DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM16–5–000; Order No. 831]

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

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is revising its regulations to address incremental energy offer caps. We require that each regional transmission organization (RTO) and independent system operator (ISO): Cap each resource's incremental energy offer at the higher of $1,000/megawatt-hour (MWh) or that resource's verified cost-based incremental energy offer; and cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices (LMP). Further, we clarify that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. This Final Rule will improve price formation by reducing the likelihood that offer caps will suppress LMPs below the marginal cost of production, while compensating resources for the costs they incur to serve load, by enabling RTOs/ISOs to dispatch the most efficient set of resources when short-run marginal costs exceed $1,000/MWh, by encouraging resources to offer supply to the market when it is most needed, and by reducing the potential for seams issues.

DATES: *Effective Date:* This rule will become effective February 21, 2017.

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I. Introduction

1. In this Final Rule, the Federal Energy Regulatory Commission (Commission) finds that current regional transmission organization (RTO) and independent system operator (ISO) offer caps on incremental energy offers [1] (offer cap) are not just and reasonable for the reasons discussed below. To remedy these unjust and unreasonable rates, we require, pursuant to section 206 of the Federal Power Act,[2] that each RTO/ISO: (1) Cap each resource's incremental energy offer at the higher of $1,000/megawatt-hour (MWh) or that resource's verified cost-based incremental energy offer; and (2) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices (LMP) (hard cap).[3] Further, we clarify that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs.

2. We reach this conclusion for several reasons. First, offer caps in some RTOs/ISOs may prevent a resource from recouping its short-run marginal costs by not permitting that resource to include all of its short-run marginal costs within its incremental energy offer. Second, current offer caps in some RTOs/ISOs are likely to suppress LMPs below the marginal cost of production during periods when fuel costs increase dramatically. Third, when several resources have short-run marginal costs above $1,000/MWh but are unable to reflect those costs within their incremental energy offers due to the offer cap, the RTO/ISO is unable to dispatch the most efficient set of resources because it will not be able to distinguish among the resources' actual costs. Finally, the $1,000/MWh offer cap in some RTOs/ISOs may discourage resources with short-run marginal costs above $1,000/MWh from offering supply to the RTO/ISO, even though the market may be willing to purchase that supply.[4] To remedy these problems, we are setting forth requirements for each RTO/ISO regarding the offer cap in this Final Rule. We believe generic action is appropriate to avoid the creation of seams that would result from different offer caps in adjacent RTO/ISO markets.

3. We have modified the proposal in the Notice of Proposed Rulemaking (NOPR) to include a $2,000/MWh hard cap for the purposes of calculating LMPs. While the offer cap proposed in the NOPR would address the concerns identified above, we are convinced by commenters that the absence of a hard cap creates practical concerns that must be addressed. First, several commenters note that RTOs/ISOs and/or Market Monitoring Units may have imperfect information about resource short-run marginal costs, which can create challenges for the proposed requirement to verify cost-based incremental energy offers above $1,000/MWh prior to the market clearing process. Additionally, as noted by market monitors, the dynamics of natural gas spot market prices during periods when they rise to levels that could result in the short-run marginal costs of some natural gas-fired resources exceeding $1,000/MWh can make verification challenging, particularly verification of expected costs. Thus, while a hard cap may diminish the ability to fully address the shortcomings of current offer caps identified above in all circumstances, we find that, on balance, a hard cap is necessary to reasonably limit the adverse impact that any imperfect information during the verification process could have on LMPs.

4. The goals of the price formation proceeding are to: (1) Maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.[5]

5. The reforms adopted in this Final Rule advance two of the Commission's goals with respect to price formation. First, the reforms will result in LMPs that are more likely to reflect the true marginal cost of production when resources' short-run marginal costs exceed $1,000/MWh. In the short run, LMPs that reflect the short-run marginal costs of production are particularly important during high price periods because they provide a signal to consumers to reduce consumption and a signal to suppliers to increase production or to offer new supplies to the market. In the long run, LMPs that reflect the short-run marginal cost of production are important because they inform investment decisions. Second, the reforms will give resources the opportunity to recover their short-run marginal costs, thereby encouraging resources to participate in RTO/ISO energy markets. Adequate investment in resources and resource participation in RTO/ISO energy markets ensure adequate and reliable energy for consumers. The benefits summarized above and discussed in detail below would ultimately help to ensure just and reasonable rates.

