markets as generally functioning well, and have concerns about possible generic Commission action to change them.

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I. OVERARCHING CONCERNS PERTINENT TO ALL STAFF QUESTIONS

TAPS approaches Staff's questions with the goal of seeking practical solutions that improve market operations, consistent with the Commission's obligation to ensure the lowest reasonable cost to consumers. From TAPS' perspective, RTO energy and ancillary services markets are generally working well. In the vast majority of hours, and for the vast majority of dollars, these markets operate smoothly and transparently. There is always room for improvement; and given the enormous size of RTO electricity markets, even relatively small market defects can represent a large amount of money. However, the additional cost, complexity, potential for adverse interactive effects on the RTO's other markets, and opportunity for market power caused by new electricity products and market design changes must be balanced against potential efficiency gains.

We are particularly concerned that efforts to change energy and ancillary services markets to increase generator revenues, in hopes that the increase will spur investment in new resources and retention of existing resources to sustain reliability,[4] will damage those markets while failing to deliver the desired benefits. In its January 2014 comments on Centralized Capacity Markets, TAPS explained that "[o]nly markets that provide the potential for long-term commitments to support long-lived, capital-intensive investments are capable of maintaining resource adequacy and meeting other federal, state, and local energy policies."[5] Almost all new capacity being constructed is either supported by a long-term power purchase agreement, or owned by a utility to serve its load. By one estimate, just two percent of all new generation in 2011 was built by an independent power producer based solely on wholesale market revenues.[6] An update for 2013 reached almost identical findings. Just 2.4 percent of new capacity built in 2013 was based solely on organized market revenues.[7]

Intermittent and unpredictable energy market price spikes will not support the investment in resources needed to sustain reliability. As explained by Patrick Connors (WPPI Energy), who spoke on behalf of TAPS during the October 2014 Workshop, "[n]o utility—regulated or unregulated—will invest in a new generator in the hope that energy prices will be extremely high for a few hours every year; utilities base those investments

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[4] Transcript of Sept. 8, 2014 Technical Conference 6:13–7:14, *In re: Price Formation in Energy & Ancillary Servs. Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Docket No. AD14-14-000, eLibrary No. 20141002-4003 ("September Workshop Tr.").

[5] Post-Technical Conference Comments of the Transmission Access Policy Study Group 15, Jan. 8, 2014, *Centralized Capacity Mkts. in Reg'l Transmission Orgs. and Indep. Sys. Operators*, Docket No. AD13-7-000, eLibrary No. 20140108-5184.

[6] The Brattle Group, *The Importance of Long-Term Contracting for Facilitating Renewable Energy Project Development* 10 & n.21 (May 7, 2013), http://www.brattle.com/system/publications/pdfs/000/004/927/original/The_Importance_of_Long-Term_Contracting_for_Facilitating_Renewable_Energy_Project_Development_Weiss_Sarro_May_7_2013.pdf?1380317003 (citing Elise Caplan, *What Drives New Generation Construction? An Analysis of the Financial Arrangements Behind New Electric Generation Projects in 2011*, Elec. J., July 2012, at 48-61).

[7] American Public Power Association, *Power Plants Are Not Built on Spec: 2014 Update* 1 (2014), http://appanet.files.cms-plus.com/PDFs/94_2014_Power_Plant_Study.pdf.

on projections of adequate margins on both capacity and energy sales over the long-term."[8]

The potential changes to energy market price formation rules discussed during the Workshops and in Staff's questions will not solve or mitigate problems with Eastern capacity markets. It would be misguided for the Commission to sacrifice the proper functioning of RTO energy and ancillary services markets—which currently work well—in hopes that they will. As the Commission considers next steps, it should not lose sight of key issues: (1) the need to protect consumers; (2) generic directives could cause more harm than good; and (3) the need to address market power.

Any market reforms required must result in the lowest possible reasonable cost to consumers. In considering potential reforms to RTO energy and ancillary services markets, the Commission must be mindful of the cost impacts on LSEs. While the introduction of Staff's questions states generally that proper price formation should "maximize market surplus for consumers and suppliers,"[9] it fails to mention the Federal Power Act's requirement that rates should result in the lowest possible reasonable cost to consumers.[10] The FPA was framed "to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."[11] Consumer protection and just and reasonable rates are the FPA's core mandate—not windfall payments or

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[8] Written Statement of Patrick T. Connors on Behalf of WPPI Energy and the Transmission Access Policy Study Group Regarding Impacts of Offer Caps and Market Power Mitigation 5, Oct. 2014, *In re: Price Formation in Ancillary Servs. Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Docket No. AD14-14-000, eLibrary No. 20141203-4014 ("Statement of Patrick Connors").

[9] Notice Inviting Post-Technical Workshop Comments, Post-Technical Conference Questions for Comment at 1.

[10] *See Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959).

[11] *Id.*

subsidies to generators. Before undertaking any changes to energy market price formation rules, RTOs should be required to demonstrate that the changes are consistent with this mandate.

Generic directives could cause more harm than good. For any given market reform, the potential gains and costs will differ between RTOs because of differences in their market structures, generation resource mixes, and load characteristics. *See, e.g.*, Staff Question 5, below. Experience in individual RTOs indicates that efficiency gains that look promising in theory may, in practice, be vanishingly small or outweighed by interactive effects on the RTO's other markets. *See, e.g.*, Staff Question 4, below. Rather than requiring that all RTOs expend their limited resources on particular market reforms that may provide little return in some RTOs, each region should be permitted to set its own priorities and to focus on the issues that are most pressing for that region, based on the assessment by the RTO and its stakeholders of the potential gains and costs, including any adverse market side-effects of proposed changes.

