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REFRESHING PRICE FORMATION POLICY IN WHOLESALE ELECTRICITY MARKETS

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EXECUTIVE SUMMARY

In less than two decades, the rise and proliferation of organized wholesale electricity markets has resulted in more efficient and reliable operations and investment in the bulk transmission system. These markets, administered by regional transmission organizations (RTOs) or independent system operators (ISOs), rely on market prices to signal efficient and reliable behavior among market participants. In short, the success of these markets depends on healthy price formation.

Ideally, short-term markets would reflect the marginal cost of operating the grid reliably and the value of resource scarcity when such conditions arise.[1] This is difficult in practice, as all operational and physical constraints are hard to represent and incorporate into software that computes prices. When market design differs from system-reliability requirements, it causes RTO/ISOs to "commit" (instruct a resource to turn-on) or "dispatch" (adjust output of an operating resource) resources in a manner inconsistent with market outcomes. If market prices do not cover the costs of these out-of-market resources, the RTO/ISOs pay them out-of-market "uplift" payments that are ultimately charged to customers. The causes of uplift often aren't transparent. They also impose costs on customers that are both unpredictable and impossible to hedge.

When there are inconsistencies between market prices and system dispatch, existing resources may be used inefficiently, investment signals can be muted and it can elevate concerns about reliability. The situation also creates false arbitrage opportunities, which lead to market manipulation. Concerns about this process of price formation have grown as market fundamentals shift and the resource mix. Recognizing this, most RTO/ISOs have pursued market-design reforms to improve price formation. The subject has also caught the eye of the Federal Energy Regulatory Commission (FERC).

In 2014, FERC launched the price formation initiative. It began with technical conferences and staff papers and led into four notices of proposed rulemaking, two of which were finalized in 2016 (Order Nos. 825 and 831). The final rules clearly improved market design and price formation, while posing limited implementation challenges for RTO/ISOs. The pending rulemaking proposals, however, elicited a wide range of responses from leading industry experts. In particular, debate over pricing commitment costs for fast-start resources, and the specific methodologies to allocate uplift costs, have proved contentious. The new FERC leadership, which will determine the direction of these pending rulemakings, has the opportunity to pursue other areas to improve price formation.

1. Short-term markets obviously drive short-run (operating) incentives for market participants, but they also play a vital role in driving long-term resource investment by providing the basis for forward prices (i.e., investors decide to build or retire resources based on forward price expectations).

A key area for improvement is shortage or scarcity pricing. The remaining items are mostly incremental improvements to marginal-cost pricing. However, these lower-salience reforms have cumulative and synergistic effects that could substantially affect system efficiency, reliability and market outcomes. Moreover, they become more significant as the generation mix evolves to include many variable (e.g., wind and solar) and use-limited (e.g., energy storage) resources, which result in more dynamic supply fundamentals that multiply the challenges for market design and administration to produce accurate price signals.

Market design changes, including those for price formation, should not be used to pick technology winners. Yet it is unavoidable that such changes will alter competitive relationships between technology and fuel types.[2] Improved price formation will better reflect stressed system conditions, like shortages (better dependability valuation) and dynamic system conditions (better flexibility valuation). This would probably benefit hydropower and energy storage the most, as many forms of each are both highly dependable and flexible. Nuclear power would benefit from reforms that reward dependability, while resources like fast-cycling natural gas-fired plants would benefit from stronger flexibility incentives. More dynamic pricing would also encourage price-responsive demand, which has substantial potential as "smart" technologies evolve.

In many ways, FERC's price formation initiative embodies the proper role of a regulator. At the same time, some specific FERC actions could result in overly prescriptive, or potentially perverse, requirements. The key for new FERC leadership is to prioritize the most important areas of reform and encourage a culture of ongoing RTO/ISO price-formation improvements. More sunlight, limited prescription and performance-based regulation offer a pathway to efficient markets and good governance. With that, further enhancements to price formation will extend U.S. leadership on electricity policy and make the economy more competitive for decades to come.

INTRODUCTION

Reliably operating the bulk electric-transmission system (colloquially known as the "grid") requires instantaneous balancing of supply and demand. This process must respect transmission line constraints ("congestion") and the limitations of generation and demand-side resources.[3] To minimize the costs of operating the system therefore requires advanced optimization that accurately reflects supply and demand fundamentals, which can fluctuate substantially in a matter of minutes.

Decades ago, domestic grid operators began to dispatch generators in ascending order of cost (i.e., from lowest to highest marginal cost). This system, known as "merit-order dispatch,"[4] reduced the cost to operate the electricity system. The process relied on crude representations of generator operating costs and did not directly account for the costs to alleviate transmission congestion.[5] At the time, generation investment planning under the cost-of-service monopoly utility model only roughly approximated the operating needs of the system.

In the 1990s and 2000s, some states restructured their electricity systems to allow market forces to drive investment and operating decisions relevant to electric generation. Liberalization of the electricity sector shifted control of operating decisions from engineers, who were focused on technical efficiency, to market participants, who are motivated by prices and profits.[6] The same incentives shifted investment decisions, which resulted in investments that better reflected the operating fundamentals of the electric system.

Liberalization required a set of organized wholesale electricity markets that are operated by regional transmission organizations (RTOs) or independent system operators (ISOs). All RTO/ISOs adopted short-term markets to balance supply and demand in real time and to send long-term price signals that facilitate the entry and exit of new resources (e.g., market forces dictate the building and retirement of power plants). Many monopoly utilities also joined RTO/ISOs, which improved the operation of their assets but does not inform investment decisions.

Three RTO/ISOs consist primarily of monopoly utility territories: the California ISO (CAISO), the Southwest Power Pool (SPP) and the Midcontinent ISO (MISO). The New York ISO (NYISO), New England ISO (ISO-NE) and the PJM Interconnection (PJM) cover entirely or primarily restructured states. The Electric Reliability Council of Texas (ERCOT) also serves a restructured territory, but is not under FERC's jurisdiction.[7]

2. Competitive electricity markets facilitate open access to the transmission system on the principle of technology-neutrality.

3. Devin Hartman, "Physical Characteristics of Energy," R Street Institute, *Electricity 101* Series No. 2, August 2016. http://www.rstreet.org/wp-content/uploads/2016/08/electricity2.pdf.

4. Devin Hartman, "Economic Characteristics of Electricity," R Street Institute, *Electricity 101* Series No. 3, August 2016. http://www.rstreet.org/wp-content/uploads/2016/08/electricity3.pdf.

5. Also, some monopoly utilities began to pool their resources, which increased the efficiency of operating a wider array of resources across a broader footprint.

6. William W. Hogan, "Getting the Prices Right in PJM: Analysis and Summary: April 1998 through March 1999 The First Anniversary of Full Locational Pricing," April 2, 1999, 1. https://sites.hks.harvard.edu/fs/whogan/pjm0399.pdf.

7. This is because most of Texas connects to an intra-state transmission "island," which does not trigger interstate commerce.

RTO/ISOs use two forms of short-term markets: Energy markets procure the bulk needs, while ancillary service markets cover the additional services (e.g., operating reserves) needed to maintain grid reliability. Energy markets are the bread-and-butter of RTO/ISOs.[8] They aim to produce prices that reflect the marginal cost to operate the system. This results in lower total system production costs than the pre-RTO/ISO era. A critical development in this history was the use of congestion pricing to account for transmission-system constraints, especially at a granular (nodal) level. PJM pioneered nodal pricing in the late 1990s and ERCOT adopted it in December 2010.[9] Today, every RTO/ISO uses locational marginal pricing (LMP) to reflect congestion costs at the nodal level.[10] As such, we have less than two decades of experience with modern energy markets.

The revenues from marginal-cost pricing are insufficient to cover the going-forward costs of existing resources, as well as the entry of new resources, at levels that maintain enough system capacity to meet reliability standards. This has led RTO/ISOs to adopt either capacity markets, or shortage or scarcity pricing.[11] Shortage pricing is a mechanism to send a price signal in the real-time market during a systemwide shortage of power reserves. Properly done, shortage pricing is an administrative tool to reflect consumers' valuation of energy and reserves. Studies suggest consumers place a very high value on avoiding involuntary curtailments to electric service, generally referred to as the "value of lost load."[12]

ERCOT is the only RTO/ISO to adopt robust shortage pricing, which plays a central role in sufficient and efficient resource investments.[13] Other RTO/ISOs have opted for "diet" versions of shortage pricing, which result in insufficient revenues to maintain industry reliability standards. ISO-NE, NYISO and PJM adopted capacity markets to make up for this revenue shortfall. Capacity markets procure a level of future capacity that has been deemed necessary to meet reliability standards.[14]

The performance of energy markets relies on prices that accurately reflect resource scarcity and the marginal costs to operate the transmission system. However, many physical properties have proven difficult to represent in pricing models, which results in prices that are sometimes inconsistent with underlying economic fundamentals and that require out-of-market "uplift" payments to cover some of the costs not reflected. Such price-formation concerns prompted action by RTO/ISOs and their stakeholders and was ultimately noticed by FERC.

