UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Offer Caps in Markets Operated	)	
By Regional Transmission	)	**Docket No. RM16-5-000**
Organizations and Independent	)	
System Operators	)	
	)	

COMMENTS OF THE
ELECTRIC POWER SUPPLY ASSOCIATION,
INDEPENDENT ENERGY PRODUCERS ASSOCIATION,
INDEPENDENT POWER PRODUCERS OF NEW YORK INC.,
NEW ENGLAND POWER GENERATORS ASSOCIATION INC. AND
THE WESTERN POWER TRADING FORUM

The Electric Power Supply Association ("EPSA"),[1] Independent Energy Producers Association[2] ("IEP"), Independent Power Producers of New York Inc. ("IPPNY"),[3] New England Power Generators Association Inc.[4] ("NEPGA"), and Western

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[1] EPSA is the national trade association representing leading competitive power suppliers, including generators and marketers. Competitive suppliers which collectively account for 40 percent of the installed generating capacity in the United States provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] IEP is a nonprofit public benefit corporation formed under the laws of the State of California to encourage the development and use of independent electric resources. Its members own and operate roughly 20,000 megawatts of electric generation capacity in California. IEP has been representing the interests of the developers and operators of renewable and other independent electricity resources before the Commission, other agencies, the Legislature, and the courts since 1982.

[3] IPPNY is a not-for-profit trade association representing the independent power industry in New York State. Its members include nearly 100 companies involved in the development and operation of electric generating facilities and the marketing and sale of electric power in New York. IPPNY's members include suppliers and marketers that participate in the NYISO's energy and capacity markets. This pleading represents the position of IPPNY as an organization, but not necessarily the views of any particular member with respect to any issue.

[4] NEPGA is a private, non-profit trade association advocating for the business interests of competitive electric power generators in New England. NEPGA's member companies represent approximately 26,000 megawatts of installed capacity throughout the New England region. NEPGA's mission is to promote sound energy policies which will further economic development, jobs, and balanced environmental policy. NEPGA's member companies are responsible for generating and supplying electric power for sale within the New England bulk power system. As active participants in the ISO-NE capacity and wholesale electricity markets, NEPGA's member companies have substantial and direct interests in

Power Trading Forum ("WPTF")[5] (Collectively the "Competitive Suppliers") respectfully submit the following comments to support and suggest necessary improvements to the Federal Energy Regulatory Commission's ("Commission" or "FERC") January, 2016 Notice of Proposed Rulemaking ("NOPR") regarding *Offer Caps in Markets Operated by Regional Transmission Operators and Independent System Operators*[6] in the above-captioned proceeding. The Commission proposes to revise its regulations in order to require each Independent System Operator ("ISO") or Regional Transmission Organization ("RTO") to revise the cap for individual resource's incremental energy offers to the higher of $1000/MWh or that resource's verified cost-based incremental energy offer. Before-the-fact verified cost-based energy offers above $1,000/MWh would be allowed to set the market clearing price, or Locational Marginal Price ("LMP"). As Competitive Suppliers have reiterated in numerous proceedings and forums over the past several years,[7] the existing generic energy offer cap of $1000/MWh is an outdated

the outcome of these proceedings, and those interests cannot be adequately represented by any other party in the proceeding.

5 WPTF is a California nonprofit, public benefit corporation. It is a broad-based membership organization dedicated to enhancing competition in Western electric markets while maintaining the current high level of system reliability. WPTF supports development of competitive markets throughout the West and the development of uniform rules to facilitate transactions among market participants.

6 *Offer Caps in Markets Operated by Regional Transmission Operators and Independent System Operators*, Notice of Proposed Rulemaking, Docket No. RM16-5-000 (January 21, 2016) ("NOPR"), 81 FR 5951, https://federalregister.gov/a/2016-01813 (Feb 4, 2016), 154 FERC ¶ 61,038.

7 *See PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,078 (February 11, 2014)("PJM Waiver Order); *California Indep. System Operator Corporation*, 146 FERC ¶ 61,218 (March 21, 2014); *New York Indep. System Operator, Inc.,* 146 FERC ¶ 61,061 (January 31, 2014)*; PJM Interconnection, L.L.C.,* 150 FERC ¶ 61,020 (January 16, 2015); *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,083 (February 9, 2015); *PJM Interconnection, L.L.C*., 153 FERC ¶ 61,289 (December 11, 2015), approving tariff revisions to energy market offer cap to become effective December 15, 2015, with no expiration or sunset date; *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,006 (January 7, 2016).

restriction distorting energy price formation within each ISO/RTO and requires reform across all the ISOs/RTOs in order to avoid seams concerns between markets.

Competitive Suppliers cannot overstate the importance of the Commission's ongoing price formation proceeding[8] to making sure that day-ahead and real-time energy markets and ancillary services markets reflect market conditions and continue to produce just and reasonable results consistent with reliability and the economically sound investment decisions on which it rests.[9] Therefore, Competitive Suppliers strongly support revision of the current $1000/MWh energy offer cap in place in each ISO/RTO, with revisions to be in place before winter 2016/2017, as a critical and timely element of the Commission's ongoing program of price formation reforms. Fundamental to that effort is the principle that competitively-based energy market price signals must truly reflect supply and demand during times of high demand so that reliability is ensured and costs are minimized. As the Commission has reiterated over nearly two decades, reliance on a single uniform clearing price supported by market-based solutions best results in efficient and reliable operations.[10] Such market structures incent competitors to operate efficiently and to reduce costs so that they will clear and earn revenue, which in turn produces long-term consumer savings. To ensure that markets are not distorted by arbitrary offer caps or pay-as-bid structures, the Commission must ensure that each regional market utilizes mechanisms so that,

[8] *Price Formation in Energy and Ancillary Service Markets Operated by Regional Transmission Organizations and Independent System Operators,* Docket No. AD14-14-000 (June 19, 2014) ("Docket No. AD14-14 Price Formation proceeding").

[9] It is the combination and totality of sufficient revenues which come from the energy, ancillary service and capacity markets (where they exist) that support the investment necessary for system operation, reliability and resource adequacy on both a near-term and sustainable long-term basis.

[10] *PJM Interconnection, LLC,* 117 FERC ¶ 61,331, at P 141 (2006); *See also, Midwest Independent Transmission System Operator, Inc.,* 102 FERC ¶ 61,196, P 32 (2003).

"[i]deally, the locational energy market prices in the energy and ancillary services markets would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."[11] These principles are central to the changes needed to the current energy market offer caps.

As explained in the NOPR, the current offer cap results in unjust and unreasonable rates for several reasons, including price suppression of market prices below the marginal cost of production.[12] This price suppression is a disincentive for resources with short-run marginal costs above the cap to offer into the market, even when supply is needed. Price suppression also hinders the ISO/RTO from dispatching the most efficient set of resources when some of those resources cannot reflect costs within their incremental energy offers due to the arbitrary and now outdated offer cap. Suppressed energy market prices impede the price signals for market participants to make efficient investments and retirements, thereby impeding long-term reliability and savings for consumers. The just and reasonable approach is to remove the arbitrary and distortive energy offer cap based on the extensive and significant improvements in electric market pricing and market monitoring since establishment of the current caps. Such market improvements, as well as extensive monitoring and mitigation mechanisms in place, overwhelmingly support not just reconsideration of, but removal of an offer cap mechanism entirely.[13] If such an approach is not taken by the Commission, Competitive

[11] *Notice of Technical Conference*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000 (June 17, 2013), at 2.

[12] While pay as bid may allow cost recovery for competitive suppliers with costs above the offer cap, allowing only such compensation to particular generators similarly suppresses and distorts market prices.

[13] Attachment A, Comments and Affidavit of the Electric Power Supply Association, Affidavit of Dr. Susan Liese Pope, Managing Director, FTI, Inc. ("Pope Affidavit"), *PJM Interconnection, L.L.C.,* Docket No. ER14-1145-000 (filed January 30, 2014), at PP 15-19.

Suppliers urge revisions to the cost verification proposal as discussed below so that any offer cap mechanism – whether cost-based or market-based – is minimally distortive and sets the market clearing price in order to allow for efficient market signals which provide market participants with the information necessary to make investment decisions and decisions with respect to hedging fuel risk.

I. BACKGROUND AND OVERVIEW

Competitive Suppliers support the Commission's decision to direct revisions to the outdated and distortive existing hard offer cap of $1000/MWh, having urged the Commission to do so in numerous forums, particularly during consideration of the short-term stop gap waivers submitted to FERC over the past several years from numerous ISOs/RTOs.[14] Such reform has been a high priority for wholesale electricity market participants since extreme weather conditions during winter 2013/2014 highlighted concerns with the existing offer cap, which artificially suppresses market prices and prevents economic outcomes that will support reliability when it is most critical, like during the Polar Vortex conditions. Thus, not only are the existing caps unnecessary, they are counter-productive as evidenced in winter 2013/2014 and the series of emergency or short-term waivers requested by several markets since that winter to allow offers to go above the current cap in order to permit recovery of demonstrated, justifiable costs. Revising this outdated and distortive mechanism is necessary, and should be completed on an expedited basis – certainly in time for winter 2016/2017, if not sooner. When prices are well under the cap, as is usually the case, the cap is unnecessary; but when the cap binds to restrict what prices would otherwise be due to

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[14] See fn 7 above.

market conditions, the cap by definition distorts market pricing when it is needed most to convey the true conditions to producers and consumers.

The instant NOPR acknowledges the extensive concerns and flaws with the current offer cap of $1000/MWh,[15] resulting in an unjust and unreasonable market mechanism, and therefore FERC proposes to revise the current offer cap in order to remedy these concerns. That proposal sets out three requirements for a revised offer cap mechanism in all six ISOs/RTOs.

First, a resource's incremental energy offer used for purposes of calculating LMPs must be capped at the higher of $1000/MWh or that resource's cost-based incremental energy offer, applicable in both the day-ahead and real-time markets. In essence, the $1000/MWh cap is retained for market-based offers as it "serves as an appropriate backstop to the existing market power mitigation rules."[16] Above that $1000/MWh level, offers with *verifiable short run marginal costs* are allowed.

Second, in the circumstance in which a resource's costs cause its incremental energy offer to go above $1,000/MWh, those costs and related energy offers must be verified by the Market Monitoring Unit or the ISO/RTO *before* that offer can be used for purposes of calculating LMPs. If such offers cannot be verified before the market clearing process begins, then that offer in excess of $1000/MWh may not be used to calculate LMPs, though the resource can be made whole after the fact through uplift payments if that resource clears the market and the resource's costs are verified after-the-fact.

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[15] NOPR at PP 43 – 47, enumerating four reasons that the current offer caps are unjust and unreasonable.

[16] NOPR at P 48.

Third, all resources, regardless of type, are eligible to submit cost-based incremental offers in excess of $1000/MWh. In order to avoid exacerbating seams issues that might arise if one ISO/RTO has an offer cap that materially differs from a neighboring ISO's/RTO's offer cap, the NOPR proposes to revise the current offer cap applicable in all ISOs/RTOs.

I. COMMENTS

A. The Current $1000/MWh Energy Offer Cap Is Unjust And Unreasonable; The Offer Cap Should Be Removed in All ISOs/RTOs

As has been explained in numerous forums, filings and papers in recent years, the original purpose of the $1000/MWh offer caps – implemented in PJM in 1997 and NYISO in 2000 – was to act as a blunt instrument to address seller market power concerns.[17] These market conditions have long since changed given the fact that there have been significant improvements in electric markets and market monitoring since establishment of the current caps; these changes overwhelmingly support not just reconsideration, but removal, of such an arbitrary cap as unnecessarily duplicative.[18]

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[17] Excerpt of Transcript from October 28, 2014 Price Formation Workshop on Scarcity and Shortage Pricing, Offer Mitigation, and Offer Caps in RTO and ISO Markets, Docket No. AD14-14, reflecting the workshop Panel 3 (ISO/RTO Internal and External Market Monitors) discussion on goals of offer caps and market power mitigation, and in particular, the theory behind the current $1,000/MWh offer cap and how it relates to current market power mitigation provisions:

> Jeffrey McDonald, Vice President, Market Monitoring, ISO New England, Transcript at p 207: "As to where the $1000 came from, I always thought it came from FERC (Laughter.) MR. McDONALD: I think it's an administrative cap, but I don't know where it came from. But we were--does anyone here have enough institutional history to--I know, and I don't speak for California, but I did used to work there. I know we were encouraged to move towards the $1000 cap over a period of time, and that seemed to be the point that everyone was encouraged to gravitate towards."