6. As discussed below, we require each RTO/ISO to submit a filing with the tariff changes needed to implement this Final Rule within 75 days of the Final Rule's effective date.

[1] The incremental energy offer is the portion of a resource's energy supply offer that varies with output or level of demand reduction.

[2] 16 U.S.C. 824e (2012).

[3] In this proceeding, a hard cap refers to an upper limit on the incremental energy offers that RTOs/ISOs can use to calculate LMPs. The hard cap does not limit the cost-based incremental energy offers that a market participant may submit to the RTO/ISO.

[4] Many resources are subject to must-offer requirements in either the day-ahead or real-time markets. These offer cap reforms ensure that such a resource has an economic incentive that matches its tariff obligation and also provide an economic incentive to those resources that are not subject to a must-offer requirement.

[5] *See Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice Inviting Post-Technical Workshop Comments, Docket No. AD14–14–000, at 1 (Jan. 16, 2015) (Notice Inviting Comments); *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice, Docket No. AD14–14–000 (June 19, 2014) (Price Formation Notice).

II. Background

7. In June 2014, the Commission initiated a proceeding, in Docket No. AD14–14–000, to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs.[6] In the notice initiating that proceeding, the Commission stated that there may be opportunities for the RTOs/ISOs to improve the energy and ancillary services price formation process. As set forth in that notice, LMPs and market-clearing prices used in energy and ancillary services markets ideally ''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.'' [7]

8. In the instant proceeding, on January 21, 2016, the Commission issued a NOPR proposing to require that each RTO/ISO: (1) Cap each resource's incremental energy offer to the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (2) use verified cost-based incremental energy offers above $1,000/MWh to calculate LMPs.[8]

9. The Commission also sought comments on the NOPR proposal regarding: (1) Whether a hard cap on cost-based incremental energy offers used for purposes of calculating LMPs should be included in any Final Rule in this proceeding and, if so, whether the hard cap should equal $2,000/MWh or another value; (2) the ability of the Market Monitoring Unit or RTO/ISO to verify the costs underlying incremental energy offers above $1,000/MWh prior to the day-ahead or real-time market clearing process, including whether the verification of physical offer components is also necessary; (3) whether the Market Monitoring Unit or RTO/ISO may need additional information to ensure that all short-run marginal cost components, such as risk or opportunity costs that are often difficult to quantify, are accurately reflected in a resource's cost-based incremental energy offer, and whether an adder is appropriate; (4) whether the Market Monitoring Unit or RTO/ISO may need additional information or the authority to require revisions or corrections to cost-based incremental energy offers to ensure that cost-based incremental energy offers are accurate reflections of a resource's short-run marginal cost; (5) whether the proposal should apply to imports and whether a cost verification process for import transactions is feasible; (6) whether excluding virtual transactions above $1,000/MWh could limit hedging opportunities, present opportunities for manipulation or gaming, or create market inefficiencies; and (7) the impact the proposal would have on seams.[9]

A. Offer Caps in RTOs/ISOs

10. Supply offers in day-ahead and real-time energy markets consist of both financial and physical components. The financial components of a supply offer are denominated in dollars (*e.g.,* $/start and $/MWh) and represent the costs underlying a resource's offer to supply electricity in a given day-ahead or real-time interval. The physical components of a supply offer, which are not denominated in dollars, describe the resource's physical operating parameters. These include, for example, a resource's minimum and maximum operating limits in a given day-ahead or real-time interval, and are denominated in MW, MWh, time, or some other unit.

11. This Final Rule addresses the incremental energy offer component of a resource's supply offer, which is a financial component consisting of costs that vary with a resource's output or level of demand reduction. Incremental energy offers typically consist of a supply curve made up of multiple price-quantity pairs that indicate the price, expressed in $/MWh, that a resource is willing to accept to produce a given quantity of energy.