Accordingly, in 2014, FERC launched the price formation initiative to explore opportunities to improve energy and ancillary service price formation in the RTO/ISOs.[15] FERC held technical conferences and issued staff reports before initiating four notices of proposed rulemakings (NOPRs), two of which FERC finalized in 2016 (Order Nos. 825 and 831).[16] The other two remain pending and new FERC leadership will decide whether and how to continue with the initiative.

The theory of price-formation improvement appeals broadly to electricity economists and other experts. However, experts have disagreed about the specific means and approaches. FERC's final rules received praise from market experts, but the pending rulemakings elicited a wide range of responses from leading industry experts. In short, economists want to "get the prices right," but do not agree entirely on the means to achieve such a goal.

More broadly, however, FERC's pursuit of price-formation improvements has been popular across a wide range of industry, NGOs and other stakeholder groups. For example, in 2015, the Electric Power Supply Association, Edison Electric Institute, Natural Gas Supply Association, Nuclear Energy Institute and America's Natural Gas Alliance issued a joint letter to FERC on price-formation principles.[17] Clean energy and advanced technology groups also have pushed price-formation reforms, recognizing the value in sending better operational and entry signals to emerging technologies.

8. One of these operates in the day-ahead to pre-position resources and the other works in real-time to account for adjustments.

9. Pat Sweeney, "Texas Nodal Market Implementation," Electric Utility Commission, May 16, 2011, 2. http://www.austintexas.gov/edims/document.cfm?id=152729.

10. LMP has three components: the marginal system energy cost (the baseline without transmission constraints), congestion cost (incremental cost of re-dispatching around a transmission constraint) and transmission line losses. ERCOT does not incorporate line losses. However, these are very small compared to the other two components.

11. Shortage pricing and scarcity pricing are often used synonymously but sometimes have different definitions in industry. For the broad purposes of this paper, they are used interchangeably.

12. London Economics International LLC, *Estimating the Value of Lost Load: Briefing Paper Prepared for the Electric Reliability Council of Texas*, Inc., June 17, 2013, p. 7. http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf.

13. Accurate shortage pricing induces signals for efficient resource entry and exit (e.g., power plant builds and retirements).

14. For a more complete discussion on the types of organized markets, see Devin Hartman, "Types of Organized Electricity Markets," R Street Institute, *Electricity 101* Series, No. 5, August 2016. http://www.rstreet.org/wp-content/uploads/2016/08/electricity5.pdf.

15. 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, June 19, 2014. https://www.ferc.gov/industries/electric/indus-act/rto/AD14-14-000.pdf.

16. For more information see FERC's Energy Price Formation homepage at: https://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp.

17. Edison Electric Institute, Electric Power Supply Association, Natural Gas Supply Association, Nuclear Energy Institute and America's Natural Gas Alliance, "Principles for Energy Market Price Formation Reforms," March 2015. http://www.ngsa.org/download/filings_testimony/2015_filings/FYI-Joint%20price%20formation%20principles%20NGSA%20EPSA%20EEI%20ANGA%20NEI.pdf.

FERC's final price-formation rulemakings, along with individual RTO/ISO initiatives, continue to advance the design and administration of wholesale electricity markets, which lead the world in many regards. For comparison, Ontario does not use nodal pricing, instead relying heavily on "uplift payments." This is more reminiscent of California's deeply flawed market design from nearly 20 years ago. China does not even use merit-order dispatch, let alone account for transmission congestion. Thus, domestic price-formation improvements enhance a foundational construct that much of the rest of the world has yet to adopt. Accordingly, further refinements will keep much of the United States at the forefront of global electricity policy.

PRICE FORMATION PRINCIPLES AND DETERMINANTS

The success of electricity markets rests with the quality of their design and administration. Market design sets the rules for how markets operate and participants interact. It provides incentives for competitive behavior and shapes the processes that guide outcomes. The physical characteristics of the electricity system require explicit consideration in market design.[18] Incentive compatibility is an essential market-design principle, whereby market rules align the economic interests of participants with the efficient and reliable performance of the electric system.

Good real-time market design should be the primary focus, because it provides short-term incentives for participant behavior (e.g., generation performance and demand response) and acts as the basis for investment and forward contract decisions.[19] Ideally, LMPs would accurately reflect the marginal cost of production and account for all operational and physical system constraints.[20] In practice, however, this is very challenging, as many system constraints are difficult to represent and incorporate into market software that computes prices. This results in price formation that sometimes diverges from the reliability requirements of operating the system.

RTO/ISOs reliably operate the system by committing (i.e., instructing a resource to turn-on) and dispatching (i.e., instructing an operating resource to adjust output) supply and demand-side resources. If market processes perfectly accounted for all costs and physical constraints, RTO/ISOs would not need to commit additional resources beyond those scheduled economically.[21] Constraints left unmodeled in market software can force the RTO/ISOs to commit and dispatch resources out of market to maintain system balance. If market prices do not cover their costs, these resources receive out-of-market "uplift" payments[22] to ensure they are not required to operate at a loss. These interventions tend to depress market prices artificially and lack transparency, while the resulting uplift charges can't be hedged and often result in unpredictable costs for market participants.

If shortage pricing accurately reflected the value of lost load, and if demand were fully price-responsive, short-term energy prices would provide an accurate price signal for short-term behavior, and would facilitate efficient long-term entry and exit.[23] However, most demand remains relatively price insensitive in the short run and the value of lost load is very difficult to approximate. All RTO/ISOs under FERC jurisdiction use shortage pricing that is well below the range of estimates for the actual value, notwithstanding performance incentives provided by capacity market commitments.

Failure to reflect the value of reliability to consumers and RTO/ISO actions in prices can lead to inefficient utilization of resources, muted investment signals and reliability concerns.[24] Furthermore, inconsistencies between dispatch and pricing can also create false arbitrage opportunities, which lead to market manipulation.[25] An extreme example was the California energy crisis of the early 2000s, which caused a complete breakdown of markets and reliability events.

Shifts in market fundamentals heighten concerns regarding any failure of energy pricing mechanisms to value resources, particularly large power plants with high capital costs.[26] The accuracy of real-time prices greatly affects incentives for fuel assurance,[27] which is increasingly important given greater reliance on natural gas. Prices that more accurately reflect supply dynamics also become increasingly important with the integration of variable energy resources, like wind and

18. William W. Hogan and Susan L. Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT," FTI Consulting, May 9, 2017, 1. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

19. Ibid., 5-7.

20. Federal Energy Regulatory Commission, "Price Formation in Energy and Ancillary Services Markets," 2. https://www.ferc.gov/industries/electric/indus-act/rto/AD14-14-000.pdf.

21. Federal Energy Regulatory Commission, *Staff Analysis of Uplift in RTO and ISO Markets*" U.S. Department of Energy, August 2014, p. 1. https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.

22. These are also known as "make-whole" payments.

23. Federal Energy Regulatory Commission, *Price Formation in Organized Electricity Markets: Staff Analysis of Shortage Pricing in RTO and ISO Markets*, U.S. Department of Energy, October 2014, p. 1. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

24. Ibid.

25. William W. Hogan, *Electricity Markets and the Clean Power Plan*, Sept. 21, 2015, p. 21. https://sites.hks.harvard.edu/fs/whogan/Hogan_CPP_092115.pdf.

26. PJM Interconnection, "Energy Price Formation and Valuing Flexibility," June 15, 2017, 2. http://www.pjm.com/-/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx

27. "Comments of the Natural Gas Supply Association on RTO and ISO Fuel Assurance Reports," Federal Energy Regulatory Commission, Docket No. AD13-7-000 and Docket No. AD14-8-000, 2015, 9-10. http://www.ngsa.org/download/filings_testimony/2015_filings/NGSA%20Comments%20on%20Fuel%20Assurance%20Reports.pdf.

solar. "Smart" technologies present more opportunities for price-responsive demand, which requires accurate price signals to spur appropriate behavior.