> Joseph Bowring, PJM IMM, Transcript at p 209: "MR. BOWRING: It was actually the highest number anybody could think of at the time and then multiplied by five. (Laughter.) MR. BOWRING: Seriously. It was a number that people thought could never be reached, and as my colleagues here said, it was therefore a backstop. But it was just considered to be beyond the possible pale. That's where it came from."

[18] Pope Affidavit, at pp 15-19.

Most germane is the continued development of both the regional and national mitigation and enforcement programs. In the ISOs/RTOs there are robust market monitoring and mitigation rules and procedures to protect all market participants, including consumers, from the exercise of market power which is enforced by detailed review and oversight of market behaviors and trends by the RTOs' Independent Market Monitor ("IMM") and/or Internal Market Monitoring Units ("MMUs").[19] Such mitigation is extensive and pervasive, including the three pivotal supplier test, test for economic withholding and other related measures. Additionally, the Commission has substantially strengthened how it administers its market-based rate authority program, as acknowledged in several court cases, including through the use of market power screens as part of the triennial review of market participants eligible for the program.[20]

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[19] *See, e.g.,* "Since 1999, the PJM Market Monitoring Unit has been responsible for promoting a robust, competitive and nondiscriminatory electric power market in PJM by implementing the PJM Market Monitoring Plan. Under the PJM Market Monitoring Plan, the PJM Market Monitoring Unit has been responsible for monitoring compliance with the rules, standards, procedures, and practices of PJM markets. We observe and comment on actual and potential design flaws in market rules, standards, and procedures, and identify structural problems in PJM markets that may inhibit robust and competitive markets. We monitor the potential of market participants to exercise undue market power, the behavior of market participants that is consistent with attempts to exercise market power and the market performance that results from the interaction of market structure with participant behavior. We monitor the actions of PJM and the impact of those actions on market outcomes." Available at http://monitoringanalytics.com/company/about.shtml. Also, Potomac Economics provides market monitoring for MISO, ISO New England and the New York ISO; as discussed on the website: "Potomac Economics is a leading provider of independent market monitoring, expert analysis and advice, and litigation support services to the electricity and natural gas industries. Potomac Economics has extensive experience in the areas of market design, pricing, regulatory policy, antitrust and other competitive issues. Potomac Economics is a leader in the field of monitoring and competitive assessment of wholesale electricity markets in the U.S., serving as the Independent Market Monitor for the Midcontinent ISO and ERCOT, the Market Monitoring Unit for the New York ISO, and the Independent Market Monitoring Unit for ISO New England. In these capacities, Potomac Economics is responsible for implementing monitoring plans to identify and remedy flaws in the market design or attempts to exercise market power. Potomac Economics also provides market monitoring software to the California ISO." Additional information available at http://www.potomaceconomics.com/.

[20] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified* 121 FERC ¶ 61,260 (2007) *order on reh'g*, Order No 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No.697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub*

Furthermore, the U.S. Congress through the Energy Policy Act of 2005 gave the Commission enhanced enforcement tools including authority to seek civil penalties of as much as $1 million per violation per day. Unlike when the arbitrary and inflexible offer caps were put in place years ago, the Commission now has a well-staffed Office of Enforcement with experts from a variety of disciplines, expanded analytical tools including real time market monitoring, and greater access to other information about market participants' behavior, such as their swaps and futures trading activity through the recent Memorandum of Understanding with the Commodity Futures Trading Commission. In light of these changes and improvements at both the federal and regional level, the consumer protection goal of the arbitrary offer cap is now more effectively and efficiently met by a comprehensive suite of targeted measures without distorting market price formation and skewing critical investment decisions as a result. While there have not been many hours that the marginal costs associated with the resources that set the clearing price in ISO/RTO markets exceeded $1000/MWh, the impact of these hours not being allowed to clear at that level and the overall suppressive impact on markets as a result of the cap is not trivial. The offer caps artificially suppress spot market and forward market prices and prevent economic outcomes that will support reliability and motivated savings for consumers precisely under stressed conditions such as the extreme weather experienced during the Polar Vortex of winter 2013/2014. For this reason, four of the six regional organized market operators requested and were granted "stop gap" waivers to allow for cost-based offers

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nom. Montana Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011), cert denied, 133 S. Ct 26 (2012).

that ensured recovery of justifiable costs, such as high natural gas or fuel costs during critical or emergency periods.

Reviewing the effects of the existing offer cap in context, Mr. Joseph Cavicchi of Compass Lexecon[21] documented the economic justification for revising the cap based on the uniform clearing price auction that the Commission has approved as the foundation of centralized electricity spot market design.[22] The Commission has correctly acknowledged the validity of this fundamental economic principle,[23] stating in

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[21] *See* Attachment B, "The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing," by A. Joseph Cavicchi, Executive Vice President, Compass Lexecon, issued March 31, 2014, *available at* http://www.epsa.org/forms/uploadFiles/29D4100000011.filename.Compass_Lexecon_Polar_Vortex_Implications_paper_3_31_2014.pdf. ("Cavicchi Paper").

[22] *Commonwealth Edison Co*., 113 FERC ¶ 61,278 at P 43 (2005), "[T]his pricing methodology is known as the 'single clearing price' method and has the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs. . . . The single price method has been proposed and found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction."

Order No. 755, Frequency Regulation Compensation In The Organized Wholesale Power Markets, 137 FERC ¶ 61,064 at P 99 (2011), "The Commission finds that paying to all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs is just and reasonable. Accordingly, this Final Rule requires that all RTOs and ISOs with centrally-procured frequency regulation resources must provide for such opportunity costs in their tariffs. Further, this uniform clearing price must be market-based, derived from market-participant bids for the provision of frequency regulation capacity. As commenters recognize, contrary market pricing rules would consistently result in artificial and inaccurate prices that do not include the total cost of reserving regulation capacity. In addition, paying an out-of-market unit-specific opportunity cost, rather than a uniform clearing price, can result in the market basing the commitment of regulating units on bids that do not reflect the true cost of providing capacity, potentially leading to committing units with higher costs than other units not committed. By not paying a uniform clearing price, it is possible, for instance, to dispatch a unit with relatively low explicit capacity costs but very high opportunity costs, rather than a lower-cost unit which has relatively higher explicit capacity costs but low opportunity costs. This can result in distorted investment and entry decisions by market participants. Paying to all cleared frequency regulation resources a uniform price that includes opportunity costs will ensure that all appropriate costs are considered and will send an efficient price signal to current and potential market participants. This will also be consistent with long-standing Commission policy approving uniform clearing prices [FN 158]."

[23] Cavicchi Paper at page 9, "Important benefits flow from efficient spot market prices. By revealing to sellers the actual value of energy production, sellers are provided the best incentives to be available, to operate reliably, and to enter into forward market sales contracts. At the same time, by revealing to buyers the actual value of consumption of spot market energy, buyers will be less likely to rely on the spot market and seek to shift costs onto others, and be more likely to enter into forward market hedges. Moreover, by setting efficient spot market prices, the spot market design guides medium and longer-term power purchase and sale decisions that tend toward more optimal resource allocation."

its order approving PJM's 2014 emergency tariff waiver that, "By limiting legitimate, cost-based bids to no more than $1000/MWh, the market produces artificially suppressed market prices and inefficient resource selection."[24] Further, the Commission has for years consistently and for good reasons stated "[p]ayments made only to individual resources and recovered in uplift fail to send clear market signals," and that those resource costs "should be reflected in transparent market prices whenever possible."[25] The Commission could not have said it any better, but did reiterate these principles in the instant NOPR, acknowledging,

> Two of the Commission's goals in the price formation proceeding are relevant here. First, clearing prices in the energy and ancillary services markets should ideally "reflect the true marginal cost of production, taking into account all physical system constraints." Second, LMPs should "ensure that all suppliers have an opportunity to recover their costs." Establishing LMPs that accurately reflect the marginal cost of production is a central goal of the price formation effort. This goal is important because LMPs are an effective way to communicate information to market participants about the cost of providing the next unit of energy. In the short-run, accurate price signals from LMPs are particularly important during high price periods because they provide a signal to customers to reduce consumption and a signal to suppliers to increase production or to offer new supplies to the market. In the long-run, accurate price signals from LMPs are important because they inform investment decisions. It is also important that RTOs/ISOs give resources the opportunity to recover their costs because failing to do so may discourage resources from participating in RTO/ISO energy markets. Adequate investment in

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24 PJM Waiver Order at P 40.

25 *PJM Interconnection, LLC*, 139 FERC ¶ 61,057, at P 78, n.72. *See also* Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, III FERC Stats. & Regs. ¶ 31,281, at P 192 (2008), as amended, 126 FERC ¶ 61,251, order on reh'g, Order No. 719-A, III FERC Stats. & Regs. ¶ 31,292, reh'g denied, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (Order No. 719) ("existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory. In particular, they may not produce prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation"); *see also,* California Independent System Operator, Corp., 141 FERC ¶ 61,069, at P 44 (2012) ("we note that we are concerned with the extent of CAISO's reliance on out-of-market solutions, which tend to artificially depress market prices. It is important for the CASIO markets to have prices that accurately reflect the market value to operate certain resources so that the market will accurately communicate through the locational pricing model where the new transmission and generation are needed").

> resources and participation of resources in RTO/ISO energy markets are necessary to ensure economic and reliable energy for consumers.[26]

As explained in the Pope Affidavit submitted by EPSA in the first PJM Waiver proceeding in January 2014,[27] market prices are set based on the cost of generation of the marginal unit that clears the market. Doing so provides an efficient price signal for both the short term (day-ahead and real-time economic dispatch by the RTO) and the long term (investment decisions for existing and new generation resources).[28] Such a signal is required at all times, but may well be most pressing to reflect conditions such as the high natural gas prices seen during the extreme weather this winter. PJM recognized this fundamental market principle, explaining in its first emergency waiver filing:

> That principle—basing clearing prices on the costs of cleared sell offers—is <u>fundamental</u> to PJM's energy market design, and that principle should not be set aside, even for an interim period. To the contrary, it is especially critical to honor that principle at the very times, such as experienced this winter, when seller costs are high. There is no question that fuel costs are a legitimate marginal cost of generation, and there also is no question that generators that have had to purchase natural gas on the spot market this winter have at times faced extremely high costs for that gas. Consequently, there is no sound basis for energy prices to ignore those costs.[29] (Emphasis added)

Dr. Pope further explains,

> PJM is able to achieve the economic efficiencies of least-cost dispatch when it receives offers from suppliers that reflect their marginal costs.

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[26] NOPR at P 7, citations omitted.

[27] *See* fn 13 above, and Attachment A herein.

[28] "If the market is competitive… then the clearing-price auction has two wonderful properties. The first is short-run efficiency. The dispatch of generation throughout the day is efficient—the electricity is generated at least-cost to the system, since all generation is supplied by the producers with the lowest cost. The second is long-run efficiency. The single clearing-price auction motivates efficient investment in new generation." Peter Cramton*, "Foreword to Ross Baldick's 'Single Clearing Price in Electricity Markets'"* prepared for the COMPETE Coalition, www.competecoalition.com, (Feb. 2009), *Available at*: http://works.bepress.com/cramton/157

[29] PJM Waiver Filing at pages 3-4.

> And, as predicted by theory and shown by experience, the most reliable way to elicit marginal cost-based offers from sellers is to pay them market clearing prices. *Provided that a competitive supplier is paid the market clearing price*, it will maximize its profits by setting its offer for each unit of output above minimum load equal to its actual marginal cost of production. Efficient pricing lies at the heart of the design of competitive energy markets based on economic dispatch and LMP, like that in PJM.[30]

To disallow offers that reflect marginal costs which may be above the current $1000/MWh cap results in a host of short-run and long-run inefficiencies, as detailed by Dr. Pope in her affidavit,[31] and as found to be unjust and unreasonable by the Commission in the instant NOPR, as well as numerous proceedings approving offer cap waivers, uplift payments, and other "fixes" for distortions caused by the existing offer cap.