12. All six Commission-jurisdictional RTOs/ISOs have at one time imposed a $1,000/MWh cap on incremental energy offers.[10] The offer cap remains at $1,000/MWh in CAISO, ISO–NE., MISO, NYISO, and SPP, and resources in these RTOs/ISOs may not submit incremental energy offers above $1,000/MWh. As discussed further below, resources in PJM may submit incremental energy offers above $1,000/MWh provided they are cost-based, but PJM applies a hard cap that limits incremental energy offers to $2,000/MWh when calculating LMPs.[11]

13. While the current offer caps restrict the incremental energy offers, one of the components used to set LMP, they do not limit LMPs to the level of the offer caps because the addition of the congestion and loss components of the LMP can result in LMPs that exceed the offer cap. Scarcity or shortage pricing and emergency purchases can also cause LMPs to exceed the offer cap.

B. Offer Caps Waivers and Tariff Changes

14. As described in the NOPR, after the extreme weather experienced during the winter of 2013/14, dubbed the ''Polar Vortex'', PJM, NYISO, and MISO filed various requests to either temporarily or permanently revise their respective offer caps.[12] During the winter months of 2014, the Commission approved requests to temporarily waive tariff provisions related to offer caps in NYISO [13] and PJM.[14] In the following winter of 2014/15, the Commission approved temporary changes to the PJM tariff and temporarily waived some MISO tariff provisions to address issues with the offer caps in the PJM and MISO energy markets.[15] During the winter of 2015/16, PJM and MISO again filed requests to modify their respective offer caps. On December 11, 2015, the Commission accepted tariff revisions in PJM that would raise the cap on cost-based incremental energy offers to $2,000/MWh for purposes of calculating

[6] Price Formation Notice, Docket No. AD14–14–000.

[7] Price Formation Notice, Docket No. AD14–14–000 at 2.

[8] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 81 FR 5951 (Feb. 4, 2016), FERC Stats. & Regs. ¶ 32,714, at P 3 (2016) (NOPR).

[9] *Id.* P 73.

[10] *See, e.g.,* California Independent System Operator Corporation, eTariff, 39.6.1.1 (11.0.0); ISO New England Inc., Transmission, Markets and Services Tariff, Market Rule 1, III.1.10.1A(c)(iv), III,1.10.IA(d)(iv), III.2.6(b)(i), and III.A.15.1(b) (46.0.0); Midcontinent Independent System Operator, Inc., FERC Electric Tariff, Module D 39.2.5 (35.0.0), 39.2.5A (34.0.0), 39.2.5B (34.0.0), 40.2.5 (35.0.0), 40.2.6 (35.0.0) and 40.2.7 (33.0.0); New York Independent System Operator, Inc., NYISO Tariffs, NYISO Markets and Services Tariff, 21.4 and 21.5.1 (7.0.0); PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT, Tariff Operating Agreement, Attachment K, Appendix, 1.10.1A(d) (24.0.0); Southwest Power Pool, Inc., OATT, Sixth Revised Volume No. 1, Attachment AE, Section 4.1.1 (2.0.0).

[11] *PJM Interconnection, L.L.C.,* 153 FERC ¶ 61,289, at P 25 (2015) (PJM 2015 Offer Cap Order).

[12] NOPR, FERC Stats. & Regs ¶ 32,714 at PP 13–17.

[13] *N.Y. Indep. Sys. Operator, Inc.,* 146 FERC ¶ 61,061, at PP 2–4 (2014).

[14] PJM filed concurrently two tariff waiver requests related to its offer cap. In its first request, which the Commission granted for the January 24–February 10, 2014 period, PJM requested that certain resources with cost-based offers above $1,000/MWh receive uplift payments to recoup those costs. *See PJM Interconnection, L.L.C.,* 146 FERC ¶ 61,041, at P 2 (PJM 2014 Waiver Order I), *order on reh'g,* 149 FERC ¶ 61,059 (2014). In its second request, which the Commission granted for the February 11–March 31, 2014 period, PJM requested that certain resources be allowed to submit cost-based incremental energy offers in excess of $1,000/MWh, with no cap on cost-based offers. *See PJM Interconnection, L.L.C.,* 146 FERC ¶ 61,078, at PP 3–4 (2014) (PJM 2014 Offer Cap Order II).