Matthew White of ISO New England ("ISO-NE") highlighted these challenges at the December Workshop,[12] emphasizing that there are no easy fixes to remaining price formation problems (Tr. at 251-53):[13]

> [U]sing New England's statistics we have a $10 billion energy market.

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[12] Transcript of Dec. 9, 2014 Technical Conference 251:25-253:14, *In re: Price Formation in Energy & Ancillary Servs. Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators: Operator Actions*, Docket No. AD14-14-000, eLibrary No. 20150107-4003 ("December Workshop Tr.").

[13] *See also*, December Workshop Tr. at 261:2-25 (Steve Wofford, Vice President, Portfolio Operations for Exelon Corp.) ("[I]t is hard to think about one size fits all. The ISOs are different. … [S]o let's not pretend that what works in California or SPP with their level of intermittent resources is going to work in PJM. It is not that simple.").

> Uplift is consistently about 1% of that total $10 billion, so most of the costs are compensated through transparent transfer market prices.
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> The question is how do we deal with that last 1%? That is what this is all about today and that is a hard problem because for one thing if it was easy we would have done it already.
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> The problem is that most solutions that come down the pike when we put them through our filters as professional market designers we start to see incentive problems or unintended consequences or countervailing effects that probably [are] not a great solution because the biggest concern is that maybe the cure may be worse than the problem.
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> … I don't think there's a silver bullet. I think it is a problem of chipping away at the remaining 1% in the ways that you are really focusing on the most important issue in each region. . . . My view is that what is most important in this last 1% is very different in different regions and it may not be helpful to have a generic direction from the Commission that all regions should devote substantial resources and any of these issues will take substantial resource[s].

During the Workshops, RTOs identified different approaches that have been, or are being, developed to address many of the concerns identified by Staff. Each RTO, however, has tailored its priorities and proposals based on its region's specific needs and characteristics. Moreover, many of their proposed solutions are recent or not-yet-live. For example, the Commission has accepted Midcontinent Independent System Operator Inc.'s ("MISO") ramp capability product,[14] as well as its Extended Locational Marginal Price ("ELMP") proposal[15] (which alters the treatment of block-loaded fast start

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[14] *Midcontinent Indep. Sys. Operator Inc.*, 149 FERC ¶ 61,095 (2014).

[15] *Midcontinent Indep. Sys. Operator Inc.*, 140 FERC ¶ 61,067 (2012) (conditionally accepting MISO's

resources for purposes of setting LMP, and includes start-up and no-load costs of fast-start resources in LMP where deployment of such units avoids transient shortage pricing set administratively). However, the ramp capability product has not yet been implemented, and ELMP first went live on March 1, 2015.[16] Likewise, Coordinated Transaction Scheduling ("CTS") between NYISO and PJM was only implemented last November;[17] CTS between NYISO and ISO-NE is expected to be implemented later this year;[18] and CTS between PJM and MISO is still being negotiated.[19] MISO is also still in the process of developing a proposal for enhancements to pricing under emergency conditions.[20]

In short, the Commission should resist the urge to take generic action. Instead, RTOs should be given time to develop experience with the types of innovations discussed during the Workshops, before the Commission considers imposing any requirement that they be applied by all RTOs. While we support Commission efforts to encourage improvements on seams issues (*see* Staff Question 11 below), we urge the Commission to allow RTOs to work with their stakeholders to enhance their energy and ancillary

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ELMP proposal, subject to certain compliance filings).

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

[17] PJM Interconnection, L.L.C. & NYISO, *News Release: PJM, NYISO Implement Coordinated Transaction Scheduling* (Nov. 5, 2014), http://www.pjm.com/~/media/about-pjm/newsroom/2014-releases/20141105-nyiso-and-pjm-implement-cts.ashx.

[18] Janine Dombrowski, ISO New England, *Coordinated Transaction Scheduling: Discussion of the Proposed Approach to Complete the Governing Document Changes for the Anticipated 2015 Implementation of Coordinated Transaction Scheduling with NYISO* (Feb. 10, 2015), http://www.iso-ne.com/static-assets/documents/2015/02/a06_iso_presentation_02_10_15.pptx.

[19] September Workshop Tr. at 237:5-9 (Stu Bresler, PJM Interconnection, L.L.C.).

[20] Midcontinent Indep. Sys. Operator, Inc., Market Subcommittee, *Pricing During Emergencies* (March 3, 2015), https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2015/20150303/20150303%20MSC%20Item%2005a%20Pricing%20under%20Emergency.pdf.

services markets, rather than address these issues through rulemakings requiring standardized market designs. In many applications diversity is a benefit, and RTOs are no exception.

Market power effects of proposed changes to energy market price formation rules must be adequately resolved before such changes are implemented. RTO energy and ancillary services markets already operate well during normal conditions and the vast bulk of operating hours. The focus of the price formation rule changes discussed in this proceeding, therefore, has been the relatively few hours and extreme conditions when RTO resources and system operators are pushed to the edge.