As such, price formation is a highly salient issue. The benefits of better real-time incentives include lower production costs and emissions, better investment and performance incentives, and less reliance on capacity markets.[28] Based on this, market design should ensure that incentives are compatible by maximizing consistency between market and reliability requirements. Some clear guiding principles for price formation include:

1. Energy and ancillary-service prices should accurately reflect the marginal cost of reliably operating the transmission system;
2. Energy and ancillary-service prices should accurately reflect resource scarcity, even when reliability operations require out-of-market actions by RTO/ISOs; and
3. Rules governing out-of-market interventions should provide for transparency, such that market participants more efficiently account for interventions. Moreover, the causes and consequences of interventions should be made more readily identifiable in order to facilitate market design and procedural improvements.

FINAL RULEMAKINGS

FERC issued the first price-formation rulemaking in June 2016 (Order No. 825), which required RTO/ISOs to trigger shortage pricing for any real-time energy or operating reserves shortage interval. It also aligned intervals for dispatch with transaction settlements.[29] This serves to improve economic efficiency by aligning prices with system operating conditions during periods of shortage. It also provides stronger incentives for market participants to follow an RTO/ISO's dispatch signal by matching payments with price signals, rather than averaging payments over multiple dispatch intervals.

The principles and substance of Order No. 825 have received widespread support among market-design experts. However, some practical short-term implementation challenges raise questions about compliance strategies in the interim. For example, PJM's independent market monitor (IMM) voiced concerns that, by staggering the shortage-price reforms and settlement reforms, the order's implementation dates will temporarily worsen the very inefficiencies they seek to rectify.[30] Ideally, these reforms would occur concurrently, as shortage-pricing reforms would likely cause more frequent scarcity pricing and thus would exacerbate problems with misaligned settlement periods until the RTO/ISO implements them.

In November 2016, FERC issued Order No. 831, which loosened the stringency of energy-offer caps.[31] This rule enhanced price formation by reducing the likelihood of artificial price suppression, where rules force resources to offer energy services below their marginal cost. This is consistent with market principles and only raises concerns that exercises of market power would have stronger consequences, and thus could become more frequent if the behavior were to be rewarded. Indeed, such concerns provided much of the rationale for instituting offer caps in the first place. Since then, practices to mitigate market power have become far more advanced. Potential enforcement actions (e.g., prosecution of fraud) now are far more likely and yield greater penalties. Order 831 further mitigated concerns by including provisions to verify the costs of offers that exceed the $1,000/MWh level (i.e., a "soft cap") and capping such offers at $2,000/MWh for calculating LMPs.

Opponents of Order No. 831 noted that existing offer caps were rarely binding and thus to revise them was an overreaction to infrequent and anomalous events. Resources rarely exceeded previous offer caps except during periods of extreme system stress, especially when natural gas pipeline congestion caused gas prices to spike. Most notably, this occurred during the 2014 polar vortex, which forced PJM, NYISO and MISO to file requests to revise their offer caps temporarily or permanently. This illustrates that offer caps provide an incentive for resources to reduce their availability during extreme conditions (i.e., they do not want to offer if they take a loss when clearing the market) and this potentially compromises system reliability in addition to undermining price formation. If anything, Order No. 831 was an overly conservative adjustment to offer caps.

28. Pallas LeeVanSchaick, "2016 State of the Market Report: Energy & Ancillary Services Market Highlights," NYISO Market Issues Working Group, June 6, 2017, 12. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-06-06/2016%20State%20of%20the%20Market%20Report_MIWG.pdf.

29. Federal Energy Regulatory Commission, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule*, Docket No. RM15-24-000, Order No. 825, June 16, 2016, p. 1. https://www.ferc.gov/whats-new/comm-meet/2016/061616/E-2.pdf.

30. "Comments of the Independent Market Monitor for PJM Interconnection, LLC to the Federal Energy Regulatory Commission,» Docket No. ER17-775-000, Feb. 1, 2017, 2. http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775_000_20170201.pdf

31. Federal Energy Regulatory Commission, "Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule," Docket No. RM16-5-000, Order No. 831, Nov. 17, 2016, 1-2. https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf. FERC had just approved energy offer cap changes for PJM, while the other jurisdictional markets had $1,000/MWh caps.

PROPOSED RULEMAKINGS

Fast-start resource pricing NOPR

In December 2016, FERC issued a notice of proposed rulemaking (NOPR) to address the inability of some "fast-start" resources[32] to set LMP, which largely stems from the exclusion of commitment costs[33] from LMP.[34] The NOPR specifically proposed RTO/ISOs to adopt five requirements with respect to the definition and pricing of fast-start resources:[35]

1. Apply fast-start pricing to any resource that is able to start within 10 minutes, that has a minimum run time of one hour or less and that submits economic energy offers to the market;
2. Incorporate commitment costs (i.e., startup and no-load costs) of fast-start resources in energy and operating reserve prices during a resource's minimum run time;
3. Relax the economic minimum operating limit of fast-start resources to zero and treat them as dispatchable from zero to the economic maximum operating limit for the purpose of price calculation;
4. Require fast-start offline resources that set prices to be feasible and economic; and
5. Incorporate fast-start pricing in both the real-time and day-ahead markets.

Pricing fast-start resources invites the broader question of whether to include commitment costs in LMP.[36] Conventional LMP only includes the incremental cost to raise dispatch of the marginal resource, which results in prices that do not reflect commitment costs. However, the goal of RTO/ISO operations is to minimize total system production costs, which consist of dispatch and commitment costs and result in prices that differ from the underlying costs of operating the system.

Whether to include commitment costs in LMP raises fundamental questions of economic theory and technical capabilities. For example, software limitations do not account for a discontinuous or "lumpy" supply curve and commitment costs create such non-convexities in the curve when calculating dispatch-based prices.[37] The theoretical question begins with whether commitment costs, often characterized as short-run fixed costs, constitute the marginal cost of production (i.e., the change in total cost to produce one more unit of output). Generally, marginal costs are a function of variable cost and sometimes fixed cost.[38] Commitment costs are sometimes necessary to provide the next unit of output in an electrical system—which is to say that commitment costs can be marginal. Since commitment costs span multiple dispatch intervals (i.e., exceed the time period in which one more unit of output is acquired), the NOPR proposes to incorporate commitment costs into LMP by amortizing them across multiple intervals.[39]

Whether to include commitment costs in the definition of marginal cost has divided leading electricity economists. As noted by the CAISO Department of Market Monitoring (DMM), "the optimal pricing system to use when discrete or lumpy costs result in decreasing average costs has been discussed in the economic literature for over 70 years."[40] Potomac Economics, the independent market monitor (IMM) for NYISO, MISO and ISO-NE,[41] argues that the marginal cost of serving load includes inflexible fast-start resources needed to satisfy marginal energy and ancillary service needs.[42] The PJM IMM insists that average-cost pricing for fast-start resources is incompatible with the concept of marginal-cost pricing.[43] The CAISO DMM similarly claims that including the average costs of fast-start resources would contradict a basic principle of economic theory – that a two-part pricing system is most efficient when discrete costs cause average costs to decrease as a function of output.[44]

Market design experts outside the IMMs also remain divided. Bill Hogan of the Harvard Electricity Policy Group considers

32. "Fast start" resources are those that can start-up in a short timeframe.

33. These include the cost to "turn on," which covers start-up and no-load costs and which comprise a high percentage of operating costs for fast-start resources.

34. An offline resource incurs costs merely to start and maintain active operation, even at a level that supplies no net output to the transmission system. In contrast, dispatch cost is simply the incremental cost to produce a higher output level (e.g., the cost to raise output from 556 MW to 557 MW at an operating power plant).

35. Federal Energy Regulatory Commission, *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, Docket No. RM17-3-000, Dec. 15, 2016, pp. 1-2. https://www.ferc.gov/whats-new/comm-meet/2016/121516/E-2.pdf.

36. It should be noted that many resources other than those defined as "fast-start" incur commitment costs.

37. Conventional software requires a continuous dispatch curve to determine the incremental dispatch cost (marginal cost) to set price, which cannot account for non-convexities. As a result, resources receive uplift payments to cover commitment costs.

38. For example, if a company must acquire a new machine to produce another widget, then the machine cost is a fixed and marginal cost.

39. In other words, short-term averaging, which departs from prices that reflect incremental costs for only a single interval.