Given that finding, the clear and correct approach is to remove the energy offer cap entirely. Simply, "It is a basic economic principle that price caps will result in shortages by discouraging sellers from offering supply to the marketplace (see, for example, Mankiw, N. Gregory, Principles of Microeconomics, Fourth Edition, Thomson South-Western, 2007, at 114-117). Although electricity spot market design seeks to circumvent this problem with uplift payments, distortionary effects remain as seller marketplace expectations are altered by the price caps."[32]

As has been highlighted throughout the Commission's energy and ancillary services market price formation efforts, largely under the auspices of Docket No. AD14-14-000, make-whole payments, or uplift, distort the market by distorting buyer and seller incentives. When LMPs are artificially suppressed due to reliance on uplift, that cost is

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30 Pope Affidavit at page 3 (notes omitted).
31 Pope Affidavit at pages 6 – 10 generally.
32 Cavicchi paper at fn 24.

spread among load or other generators outside of the LMP mechanism. By definition, the resulting LMPs when this occurs understate the amount of revenue necessary to serve the system because the LMPs do not include the cost of all of the actions actually taken in the name of reliability but paid via uplift instead. This significantly mutes the price signals including forward prices on which investment decisions are based, resulting in muted investment relative to what is required in a competitive market and thereby undermining efforts that would result ultimately in savings to consumers. Additionally, reliance on uplift payments creates incentives for market participants to deviate from otherwise efficient bidding behavior; dampens nodal pricing which distorts price signals for locational resources, including demand response and energy efficiency resources, and shifting end-use customer costs between lower and higher priced locations; and, disallows market participants from hedging against uplift charges or costs, exposing energy buyers and sellers to price volatility and cost uncertainty.[33]

Aside from the market fundamentals that urge against use of an offer cap in any form, the market conditions which warranted a “stop gap” offer cap nearly 20 years ago have long since changed given the fact that there have been significant improvements in electric markets and market monitoring in the intervening years, which overwhelmingly supports not just reconsideration of, but removal of, such an arbitrary cap as unnecessarily duplicative.[34] As described above, due to the development of and improvements to monitoring, mitigation, enforcement and market processes since the initial hard offer cap was put in place support that the principle of consumer protection is now more effectively and efficiently met by a comprehensive suite of targeted measures

[33] Cavicchi paper at pp 7-8.
[34] Pope Affidavit.

without distorting market price formation and skewing critical investment decisions as a result. [35]

If the Commission will not remove the offer cap altogether, the Commission should, in the very least, increase the market-based offer cap significantly to accommodate real, verified offer costs, such as the offer of $1724/MWh proposed by PJM in 2014.[36] The Commission has previously acknowledged that the offer cap may need to be increased over time to ensure that it does not suppress market clearing prices.[37]

B. If the NOPR Proposal Is Approved, Clarification Is Required on the Process to Allow Cost-Based Offers To Set LMP

In an approach that replicates aspects of the current PJM offer cap modification in place pending generic action or guidance from the Commission, the instant NOPR would allow incremental cost-based energy offers to go over the $1000/MWh market-based offer cap, for both the day-ahead and real-time energy markets. If an offer cap of any sort is retained, this revision is necessary to protect against limiting some

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[35] *California Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 488 (2007) (the Commission stated that "[a] significant downside to 'soft' caps is the lack of transparency and uplift costs they create. For these reasons, if generation costs were to appear sufficiently likely to exceed the prevailing cap, our preferred approach would be to adjust the level of the energy cap, as has been done in the past. This way, instead of suppressing the market clearing price by regulatory fiat, all competitive bids would be allowed to clear supply and demand and send transparent price signals to encourage demand response, market entry, and forward contracting").

[36] *PJM's December 15, 2014 Filing* in Docket No. EL15-31-000 at page 9.

[37] *California Independent System Operator Corp.* 119 FERC ¶ 61,076, at P 488 (2007), *order on reh'g,* 120 FERC ¶ 61,023 (2007), *reh'g denied*, 124 FERC ¶ 61,094 (2008), *aff'd Sacramento Mun. Util. Dist. V. FERC,* 616 F. 3d 520 (D.C. Cir. 2010) (footnotes omitted) ("if generation costs were to appear sufficiently likely to exceed the prevailing cap, our preferred approach would be to adjust the level of the energy cap, as has been done in the past. This way, instead of suppressing the market clearing price by regulatory fiat, all competitive bids would be allowed to clear supply and demand and send transparent price signals to encourage demand response, market entry and forward contracting").

resources' incremental energy offers "to a level below their short-run marginal cost during intervals with high natural gas prices."[38] The Commission continues,

> In addition, allowing all resources to offer consistent with short-run marginal cost will enhance an RTO/ISO's ability to dispatch the lowest cost resources, particularly when multiple resources have short-run marginal cost greater than $1,000/MWh. Furthermore, allowing a resource to submit a cost-based incremental energy offer above $1,000/MWh would help ensure that resources with short-run marginal costs above $1,000/MWh have an incentive to offer electricity into the market during high price periods, when their electricity may be needed. Allowing LMPs to reflect a given RTO/ISO's marginal cost of production could result in more economic power flows across seams because electricity would flow to where it is most valued.[39]

Competitive Suppliers support this revision as critical in order to ensure that ISOs/RTOs do not go through *another* winter with a $1,000/MWh cost-based offer cap mechanism that does not allow recovery of demonstrated, justified fuel costs – particularly at those times when a sufficient price signal is needed most to convey the true conditions to producers and consumers. As PJM explained in comments filed last year in the Commission's broad energy price formation proceeding,

> PJM believes it is appropriate to ***eliminate*** the cap on cost-based offers. Resources should be allowed to recover their costs of providing energy and not be limited by any arbitrary cap. ***Not allowing resources that provide energy the opportunity to recover their costs of operating would result in unjust, unreasonable, and likely confiscatory rates. While some may argue that not having a cap on cost-based offers would invite offers that would unreasonably raise prices on consumers, PJM does not believe this would be true.*** In PJM, cost-based offers must be submitted in accordance with PJM's Cost Development Guidelines, which in [and] of themselves limit the type of costs that can be included in cost-based offers. Absent fraud or an inadvertent failure to adhere to the Cost Development Guidelines, the Cost Development Guidelines effectively cap cost-based offers at the

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38 NOPR at P 54.

39 NOPR at P 54.

> approximate actual costs incurred by generation resources when operating.[40] [Emphasis added.]

The Commission proposal differs from the current PJM approach to offer caps, however, by instituting the following requirement for any cost-based bid to be allowed to set the market clearing price:

> The costs underlying a resource's cost-based incremental energy offer above $1,000/MWh must be verified before that offer can be used for purposes of calculating Locational Marginal Prices. If a resource submits an incremental energy offer above $1,000/MWh and the costs underlying that offer cannot be verified before the market clearing process begins, that resource's incremental energy offer in excess of $1,000/MWh may not be used to calculate Locational Marginal Prices. In such circumstances a resource would be eligible for a make-whole payment if that resource clears the energy market and the resource's costs are verified after-the-fact.[41]

In the NOPR, the Commission seeks comment on the ability of the MMU or ISO/RTO to timely verify such costs prior to the day-ahead or real-time clearing process, and also on whether additional information would be needed on cost components that are "difficult to quantify" in order to accurately reflect those costs in the cost-based offer. Further, and of particular importance, the NOPR asks each ISO/RTO "to include in its tariff a process by which the Market Monitoring Unit of RTO/ISO verifies the costs included in cost-based incremental energy offers above $1,000/MWh"[42] without specifications as to that process, aside from guidance that before-the-fact verification "should build upon existing procedures"[43] and may differ across ISOs/RTOs.

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[40] Comments of PJM Interconnection, L.L.C. at 3, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, (filed March 6, 2015).

[41] NOPR at P 56.

[42] NOPR at P 60.

[43] NOPR at P 60.

This requirement, which appears to specify a before-the-fact verification process for individual offers, will very likely leave regional market operators without the ability to verify each cost-based offers in advance of their market clearing processes, foreclosing the ability of cost-based offers to set the market clearing price. This result is untenable, and therefore requires modification in a final rule. We do note that removing the offer cap altogether, or increasing it significantly, would alleviate any challenges inherent in a before-the-fact verification process.

First, though *market-based* incremental energy offers should be allowed over the $1000/MWh threshold and should set the market clearing price, if such offers over that threshold are limited to cost-based offers, it is critical that they be allowed to set the market clearing price. As explained by Dr. Susan Pope in previous PJM offer cap waiver proceedings,

> PJM is able to achieve the economic efficiencies of least-cost dispatch when it receives offers from suppliers that reflect their marginal costs. And, as predicted by theory and shown by experience, the most reliable way to elicit marginal cost-based offers from sellers is to pay them market clearing prices. *Provided that a competitive supplier is paid the market clearing price*, it will maximize its profits by setting its offer for each unit of output above minimum load equal to its actual marginal cost of production. Efficient pricing lies at the heart of the design of competitive energy markets based on economic dispatch and LMP, like that in PJM.[44]
>
> The illogic of excluding a supplier's cost-based offer from the determination of LMPs is highlighted by a list, in a recent PJM document, of all bids and offers that *are* eligible to set LMPs: online generators following PJM's dispatch instructions; dispatchable transactions following PJM's dispatch instructions; Economic Demand Response; Price Responsive Demand; Emergency Demand Response; Emergency Import Transactions; and Generation from Emergency segments of units already on-line and operating in the real-time energy market. Implicit in all of these considerations is the intention to accurately represent the offer price of the related supply product. PJM and other ISOs have detailed market rules to attempt to insure that LMPs are market clearing prices for a

[44] Pope Affidavit, citations omitted, Para 7.

variety of resources that may be marginal in the dispatch because of the importance of “getting the prices right.”[45]

Therefore, it is imperative that the Commission clarify and modify its energy offer caps verification proposal to include a process that verifies cost-based offers in a manner that allows them to set LMP. It is incredibly challenging for a gas-fired generator to verify its exact costs after the market has cleared. The gas may have been purchased at different times, in different blocks, and for the market participant’s total fleet. Further, the generator may not have burned the total capacity purchased. Therefore, producing receipts, screen shots, and broker quotes that reflect a generator’s actual costs is incredibly challenging. While the after the fact verification is challenging, a before the fact verification is largely impossible to do with exact certainty. As PJM has referenced in comments submitted in this administrative proceeding, it currently has in place Cost Development Guidelines that provide a means of verifying costs. Competitive Suppliers note that this discussion offers an alternative approach to the instant NOPR’s apparently offer-specific before-the-fact verification requirement. The RTO/ISO and the generator should be able to identify a set of accepted criteria and data inputs by which cost-based offers are submitted and accepted by the ISO/RTO in a manner which allows such offers, submitted pursuant to that established cost-based offer criteria, to set the LMP – a fundamental principle to avoid distortions and inappropriate incentives.

Importantly, the ISOs/RTOs already have a significant amount of cost information that they use to monitor the bidding behavior of market participants. Whether it is the current PJM reliance on guidelines or a fuel cost policy, or reference price processes

[45] Pope Affidavit, Para 8.

used in other ISO/RTOs to monitor supplier exercise of market power, the ISOs/RTOs already have a tremendous amount of information on supplier marginal costs, information sufficient to facilitate a prospective process for developing cost-based offers deemed verified by the market operator. In fact, most ISOs/RTOs already have established and approved guidelines in place for the development and submission of such offers which can serve as the basis for any prospective cost-based program.[46] Given this, the Commission can require the details of any cost verification program to be part of a compliance filing by the ISOs/RTOs.