Market power issues are a much bigger problem in those conditions when there are few potential suppliers, and resources that cannot exercise market power under normal conditions may become pivotal and capable of extracting monopoly prices. In addition, changing price formation rules may create opportunities for market manipulation. As the Director of the Commission's Division of Investigations recently noted, "RTO tariffs and rules create opportunities 'for a lot of mischief' given their complicated nature," and "'[t]he more complicated you make it, the more opportunities there are for exploitation.'"[21] The Commission has an obligation to assure that any changes to energy market price formation rules do not exacerbate or create new market power or gaming problems.[22]

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[21] Glen Boshart, *FERC Enforcement Is Different Because Energy Markets' Purpose Is Different, Regulators Told*, SNL Energy (Feb. 16, 2015, 11:49 AM), https://www.snl.com/InteractiveX/article.aspx?ID=31170749&KPLT=4 (password required), *available at* https://advance.lexis.com/api/permalink/483b22c3-485c-4751-b2f9-4f268aad5b74/?context=1000516.

[22] When relying on competition to set prices, the FPA requires "empirical proof" that "existing competition would ensure that the actual price is just and reasonable." *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984). "[U]ndocumented reliance on market forces" is insufficient to

II. STAFF QUESTION 1. OFFER CAPS

a. Should the $1,000/MWh offer cap be modified?

i. If the offer cap is modified, what form should the offer cap take? For instance, should a modified cap be set at a level greater than the current $1,000/MWh cap and apply even if a resource has costs greater than the new cap or should the offer cap be replaced with a structure that allows offers at the higher of marginal cost or the existing $1,000/MWh cap? Should it be a fixed cap or a floating cap that varies with the price of fuel (e.g., natural gas)? If a modified cap were set as a fixed offer cap, what should the new offer cap be? What should be the basis for determining the fixed offer cap?

ii. If the offer cap should not be modified or set such that marginal costs could be greater than $1000/MWh, how should the Commission ensure that suppliers with costs greater than the cap have the opportunity to recover those costs?

iii. Do the real-time and day-ahead market clearing processes allow sufficient time to verify the cost-basis of the marginal resources that exceed the offer cap? Does the settlement process allow sufficient time to verify costs of resources that receive uplift associated with offers that exceed the offer cap?

TAPS Response:

TAPS believes that offer caps continue to play an important role in preventing market power abuse, and that permanently increasing the offer cap above $1,000/MWh is unwarranted and unjust and unreasonable. As explained by Mr. Connors:[23]

> In the absence of large quantities of price-responsive demand, there is a significant potential for market power abuse when resources are tight and individual sellers may become pivotal suppliers. This problem can occur market-wide; or it may exist only in locally constrained areas, while the remainder of the market is competitive. Price caps provide a crucial circuit-breaker for such situations, and may play an increasingly important role in market power mitigation as the national economy recovers and the capacity surpluses of the past several years become smaller in the face of generation retirements due to environmental compliance efforts.

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satisfy the Commission's regulatory responsibilities. *Id.* at 1508. *See also California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (2004).

[23] Statement of Patrick Connors at 4.

> The Commission's current approach—establishing and maintaining offer price caps as a backstop, before specific market power problems emerge—should be maintained. Unlike stock markets in which trading can be halted if supply and demand are significantly out of balance, RTO electricity markets cannot be taken out of service without threatening reliability. As a result, consumers may incur huge costs before market power abuse is recognized and regulators can respond. And as the experience of the California energy crisis of 2000 demonstrates, the costs and resources required to address non-competitive markets outcomes after-the-fact, perhaps including through litigation and complicated RTO re-settlement procedures, can be massive.

The Commission has recognized that "[e]lectricity markets possess unique characteristics including, but not limited to, inelastic demand and the need to balance the entire transmission grid in real-time."[24] According to the Commission, "[e]conomic theory and empirical estimates of the short-run elasticities of electricity demand suggest that these unique conditions allow sellers in wholesale electricity markets to exercise market power using a much more limited withholding of supply than [other] industries."[25]

While there has been some increase in the role played by demand response since the $1,000/MWh offer cap was first put in place, electric demand continues to be largely inelastic. In most regions, the bulk of load is not sensitive to short-term price changes. In MISO, most load is served by utilities regulated by state public utility commissions, often at retail rates that do not vary by time of day or wholesale electric market

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[24] Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order 697-A, 73 Fed. Reg. 25,832, 25,838 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, P 37 (2008), *clarified*, 124 FERC ¶ 61,055 (2008) (subsequent history omitted).

[25] *Id.*

conditions. Even in regions with more retail competition, retail loads often do not see real-time wholesale market price signals.

Moreover, the Commission's demand response policies are currently in flux. The Commission has issued numerous orders in an effort to increase the participation of demand response in RTO markets; but the future of its primary approach—i.e., treating demand response as a resource that can be offered into the supply side of RTO wholesale markets, and paying those demand response providers full LMP when the "net benefits" test is satisfied—is uncertain given recent court decisions.[26] While there will be opportunities to restructure the participation of demand response in wholesale markets, this is not the right time to make a major policy change regarding the $1,000/MWh offer cap based on the assumption of ample demand response.

The existing offer cap is a binding constraint on the offers made by resources every day—even though under normal circumstances, there are no generators with a short-run marginal operating cost anywhere close to $1,000/MWh.[27] According to Joseph Bowring, PJM's Independent Market Monitor, raising the offer cap applicable in normal conditions will inappropriately change the energy market supply curves that RTOs face on a daily basis:[28]

> [I]f you look at the PJM aggregate offer curve, every day there are 3- or 4000 megawatts at $1000. So we could

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[26] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *reh'g en banc denied*, No. 11-1486 (D.C. Cir. Sept. 17, 2014), *petitions for certiorari filed*, Nos. 14-840 and 14-841 (U.S. docketed Jan. 16, 2015).