40. "Comments of the Department of Market Monitoring for the California Independent System Operator Corporation to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 1.

41. Potomac Economics is the external market monitor for ISO-NE, which also employs an internal market monitor.

42. "Comments of Potomac Economics, LTD to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 1-3.

43. "Reply Comments of the Independent Market Monitor for PJM to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, March 15, 2017, 3. http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Reply_Comments_Docket_No_RM17-3_20170315.pdf

44. "Comments of the Department of Market Monitoring for the California Independent System Operator Corporation to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 4.

TABLE I: INDEPENDENT MARKET MONITORS ON FERC'S FAST-START RESOURCE PRICING NOPR

	POSITION	UPLIFT AND MARKET IMPACT	OTHER NOTES
Potomac Economics (ISO-NE, NYISO, MISO)	Strongly support fast-start pricing and proposed rules, with specific caveats.	Will reduce uplift and increase market efficiency.	• Separate criteria for offline pricing from fast-start pricing. • Lengthen start-up and minimum run time definitions. • Proposed feasible criteria unsupported (most shortages are brief and unexpected), only offline resources receiving start instruction should be eligible to set price. • Little value in extending fast-start pricing to day-ahead market. • Fast-start pricing in NYISO and MISO has not caused over-generation problems.
Monitoring Analytics	Fundamentally opposed. Replaces marginal-cost pricing with average-cost pricing.	Inefficient and will not necessarily reduce total uplift. Will increase total cost of energy.	• Commitment costs are not the incremental costs that are the marginal cost of energy. • Will lower capacity prices and may not alter investment incentives overall. • May create disincentives for flexible resources and encourage inflexible fast-start resources. • If offline resources set price, should include non-performance penalties and/or disqualification from ability to set price. • Although the policy aim is to increase, it will likely decrease day-ahead and real-time price convergence. • Relaxing economic minimum creates an energy imbalance that requires manual RTO correction. • Agrees offline fast-start resource can be marginal.
CAISO DMM	Fundamentally opposed. Marginal-cost pricing does not cover commitment costs that decrease average costs.	Will create market inefficiencies and prevent optimal dispatch.	• Most important cost of NOPR compliance is opportunity cost of deferred or avoided alternative market initiatives and software enhancements. • Will undermine incentive for resources to bid their true marginal value. • Will not affect investment incentives significantly, as CAISO relies on separate capacity payments to support investment decisions. • Will not necessarily increase revenues for fast-start resources. • Improved verification of resource characteristics, and consideration of non-gas fast-start resources and effects on virtual trading are necessary.
SPP*	Generally agrees with theory and rationale but disagrees with particular provisions.	Depends on methods used.	• Base pricing logic on fast-start resource use not capabilities. • Offline units should not set price, unless shortage is related to contingency reserves. • Challenges with economic minimum relaxation. • Concerned that it will provide incentives for inflexible fast-start resources.

*Refers to comments of SPP, not its market monitor. The monitor did not submit separate comments.

it a reasonable goal for energy pricing to reflect the total cost of commitment and dispatch.[45] This derives from "convex hull pricing," which modifies the marginal-cost pricing concept to integrate discontinuities (i.e., commitment costs) into a continuous (convex) approximation. Hogan suggests that to relax constraints in operations models may not be a good way to determine commitment and dispatch, but that it provides a workable way to approximate prices.[46] Thus, Hogan's views suggest aspects of the NOPR (e.g., relaxing minimum economic constraint) may incrementally improve market efficiency, with full convex-hull pricing as the ideal solution.

In contrast, Dane Schiro and colleagues from ISO New England's Department of Business Architecture and Technology caution that convex hull pricing is "not an established economic concept and deviates from the traditional understanding of marginal cost pricing." Its appropriateness, Schiro and team argue, is therefore open to debate.[47] As such, they note that implementation of this less-than-fully understood pricing technique would result in some unpredictable outcomes. They emphasize that convex hull pricing requires full (as opposed to piecemeal) implementation and that it must have the same time horizon as the commitment problem.[48]

The difficulty in defining the commitment time horizon is evident in the NOPR's definition of fast-start resources. For example, Potomac Economics notes that the NOPR's definition of "fast-start" as a resource that can start in 10 minutes excludes the bulk of resources it considers "fast-start" and that have start times of up to 30 and 60 minutes.[49] This highlights a broader issue: whether to include commitment costs in pricing logic for medium- and long-start resources.[50] Thus, while the NOPR remains limited to fast-start resources, the

45. William W. Hogan, *Electricity Market Design and Efficient Pricing: Applications for New England and Beyond* June 24, 2014, p. 17. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pricing_062414r.pdf.

46. Ibid., p. 18.

47. Dane A. Schiro et. al., C*onvex Hull Pricing in Electricity Markets: Formulation, Analysis, and Implementation Challenges*, May 1, 2015, p. 35. http://www.optimization-online.org/DB_FILE/2015/03/4830.pdf.

48. Ibid.

49. "Comments of Potomac Economics, LTD to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 6-7.

50. Here, distinguishing between "fast" and "medium," etc. is irrelevant.

precedent it sets would raise fundamental pricing questions applicable to the full array of resources.

A less obvious underpinning of the differences among expert opinions may stem from their related preferences for resource-adequacy mechanisms (i.e., differences on the role of energy markets for fixed-cost recovery and signaling long-term investment decisions). Bill Hogan and Potomac Economics generally prefer strong investment signals in energy and ancillary-service markets and minimized reliance on capacity markets. This may contribute to Potomac Economics' position that pricing fast-start resources in energy markets is "essential for efficient locational investment,"[51] as capacity markets do not send investment signals as efficiently on a locational basis.[52] In contrast, CAISO and SPP rely on state procurement processes to achieve resource adequacy, and the PJM IMM is a proponent of a "strong" capacity market.[53] This suggests that the value proposition of pricing fast-start resources may depend in part on the underlying resource-adequacy process. After all, energy markets in RTO/ISOs that span mostly (or entirely) regulated monopoly states do not signal investment decisions to nearly the same degree as those in restructured states.

Beyond the fundamental question of whether to include commitment costs in LMP, a variety of market experts have raised concerns with implementation of the NOPR's prescriptions.[54] Additionally, a common theme in NOPR response comments was to let RTO/ISOs issue different rules to suit their particular generation fleets.[55] Considering this and the lack of conceptual and methodological consensus, the value of regional experimentation appears high. NYISO, MISO, PJM and ISO-NE have already enacted and/or considered further pricing rule reforms that address offline and fast-start resources. These will provide critical lessons learned in the next year or two.

51. "Comments of Potomac Economics, LTD" 7.

52. The zones of capacity markets are less granular than nodal pricing signals in energy markets and do not reflect actual dynamic conditions. Rather, capacity markets use administratively determined planning needs.

53. Strong in terms of capacity performance requirements and associated non-performance penalties.

54. Examples include "over-generation" problems, resource definition concerns, separate problems with pricing offline resources and costs exceeding benefits of applying fast-start pricing in the day-ahead market.

55. Modern Markets Intelligence, Inc., "ISO/RTO, monitors react to fast-start pricing NOPR," *PowerMarketsToday*, March 6, 2017. https://www.powermarketstoday.com/public/ISORTO-monitors-react-to-faststart-pricing-NOPR.cfm.

Uplift cost allocation and transparency NOPR

One month after the fast-start resource pricing NOPR, FERC issued another NOPR on the allocation and transparency of uplift costs.[56] Specifically, the NOPR proposes to require RTO/ISOs to allocate the real-time uplift costs incurred by market participants who deviate from day-ahead market schedules to those that caused them.[57] The commission also proposes to enhance transparency by requiring RTO/ISOs to post uplift payments and operator-initiated commitments publicly and to define transmission constraint penalty factors in the RTO/ISO tariff, along with the circumstances the factors used to set LMPs and any procedures to modify the factors.[58]

The NOPR intends to align the causation and allocation of uplift costs, a sound economic principle but one that is difficult to execute in practice. The PJM IMM has noted that assigning uplift charges only to those transactions responsible for incurring them is ideal, but not possible.[59] The ISO/RTO Council specified that allocating uplift costs on cost-causation principles is frequently difficult and infeasible given the myriad factors involved.[60] However, Potomac Economics considered examples where cost-causation is difficult to establish to be anomalous, arguing that these should not deter FERC from pursuing the NOPR to allocate uplift charges based on cost-causation.[61]

The NOPR goes further to require RTO/ISOs to distinguish between deviations that "help" and those that "harm" the ability to address system needs. Further, it uses net "harming from helping" deviations to determine how to allocate uplift costs. The comments of most RTO/ISOs and their IMMs reflect deep concerns. Some consider the methodology to be error-prone and subjective and that it presents potentially insurmountable problems.[62] The methodology could result in conflicting market signals and perverse incentives for market participants, such as resources engaging in "helping" deviations to counteract those "hurting" ones that may

56. Federal Energy Regulatory Commission, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, Docket No. RM17-2-000, Jan. 19, 2017. https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-1.pdf.