The development of a verification process and/or criteria, in place of a before-the-fact offer-specific verification requirement, is a fundamental change that must be made to the Commission's NOPR proposal, should the offer cap not be lifted entirely as supported by the record in this and numerous related proceedings. Such a process will allow all offers, even cost-based offers, to set the LMP. The only instances where verification will be difficult is when the IMM or ISO/RTO will need to validate spot market gas supply costs. EPSA believes that a predetermined risk factor should be set that would trigger after-the-fact verification.

However, in certain instances in which a resource cannot utilize an ISO's/RTO's verification process or may lack certain aspects of the documentation or criteria needed for the offer to set the market clearing price, it may be necessary to compensate that resource through a make-whole payment based on after-the-fact cost verification for

[46] Pursuant to Attachment H of the NYISO Market Administration and Control Area Services Tariff, NYISO develops reference level prices under its market mitigation and monitoring procedures. They rely in part on cost based information for energy market offers. See Section 23.3.1.4 of Attachment H which sets reference levels and Manual 34 for description of how to set a cost-based reference level. See also PJM Operating Agreement, Schedule 2 and PJM Manuals for information of developing cost-based energy offers.

costs incurred in order to serve the system as dispatched. These instances should be rare, as competitive markets rely on revealing to sellers the actual value of energy production through market-based rates so that sellers are provided the best incentives to be available, to operate reliably, and to enter into forward market sales contracts and hedging arrangements. However, though rare, any time that a resource incurs justifiable and demonstrable short-run marginal costs, those costs should be recovered so that the resource is not forced to operate at a loss, or is discouraged from offering its supply to the market when market participants are willing to buy that supply. While all ISOs/RTOs should strive to decrease uplift payments to de minimis levels, there may be circumstances for which such out of market make-whole payments are a necessary backstop.

C. Virtual Transactions Must Be Allowed To Be Priced Above $1000/MWh

Scarcity pricing in the real-time energy market can far exceed the existing $1000/MWh cap on virtual supply and demand bids. This currently precludes convergence of day-ahead with real-time energy prices when it matters most – in periods where next day demand is anticipated to challenge next day supply. As an example, following the Commission's FPA Section 206 direction that ISO-NE increase its scarcity prices, New England real-time energy prices can exceed $3500/MWh where the aggregate supply is inadequate to meet combined energy and operating reserve needs, yet day ahead virtual bids intended to facilitate convergence between the two markets is capped at $1000/MWh.[47] As it was necessary and appropriate for the

[47] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014) (the "May 30 Order" or "Order"). Par. 107. "(W)e direct ISO-NE to implement both the Reserve Constraint Penalty Factors and the two-settlement FCM design because we find that there is value to providing incentives in

Commission to direct improvements to scarcity signals in the real-time energy market, it is equally important for the Commission to allow the day-ahead energy market to reflect scarcity pricing through at least virtual bid convergence. While such scarcity pricing signals remain important to real-time energy (and operating reserve) market signals, the existing $1000/MWh cap on virtual bids essentially prevents convergence of day-ahead and real-time energy market pricing where next day system demand levels are expected to strain system supply. This constraint – precluding day-ahead energy market valuation of anticipated next day short supply conditions – is particularly troubling given that the majority of energy supplied to the market is sold at day-ahead energy market prices.[48] It administratively caps the price of day-ahead energy sales while exposing such sellers to performance penalty rates (real-time energy purchase to cover the day-ahead sale) far in excess of the day-ahead energy price that could possibly be realized.[49] At a minimum, virtual bidding should be allowed to make convergence with the highest real-time energy market prices possible.

Competitive Suppliers acknowledge that allowing virtual bids to exceed $1000/MWh will require working out details because virtual bids that set the LMP by their very nature do not have the verifiable costs on which physical transactions are based. The cost of a day-ahead virtual energy sale is the seller's estimated risk of buying back that position at a higher real-time energy market price. However,

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both the FCM and the energy and ancillary services markets. This is because different combinations of revenue streams make sense for different resources." (par. 108).

[48] Most day ahead energy sales are required by virtue of either capacity sale-related must offer obligations or energy market mitigation restrictions and the opportunity to sell at higher real-time prices does not exist absent meaningful virtual bidding flexibility to permit convergence of day-ahead energy prices with high real-time energy prices.

[49] Where the market anticipates real-time prices above $1000/MWh, market participants will be unable to fully value that future sale opportunity through a day-ahead demand bid.

discussed further below, virtual transactions are needed for convergence between day-ahead and real-time and to meet scarcity pricing as directed by the Commission. Under the $1000/MWh cap, in times of extreme demand and anticipated tight system conditions, virtual transactions are actually discouraged because they cannot adequately cover their real-time imbalance cost risk. If the Commission does not direct the RTOs to raise the cap to at least the level of plausible real-time scarcity prices in their market, it is imperative that the Commission establish a process to require this matter to be addressed by a time certain.

D. All Market-based Offer Cap Rules Should Be Consistent Across Transactions

While the Commission and others have clearly and correctly explained the need to revise energy offer caps across all ISOs/RTOs in the same manner,[50] it is also necessary to ensure that the revised offer cap applies equally to all of the different types of market transactions. Market-based generation offers, virtual transactions, import transactions and emergency demand response should all be capped at the same level. If that is not directed by the Commission, the market-based cap should not be $1000/MWh, but rather should be set high enough to accommodate true system conditions. Such a revised cap could be based on some recent cost-based offer history, for instance.

[50] Comments of PJM Interconnection, L.L.C. at 4, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, (filed March 6, 2015), "Offer caps should be implemented on a uniform basis across all RTOs/ISOs. Having different offer caps in different RTOs/ISOs would exacerbate interface pricing and seams related issues because a discontinuity could create dispatch and pricing anomalies and transmission congestion coordination discontinuities at the market borders, especially during periods of extreme weather."

One of many concerns over retaining the current $1000/MWh cap is that doing so exposes a competitive supplier to being committed in the day-ahead market at $1000/MWh, and then that supplier is exposed to having to buy back in real-time at shortage pricing if it fails to perform. The real time buy back price, during times of extreme demand, can greatly exceed $1000/MWh. The problem is even more complex when one considers the impact on competitive suppliers with capacity resource commitments that require them to offer into the day-ahead energy market.[51] If their offer cannot exceed $1000/MWh, they will likely be committed day-ahead at that level, thereby exposing themselves to the risk of having to buy back at shortage prices in real time if they cannot deliver.[52] Without the ability to offer into the Day Ahead market above $1000/MWh, there is no way to mitigate this risk.

[51] This is a standard requirement for ISO/RTOs with capacity markets.
[52] PJM and the ISO-NE have implemented new capacity performance markets that increase penalties significantly for a capacity resources' failure to perform during critical hours.

III. CONCLUSION

WHEREFORE, Competitive Suppliers respectfully request that the Commission modify and implement a final rule in this proceeding as discussed herein. This generic revision of offer price caps – optimally the removal of the current outdated incremental energy offer cap – is needed to be in place in all six ISOs/RTOs *before the start of winter 2016/2017* in order to ensure the efficiencies and functional market operations supported by the multitude of market design improvements underway or under consideration will be derived across the regions and protect against seams or inter-market distortions, particularly during peak or critical periods.

Respectfully submitted,

/s/

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Dated: April 4, 2016

Attachment A

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION, INDEPENDENT ENERGY PRODUCERS ASSOCIATION, INDEPENDENT POWER PRODUCERS OF NEW YORK INC., NEW ENGLAND POWER GENERATORS ASSOCIATION INC. AND THE WESTERN POWER TRADING FORUM

Offer Caps in Markets Operated By Regional Transmission Organizations and Independent System Operators

Docket No. RM16-5-000
April 4, 2016

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)** **)**	**Docket No. ER14-1145-000**

AFFIDAVIT OF SUSAN LIESE POPE

COMMONWEALTH OF MASSACHUSETTS)
)
COUNTY OF SUFFOLK)

I, Susan L. Pope, having first been duly sworn under oath, state:

1. My name is Susan Liese Pope. I am a Managing Director at FTI, Inc., which is located at 200 State Street, Boston, Massachusetts 02109. My firm specializes in providing economic, financial and regulatory policy consulting services to private and, to a lesser extent, public organizations in regulated industries. My *curriculum vitae* is attached as Appendix A.

2. I am an expert in the economic and public policy analysis of electricity market design. During my career I have advised clients on the creation of independent system operators and on the design of bid-based electricity spot markets, two-settlement systems, and markets for ancillary services, financial transmission rights and capacity. I have worked with many types of clients across the United States to develop rules and structures for efficient electricity markets that meet both federal and state requirements.

3. I write this affidavit in support of the Comments of the Electric Power Supply Association ("EPSA") on PJM Interconnection, L.L.C.'s ("PJM") January 23, 2014 filing of its "Request of PJM Interconnection, L.L.C. for Waiver, Request for 7-Day Comment Period,

and Request for Commisison [*sic*] Action by February 10, 2014" with the Federal Energy Regulatory Commission ("Commission") in the above-captioned proceeding ("Waiver Filing"). EPSA has asked me to address why PJM's request for a waiver of its $1,000/MWh offer-price cap through March 31, 2014 is essential for economically efficient operation of its day-ahead and real-time energy markets and should be approved immediately.[53]

4. In its filing, PJM requests a waiver of its current $1,000/MWh cap on offer prices through March 31, 2014 for Generation Capacity sellers submitting cost-based offers to its energy market. PJM requests that Generation Capacity sellers be permitted to submit offers based on their marginal costs, even if this results in their offer prices exceeding $1,000/MWh. PJM explains that the increase in the level of permissible offers would affect the calculation of market clearing electricity prices in PJM, *i.e*., the LMPs.

5. The Waiver Filing was precipitated by record-setting natural gas prices in the PJM region during several recent cold days in January (commencing approximately January 21), that caused the marginal costs of some generators to rise above PJM's $1,000/MWh offer price cap. Recognizing the legal, economic and reliability implications of capping offers below marginal costs, PJM acted quickly to insure that Generation Capacity sellers, who are obligated to offer their supply into PJM's energy markets, would recover their costs of generation through make-whole payments.[54] PJM also recognized that the same fuel

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53 This affidavit addresses the second of the two waiver requests PJM filed on January 23, 2014 . The first related to allowing generators to recover appropriate costs in excess of $1,000/MWh. The instant filing addresses the waiver of the offer caps associated with these units and their participation in the price formation process.

54 *PJM Interconnection, L.L.C*., Request of PJM Interconnection L.L.C. For Waiver And For Commission Action By January 24, 2014, Docket No. ER14-1144-000 (filed Jan. 23, 2014)(" Make-Whole Payment Filing") and *PJM Interconnection, L.L.C.,* Order Granting Waiver, 146 FERC ¶ 61,041 (issued Jan. 24, 2014).

supply conditions could occur again this winter and the need for a solution – other than the stop-gap of make-whole payments – that is consistent with the principles of its competitive energy market. In the Waiver Filing, PJM explains why waiving the offer cap is essential for the operation of its energy markets this winter.

6. The waiver of the offer cap is necessary to maintain the market pricing system in PJM that is the basis of its economic dispatch. PJM is able to achieve the economic efficiencies of least-cost dispatch when it receives offers from suppliers that reflect their marginal costs. And, as predicted by theory and shown by experience, the most reliable way to elicit marginal cost-based offers from sellers is to pay them market clearing prices. *Provided that a competitive supplier is paid the market clearing price*, it will maximize its profits by setting its offer for each unit of output above minimum load equal to its actual marginal cost of production.[55] Efficient pricing lies at the heart of the design of competitive energy markets based on economic dispatch and LMP, like that in PJM.

7. The offer cap must be waived to insure that suppliers will be paid market clearing prices if fuel prices again cause supplier marginal costs to exceed $1,000/MWh this winter in PJM.[56] Market pricing for PJM means paying suppliers and charging buyers LMPs for their cleared schedules, *where the LMPs are determined from the marginal offers of all sellers scheduled to serve load and the marginal bids of price-responsive loads (i.e., the marginal cost of forgoing consumption).* If the Commission declines the approval of the offer cap waiver, it will effectively be directing PJM to set LMPs at something other than market clearing

[55] The tie between market pricing and economic efficiency, applied here to electricity markets, is a fundamental theorem of microeconomics. *See, e.g.,* William W. Hogan, "Electricity Market Restructuring: Reforms of Reforms," *Journal of Regulatory Economics*; 21:1, 103-132, 2002.