[27] Statement of Patrick Connors at 6. *See also* Transcript of Oct. 28, 2014 Technical Conference 215:1-25, *In re: Price Formation in Energy & Ancillary Servs. Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators: Scarcity & Shortage Pricing, Offer Mitigation, & Other Price Caps Workshop*, Docket No. AD14-14-000, eLibrary No. 20141028-4008 ("October Workshop Tr.") (Joseph Bowring, stating that cost-based bids of $1,000/MWh or higher only occur under extreme circumstances).

[28] October Workshop Tr. at 217:17-21.

> anticipate seeing 3- or 4000 megawatts at $2000 or $3000 if you simply raise the offer cap to $2000 or $3000.
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> I don't think that's appropriate.

All of the RTO Internal Market Monitors and most RTO representatives at the October Workshop pointed out that the $1,000/MWh offer cap continues to provide important market power mitigation functions, as well as "backstop" or "damage-control" protection to consumers, during normal market conditions.[29] Permanently increasing the offer cap to allow offers above $1,000/MWh, day-in and day-out, would sacrifice those substantial benefits to address extreme circumstances that may rarely or, depending on the RTO, never occur.[30]

Increasing the offer cap would also have no practical impact on resource investment decisions. A higher offer cap will not directly raise LMPs—in the vast majority of hours, the marginal resource is not bidding anywhere near the price cap. Indeed, until Winter 2013-2014 and the extreme conditions of the Polar Vortex, many people believed that cost-based offers would never reach $1,000/MWh.[31] No one will invest in a new resource in hopes that energy prices will be extremely high for just a few hours in some years, or even every year.[32]

If the Commission determines that some temporary or seasonal increase in the offer cap is warranted, it should only do so on a region-by-region basis where the

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[29] October Workshop Tr. at 204-206 (Shaun Johnson, NYISO), 206-207 (Jeffrey McDonald, ISO-NE), 209-210 (Richard Dillon, SPP (noting that "prices may rise too high in the nonconstrained—'constrained' being cost wise—nonconstrained periods of the year.")), 210-211 (Eric Hildebrandt, CAISO). *See also id.* at 211-214 (David Patton, MISO (stating that greatest purpose of the offer cap is to address gaming strategies)).

[30] *See, e.g.*, October Workshop Tr. at 210:24-211:8 (Eric Hildebrandt, CAISO).

[31] October Workshop Tr. at 209:18-22 (Joseph Bowring).

[32] *See* pages 3-4 & nn.5-7 *above*.

evidence demonstrates the need for the increase, and should, at the very least, require that: (1) any offers in excess $1,000/MWh be cost-justified; and (2) generators wishing to submit such offers obtain review by the RTO's market monitor to confirm that the offer is cost-justified. The requirement that offers in excess of $1,000/MWh be cost-based is essential to curbing market power abuse in periods when extreme conditions and fuel shortages may turn individual resources into pivotal suppliers. Particularly given the potentially enormous financial exposure from such extreme conditions—which may be inflated by problems with real-time modeling; limited experience with unusual system conditions; or, as apparently occurred in PJM in January 2014, operator uncertainty as to the likely rate of generator outages during such conditions[33]—requiring that any offers in excess of $1,000/MWh be cost-based appropriately limits the ability of generators to drive energy prices to unjust and unreasonable levels.

Restricting offers above $1,000/MWh to out-of-market compensation would allow for more complete, after-the-fact review of their cost justification by the market monitor. However, advance review and verification of such offers should be possible for most generators. So long as a generator has provided the market monitor with up-to-date information on its heat rates, it should be possible to calculate a cost-based energy offer quickly from data on the generator's fuel costs. Recognizing that a generator's actual fuel costs may be different from the spot price because of its specific purchase arrangements, generators could be given an opportunity to work with the market monitor in advance to come up with a method to review and verify its cost-based offers, to the

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[33] PJM Interconnection, L.L.C., *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* 44 (May 8, 2014), http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

extent that an RTO's tariff and business practices do not already provide an adequate mechanism.

If the Commission decides to permit such cost-based offers above $1,000/MWh to set LMPs, it should also direct RTOs to consider establishing a limit beyond which accepted offers will be paid in full, but LMPs will not rise. The Commission recently approved such a temporary $1,800/MWh cost-based cap on LMPs for PJM during winter 2014-2015.[34] That temporary cap on cost-based LMPs was designed to limit the economic rents received by infra-marginal resources during extreme conditions when normal RTO market operations start to break down. While the specific level set for PJM may well be too high—PJM proposed a cap that will not be triggered until cost-based offers reach literally unprecedented levels[35]—a reasonable safety-net price cap could be essential in extreme circumstances to protect from enormous consumer harm.[36]

A safety-net price cap also provides a crucial mechanism to limit damage from potential market power and manipulation in fuel markets. As shown by the experience of

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[34] *PJM Interconnection L.L.C.*, 150 FERC ¶ 61,020 (2015).

[35] *See* Tariff Filing of PJM Interconnection, L.L.C., Transmittal Letter 8-9 & n.22, *PJM Interconnection, L.L.C.*, Docket No. EL15-31-000 (Dec. 15, 2014), eLibrary No. 20141215-5253. According to PJM, its proposed $1,800/MWh cap on LMP is reasonable because:

> During last year's extreme, unprecedented winter, in which a volatile gas market caused cost-based offers to rise to their highest level in PJM's history, the highest cost-based offer submitted by a Market Seller of a generation resource in accordance with PJM's Cost Development Guidelines was $1,724/MWh.