57. For example, a resource that deviates in real-time from its day-ahead schedule may cause last-minute changes to system unit commitment and dispatch that create uplift costs.

58. Federal Energy Regulatory Commission, *Uplift Cost Allocation and Transparency*, p. 1.

59. "Comments of the Independent Market Monitor for PJM to the Federal Energy Regulatory Commission," Docket No. RM17-2-000, April 10, 2017, 4. http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_RM17-2_20170410.pdf.

60. "Comments of the ISO/RTO Council to the Federal Energy Regulatory Commission," Docket No. RM17-2-000, April 10, 2017, 5-6.

61. "Comments of Potomac Economics, LTD to the Federal Energy Regulatory Commission," Docket No. RM17-2-000, April 17, 2017, 8.

62. For example, see comments of SPP, PJM and ISO-NE in particular under the aforementioned docket number.

result in additional uplift costs.[63] Though the NOPR mirrored MISO's rules on uplift cost allocation, these rules have also been critiqued by market experts, including the PJM IMM, as failing to constitute a best practice.

The NOPR's transparency provision, on the other hand, have yielded favorable reviews from the IMMs and would enhance price formation transparency in many regards.[64] The consensus is that this provision enhances the optimal operational and investment behavior from market participants and enables IMMs, market participants and other stakeholders to evaluate market performance, diagnose market design concerns and propose more efficient remedies. This is especially the case for chronic uplift conditions, which often constitute a large percentage of the total. Some RTO/ISOs expressed mild caution about weighing the costs and benefits of transparency requirements, while they encouraged stronger caution about making reporting requirements too granular to the point of raising concerns about confidentiality. RTO/ISOs vary on the types of data they publicly release and some provide information on a much more timely and granular basis than others do.

Pursuing principle-based NOPRs

Altogether, the fast-start pricing and uplift NOPRs should increase transparency and *may* offer more efficient approaches to resource pricing and uplift cost allocation. However, unintended consequences loom and divisions among market experts suggest best practices remain unclear. Still, even market experts critical of the NOPRs' remedies agree with the broad underlying policy goals. For example, the PJM IMM shares concerns about uplift charges (that they are unpredictable for market participants and can't be hedged). They also agree that ensuring a low level of and little variability in uplift costs, in ways that are consistent with operating a reliable system, will improve market efficiency.[65] In fact, even a number of economists who are otherwise critical of the proposed uplift "netting" requirement agree with the NOPR's goal that uplift charges should be allocated to reflect their causes to whatever extent possible.

Similarly, market experts and economists generally agree that efficient marginal-cost pricing is the goal of price formation, even as they differ on its definition and the means to achieve it. In other words, market participants want to get the "right price" for energy services but consensus on a complete mathematical definition has not emerged.[66]

This suggests there is value in continued discussion and a principles-based approach (e.g., efficiently addressing non-convex commitment costs) more than a remedy-prescriptive approach. Some RTO/ISOs have already undertaken actions to address these issues and FERC should facilitate the lessons learned. Such regional experimentation may reveal best practices, as well as unintended consequences that provide insights for "follower" RTO/ISOs.

POTENTIAL REFORMS

In fact, an array of potential market reforms could improve price formation. Most of these involve "tweaking" market designs, which have improved dramatically since the 2000s. However, one area in which fundamental improvement still could be achieved is shortage pricing, even in regions with capacity markets.

Shortage pricing

In order for energy prices to provide an accurate signal for short-term supply and demand behavior and to facilitate efficient long-term investment decisions, the rules for shortage or scarcity pricing[67] must accurately reflect the value of avoiding involuntary demand curtailments.[68] To do so necessarily results in energy costs rising to reflect both the likelihood of such curtailments and the degree to which consumers value avoiding involuntary loss of service. Deficiencies in shortage-pricing rules are perhaps the most fundamental pricing design flaw in FERC-jurisdictional RTO/ISOs, while ERCOT is the only domestic RTO/ISO that currently employs robust shortage pricing.

Bill Hogan and FTI Consulting's Susan Pope note that ERCOT is the only RTO/ISO to adopt a demand curve for operating reserves that explicitly connects to underlying principles of reliability and efficient market design.[69] ERCOT uses an operating reserve demand curve (ORDC) to reflect the probability and cost of involuntary demand curtailment in real-time prices. The keys are accurate parameters that pertain to the value of and probability of lost load, along with effective implementation (e.g., triggering shortage pricing when con-

63. "Comments of the R Street Institute to the Federal Energy Regulatory Commission," Docket No. RM17-2-000, April 10, 2017, 3-4. http://www.rstreet.org/wp-content/uploads/2017/04/20170411-503432092930.pdf.

64. For example, with respect to RTO/ISO operator-initiated unit commitments and transmission constraint penalty factors.

65. "Comments of the Independent Market Monitor for PJM to the Federal Energy Regulatory Commission," Docket No. AD14-14-000, April 6, 2016, 8. http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_AD14-14-000_20160406.pdf

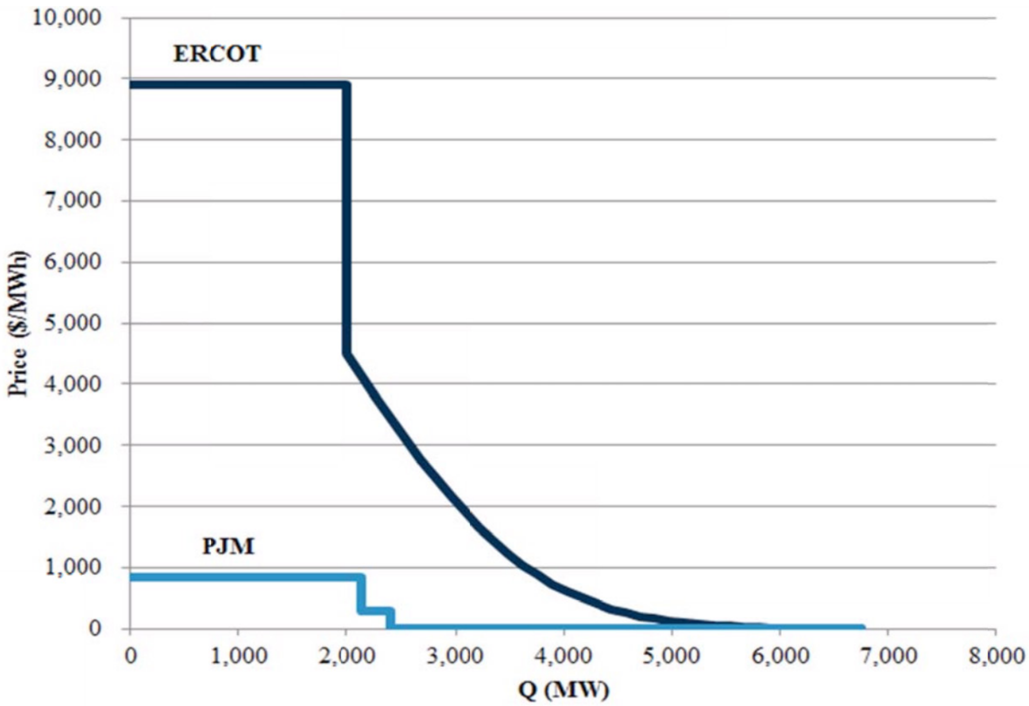
66. Schiro et. al., *Convex Hull Pricing in Electricity Markets*, p. 1. http://www.optimization-online.org/DB_FILE/2015/03/4830.pdf.

67. Scarcity pricing and shortage pricing are often used interchangeably. However, some RTO/ISOs may have differentiated meanings. For the purposes of this paper, the terms are considered synonymous.