[56] It would be advisable for PJM to petition the Commission to extend the proposed changes until it has completed the stakeholder process proposed to resolve this issue on a longer-term basis.

prices in the event that supplier marginal costs again exceed the offer cap this winter.[57] As PJM states in its Waiver Filing,

> That principle – basing clearing prices on the costs of cleared sell offers – is fundamental to PJM's energy market design, and that principle should not be set aside, even for an interim period. To the contrary, it is especially critical to honor that principle at the very times, such as experienced this winter, when seller costs are high.[58]

8. It is economically efficient for offers in excess of $1,000/MWh from suppliers running to serve load to be included in the determination of LMPs, as requested by PJM, and *ad hoc* to provide for cost recovery but exclude such marginal costs from the price formation process. There is absolutely no economic logic for excluding the verified marginal–cost offers of suppliers operating to serve load from the determination of LMPs, and compelling reasons for the inclusion of these offers. The illogic of excluding a supplier's cost-based offer from the determination of LMPs is highlighted by a list, in a recent PJM document, of all bids and offers that *are* eligible to set LMPs: online generators following PJM's dispatch instructions; dispatchable transactions following PJM's dispatch instructions; Economic Demand Response; Price Responsive Demand; Emergency Demand Response; Emergency Import Transactions; and Generation from Emergency segments of units already on-line and operating in the real-time energy market.[59] Implicit in all of these considerations is the intention to accurately represent the offer price of the related supply

[57] If the Commission does not approve PJM's Waiver Filing, it will be creating a wholly new and untested market structure in which the energy markets will clear based on LMPs as long as supplier marginal costs are less than $1,000/MWh, but not on marginal costs when they these exceed $1,000/MWh . When supplier offers are capped, the market will be settled under a different price regime combining uplift and pay- as-bid pricing for a portion of the market with settlements for the rest of the market based on LMPs that are not market clearing prices.

[58] Waiver Filing, p. 3.

[59] Energy Market Uplift Senior Task Force ("EMUSTF"), "Solutions Matrix", January 23, 2014, http://wired.pjm.com/~/media/committees-groups/task-forces/emustf/20140123/20140123-item-03-solutions-matrix.ashx

product. PJM and other ISOs have detailed market rules to attempt to insure that LMPs are market clearing prices for a variety of resources that may be marginal in the dispatch because of the importance of "getting the prices right". In contrast to the painstaking work required to craft rules to insure market clearing LMPs in a variety of market situations, it is a simple matter to waive the offer cap as requested by PJM.

9. The continued imposition of an offer cap of $1,000/MWh on Generation Capacity sellers with actual marginal costs in excess of this amount is clearly inconsistent with the default offer price of $1,800/MWh that PJM employs for Emergency Demand Response ("EDR").[60] PJM may activate EDR before it enters a situation of reserve shortage and, when EDR is activated, the offer price is set at $1,800/MWh. In turn, this price can and does participate in price formation and thus flows through into PJM's LMP pricing. In contrast, under the present market rules, if marginal generation supply were available during the same hour at a marginal cost of $1,800/MWh (for the purposes of this example), its offer would be capped at $1,000/MWh, and used to determine the LMPs reflecting this artificially reduced offer price. The inconsistency of this application of offer caps and determination of LMPs in the two situations is starkly apparent. If EDR were activated, suppliers with marginal costs over $1,000/MWh would earn a profit margin on the difference between their costs and their LMP, where the LMP would be determined based on one or more marginal EDR offers of $1,800/MWh. If EDR were not activated, the supplier would be paid as bid, *even if* the marginal supplier had a marginal cost of $1,800/MWh, and the difference would be recovered through the imposition of unhedgable

[60] The PJM Independent Market Monitor filed a complaint about this inconsistency on January 27, 2014. *See* Independent Market Monitor for PJM v. PJM Interconnection, L.L.C, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, Docket No. EL14-20-000, (filed Jan. 28, 2014).

uplift charges on market participants. This illogical and inconsistent pricing would be temporarily eliminated by approval of the Waiver Filing.[61]

10. Setting LMPs at market clearing prices supports the objectives of short-run and long-run efficiency in electricity markets. If the Commission does not approve the Waiver Filing, the offers of sellers with marginal costs greater than $1,000/MWh would be capped at $1,000/MWh in PJM's LMP pricing algorithm, rather than being set at the supplier's actual marginal costs, causing LMPs (in locations electrically related to the capped supply offer) to be lower than the true market clearing prices. The short-run consequences of this underpricing – insufficient incentives for reductions in load or for increases in supply, as well as for reductions in the consumption of the scarce underlying fuel (natural gas) – are tremendously important in situations of tight electricity supply.[62] A failure to let LMPs rise to reflect the marginal cost of supply required to serve load would fly in the face of the Commission's efforts to encourage the development of price-responsive demand to help alleviate such situations.[63] If LMPs do not rise to signal the avoided costs of generation, inefficiencies will occur because loads will continue to consume energy even when they value it at less than what it costs to produce. Moreover, LMPs that are set below the true marginal costs of supply will fail to signal the true value of additional electricity imports,

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[61] The exclusion of marginal cost offers in excess of $1,000/MWh from the determination of LMPs also distorts and depresses prices for ancillary services under PJM's co-optimization of schedules and internally consistent prices for energy, reserves and regulation.

[62] *See* Scott Harvey and Scott Travers, "Market Incentives for Generation Investment," December 2, 2008, for a thorough discussion of the link between offer caps, "missing money" and market incentives for efficient investment in electricity markets: "The underlying problem is that bid caps and other measures that limit the price paid by load under stressed system conditions also limit the revenue foregone by the generator that is not available during these stressed system conditions. The incentive problem can be addressed by adding additional penalties that withhold capacity payments when the plant is not available during specified conditions, but without spot prices that reveal the true value of spot power, it is difficult to design contract provisions that accurately reflect the social value of power and thus incent the supplier to incur extraordinary costs, but only when power is very valuable." (p. 27)

[63] *See PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 at PP 131 (2012).

leading to the possible missed opportunity to elicit offers from imports with a marginal cost that is less than some of the supply subject to the offer cap. LMPs that are set below the true marginal costs of supply also will fail to signal the value of increased gas supply during such times. On both the demand and supply side, failure to approve the Waiver Filing would lead to short-run inefficiencies, increasing the real resource cost of supplying load in PJM and inflating unhedgeable make-whole payments.

11. If the Commission does not approve the Waiver Filing, more complex short-run inefficiencies also will arise due to the impact of the offer cap on the legitimate business decisions confronted by electric suppliers who have gas in storage or gas supply that can be used to generate electricity at different locations with different LMPs. Such suppliers must make decisions about where and when to use their gas so as to maximize their profits and meet their obligations as Capacity Resources, when their gas supply may be limited. If their energy supply offer is capped, such suppliers are essentially operating under a "pay as bid" regime of price formation through make-whole payments. The result is that they do not make a margin above marginal costs on electricity generated from their gas, even when they are an infra-marginal supplier of electricity. This can lead to the misallocation of the gas, and jeopardize electric reliability as, for example, at such times stored gas might be sold at a profit rather than saved for later electricity production. The business decisions are complex for this supplier because it cannot simply offer its supply at marginal cost with the assurance that it will be paid the true electricity market clearing price, if higher. The interim "pay as bid" approach that currently applies (in place of market pricing) leads to the necessity for suppliers to make complex intertemporal decisions about when and where

they should use their gas, while facing the possibility of ex post proceedings to justify their gas purchase and sale decisions should a true electricity shortage occur.

12. The Waiver Filing also should be approved in order to provide PJM's market participants with the LMP price signals that incent efficient long-run economic decisions. It is true, *in a narrow sense,* that Capacity Resources made offers into the RPM with full knowledge of the offer price cap.[64] The larger context, though, is that such suppliers operate in the PJM energy market and in other energy markets under the full expectation that the rules in these markets will produce LMPs that are market clearing prices. This is the theory of LMP, which ISOs around the country have implemented, and suppliers have a right to expect that if and when LMPs deviate from market clearing prices ISOs and the Commission will act expeditiously to correct the precipitating market flaw. PJM's energy market and other ISO energy markets are settled based on market clearing prices in order to send price signals to incent investors to make efficient long-run decisions about the types of new supply-side, demand-side and transmission resources to build, and where to build them. The Commission must act decisively, as requested by PJM, to assure these investors that over the long-run LMPs *will consistently be set at market clearing prices determined from marginal offers for supply or demand response.* Investors require confidence that PJM and the Commission will adhere to the principles of the market design over the long-run, as they must commit capital over the long-run on the expectation of earning profits. If the Commission declines to approve the Waiver Filing, its decision will seriously damage investor confidence in its commitment to marginal cost pricing in ISO energy markets.

[64] Moreover, LMPs may currently rise above the offer cap due to shortage pricing and the activation of EDR, and the current EDR offer price of $1,800/MWh is scheduled to rise over the coming years.

13. Recovery of supplier marginal costs in excess of $1,000/MWh through a make-whole payment[65] rather than through payment of an LMP determined pursuant to waiver of the offer cap is inconsistent with the operation of a competitive market for all of the reasons described above. The problems with continuation of PJM's interim solution of making suppliers whole for their costs in excess of $1,000/MWh are not limited to efficiency and incentive issues, however. The stop-gap make-whole solution does not "make the problem disappear"; rather it arbitrarily creates economic winners and losers relative to the economic solution of granting the offer waiver. All infra-marginal suppliers that have not pre-sold their energy through hedging contracts or other supply arrangements clearly lose, as they are paid LMPs determined from marginal offers of $1,000/MWh, rather than being paid LMPs that are market clearing prices determined from the actual marginal costs of marginal suppliers. Load that is not covered by a hedging arrangement of some kind wins, as it pays a lower LMP for its spot market energy purchases. It is important to note that the overall impact on load and generators is mitigated by the degree to which they have entered into forward hedging arrangements; any evaluation of the possible rate impacts of the waiver must take into consideration the dampening effect of such hedging. Looking beyond suppliers and loads transacting in the energy markets, the biggest losers, by far, from the continuation of the make-whole solution are the parties who must pay the unhedgable uplift to make-whole all suppliers with offers in excess of $1,000/MWh.[66] Without the offer cap waiver, this uplift will potentially balloon, and my understanding is that a large portion will be paid by load serving entities who acquired this payment obligation in contracting to

[65] *See* Make-Whole Payment Filing.

[66] Concerns about the magnitude of uplift in PJM are currently under review by the PJM Energy Market Uplift Senior Task Force.

provide supply for retail customers. For example, LSE's that provide fixed cost supplies for the New Jersey Basic Generation Service (BGS) will have fixed revenues but escalating costs due to uplift charges, regardless of whether or not they entered into hedges for their energy supplies.

14. Offer caps, as a matter of market design, are not intended to constrain prices in markets deemed to be competitive to be set at anything other than the competitive market clearing price; in particular, offer caps are not intended to cause market clearing prices to be set below the marginal cost of supply required to serve load. In the short time available for comments in this proceeding, I have not been able to locate the rationale provided for imposing the $1,000/MWh offer cap in PJM.[67] However, in the Commission's Docket No. RM01-12-000, "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design," PJM explained its position on offer caps in 2002:

> PJM's experience demonstrates that $1,000 per megawatt-hour is an appropriate and reasonable level for the bid cap. Depending on fuel costs, $1,000 is five to seven times higher than the marginal cost of production of the highest cost units in the PJM region. Furthermore, prices in PJM have approached the $1,000 mark on only a few occasions. Thus, the $1,000 safety-net bid cap serves to permit scarcity pricing while preventing the exercise of market power that would result if the cap were higher.[68]

Thus, PJM intended at that time for the $1,000/MWh offer cap high enough so as not to constraint the determination of competitive market clearing prices.