[36] The Midwest price spikes during summer 1998—when prices in Midwest wholesale bulk power markets rose to $3,000-$7,000/MWh, with price jumps of thousands of dollars per MWh in a matter of minutes—are a cautionary tale. Comments of Transmission Access Policy Study Group 5, *Cincinnati Gas & Elec. Co.*, Docket No. EL98-53-000 (Sept. 14, 1998), eLibrary No. 19980915-0014. Although much has changed since that time, the experience of the Midwest price spikes highlights the challenge of maintaining stable markets and anticipating contingencies that may dramatically affect market outcomes. While current RTO markets have more safeguards than the Midwest bulk power markets of 1998, they use a single clearing price for all loads, which would allow price spikes to affect a huge number of consumers, potentially inflicting even greater damage than the 1998 price spikes that were paid by only selected entities.

the 2000-2001 Western Energy Crisis, manipulation of natural gas prices can cause electric rates to spike and can be difficult to detect while it is happening.[37] Particularly because it may be impossible to unwind fuel markets after-the-fact, and re-running affected electricity markets is so costly and difficult, a safety-net price cap that operates as a circuit-breaker—limiting LMP increases when fuel prices exceed levels expected if those fuel markets are operating normally—could be essential to protecting consumers and avoiding unjust and unreasonable rates.

III. STAFF QUESTION 4. SETTLEMENT INTERVALS

a. What are the advantages and disadvantages of moving to sub-hourly settlements for the real-time market as they relate to price signals, market efficiency, and operations?

b. What metering and RTO/ISO software changes would be needed to change settlement intervals from hourly to sub-hourly for the real-time market, and how long would these changes take to implement? Are there significant costs to RTOs/ISOs, and to market participants, of such changes? Are there any other impediments to adjusting settlement intervals?

c. What are the advantages and disadvantages of changing from hourly to sub-hourly settlements in the day-ahead market?

TAPS Response:

TAPS sees some potential advantages from moving to sub-hourly settlements, but any such transition should be considered only after careful assessment by each RTO of both the effects of the change on its markets and the costs of implementing the switch. While the change may have relatively little effect on the total energy and reserve market payments made to the RTO,[38] it could significantly increase other LSE costs. RTO

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[37] *See, e.g.*, *San Diego Gas & Elec. Co.*, 102 FERC ¶ 61,317, PP 56-63 (2003) (adopting Staff recommendation to modify the mitigated market-clearing price formula in the California refund proceeding, based on Staff findings that the prices established in the California gas spot market were not solely the outcome of fundamental supply and demand forces, but were artificially high).

[38] ISO-NE, for example, has performed an analysis using 2013 market data to model the energy and reserve market revenue effects of shifting to five-minute settlement. Matt Brewster, ISO New England, *Subhourly*

administrative costs—which are typically borne by load—will rise. LSEs will incur increased costs to transfer and store the extra data, and process settlements in accordance with RTO timelines. If switching to sub-hourly settlements requires replacement of metering systems or other changes, the costs to LSEs will be even higher.

In addition to increasing costs, it is unclear whether the switch to sub-hourly settlements will significantly improve incentives for the development of flexible generation. In theory, more fine-grained settlements, by altering how energy and ancillary services revenues are shared among different generators and rewarding those that provide needed flexibility to the grid, can potentially create incentives for the development of flexible units in the future. As a practical matter, however, the magnitude of the anticipated changes to the energy and ancillary services payments made to individual generators may well be much too small to have any effect on their long-term investment decisions.

In fact, given the complexity of RTO market structures, any new financial incentive for flexible units from sub-hourly energy market settlements may be swamped by other effects from the switch. For example, to evaluate a proposal to move to five-minute settlement intervals for generators, ISO-NE performed an analysis using 2013 market data as a baseline and modeling the effects of the proposed switch on

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Real-Time Market Settlements: Quantitative Analysis Demonstrating Energy and Reserve Market Revenue Results (May 6-7, 2014), http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/may672014/a11_iso_presentation_05_07_14_r1.pptx ("ISO-NE Quantitative Analysis"). According to that analysis (at 12-13), the shift to five-minute settlement intervals would have increased the total market-wide costs for real-time energy and reserves by only about $600,000. Even this difference appears to largely result from ISO-NE's use of a simple average in 2013, rather than a weighted average, to derive hourly settlement prices from sub-hourly real-time prices.

revenues in real-time energy and reserve markets.[39] That simulation showed total real-time energy and reserve market revenues for Fast Start Assets would actually *decrease* if sub-hourly real-time market settlements are implemented,[40] while the total real-time energy and reserve market revenues for Non-Fast Start Assets would *increase*[41]—i.e., the exact opposite of the outcome predicted by theory.

There may well be other valid reasons for an RTO to transition from hourly to sub-hourly settlements. However, fact-specific cost, benefit, and revenue impact issues must be closely examined by each individual RTO before making the decision to switch. Therefore, if the Commission decides to propose any rule with respect to moving to sub-hourly real-time market settlements, it should not mandate that change and should, at most, direct RTOs to consider sub-hourly settlement, with such change allowed only if the RTO demonstrates that the benefits outweigh the costs.

IV. STAFF QUESTION 5. NEW PRODUCTS TO INCENT FLEXIBILITY

c. What are the tradeoffs between sending a price signal through a short-duration shortage event versus establishing a ramping product that is priced separately?