[15] The temporary revisions to the PJM tariff were accepted for the January 16, 2015 through March 31, 2015 period. *See PJM Interconnection, L.L.C.,* 150 FERC ¶ 61,020, at P 5 (2015) (PJM 2014/15 Offer Cap Order). The temporary waiver of the MISO tariff provisions was granted for December 20, 2014 through April 30, 2015 period. *See Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,083, at P 3 (2015) (MISO 2014/15 Offer Cap Order).

LMPs.[16] The Commission also granted MISO's request to temporarily waive tariff provisions related to its $1,000/MWh offer cap.[17] MISO recently filed another request to temporarily waive tariff provisions related to its offer cap for the upcoming winter of 2016/17.[18]

III. Need for Reform

15. In the NOPR, the Commission preliminarily found that the $1,000/MWh offer caps currently in effect in some RTOs/ISOs [19] are unjust and unreasonable for four reasons.[20] First, some current RTO/ISO offer caps may prevent a resource from recouping its short-run marginal costs by not permitting that resource to reflect its short-run marginal costs within its incremental energy offer. Second, current offer caps may suppress LMPs below the marginal cost of production. Third, when several resources have short-run marginal costs above $1,000/MWh but are unable to reflect those costs within their incremental energy offers due to the offer cap, the RTO/ISO may not dispatch the most efficient set of resources because it will not be able to distinguish between the resources' actual costs. Finally, the $1,000/MWh offer cap in some RTOs/ISOs may discourage resources with short-run marginal costs above $1,000/MWh from offering supply to the RTO/ISO, even though the market may be willing to purchase that supply.[21] We believe generic action is appropriate to avoid the creation of seams that would result from different offer caps in adjacent RTO/ISO markets. As described below, based on our analysis of the record, we adopt the preliminary findings in the NOPR and conclude that the current offer caps in RTOs/ISOs are unjust and unreasonable.

A. Comments

1. Comments That Support the Preliminary Finding That Current Offer Caps are Unjust and Unreasonable

16. Several commenters, for various reasons, support the Commission's preliminary finding in the NOPR that existing offer caps in RTOs/ISOs are unjust and unreasonable,[22] and others express general or conditional support for the NOPR.[23] Some commenters agree that the $1,000/MWh offer cap prevents resources from recovering their short-run marginal costs.[24] For example, Direct Energy states that generator cost assurance is key to maintaining reliability because it ensures that resources will have the incentive to follow RTO/ISO dispatch instructions when called upon by the RTO/ISO, without concern for receiving compensation below their short-run costs.[25] Six Cities states that exceptional circumstances may give rise to marginal costs for specific resources that exceed $1,000/MWh and those resources should have an opportunity to recover their actual costs of production.[26]

17. Several commenters support the Commission's preliminary finding that existing RTO/ISO offer caps should be reformed because they can suppress LMPs below the marginal cost of production.[27] For example, PJM/SPP [28] state that the current offer caps could undermine market efficiency by preventing legitimate incremental energy offers above $1,000/MWh, which they state has occurred in some parts of the country, because LMPs that fail to reflect the cost of serving demand are inefficient.[29] Competitive Suppliers assert that while the costs of the marginal resources have not frequently exceeded $1,000/MWh, the impact of the $1,000/MWh offer cap is not trivial because artificially suppressing day-ahead or real-time LMPs during those few intervals can prevent economic outcomes that will support reliability and motivate consumers to reduce consumption during stressed system conditions.[30] Midcontinent Joint Consumer Advocates support changing the offer cap because incremental energy costs would only exceed $1,000/MWh in extreme conditions.[31]

18. Other commenters agree with the Commission's preliminary finding that the $1,000/MWh offer cap should be reformed because it can discourage a resource with costs above the offer cap from offering its supply to the RTO/ISO, even though the market may be willing to purchase that supply.[32] For example, OMS states that when the (primarily fuel) cost to generate electricity is unusually high, the current $1,000/MWh offer cap can limit the willingness of resources to offer into the day-ahead and real-time markets.[33]

19. CEA and EEI express general support for the Commission's preliminary finding in the NOPR that current offer caps could also prevent the RTO/ISO from dispatching the most efficient set of resources because the RTO/ISO will not have access to the underlying costs associated with the multiple incremental energy offers above the offer cap.[34]