[67] *See* PJM Order 81 FERC ¶ 61,257, November 1997.
[68] *See Remedying Undue Discrimination through Open Access Transmission Service,* Initial Comments of PJM Interconnection, L.L.C., Docket No. RM01-12-000 at 45 (filed Nov. 15, 2002).

15. Offer caps operate as a safety net for energy markets to quell concerns about potentially large wealth transfers due to the exercise of market power, market manipulation, or software flaws when there is insufficient price-responsive demand to dampen potential price increases.[69] When the offer cap was decreased to $1,000/MWh in the New York ISO ("NYISO") in 2000 from its initial level of $10,000/MWh, it was principally due to concerns about unknown software flaws and the lack of price-responsive load to limit price excursions. Although the NYISO proceeding concerned market-based offers, not the cost-based offers at issue in the present case, there was still substantial debate about whether such concerns justified the lower offer cap. In 2000 the NYISO requested a lower offer cap as an interim measure for the summer, and specifically requested a cap that was approximately equal to the highest LBMP that had been experienced to that point in New York. The intention of the NYISO was consistent with the views PJM expressed in 2002: to choose a bid cap so as not to interfere with competitive price formation.[70] The dispute over the imposition of the $1,000/MWh *market-price* offer caps in NYISO in 2000 give emphasis to the absurdity of imposing the same cap on *cost-based* offers in PJM today, taking into account ten years of improvement in market monitoring and the long track-record for PJM's market software.

16. The intentional imposition of an offer price cap that is less than the marginal cost of supply required to serve loads is at odds with the rationale for the use of offer caps, rather than price caps. The advantage of an offer cap in competitive markets, as opposed to an

[69] This view is shared by other economists. *See Remedying Undue Discrimination through Open Access Transmission Service,* Initial Comments of John D. Chandley and William W. Hogan, Docket No. RM01-12-000 at 81 (filed Nov. 13, 2002).
[70] NYISO Order on Tariff Filing and Complaint 92 FERC ¶ 61,073. Commissioner Hébert dissented in strong terms, critiquing the impact of offer caps on competitive markets.

equivalent price cap, is that with an offer cap the supplier will be paid the market clearing price, even when this exceeds its offer cap. The use of offer caps thus is consistent with the principle of designing market rules that give suppliers the incentive to offer their generation at its actual marginal cost. The imposition of an offer cap in PJM that is less than a supplier's marginal cost clearly runs afoul of the basic logic and justification for using offer caps as a policy instrument, as it leads to suppliers being paid LMPs that are not market clearing prices.

17. Waiver of the offer cap as requested by PJM would be consistent with major changes and improvements to electricity markets since their inception to better align market pricing with the physical facts of electricity production. Examples of such improvements include three-part bidding, to better account for the actual characteristics of generation supply curves, and the co-optimization of schedules for energy and ancillary services, to enable optimization of schedules for generating capacity across multiple markets. In the present case, there is a need to waive the offer cap to reflect the realities of fuel supply costs. Alignment of market clearing prices with the physical realities of electricity production, as requested by PJM in its Waiver Filing, has repeatedly been shown to be desirable for the efficient and reliable operation of electricity markets.

18. Granting PJM's Waiver Filing is economically efficient but does not eliminate the need to examine and resolve issues that may exist in the interaction between gas and electricity markets, particular during times of tight gas supply. Both gas and electricity markets will require continued monitoring so as to protect electricity consumers and suppliers from the exercise of market power and from the risk of ex post investigations of the actions they undertake during periods of tight fuel supply. Nothing in the requested waiver diminishes

the ability to maintain such monitoring and review, and in fact, my understanding is that the PJM Independent Market Monitor in the stakeholder process has expressed his intention to closely review all recent gas procurement. Indeed, allowing cost based marginal fuel expense above $1,000/MWh to set LMPs will increase the transparency of the market and facilitate market monitoring.

19. The Commission should resist the temptation to delay ruling on PJM’s Waiver Request. A longer-term initiative is clearly needed to address underlying problems with price formation in PJM, but the Commission also needs to demonstrate a commitment to act quickly to correct market flaws that are clearly inconsistent with the intended operation of competitive electricity markets. There is a time for stakeholder process to consider and deliberate over complex issues, or over the crafting of market rules for which there is not a clear economic “first best” answer, but this is not one of those times.

20. This concludes my affidavit.

<u>DECLARATION OF WITNESS</u>

I, Susan L. Pope, declare under penalty of perjury that the statements contained in the foregoing Affidavit of Susan L. Pope on behalf of the Electric Power Supply Association in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 30st day of January, 2014.

/s/Susan L. Pope

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Susan L. Pope

Attachment B

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION, INDEPENDENT ENERGY PRODUCERS ASSOCIATION, INDEPENDENT POWER PRODUCERS OF NEW YORK INC., NEW ENGLAND POWER GENERATORS ASSOCIATION INC. AND THE WESTERN POWER TRADING FORUM

Offer Caps in Markets Operated By Regional Transmission Organizations and Independent System Operators

Docket No. RM16-5-000
April 4, 2016

The Polar Vortex: Implications for Improving the Efficiency of Wholesale Electricity Spot Market Pricing[71]

A. Joseph Cavicchi

Prepared for the Electric Power Supply Association

March 2014

[71] The views and opinions expressed in this study are solely those of the author and do not necessarily reflect the views and opinions of Compass Lexecon, employees and other affiliates of Compass Lexecon, or members of the Electric Power Supply Association.

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I. Summary

Extreme cold weather in early January 2014 provided a stress test for Mid-Atlantic and Northeastern wholesale electricity market designs. Following this unusual polar vortex weather event several important concerns were identified for review and modification.[72] Many of these concerns are appropriately associated with ensuring that independent system operators ("ISOs") have the ability to effectively manage electricity operations during periods when system conditions may be stressed. In addition, the recent cold weather events revealed several electricity spot market[73] pricing inefficiencies which can negatively impact operations and reliability. The polar vortex provides an important opportunity to highlight existing wholesale electric spot market energy pricing inefficiencies, and to embrace future market design policy that will eliminate these problems.

Two particular electricity spot market design inefficiencies were exposed during the polar vortex event. First, the polar vortex illuminated the ongoing problem where uneconomic out-of-market resource compensation ("uplift") puts downward pressure on spot market prices. Although it has been suggested that obfuscating spot market volatility through the payment of uplift is a preferable approach for wholesale electricity market design, the perpetuation of uplift distorts spot market prices and creates incentives for buyers and sellers to deviate away from efficient behavior over both the short and the long run. Since uplift can suppress market prices throughout the year, it can result in the premature retirement of economic resources that are needed during times such as the polar vortex. Some progress has been made over the last several years to formulate and implement more efficient resource commitment and dispatch algorithms that reduce uplift and result in more efficient spot market prices. Additional progress is needed, however, as good market design policy dictates that a concentrated effort be made to minimize uplift.

Second, price caps may have suppressed wholesale electricity market prices below competitive levels. That is, offer and price caps were demonstrably below input costs, and could have prevented spot market clearing prices from reflecting the actual value of electricity supply to the wholesale market. The polar vortex revealed that the expectations which originally formed the basis for a $1,000/MWh price cap were wrong. Moreover, once it was clear that rule changes were necessary, there was little time available to do so before reliability may have been adversely impacted. Thus, we have learned from the polar vortex that offer and price caps need to be expeditiously revised.

There are numerous reasons that an immediate permanent response is appropriate to eliminate these inefficiencies. In particular, it is broadly accepted that efficient wholesale electricity spot market design requires that market clearing prices (whether high or low) accurately reflect the marginal cost of balancing supply and demand. Accurate price signals guide market participants to make better decisions. For example, market sellers can make accurate fuel procurement decisions confident that their costs will be covered by spot market prices (e.g., day-ahead and intra-day gas

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[72] The Federal Energy Regulatory Commission ("FERC" or "Commission") has convened a technical conference to review electric system operator experiences during the cold weather events. See Notice of Technical Conference in Docket AD14-8-000, "Winter 2013-2014 Operations and Market Performance in [RTOs and ISOs]," scheduled for April 1, 2014.

[73] The term "spot market" as used herein refers to the day-ahead and/or real-time hourly markets administered by ISOs.

purchases and oil stock decisions) and submit offers that allow efficient dispatch decisions among different resources. Market sellers will also face better short-run performance incentives and see more accurate price signals for longer-term investment decisions including the value of fuel arrangements and dual-fuel capability. In other words, if market prices are predictably allowed to clear at the cost of the marginal unit (both during times of scarcity as well as under normal operating conditions), the market will drive sellers to invest in firmer fuel strategies to ensure performance so that they can avail themselves of the benefits of the more robust markets. At the same time, market buyers will face incentives to submit accurate day-ahead load schedules and to make better hedging decisions. Finally, incentives for demand response will be better aligned with the value of energy.

The polar vortex revealed that electricity spot market price setting rules are inconsistent with sound market design policy. Short-term market rule "fixes" will not resolve the adverse impact of binding price caps on spot market prices. Moreover, ongoing and increased reliance on uplift payments exacerbates spot market pricing inefficiencies, pointing clearly to the need to make a concerted policy effort to reduce these out-of-market payments. The polar vortex illuminated the need to work diligently to resolve ongoing spot market design shortcomings that distort prices. Market design changes should be implemented without hesitation to clearly signal to market participants that electricity spot market pricing will not be distorted by potentially binding price caps and unnecessary uplift.

II. Uplift Payments: The Problem and its Solution

Out-of-market (uplift and make-whole) payments currently are a critical cost-recovery guarantee for market suppliers that took on particular importance during the polar vortex.[74] While uplift payments will increase as a result of the high fuel prices associated with the polar vortex market conditions, it is important to recognize that increased reliance on uplift distorts spot market prices.[75] Contrary to arguments that uplift is a desirable means of protecting consumers from spot market volatility, uplift prevents spot market prices from signaling to market participants the true value of energy and results in price discrimination among sellers. Because uplift distorts spot market prices, good market design policy dictates that uplift payments should be minimized, and market design objectives should seek to ensure that resource commitment decisions are accurately reflected in spot market prices.

Uplift payments arise when an ISO commits a generation resource which operates as directed, but cannot recover its total commitment costs from only spot market revenues.[76] In other words, ex post spot market prices (day-ahead and/or real-time) were not high enough to fully compensate the

[74] As explained below, both the PJM Interconnection ("PJM") and the New York Independent System Operator ("NYISO") sought and received Commission authorization to "uplift" suppliers whose costs increased as a result of the polar vortex. The Commission has previously authorized ISO-NE to introduce unique winter 2014 fuel expense management, however the polar vortex impact on ISO-NE, although significant, appears to have been manageable (see January 2014 FERC Data Request, ISO New England, System Operations, January 10, 2014).

[75] PJM and NYISO have reported expected increases in uplift; however, final data are unavailable as of early March 2014.

[76] Total operational cost refers to start-up, minimum load and incremental energy costs.

committed generation resource. The uplift payments created by this uneconomic resource commitment can occur for several reasons. For example, ISOs must ensure that when they award supply resources schedules in the day-ahead spot market, they have sufficient resources to meet forecasted demand. Because day-ahead markets include virtual bidding and the possibility that load bids might underestimate demand day-ahead, ISOs carry out unit commitment reliability checks to ensure sufficient resources will be available during the operating day. In addition, ISO dispatch algorithms incorporate numerous operational constraints, and it can be the case that a resource is dispatched because it is needed for energy, but it may only operate at minimum load, or be committed as block-loaded supply.[77]

However, many resources committed to operate at minimum output levels, or whose dispatch is inflexible, are ineligible to set spot market clearing prices. This means that these resources' supply is part of the market, but the resources' costs are not explicitly taken into account when setting spot market prices. Moreover, it can often be the case that these resource commitments occur after that time when a resource can nominate natural gas in the more liquid day-ahead market, causing a supplier to procure gas in less liquid intra-day markets, driving up costs and increasing system reliability risk (when compared to receiving a commitment in the ISO day-ahead market). The payment of such costs through uplift rather than the energy price distorts market prices, and it can do so not only under stressed conditions such as the polar vortex, but throughout the year. This persistent price suppression through uplift can result in the premature retirement of economic resources, which in turn exacerbates reliability challenges during operating conditions that stress the electricity system.