<u>TAPS Response:</u>

Establishing a separately priced ramping product is generally a better approach than sending a price signal through a short duration shortage event. A properly designed ramping product will reward units that provide the RTO with needed flexibility, rather than award a windfall to all units that happen to be in the market during the short-

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[39] *Id.*

[40] Energy market revenues would increase by $1.2M, but Reserves market revenues would decrease by $2.4M, for a total revenue change of -$1.2M. ISO-NE Quantitative Analysis at 12-13.

[41] Energy market revenues would increase by $2.1M, but Reserves market revenues would decrease by $0.4M, for a total revenue change of $1.7M. ISO-NE Quantitative Analysis at 12-13.

duration shortage event. A ramping product can also provide a more reliable income stream than infrequent and unpredictable shortage events—a crucial prerequisite to supporting new capital investment.

Creating the right incentives for flexible resources can help the grid deal with expected changes to the Nation's generation portfolio and a greater reliance on intermittent renewable generators. RTOs, however, are already working on new products to address this need. Rather than mandate particular reforms, the Commission should let RTOs develop region-specific solutions to important regional concerns with their stakeholders and market participants.

Those region-specific solutions should include the development of new products when they are needed and cost-effective; but solutions chosen by one RTO may not work as expected in others. In October 2014, for example, the Commission approved MISO's introduction of a new ramp capability product.[42] That new product, however, is a work in progress and is not expected to be implemented until 2016.[43] While it might eventually serve as a model for other regions, it is too soon to know.

Any new ramping product must also be carefully integrated with, and tailored to, other markets within the particular RTO. MISO specifically noted the extra time it needed to address that challenge.[44] At MISO's request, the Commission's acceptance of

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[42] *Midcontinent Indep. Sys. Operator, Inc.*, 149 FERC ¶ 61,095 (2014).

[43] Compliance Filing regarding Ramp Capability Product of Midcontinent Independent System Operator, Inc., Transmittal Letter 6, Dec. 30, 2014, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-2156-001, eLibrary No. 20141230-5258.

[44] *See, e.g.*, Filing to Implement the New Ramp Capability Product of Midcontinent Independent System Operator, Inc., June 10, 2014, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-2156-000, eLibrary No. 20140610-5199 (noting the complexity of integrating MISO's proposed ramp product with other RTO markets).

the proposed ramping product is subject to the outcome of the ELMP proceedings, as well as eight other pending dockets, because tariff provisions for the new product are intertwined with other markets.[45] Because each RTO's markets are different, a standardized new ramping product cannot simply be grafted onto each region's existing systems without risking significant market disruption, opportunities for gaming, and unintended consequences with adverse impacts that could dwarf the hoped-for benefits.

Moreover, the Commission should allow each RTO to set its own agenda based on its particular needs. As explained by Todd Ramey (MISO) at the October Workshop, MISO's ramp capability product was developed to address the characteristics of that region's generation fleet—i.e., "lots of coal-fired generation, relatively slower ramping capabilities."[46] According to Mr. Ramey, because of the composition of MISO's fleet "[f]rom time to time we will run into transient ramp constraints, just interval to interval, that makes it a challenge to meet the full requirement for that interval."[47] Transient ramp constraints may be less of a concern in regions with a different resource mix, where more responsive units make up a larger share of the region's generation portfolio, or there are fewer intermittent wind resources with variable output.

Or other regions may have reasonably decided that they have more pressing needs to address. The State of California, for example, has made energy storage technology a priority. *Advancing and Maximizing the Value of Energy Storage Technology: a California Roadmap*[48]—a collaborative document produced by the California

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[45] 149 FERC ¶ 61,095, P 61.

[46] October Workshop Tr. at 18:10-11.

[47] *Id.* at 18:11-14.

[48] *Advancing and Maximizing the Value of Energy Storage Technology: a California Roadmap*

Independent System Operator ("CAISO"), the California Public Utilities Commission, and the California Energy Commission—identifies (at 3) the "ability to realize the full revenue opportunities consistent with the value energy storage can provide" as a key challenge that needs to be addressed by the state. High priority CAISO actions identified in the *California Roadmap* include (at 15):

- Clarify existing ISO requirements, rules and market products for energy storage to participate in the ISO market.
- Identify gaps and potential changes or additions to existing ISO requirements, rules, market products and models.
- Where appropriate, expand options to current ISO requirements and rules for aggregations of distributed storage resources.

A new ramping product may well be part of what CAISO will analyze under the *California Roadmap*'s list of high priority needs. But in a world of limited resources, CAISO, as well as other RTOs, should be permitted to set their own priorities and to focus on the issues that are most pressing for that region, based on their assessment of the potential gains and costs of market changes.

V. STAFF QUESTION 6. OPERATING RESERVE ZONES

a. How does the establishment, elimination or reconfiguration of reserve zones affect price formation? What should the triggers be? From experience, do the RTOs/ISOs have the appropriate reserve zones defined? Are additional, fewer, or different reserve zones needed?

TAPS Response:

To support efficient market operations while minimizing market power issues, operating reserve zones should be as large as possible, consistent with supporting reliable operations (i.e., deliverability in the event of a contingency that results in a call on

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(Dec. 2014), http://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf ("*California Roadmap*").

operating reserves). Creation of smaller reserve zones might allow more fine-grained shortage pricing, with higher administrative prices triggered more frequently in certain of the smaller reserve zones. If those smaller zones have been designated correctly and reflect real deliverability constraints in the event of a contingency, the short-term result could—at least in theory—be more accurate locational energy pricing.