68. Federal Energy Regulatory Commission, *Price Formation in Organized Electricity Markets*, p. 1. https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

69. Hogan and Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design," p. 35. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

FIGURE I: OPERATING RESERVE DEMAND CURVES OF PJM AND ERCOT



SOURCE: Hogan and Pope (2017)1

1. Hogan and Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design," p. 36. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

ditions warrant it). Outside ERCOT, several RTO/ISOs have implemented ORDC variants, but without connecting them to underlying scarcity principles.[70] These approaches to shortage pricing do not use pricing levels or triggers "derived from the underlying principles of economic dispatch or an explicit model for the reliability requirement."[71]

Recently, some RTO/ISOs have pursued notable improvements. ISO-NE has achieved increases in reserve penalty factors. In November 2015, NYISO implemented its Comprehensive Shortage Pricing project, which increased demand curve values and resulted in increased reserve prices. This contributed to a large share of generator net revenues, up to $59 per kilowatt-year, from revised shortage pricing in 2016.[72] PJM uses an ORDC and in May 2017, filed a revision to add a smaller step to the curve to reflect the lower reliability risks of small reserve deficiencies.[73]

Despite these modest-to-moderate improvements, the efficiency of shortage-pricing mechanisms in FERC-jurisdictional RTO/ISOs falls dramatically short of ERCOT. For example, PJM's ORDC does not apply in all hours (only during declared emergencies) and reflects only an estimate of supply costs. In ERCOT, the ORDC reflects the value of reserves, not supply costs.[74] This leads to a gross undervaluation of reserves in PJM, aside from capacity market performance incentives. Figure 1 depicts the shape and magnitude of differential (roughly an order of magnitude along much of the curve) between the two ORDCs. Should FERC decide to pursue shortage pricing based on the probability and value of lost load, it is important to recognize that the value of lost load is a difficult empirical exercise that varies by customer class (residential, commercial and industrial) and location (regional differences).[75]

Efficient shortage pricing requires locational capabilities in order to address situations where transmission constraints create an elevated loss of load probability in only a subset of the transmission system. Even a regional pricing mechanism

70. Hogan, *Electricity Market Design and Efficient Pricing*, p. 8. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pricing_062414r.pdf.

71. Ibid.

72. David B. Patton et. al., *2016 State of the Market Report for the New York ISO Markets*, May 2017, p. viii. http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf.

73. See filings under FERC Docket No. ER17-1590-000.

74. Hogan and Pope, "Priorities for the Evolution of an Energy-Only Electricity Market Design," p. 36. https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

75. London Economics International LLC, *Estimating the Value of Lost Load*, p. 9. http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf.

would better reflect locational variances in reserve needs than standard systemwide shortage pricing. ERCOT may consider locational scarcity pricing reforms. Pope and Hogan suggest introducing local reserve requirements through co-optimization of dispatch and reserve schedules to set prices properly when there are reserve constraints in a subregion.[76] To this end, Potomac Economics, ERCOT's IMM, has been a proponent of adopting locational shortage pricing.[77] PJM's IMM also encourages "better and more locational scarcity pricing" for PJM.[78]

The aforementioned Order No. 825 standardized one important aspect of triggering shortage pricing. FERC should consider a deeper public examination of RTO/ISOs' shortage-pricing triggers, as well as loss of load probability determinants and demand curve or penalty factor levels. FERC, perhaps in conjunction with price-formation efforts in ERCOT, should explore locational shortage pricing.

To create a robust shortage-pricing framework would require adjoining reforms. An obvious example includes raising price caps. Currently, price caps in FERC-jurisdictional RTO/ISOs are well below the value of lost load, which disables efficient shortage pricing. Proper shortage-pricing foundations would enable other efficient reforms, including the softening or elimination of capacity-performance penalties and mandatory capacity obligations.[79] This underscores the value of shortage-pricing reforms even in regions that are currently capacity-long, or those that almost never trigger shortage pricing. For example, PJM did not trigger shortage pricing in 2015 or 2016.[80]

Additional reforms

In addition to those outlined above, RTO/ISOs, FERC and stakeholders could consider the following additional categories of reforms to improve price formation:

1. *Adjustments to rules and practices governing economic and physical offer and bid parameters*. Ongoing market-design reforms and an increasingly dynamic resource mix make accurate economic and physical resource representations (parameter submittals) more important for price formation, yet increasingly difficult to verify. For example, combustion turbines in CAISO and coal units in PJM have understated their physical operating flexibilities in recent years. This has become increasingly problematic, given the increased value of cycling fossil plants. Moreover, some nuclear units have experienced more cycling demands. The safe relaxation of regulatory constraints on operating requirements as a means to enable nuclear cycling may allow these units to avoid the incurrence of energy market losses when prices drop near or below zero. More use-limited resources like energy storage and occasionally fossil plants with limited fuel (from pipeline constraints or backup fuel limitations) amplify the importance of efficient opportunity cost inclusions in energy offers, which are most pronounced in shortage or near-shortage conditions. This may require additional information from resource owners (e.g., fuel schedules). Altogether, these issues may require refining methods for effective market monitoring to mitigate increased opportunities for creative economic and physical withholding.
2. *Inclusion of all active constraints in price formation*. Pope (2014) recommended the use of "soft constraints" in dispatch and price models in lieu of relaxing violated constraints, which creates explicit representations of known constraints and develops methodologies to represent voltage ones[81] in pricing software.[82] Since then, RTO/ISOs have undertaken various efforts to represent active constraints in prices, but there are numerous opportunities for improvement.
3. *Improving locational reserve products and spatial determinations*. Local reserve products may send more efficient price signals and reduce RTO/ISO interventions and uplift. Reserve areas should reflect transmission constraints, which may be more granular than zones. Updated reporting and performance metrics may indicate the efficacy of current practices.
4. *Intertemporal modeling improvements to dispatch and unit commitment*. Some RTO/ISOs, such as MISO, have implemented or pursued "look-ahead" modeling capabilities that better reflect dynamic conditions that affect the optimality of dispatch and commit-

76. Ibid., pp. 63-67.

77. Based on personal conversations with staff at Potomac Economics.

78. Devin Hartman, "The Market Advantage: A Q&A with Joe Bowring," *R Street Shorts* No. 40, June 2017, p. 2. http://www.rstreet.org/wp-content/uploads/2017/06/RSTREETSHORT40.pdf.

79. Softening may include reducing obligation levels, which some contend are set inefficiently high, or making a portion or all capacity procurement voluntary. Given "smart" technologies that enable apportioning of reliability consequences, this may offer the preferred path forward on resource adequacy.

80. Monitoring Analytics, LLC, *PJM State of the Market – 2016: Energy Market*, March 9, 2017, p. 171. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec3.pdf.

81. The current market concept of physical constraints is limited to thermal transmission and interface limits. This excludes operating constraints like voltage limitations. Pope (2014) recommends expanding the definition of constraints to include voltage limitations, as well as minimum on-line capacity constraints and reserve, while ramping up and regulating capacity requirements.

82. Susan Pope, "Price Formation in ISOs and RTOs: Principles and Improvements," FTI Consulting, October 2014, 2-3. http://lmpmarketdesign.com/papers/Pope.EPSA_Price_Formation_Oct_29_2014_FINAL.pdf.

ment across multiple intervals.[83] For example, ISO-NE recently noted that, as the resource mix changes, using traditional dispatch has contributed to problems with efficiency and compensation. The ISO is exploring multi-interval pricing as a remedy.[84]

5. *Enhancement of the RTO/ISO interchange*. Many of the improvements made between the "seams" of RTO/ISOs have been handled on an ad hoc basis (e.g., coordinated transaction scheduling). However, some systemic improvements, like dynamic interchange modeling, could further enhance price formation, especially during shortage conditions. For example, NYISO relies exclusively on internal resources to meet operating reserve requirements and ignores the value of imports. As a result, its IMM has recommended a shift to determine reserves dynamically.[85] Further coordination improvements, such as shorter interchange notification periods, are also worth examining, as current delays between energy scheduling and price modeling sometimes result in uneconomic transactions and distorted price formation.

6. *Further transparency and pricing of grid operator interventions*. All RTO/ISOs should price operator interventions, and most already do for emergency purposes. However, they should price all interventions and techniques to do so may benefit from refinement. Better documentation of RTO/ISO interventions will help diagnose the causes and potential means to mitigate interventions. The PJM IMM has requested that FERC require documented rules and transparent reporting of any RTO/ISO interventions that alter the determination of shortages.[86]

7. *Removing additional administrative price controls*. Order No. 831 provided incremental relief from some artificial price suppression but retained an extensive price control framework—floors and ceilings—that have no practical use with sufficient market-power-mitigation practices. Further relaxing or eliminating price controls may require some mitigation and software improvements that warrant consideration before pursuing reforms. Often overlooked, price floors must not obfuscate the ability to reflect the negative value of supply during over-generation events.