A. Uplift Reduction

Uplift is carefully tracked by ISOs. For example, PJM recently established an energy market uplift cost task force that is actively examining the causes of uplift and examining market design changes that will minimize uplift.[78] PJM notes that resource commitments which result in significant uplift are for generating units that cannot set spot market prices, but whose supply was committed to provide energy in association with operational constraints.[79] Similarly, ISO New England ("ISO-NE") reports significant net commitment period compensation ("NCPC") costs (uplift) that result from resource commitments that do not receive adequate revenues from the spot markets.[80] Moreover,

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[77] It is important to discern between uplift associated with resource commitments for specific local reliability requirements (e.g., reactive power) and uplift associated with resource commitments to provide energy and/or to guard against potential contingencies. The discussion herein focuses on the latter.

[78] See, generally, http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

[79] See, for example, meeting materials for PJM energy market uplift cost task force, November and December 2013, available at http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

[80] See, for example, 2013 Fourth Quarter, Quarterly Markets Report, ISO New England Inc., Internal Market Monitor, February 10, 2014, at 21, where ISO-NE reports that "Economic NCPC is the difference between the cost of committing and operating a generating resource to meet capacity and energy needs in the day-ahead and real-time markets and the energy revenues the resource realizes during the market day." Available at: http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2013/q4_2013_qmr.pdf, accessed March 7, 2014.

because there is often a tendency toward making additional resource commitments to ensure reliable system operations, it is more likely than not that there is extra supply committed.[81] The commitment of additional supply that is compensated out-of-market puts downward pressure on spot market prices.

However, the importance of seeking to minimize uplift through better spot market pricing has been the subject of research for several years.[82] The spot market pricing features necessary to account for the costs of resources dispatched at minimum load, or as fixed blocks, are well understood. Recognizing that an efficient electricity spot market design should result in spot market prices that are sufficient to cover the costs of all resources that are committed to provide energy, efforts are being made to minimize uplift.

For example, the NYISO allows fixed block units to be treated as "flexible" during the unit commitment process so that they are allowed to set spot market prices.[83] By allowing fixed block units to set market prices, and receive greater compensation through the energy markets, NYISO reduces uplift that would otherwise be paid to these resources and sets more efficient spot market prices.[84] In addition, the Midcontinent Independent System Operator ("MISO") is nearing implementation of a series of software changes referred to as extended locational market pricing ("ELMP").[85] Under ELMP the MISO will allow certain inflexible resources, particularly gas and combustion turbines, to set spot market prices, reducing uplift and improving spot market efficiency. Finally, PJM represents that its software allows block-loaded resources (combustion turbines) to set spot market prices.[86] Moreover, PJM's energy market uplift cost task force has recommended that software changes be implemented that will allow resources operating at minimum load to set spot market prices.[87] Thus, it is widely understood that prices that reflect the incremental cost of meeting demand, and thereby minimize uplift, provide better spot market price signals for market participants.

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[81] For example, ISO-NE notes that "additional capacity was committed in December [2013] to supply energy during extremely cold weather days" (Id). PJM has also indicated in association with its energy market uplift cost task analyses that it is better to have more resources available than fewer (see Uplift in PJM, Adam Keech, PJM Interconnection, February 21, 2014, at 16)

[82] See, for example, Gribik, P. R., Hogan, W. W., and Pope, S. L. (2007). Market-Clearing Electricity Prices and Energy Uplift. Available at http://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf.

[83] See, NYISO Market Administration and Control Area Services Tariff ("MST"), 17.1 MST Att B LBMP Calculation Method, 7.0.0, New York Independent System Operator, Inc., as of 03/06/2014.

[84] For example, if high-cost gas turbines are being dispatched to meet load, but their cost is not reflected in market prices, market prices will not send the correct signal for scheduling either imports or exports, or indicate geographic regions where higher-cost supply is needed to meet demand.

[85] See, https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/ELMP.aspx.

[86] See Manual 11: Energy & Ancillary Services Market Operations
Section 2: Overview of the PJM Energy Markets, PJM © 2014, Revision 66, Effective Date: 03/07/2014, at 26.

[87] See, for example, meeting materials for PJM energy market uplift cost task force, November and December, 2013, available at http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={0584BFB6-F932-44FF-8CBA-AE4320338982}, accessed March 7, 2014.

B. Uplift Distorts Buyer and Seller Incentives

Not only does uplift distort market prices, it also creates incentives for market participants to deviate from otherwise efficient bidding behavior. In particular, uplift cost allocation is often complicated and creates incentives for buyers to make decisions that take into account its cost allocation, which can distort bidding behavior. For example, if buyers can benefit from greater reliance on the spot market by shifting costs that end up in uplift onto other market participants, they will seek to do so. Minimizing the incidence of uplift diminishes incentives to alter bidding behavior.

Moreover, uplift can undermine the Commission's objective of relying on nodal pricing to ensure that electric energy markets reflect local conditions. Nodal pricing sends the appropriate price signals for the need for resources at a particular location, including demand response and energy efficiency resources. When ISOs turn to uplift to allocate the cost of energy, the uplift mechanisms do not assign costs at the same level of granularity that locational nodal energy market pricing provides. Instead, uplift cost allocation mechanisms tend to allocate based on the demand customers place on various regions with ISO-controlled transmission systems.[88] Thus, uplift can result in customers in a relatively low-cost location subsidizing the energy costs of customers in higher-priced locations. This is another undesirable result that uplift imposes on market participants, especially end-use customers.

Finally, market participants cannot hedge against uplift charges. Because uplift costs are a function of ISO day-to-day commitment and dispatch decisions and are not reported in a granular fashion (like spot market prices), there is no means by which its costs can be hedged (there are not forward markets for uplift). This means that those market participants that bear the burden of uplift cost allocation, often energy buyers, are exposed to price volatility. However, to the extent that uplift can be minimized by ensuring that spot market prices more accurately reflect actual system resource dispatch cost, buyers can hedge the cost through energy market forward/future contracts. This is a significant benefit for both buyers and sellers. Buyers avoid cost uncertainty and sellers can make forward sales at prices that reflect the true value of energy. This is a win-win outcome for market participants. A sound market design policy objective is to focus on reducing uplift.[89]

Improvements in market design that result in reduced uplift and more efficient spot market prices are beneficial. The economic reasoning supporting spot market price setting approaches that incorporate all resources committed to meet demand is straightforward; the costs of supply resources committed to meet energy demand should be taken into account when setting spot market prices. Efficient price signals will provide incentives to sellers to be available and operational in the short run (including supporting fuel procurement decisions) and ensure that economic

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[88] See, for example, Manual 28: Operating Agreement Accounting, Section 5: Operating Reserve Accounting, PJM © 2013, Revision 63, Effective Date: 12/19/2013, at 32-33.

[89] The importance of reducing uplift is reinforced by the 2013 State of the Market Report for PJM which states: "PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges." (2013 State of the Market Report for PJM, Monitoring Analytics, LLC, March 13, 2014, Volume II, Section 4, Energy Uplift, at 124).

resources do not prematurely retire as a result of suppressed energy prices. Moreover, any concerns that improved rules for minimizing uplift may increase incentives to exercise market power are not material, as existing rules like those used by the NYISO have demonstrated that more efficient spot market price setting is workable. Although it can be difficult to define precisely the most efficient rules for improving the price setting process, additional progress is required to ensure that uplift payments are not utilized in lieu of competitive spot market prices that truly reflect all costs.

III. Offer/Bid Caps and Spot Market Pricing

An efficient electricity spot market design provides sufficient flexibility to market participants so that they can submit offers that are based on the costs they actually face (including opportunity costs as appropriate) and expect that market prices will be set consistent with those bids and offers accepted by an ISO. Attributes of an efficient electricity spot market design ensure that: offer-caps are consistent with underlying market conditions; gas-electric timelines are realistically accounted for to allow sellers to update bids accordingly and to coordinate commitment and dispatch as necessary; spot market prices are based on the appropriate set of bids and offers; and, any uplift payments are sufficient to cover resource operating costs.

However, market data during the polar vortex show that existing offer and price caps likely prevented wholesale markets from setting efficient electricity prices in portions of the Northeastern U.S. and Mid-Atlantic.[90] Two particular market design issues led PJM and NYISO to file with the Commission emergency requests seeking waivers from certain tariff restrictions. First, PJM and NYISO both sought and received approval to temporarily raise offer price caps above the then applicable $1,000/MWh limit set out in their tariffs.[91] Second, PJM sought and received approval to include in its calculation of spot market prices offers that exceeded the $1,000/MWh offer price cap.[92] Although these waiver approvals ensured that resources would be adequately compensated when costs exceeded historical offer-caps, these emergency measures expire this winter.

The polar vortex event provides an opportunity to recognize these market design flaws and prescribe market design policy initiatives that allow the Commission to act before such an event occurs again.[93] First, out-of-date offer and price cap tariff rules need to be permanently revised to ensure that if short-run marginal costs increase unexpectedly, market offers can be increased accordingly, and market clearing prices can reflect the appropriate value of spot market energy. Second, market offer rules must be sufficiently flexible to allow buyers and sellers to make offers

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[90] See, generally, PJM Interconnection, L.L.C., 146 FERC ¶ 61,078 (2014) ("PJM Waiver Order"), and New York Independent System Operator, Inc., 146 FERC ¶ 61,061 (2014) ("NYISO Waiver Order"). In addition, volatile natural gas prices also impacted the California Independent System Operator's ("CAISO") ability to ensure efficient market outcomes (see below).
[91] Id.
[92] PJM Waiver Order at P 38. In its waiver request the NYISO indicated that it could not request authority to allow offers above $1,000/MWh to set spot market prices as its software could not readily support this modification (NYSIO Waiver Order at P 15).
[93] In its waiver approvals the Commission did not order any immediate ISO initiatives; stakeholder processes are expected to begin to consider permanent market rule revisions.

that reflect actual real-time market conditions. There are several sound economic reasons for pursuing tariff changes to eliminate offer and pricing limitations based on out-of-date price caps.

A. Efficient Spot Market Design

First, the foundation of centralized electricity spot market design is the use of a uniform clearing price auction to set prices based on market participant bids and offers. The uniform price market design ensures that wholesale electricity market welfare is maximized by setting electricity spot prices at the level where buyers and sellers have no incentive at the margin to buy or sell more energy.[94] That is, prices are set such that the market clearing price represents an "equilibrium" price. All buyers and sellers transact based on the same transparent spot market prices, ensuring that all market participants are treated equally.

Basic economics teaches that binding price caps prevent a uniform clearing price auction from establishing a market clearing price that is efficient and non-discriminatory.[95] For example, capping offer prices used in the calculation of spot market prices means that prices will not reflect market conditions when underlying marginal costs increase and offers rise above $1,000/MWh (offer prices are capped in the spot market price calculation). In electricity spot markets, this means that accepted offers above the price cap must be compensated through uplift, which results in price discrimination and market price distortion. However, the Commission has consistently stated "[p]ayments made only to individual resources and recovered in uplift fail to send clear market signals," and that those resource costs "should be reflected in transparent market prices whenever possible."[96] Moreover, the Commission noted in its recent order approving PJM's waiver request that "By limiting legitimate, cost-based bids to no more than $1,000/MWh, the market produces artificially suppressed market prices and inefficient resource selection."[97] Clearly, preventing legitimate offers above binding offer price caps from setting market clearing prices is distortionary.

Important benefits flow from efficient spot market prices. By revealing to sellers the actual value of energy production, sellers are provided the best incentives to be available, to operate reliably, and to enter into forward market sales contracts. At the same time, by revealing to buyers the actual value of consumption of spot market energy, buyers will be less likely to rely on the spot market and seek to shift costs onto others, and be more likely to enter into forward market hedges. Moreover,

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[94] It has been widely established that an electricity market design using bid-based, security constrained, economic dispatch with locational marginal prices and financial transmission rights will provide those features necessary for an open and transparent marketplace (see, for example, International Energy Agency ("IEA"), Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, IEA, Paris, 2007, at 18-21). All U.S. ISOs use this market design framework, which establishes uniform market clearing prices for all buyers and sellers (differentiated as appropriate to account for losses and congestion), and the Commission has consistently endorsed this market design.