Given the infrequency of shortage events, however, there is no evidence that any such price separation in the energy market will incent construction of new generation. Indeed, it is even unclear whether the change would increase or decrease total energy market revenues. In theory, shortage pricing might be triggered more frequently in redefined smaller reserve zone(s), increasing energy market revenues in that area; but energy market revenues in other areas could simultaneously decrease if reserve zone boundaries are changed.

Moreover, RTOs may already be able to address any concerns raising the potential need for smaller operating reserve zones, without generic changes to the rules governing price formation or zone creation. Local reserve zones have already been created by some RTOs; and based on the discussion in Staff's Shortage Pricing Paper, current RTO business practices can already be used to trigger large energy price increases in sub-areas of operating reserve zones, imposing prices comparable to administrative shortage pricing without actually invoking shortage pricing.[49] If RTOs can trigger

[49] *Staff Analysis of Shortage Pricing in RTO and ISO Markets* 16 (Oct. 2014), eLibrary No. 20141021-4013 ("Staff Shortage Pricing Paper"). According to the Staff Shortage Pricing Paper (at 16), on September 10, 2013, PJM was forced to involuntarily shed 16 MW in the ATSI transmission zone, but shortage pricing was not triggered. Staff notes that defining the ATSI transmission zone as a separate operating reserve zone would have allowed shortage pricing to be triggered. *Id.* Staff also notes, however, that "PJM invoked the ATSI Interface, a closed loop interface developed on July 17, 2013, to set energy prices any time emergency load management is issued in the ATSI zone," which "resulted in prices that reflect the shortage event, but without accounting for reserve deficiencies on a local basis." *Id.*

increased energy prices in problem areas by using a different mechanism, there may be no need to define and establish new smaller operating reserve zones to accomplish that goal.

Particularly given the need for the Nation to develop a robust grid that is capable of integrating a growing fleet of intermittent, location-constrained renewable resources, encouraging or mandating smaller operating reserve zones is a step in the wrong direction. Indeed, an RTO's decision to break out smaller reserve zones from existing zones should trigger examination of the RTO's transmission planning to determine whether transmission construction should be undertaken to relieve the constraints that might point toward that decision. The grid must be kept reliable; and before the transmission planning and development process has time to work, physical transmission constraints must be taken as a given in evaluating reliability, defining operating reserve zones, and setting reserve requirements. In the longer term, however, it would not be reasonable—or consistent with the FPA—to "solve" transmission constraints that prevent the reliable delivery of resources to load by simply creating new smaller reserve zones and requiring loads in those zones to procure additional resources. As the Commission has found, "Section 217(b)(4) of EPAct 2005 directed the Commission to use its authority to facilitate transmission planning and expansion to meet the reasonable needs of LSEs with respect to meeting their service obligations."[50] This mandate requires that the Commission direct RTOs to incorporate in their plans solutions to the transmission constraints that necessitate new smaller operating reserve zones.

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[50] *Midwest Indep. Transmission Sys. Operator Inc.*, 121 FERC ¶ 61,062, P 3 n.3 (2007).

VI. STAFF QUESTION 10. TRANSIENT SHORTAGE EVENTS

a. Should there be a minimum duration for a shortage event before it triggers shortage pricing? Why or why not? How would one determine that minimum time, and how does it relate to the settlement interval?

b. Do RTO/ISO rules regarding transient shortage events result in appropriate price signals? Why or why not? To the extent possible, please provide empirical evidence supporting your answer.

c. *Should treatment of transient shortages be consistent across all RTOs/ISOs? Why or why not?*

TAPS Response:

For very short, transient shortage conditions that are in the process of being resolved by system operators, it is inappropriate to trigger a shortage pricing event. Any "price signal" provided by such transient events is meaningless, because the condition will usually be over before resources can respond to the higher shortage price.[51] If market participants with physical resources were to react to the price change, the result could be over-generation in subsequent intervals and increased price volatility. These

[51] *See, e.g.*, October Workshop Tr. at 41:7-24 (Todd Ramey, MISO):

> So, you know, operators asking questions. We've got stakeholders asking questions. What do you want us to do, MISO, in five minutes to react to a $1100 pricing signal? Do you want us to commit a unit?
>
> Well, no, we don't want you to do that. We go with the system operators. Did you see this coming? Yes, we could see it coming but I knew it was transient. I knew it was a five-minute event. My choice was to go short of an operating reserve at a small increment or to commit a resource and commit the market to bearing the cost of that commitment decision to solve a five-minute problem. So working back and forth between operators, how they view system conditions and the value of reliability either from an operating reserve perspective, or even a transmission constraint perspective, what is it that's causing them to make decisions on unit commitment? So unit commitment even in real-time time frame is how you solve scarcity events.

See also id. at 246:14-20 (Robert Nelson, Southern California Edison):

> [California ISO] has had a material amount of price spikes in its real-time market. They're very short. They're transient. They're often extreme. And generally the only people that are able to capture this are virtual bidders because it's too late for the physical people to move. It's not physically signaling. It's just … financial.

See also Prepared Direct Testimony of Joseph Gardner 7:5-10, June 10, 2014, *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-2156-000, eLibrary No. 20140610-5199 (noting that when scarcity events have a short duration, market participants cannot respond before the event ends).

very short-term scarcity events do not pose a significant reliability risk and can occur when the RTO has ample capacity to meet energy and operating reserve requirements, but cannot meet changes in net load due to difficulties in predicting the output of variable energy resources and ramp limitations within the current dispatch interval.[52] Triggering shortage prices in such situations accomplishes nothing, other than to provide a financial windfall to generators already in the market, needlessly burdening consumers who will pay more for exactly the same resources that those sellers committed to provide in the absence of a declared shortage.