8. *Improvement of additional uplift-cost-allocation methods*. The uplift-cost-allocation NOPR focused on a narrow subset of uplift causes. To shed light on other uplift costs and causation methodologies could allow RTO/ISOs to pursue allocation reforms that accurately reflect the causes of uplift costs.

9. *Improving day-ahead settlement and scheduling intervals*. Shortening day-ahead settlement and scheduling intervals (i.e., sub-hourly) may improve both day-ahead and real-time price convergence. However, this would increase computational time and may require day-ahead markets to clear earlier. Moving the day-ahead market in this manner would increase load and variable resource (wind and solar) forecasting error, which would increase pressures on price divergence. While this trade-off would require close examination, ongoing software improvements may mitigate the time required to move the day-ahead period earlier.

10. *Pricing unpriced resources other than fast-start resources*. Upon determining the precedent issue of whether pricing should reflect all operational costs, a logical next step is to examine pricing issues for all resources. For example, PJM highlights that inflexible resources are ineligible to set price under some circumstances.[87] Pricing improvements tied to a particular operating characteristic would fall under the scope of the price-formation umbrella. However, a separate dedicated initiative might prove more effective for technology-specific pricing concerns.

Additionally, there are several opportunities to improve price formation outside the perceived scope of the current price-formation initiative. These include:

1. *Technology-specific economic integration*. Incomplete integration of unconventional resources may necessarily be technology-specific and addressed through a dedicated initiative, such as the participation barriers and pricing-integration challenges of energy storage already proposed by FERC.[88] RTO/ISOs have made varying degrees of progress on integrating demand response.[89] Integration includes enabling resource-dispatch and price-setting capability. For demand

83. For example, traditional approaches minimize costs for a single interval, which cumulatively does not always minimize costs over multiple intervals.

84. Dane A. Schiro, *Flexibility Procurement and Reimbursement: A Multi-period Pricing Approach*, ISO-New England, June 26, 2017, pp. 24-31. https://www.ferc.gov/CalendarFiles/20170623123635-Schiro_FERC2017_Final.pdf.

85. Patton et. al., *2016 State of the Market Report*, pp. x, 72. http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf.

86. "Comments of the Independent Market Monitor," 6-8. http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775_000_20170201.pdf.

87. PJM Interconnection, "Energy Price Formation," 3. http://www.pjm.com/-/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

88. Federal Energy Regulatory Commission, "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators," Notice of Proposed Rulemaking," Docket Nos. RM16-23-000 and AD16-20-000, Nov. 17, 2016, 1. https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf.

89. ISO-NE, for example, expects full demand response integration in June 2018.

response and distributed resources, integration may also include bidding at the nodal level.[90] This concept could also expand to the dispatch ability and must-offer requirements for variable energy resources. CAISO has proceeded with improved modeling of multi-stage generators (namely, combined-cycle gas units capable of multiple configurations), which the fast-start pricing NOPR does not explicitly address. The benefits and costs of such improvements elsewhere is worth examination.

2. *Evaluate the creation of ancillary-service products for discrete reliability services*. Some RTO/ISO-initiated actions and FERC rulemakings have proposed or enacted new approaches to procure essential reliability services. These endeavors should examine the future, as opposed to merely the backcasted costs and benefits of creating market products for these discrete services. FERC's pending NOPR on primary frequency-response capability[91] does not reflect this philosophy (it would mandate the capability). Instead, a market-based approach may result in primary frequency-response procurement at lower short-run cost and encourage innovative forces to drive further long-term cost reductions.[92]

3. *Improve reporting of real-time fuel prices*. Natural gas prices vary considerably by location and fluctuate substantially between—and occasionally within—days. This drives large and frequent changes in gas generators' marginal costs and makes accurate fuel-price reporting critical for price formation. Prices pegged to voluntary gas index reporting has raised concerns about index accuracy and gas-market liquidity and/or transparency, because reporting has declined. There are several carrots and sticks FERC could deploy to consider increased gas-transaction reporting, which may boost price discovery and formation in both gas and electric markets. FERC has begun publicly to examine the costs and benefits of potential reforms.[93] This may not fall under the electric price-formation umbrella *per se*, but the health of natural gas price formation becomes increasingly important for electric price formation, given ongoing expansion of gas generation.

EFFECTS OF REFORMS

The effects of market design and administration changes are reform-specific, but some generalizations are safe for overall price-formation improvement. Reforms will alter price levels and patterns, along with associated costs and revenues to market participants. Most importantly, quality reforms will directly improve the performance of energy and ancillary-service markets and indirectly improve capacity-market performance.

Many price-formation improvements will result in higher and more volatile energy prices, because correctable flaws in market design and administration tend to suppress price levels and volatility artificially. Such results often face opposition from certain groups, yet price levels and volatility should freely and accurately reflect underlying supply and demand fundamentals. Although the immediate result may increase energy prices, it will lower total costs to customers by reducing uplift payments, production costs (more efficient dispatch and unit commitment) and investment costs—especially in RTO/ISOs spanning mostly restructured states. A reduction in investment costs in ISO-NE, NYISO and PJM will come in the form of reduced capacity prices but also should reduce payments for must-run reliability.[94] As energy prices rise relative to operating costs, they reduce the "missing money" problem, placing downward pressure on capacity prices. The investment signals sent in energy markets more accurately represent reliability needs than capacity markets, and thus an efficient shift towards greater influence of energy markets in investment decisions should lower the total cost of the investments necessary to meet reliability standards.

Comments on existing reforms provide insight into the potential magnitude of effects. For example, Potomac Economics noted that implementation of "extended LMP"[95] in August 2016 raised real-time prices in MISO in all hours by 20 cents per-MWh.[96] This is a very modest energy-price increase (less than 1 percent of common energy prices). However, the accumulation of modest reforms may result in moderate effects. Furthermore, these effects grow as the underlying fundamentals shift in a manner that makes new market design and practices more advantageous (e.g., combustion turbines more often on the margin).

Some price-formation reforms appear inconsequential on the surface, but have sizable, and often concentrated, effects. For example, the PJM IMM stated that the fast-start pric-

90. "Comments on ISO/RTO Reports of the Financial Marketers Coalition," Docket No. AD14-14-000, April 6, 2016, 5-7. NB: Supply resources bid at the nodal level but loads bid at the zonal level, which can distort the congestion component of LMP.

91. Federal Energy Regulatory Commission, "Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response," Notice of Proposed Rulemaking, Docket No. RM16-6-000, Nov. 17, 2016, 1. https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf.

92. "Comments of the R Street Institute," Docket No. RM16-6-000, Feb. 1, 2017, 1-6. http://www.rstreet.org/wp-content/uploads/2017/02/PFR-Comments-FINAL.pdf.

93. Monique Watson and Marc L. Spitzer, "Liquidity and Transparency in Natural Gas Markets," Steptoe & Johnson LLP, July 2017. https://www.lexology.com/library/detail.aspx?g=12422cd7-54bf-493e-a47b-5465a0bd686b.

94. These refer to contracts designed to keep generators on "life support" until the RTO/ISO facilitates a fix to a local reliability problem.

95. This refers to the pricing method that formed the basis of the fast-start pricing NOPR.

96. "Comments of Potomac Economics, LTD to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 18.

ing NOPR would affect a maximum of 0.6 percent of PJM's uplift costs in 2016,[97] adding that uplift typically results from inflexible operating parameters from larger units.[98] Uplift payments are often highly concentrated.[99] Thus, even a reduction in a very modest share of total uplift charges could significantly affect some market participants' revenues, costs and behavior. Modest changes in total uplift or the number of affected dispatch/pricing intervals does not imply that effects on energy prices would be proportionately small. The infrequency, yet outsized market effects, of shortage events suggests improvements in shortage pricing may substantially alter investment decisions—even if the vast majority of pricing intervals remain unchanged.