[95] It is a basic economic principle that price caps will result in shortages by discouraging sellers from offering supply to the marketplace (see, for example, Mankiw, N. Gregory, Principles of Microeconomics, Fourth Edition, Thomson South-Western, 2007, at 114-117). Although electricity spot market design seeks to circumvent this problem with uplift payments, distortionary effects remain as seller marketplace expectations are altered by the price caps.

[96] *PJM*, 139 FERC ¶ 61,057, at P 78, n.72.

[97] PJM Waiver Order at P 40.

by setting efficient spot market prices, the spot market design guides medium and longer-term power purchase and sale decisions that tend toward more optimal resource allocation.

For example, electricity spot market prices that are allowed reflect high marginal cost supply provide market sellers assurance that their costs will be covered by spot market prices and more efficiently guide firm fuel procurement decisions such as day-ahead and intra-day gas purchases and oil supply restock decisions. In addition, reducing seller uncertainty regarding receipt of adequate compensation for providing electricity will improve seller creditworthiness and ensure that fuel supply can be readily purchased when prices are volatile. Accurate price signals will also provide sellers stronger performance incentives and provide more effective signals for longer-term investment decisions, including the value of fuel stocks and dual-fuel capability. Moreover, efficient prices are an important signal as to where, when, and how much new capacity may be economical. Higher prices often indicate that the introduction of newer, more efficient resources is likely to be profitable. Existing resources facing accurate prices can make better ongoing operational and capital investment decisions.

In addition, ensuring efficient spot market pricing reduces the incentive market participants face to take actions that distort market clearing prices. For example, if spot market prices omit certain costs, or are capped at levels below the actual value of energy to the marketplace, buyers will take this into account in their decision-making. Buyers can avoid payment for higher-cost energy by relying more on the spot market and shifting these costs (collected through uplift) onto other market participants that are likely to have hedged.[98] Such cost shifting results in price discrimination, which is clearly against Commission policy.[99] It also undermines the value of a hedge, since uplift cannot be hedged, which discourages customers from hedging as they will be paying for a product that is not capable of giving them the value they require. However, efficient spot prices provide incentives to market buyers to accurately schedule load and to make better hedging decisions.[100] At the same time, buyers can make better decisions about the benefits of hedging and the value of forgoing consumption when prices are high.

Finally, in addition to allowing market clearing prices to reflect offers that may be above outdated offer price caps, market participant offers used to determine spot market clearing prices must reflect current market conditions. This is especially relevant in two ways. First, efforts that are currently underway to better coordinate gas and electric markets require increased offer flexibility to accommodate gas price variation between day-ahead and day-of scheduling and delivery

[98] This behavior is not hypothetical, as these kinds of uplift cost allocation debates occur frequently. See, for example, ongoing market design modifications being pursued by ISO-NE in association with uplift: NCPC Cost Allocation: Phase 1 - Strengthen Incentive for Load to participate in the Day-Ahead Energy Market ('DAEM'), by Catherine McDonough, http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/mar12132014/index.html, accessed March 25, 2014.

[99] See, for example, *Blumenthal v. ISO New England*, 117 FERC ¶ 61,038, at P 83.

[100] Virtual bidders also face distorted price signals and possible misallocation of costs resulting from inefficient physical buyer and seller bidding behavior.

times.[101] Second, in instances where daily gas price volatility is high it is critical that ISOs use appropriate fuel prices when setting cost-based offers.[102] Offer flexibility is critical for ensuring that market participants can adjust offers as appropriate to reflect market conditions.

B. Supplier Spot Market Offer Flexibility

The importance of supplier offer flexibility and efficient pricing has been a long-standing market design issue that the NYISO has worked to address. The NYISO tariff currently provides market participants the flexibility to structure and modify supply offers consistent with underlying costs. In particular, the NYISO permits sellers to adjust real-time offers to account for fuel price volatility between the day-ahead and real-time markets.[103] This ensures that generators are able to reflect actual fuel prices in their adjusted offers, which was of particular importance in the context of the polar vortex experience due to the volatility of natural gas prices during that time. The offer flexibility that NYISO provides is an example of good market design policy, though it was impaired by the current $1,000/MWh offer cap as discussed above.

However, the NYISO is the exception. Given New England's growing reliance on natural gas electric generation resources, ISO-NE has pursued tariff changes to provide sellers greater offer flexibility to better accommodate fuel market price volatility. Although the Commission conditionally approved ISO-NE's tariff changes to improve offer flexibility in October 2013, these changes have yet to be implemented, though it is hoped that they will improve sellers' ability to reflect real-time fuel costs, as occurs in NYISO.[104] Most recently, gas price volatility and supplier offer restrictions have significantly impacted the CAISO. On March 4, 2014, certain CAISO suppliers filed an emergency request for temporary waiver, explaining that compliance with CAISO dispatch directives was resulting in significant unrecoverable fuel expenses.[105] Just two days later, on March 6, 2014, the CAISO filed emergency waiver requests in an apparent effort to assure sellers that they will not be committed and dispatched and unable to recover their costs.[106] However, contrary to the relief requested by the CAISO suppliers, the CAISO's waiver request proposes only limited instances where fuel price volatility will be acknowledged and therefore will continue to leave suppliers exposed to losses when following CAISO dispatch instructions. Suppliers need to be provided assurance that they will be fully compensated for performance with dispatch directives.

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[101] There are a series of important issues associated with gas-electric coordination. The focus herein is on assuring that supplier offers have sufficient flexibility to change offers to reflect gas market price volatility.

[102] These two concerns significantly overlap; however, they have arisen in different contexts when considering the polar vortex experience in comparison to recent cost recovery issues in the CAISO market.

[103] See New York Independent System Operator, Inc. - NYISO Tariffs - Market Administration and Control Area Services Tariff (MST) Services Tariff, section 23.4.7.

[104] ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014(2013).

[105] See, Indicated CAISO Suppliers, Emergency Request for Temporary Waiver and Shortened Comment Period, Docket No. ER14-1428, March 4, 2014.

[106] See, California Independent System Operator Corporation, Petition for Limited Waiver of Tariff Provisions and Request for Next Day Commission Action, Docket ER14-1442, and Petition for Limited Waiver of Tariff Provisions, Request for Shortened Comment Period, and Request for Expedited Commission Action by March 19, 2014, Docket ER14-1440, March 6, 2014.

It is clear that seller incentives to competitively offer supply to the market require that sellers be permitted to submit supply offers consistent with actual costs, and be compensated appropriately. Providing offer flexibility that allows hourly differentiation of day-ahead and real-time offers reduces financial risks faced by sellers and provides an ISO with greater assurance that sellers will have an incentive to follow commitment and dispatch awards. The ability to incorporate gas price variation between the day-ahead and real-time spot markets will improve ISO commitment and dispatch decisions (e.g., less uncertainty regarding cost recovery will allow more accurate bids which should improve commitment and dispatch). In addition, in instances where seller resources have dual-fuel capability, improved flexibility should provide better signals for fuel switching decisions. Moreover, offer flexibility results in spot market prices that better reflect actual fuel supply costs (see above).

C. Criticisms Against Efficient Spot Market Pricing Are Unfounded

Various criticisms have been put forth as a basis to continue the "status quo" offer price cap and spot market price cap limits. For example, it has been suggested that the offer and price caps are essentially a market feature that market participants ought to expect will not be subject to change (at least not quickly), and that instances where seller costs exceed the cap can be collected through uplift.[107] In addition, it has been suggested that allowing spot market prices to be set based on offers above $1,000/MWh will materially increase buyer costs and create incentives for both gas sellers and electricity market participants to raise prices un-competitively.[108] Moreover, it has been suggested that relaxing offer and bid caps affects hedging decisions and can result in increased exposure to high prices.[109] None of these arguments provides a sound economic basis to perpetuate out-of-date offer and market price caps.

Historically, offer and price caps were set at $1,000/MWh under the expectation that this level was sufficiently greater than historically observed supplier short-run marginal costs and would provide fail-safe protection against the possible exercise of market power.[110] However, the polar vortex event demonstrated that the historical basis for the offer/price cap is no longer valid.[111] The simple fact that seller costs could credibly increase, causing the historical offer/price cap to bind, provides a reasoned economic basis to relax the offer/price caps. It is clear that market expectations have now changed.

Next, it has been suggested that "unlimited" price exposure could result if offer and price caps are relaxed so that spot market prices can be set based on offers above $1,000/MWh.[112] This assertion is misplaced. First, as explained above, an efficient market design requires that prices be consistent with underlying market conditions. Second, market power monitoring and mitigation has been

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107 See, for example, PJM Waiver Order at P 21.
108 Id. at PPs 19 and 23.
109 These concerns were specifically raised in the context of PJM's waiver request that sought authority to include offers above $1,000/MWh in the determination of spot market prices.
110 See, for example, Answer of PJM Interconnection, L.L.C., to Comments and Protests, Commission Docket No. ER14-1145-000, February 3, 2014, at 6-7.
111 See, Id. at 1 and Petition for Temporary Tariff Waivers, Request for Shortened Comment Period, and Request for Expedited Commission Action by January 31, 2104, New York Independent System Operator, Inc., Docket No. ER14-1138-000, January 22, 2014, at 3.
112 PJM Waiver Order at P 22.

substantially refined since the establishment of the $1,000/MWh offer cap.[113] The original purpose of the offer caps was to mitigate seller market power; however, there is no mitigation purpose being served by preventing sellers from submitting cost-based offers. In addition, extensive market power mitigation rules will continue to guard against artificially increased prices; the Commission acknowledged the importance of ongoing market power monitoring and mitigation in its PJM waiver order as well as its ISO-NE offer flexibility order.[114] Third, buyers and sellers will continue to enter into hedging contracts that provide financial protection against spot market price volatility. Actual consumer exposure to spot market prices is limited, and numerous contractual instruments are available to buyers and sellers to hedge spot market price volatility.[115]

Finally, arguments that reference prior reliance on particular hedging strategies by buyers and sellers as a reason for maintaining offer and price caps are not economically sound. Allowing legitimate costs to be reflected in market clearing prices will ensure that strategies of relying on spot markets and the prospect of shifting uplift costs to others is not beneficial. Moreover, sellers will not, and should not, be expected to use hedges to keep spot market prices artificially low. Buyers and sellers will seek all profitable transactions taking into account current opportunity costs, not the historical cost or benefit associated with a pre-existing hedging arrangement.[116]

In summary, the polar vortex event revealed that there are critical aspects of electricity spot market rules that are inconsistent with sound market design policy. Short-term market rule "fixes" will not resolve the adverse impact of out-of-date price caps on spot market prices. Moreover, ongoing and increased reliance on uplift payments exacerbates spot market pricing inefficiencies, pointing clearly to the need to make a concerted policy effort to reduce these payments. The polar vortex illuminates the need to work diligently to resolve ongoing spot market design shortcomings that distort prices. Market design changes should be implemented without hesitation to provide clarity to market participants that spot markets are intended to price spot electricity consistent with underlying market conditions.

113 See, for example, Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets, The Brattle Group, September 14, 2007.

114 PJM Waiver Order at PPs 42-43 and ISO New England Inc. and New England Power Pool, 145 FERC ¶ 61,014(2013), at P 37.

115 The majority of smaller electricity consumers in the Northeastern and Mid-Atlantic U.S. obtain retail electricity through standard offer service (also referred to as default or basic generation service), which is almost exclusively procured by utilities under fixed price supply contracts of various terms. Other larger customers actively seek service from competitive retailers and understand the costs and benefits of hedging. Finally, numerous electricity spot market hedging instruments are available to buyers and sellers (see, for example, http://www.cmegroup.com/trading/products/#pageNumber=1&sortField=oi&sortAsc=false&page=1&subGroup=11).

116 To be clear, buyers and sellers will take into account their net market positions (which includes hedging contracts) when making short-run decisions, but it will be the costs and benefits at the margin that inform these day-to-day and hour-to-hour decisions.