To avoid shortage pricing that is either meaningless or misleading, it is appropriate for RTOs to have rules that provide operators with discretion not to trigger shortage prices for transient condition that they are in the process of resolving. The extent of that discretion and the specific protocols used by each RTO's operators should be developed by each RTO and its stakeholders based on the region's particular circumstances, including the characteristics of its generation fleet.

In the alternative, should the Commission attempt to reduce this type of operator discretion, it should also direct RTOs to reevaluate the administrative prices used during such transient shortages. During the October Workshop, Todd Ramey (MISO) described MISO's operating reserve demand curves and its effort to take into account differences in system conditions and operating circumstances in setting shortage prices:[53]

> Scarcity pricing is a generic term to refer to administered price curves to set prices. Then the scarcity pricing during those events of short durations in time, in small shortages

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[52] *See, e.g.*, *id.* at 6-7. MISO's recently approved ramping product was developed to reduce the frequency of such scarcity events. *Id.* at 15-16.

[53] October Workshop Tr. at 43:16-22.

> relative to your requirement, are deemed to have very low marginal value impacts to system reliability. So we have adjusted our curves to be reflective of that lower value.

Consistent with this approach, if RTO operators are required to trigger shortage pricing during transient events that they are already in the process of resolving, the shortage prices paid by the RTO should also be adjusted so that they do not exceed the value of the incremental reliability benefit (if any) provided by an additional resource in those circumstances. To the extent that an RTO's shortage prices are currently set at a higher level—e.g., based on the assumption (or RTO practice) that administrative shortage prices will be triggered by operators only in more extreme circumstances—those prices should be replaced with shortage pricing levels that more accurately reflect the actual benefits provided by the resources receiving the shortage price.

VII. STAFF QUESTION 11. INTERCHANGE UNCERTAINTY

a. *What can the RTOs/ISOs do to reduce interchange uncertainty? Does CTS help to reduce the uncertainty in interchange created by the lag between price posting and interchange schedules? Does the ability to reduce uncertainty depend on whether all interchange spread bids are incorporated into the RTO/ISO dispatch model (as proposed for the CTS implementation between NYISO and ISO-NE) rather than simply allowing interchange spread bids on a voluntary basis (as proposed for the CTS implementation between NYISO and PJM)? Are there other steps that should be taken to reduce interchange uncertainty?*

b. *What information do market participants need to better respond to interchange price signals?*

<u>TAPS Response:</u>

As TDUs, TAPS members do not dictate the boundaries of RTOs and have no say over the location of RTO seams. Seams issues, however, can enormously complicate our members' operations. Some TAPS members have loads and resources located in multiple RTOs, so are constantly dealing with seams issues to serve their customers. Seams problems also impose significant costs on our members and can invite gaming.

TAPS recognizes the importance of improving the efficiency of operations at RTO seams. We note, in particular, the obligation of PJM and MISO to function as a joint and common market;[54] and we urge the Commission to seek ways to improve all RTO seams by encouraging RTOs to move beyond the low-lying fruit and to address the difficult coordination and market design issues that must be resolved to integrate new resources, support reliable operations, and deliver just and reasonable rates to consumers. The expected changes to the generation mix as a result of environmental requirements, and the need to maintain reliability while integrating large amounts of new intermittent and location-constrained renewable generation, heighten the need to get inter-RTO interchange right.

The Commission, however, should not take generic action by rulemaking. CTS, the focus of Staff's questions, is an indication of the positive, but limited, progress that has been made on RTO seams issues to date. CTS appears to be an improvement over current inter-RTO scheduling practices; and it is being rolled out to address inter-RTO scheduling practices between several Eastern RTOs, obviating the need for the Commission to consider imposing such a requirement for those locations.[55] However, while CTS may help make interface transactions more orderly and predictable, the outcome may still be wrong from an efficiency perspective in the absence of agreement on interface pricing definition and other issues. Basic questions remain as to how much CTS will help, and what additional steps, if any, will be needed.

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[54] *See Alliance Cos.*, 100 FERC ¶ 61,137, PP 37-40 (2002), *order on clarification*, 102 FERC ¶ 61,214, *order on reh'g and clarification*, 103 FERC ¶ 61,274, *order denying reh'g and granting clarification*, 105 FERC ¶ 61,215 (2003), *appeal docketed sub nom. Am. Elec. Power Serv. Corp. v. FERC*, No. 03-1223 (D.C. Cir. 2003).

[55] *See* page 8, nn.17-19, *above*.

For more challenging issues, significant groundwork must be completed by the RTOs in order for progress to be made. TAPS appreciates the Commission's efforts to encourage RTOs to do that work and to identify potential approaches that might be explored to develop solutions.[56]

CONCLUSION

The Commission should take account of TAPS' comments in deciding on any action to be taken in response to the Price Formation Technical Workshops.

Respectfully submitted,

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[56] We are hopeful that the Commission's recent Order Requesting Additional Information on coordination across the MISO/PJM Seam will help jump-start efforts by those RTOs to tackle these important issues. *Coordination Across the Midcontinent Indep. Sys. Operator Inc./PJM Interconnection L.L.C. Seam*, Docket No. AD14-3-000, 150 FERC ¶ 61,132 (2015).