To quantify the effects of reforms would require modeling market operations. Many reforms affect infrequent events, making probabilistic estimates particularly difficult to project accurately. However, illustrative examples demonstrate the salience of reforms. For example, an energy market with an annual average price of $25/MWh triggers shortage pricing at $850/MWh for three hours per year on average. An increase in the ORDC from $850/MWh to $8,500/MWh would increase average energy prices in this hypothetical market by 10 percent. This would also have a sizable effect on total net revenues, which drive investment decisions. In this case, it would increase energy revenues by nearly $23 million (12 percent) annually for a 1,000 MW unit (the size of a nuclear reactor or large coal or gas plant) operating at 90 percent annual utilization.[100] Raising the ORDC by an order of magnitude would also provide much stronger incentives for reliable performance. For example, a resource may undertake better maintenance or backup fuel practices to increase the probability it can capture shortage rents.

Although the aim of price-formation improvements is precisely to not pick winners—but instead to enhance the ability of competitive markets to determine resource allocations—such reforms will change competitive relationships between technology classes and fuel types. Generally, reforms would benefit more dependable and flexible[101] resources.

Perhaps the clearest winner is energy storage that, in many forms, offers both superior flexibility and dependable performance. Healthy energy-price formation is critical to unlock the economic value of storage. Storage relies more on real-time price transparency than other resources. Prices that more accurately reflect dynamic system conditions will also likely result in greater short-term volatility. This presents additional arbitrage opportunities and value. Many forms of storage, like pumped storage and batteries, have exceptionally dependable performance records, provide flexible services and would benefit considerably from an increase in the frequency and magnitude of transient shortage prices.

The strongest incentives for dependable generation should accrue to those with the best performance overall, but especially during shortage conditions. Based on overall performance profiles and shortage-performance profiles, nuclear would likely benefit the most among existing generation sources from improved price formation. This is because nuclear often has the lowest forced-outage rates overall but, more importantly, generally performs comparatively well during shortage periods.[102] It also has a track record of performance uncorrelated to external factors that often drive supply-reduced shortage events, such as cold weather creating mechanical malfunctions and affecting fuel availability for fossil generators.

The effects of stronger flexibility incentives have nuance, as flexibility has many different definitions and characteristics. From a reliability-attribute perspective, it includes short minimum run times and cycling capabilities, such as short start-up and shut-down times and high ramp-rates. Ramp capability falls into three essential reliability services, including regulation, contingency reserves and load-following services.[103] Price-formation improvements may affect these services' flexibility and how they are valued in a number of ways. The comparative advantages of technology and fuel categories thus differ across these attributes. One clear winner is conventional hydropower, which exhibits all capabilities to provide flexibility and ramp capability for essential reliability services.[104] In fact, the U.S. Energy Department identified "enhanced revenue and market structure" for grid support services as one of five elements in its roadmap for the *Hydropower Vision*.[105] Natural gas and oil-fired combustion turbines, storage, demand response, solar and wind also score well on flexibility. Steam units (oil, gas and coal) and

97. "Reply Comments of the Independent Market Monitor for PJM to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, March 15, 2017, 3.

98. "Comments of the Independent Market Monitor for PJM to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 4.

99. A handful of units may account for the majority of a particular uplift category.

100. This assumes full availability during the shortage event.

101. For example, resources with greater rate of dispatch change, or "ramp," as well as dispatch range, and quicker start/stop capability.

102. Devin Hartman, "Embracing Baseload Power Retirements," *R Street Institute Policy Study*, No. 97, May 2017. http://www.rstreet.org/wp-content/uploads/2017/05/97.pdf.

103. PJM Interconnection, LLC, "PJM's Evolving Resource Mix and System Reliability," March 30, 2017, 16. http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

104. Ibid.

105. Department of Energy, *Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source*, 2016, p. 4. https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

storage exhibit strong ramp capability for essential reliability services.[106]

Price-formation improvements will also send much stronger incentives for price-responsive demand. While the vast majority of real-time demand is not price-responsive, technological and methodological tools have advanced to enable more active demand participation in real-time. An uptick in efficient price-responsive demand would have numerous benefits, by shifting and reducing demand in ways that use supply resources more efficiently and mitigate the exercise of market power by power suppliers.[107]

CONCLUSION

The new FERC leadership should assertively, but thoughtfully, carry the banner of price formation forward. A refreshed take should facilitate buy-in from market experts on fundamental principles and, unless major problems are imminent, should hesitate to enact reforms that deeply divide them. For example, FERC should seek a consensus among experts on whether energy prices should reflect commitment costs before issuing the final fast-start pricing rulemaking. Some RTO/ISOs have already implemented the highly controversial aspects of the fast-start pricing and uplift-cost-allocation NOPRs. Thus, whether these constitute best practices should surface over time.

For some other price-formation issues, experts agree in principle, but disagree on best practices, or whether the benefits of best practices exceed implementation costs. In such cases, FERC should issue a principles-based rulemaking that avoids overly prescriptive remedies and requires noncompliant RTO/ISOs to demonstrate why efficient practices in theory are inefficient in practice—or alternatively, that the benefits do not outweigh the costs. For example, FERC could issue a principles-based rulemaking that requires uplift cost allocation to align with cost-causation principles, but permits RTO/ISOs to determine their specific methodological approach. Alternatively, FERC could require a default methodology, unless RTO/ISOs can demonstrate why this does not constitute a best practice or that the benefits do not outweigh the costs of implementation.

Price-formation improvements would ideally come from a bottom-up approach, with RTO/ISOs serving as incubators. Accordingly, FERC, RTO/ISOs and other stakeholders need to facilitate a collaborative culture that drives continuous improvement, with a careful eye toward avoiding unintended consequences. More regulatory transparency and less prescription from FERC may encourage RTO/ISOs to answer the bell. Sunlight regulation often spurs cross-fertilization of ideas and speedier adoption of best practices. Given recent interest in ERCOT to examine price-formation issues, FERC should certainly invite ERCOT to the table to share concepts and lessons learned.

This notwithstanding, the complexity of price formation complicates the ability to forge consensus within and across RTO/ISOs and stakeholders. Furthermore, RTO/ISO stakeholder processes do not always result in timely pursuit of reforms, especially if key voting blocs have a vested interest in preventing them. Some stakeholders report that leaving price-formation issues to the RTO/ISO stakeholder processes results in little consensus or progress.[108] Deadlocked or de-prioritized reforms from stakeholder self-interests have reoccurred in market-design issues within and beyond price formation. If sunlight regulation fails to achieve desired results, FERC may consider issuing a show cause order under Section 206 of the Federal Power Act, where the RTO/ISOs must provide persuasive arguments to justify current practices. This offers a mechanism to spur improvements in lagging RTO/ISOs without prescribing rule changes through the official rulemaking process.

FERC could also explore performance-based regulation, which may require more consensus on some nuanced price-formation principles and specific metrics. For example, SPP considered a market-efficiency metric where energy and congestion rights achieve a minimum of 95 percent of the long-run equilibrium cost recovery to induce investments, with uplift comprising a 5 percent maximum.[109] Such an approach may help to identify market performance progress and remaining problems, as well as provide guidance on what reforms to prioritize.

Forward cost-benefit analysis, not just backcasting effects, should guide decision points and reform prioritization. The opportunity cost to pursue some price-formation reforms is high, considering other high priority reform needs. For example, the CAISO DMM believes that one or more discretionary initiatives CAISO planned to undertake over the next few years would have to be delayed or deferred indefinitely to divert resources to fast-start pricing compliance.[110]

106. PJM Interconnection, LLC, "PJM's Evolving Resource Mix," 16. http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

107. Devin Hartman, "Pathways to Competition in Demand Response," *R Street Shorts*, No. 30, July 2016. http://www.rstreet.org/wp-content/uploads/2016/07/RSTREETSHORT30.pdf.

108. "Comments on ISO/RTO Reports of the Financial Marketers Coalition to the Federal Energy Regulatory Commission," Docket No. AD14-14-000, April 6, 2016, 2-3.

109. Southwest Power Pool, "Conference call: documentation of discussions, Price Formation Task Force, March 7, 2016, 3. https://www.spp.org/documents/37571/pftf%20minutes%2020160307.pdf.

110. Comments of the Department of Market Monitoring for the California Independent System Operator Corporation to the Federal Energy Regulatory Commission," Docket No. RM17-3-000, Feb. 28, 2017, 39.

In any event, performance-based regulation, more sunlight and less prescription offer a pathway to efficient markets and good governance. But FERC should not shy away from assertive tools if the community of market experts forge a compelling consensus on applied reform principles. With sound price-formation improvements, the United States will extend its global leadership on wholesale electricity policy and make the economy more competitive for decades to come.

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