2. Comments That Oppose Reforming Current Offer Caps

20. Several commenters disagree with the Commission's finding that the current offer cap is unjust and unreasonable and therefore should be reformed. For example, CAISO argues that the current $1,000/MWh offer cap in CAISO should not be changed because $1,000/MWh is far in excess of what the highest reasonable cost-justified offer could be from a CAISO resource.[35] CAISO explains that natural gas prices have generally been stable, and argues that even if natural gas market fundamentals changed, periods when incremental energy costs exceed $1,000/MWh would be infrequent and short-lived and do not justify the offer cap changes proposed in the NOPR.[36] ISO–NE does not oppose raising its current offer cap to a higher fixed level, but nonetheless maintains that the

[16] PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 25. The tariff provisions related to the offer cap do not have a sunset date.

[17] *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,006, at P 1 (2016) (MISO 2015/16 Offer Cap Order). This waiver was granted for the January 1, 2016 through April 30, 2016 period.

[18] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal, Docket No. ER16–2685–000.

[19] Specifically CAISO, ISO–NE., MISO, NYISO, and SPP. *See supra* n.10.

[20] *See* NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 43–47.

[21] *Id.* PP 44–47.

[22] *See generally* CEA Comments at 3–4; Direct Energy Comments at 2–3; Exelon Comments at 5–7; PJM/SPP Comments at 1–2; EEI Comments at 3–4; Competitive Suppliers Comments at 4, 6, 7–15; Ohio Commission Comments at 4. A list of commenters and the abbreviated names used for them in this Final Rule appears in the Appendix.

[23] *See generally* Dominion Comments at 3; EEI Comments at 3–5; Golden Spread Comments at 1; Midcontinent Joint Consumer Advocates Comments at 2; MISO Comments at 1; NESCOE Comments at 1; New Jersey Commission Comments at 1; NY Transmission Owners Comments at 2; NYISO Comments at 2; OMS Comments at 2; OPSI Comments at 10; PJM/SPP Comments at 1; Potomac Economics Comments at 1; Powerex Comments at 6; Six Cities Comments at 2.

[24] CEA Comments at 4; Direct Energy Comments at 2–3; OMS Comments at 2; Six Cities Comments at 2.

[25] Direct Energy Comments at 2.

[26] Six Cities Comments at 2.

[27] *See generally* CEA Comments at 3–4; Competitive Suppliers Comments at 9–13; Exelon Comments at 5–7; EEI Comments at 3–5; PJM Power Providers Comments at 1–2; PJM/SPP Comments at 1–2; Powerex Comments at 6.

[28] "PJM/SPP" indicates comments filed jointly by PJM and SPP. PJM and SPP also make individual comments within their joint filing.

[29] PJM/SPP Comments at 1–2 (citing PJM, Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events (May 8, 2014), *available at http://www.pjm.com/~/media/committeesgroups/task-forces/cstf/20140509/20140509-item-02-cold-weather-report.ashx*).

[30] Competitive Suppliers Comments at 9.

[31] Midcontinent Joint Consumer Advocates Comments at 3–4.

[32] *See generally* CEA Comments at 3–4; Competitive Suppliers Comments at 13; OMS Comments at 2; Powerex Comments at 6.

[33] OMS Comments at 2.

[34] CEA Comments at 2–3; EEI Comments at 3–4.

[35] CAISO Comments at 4.

[36] *Id.* at 4–5.

current $1,000/MWh offer cap in ISO–NE is just and reasonable because the cap has not inappropriately limited LMPs below the marginal cost.[37]

21. The ISO–NE and SPP Market Monitors assert that there is no need to reform the offer caps in their markets. The ISO–NE Market Monitor states that there is no need to revise ISO–NE's $1,000/MWh offer cap because natural gas prices have become more stable and, if completed, proposed pipeline expansions in New England will help alleviate some of the natural gas congestion that led to the high LMPs observed in ISO–NE in 2014.[38] The SPP Market Monitor states that SPP resources have not experienced costs above $1,000/MWh and the SPP Market Monitor expects that fuel price spikes that would raise costs to that level would rarely occur.[39]

22. A number of commenters argue, for various reasons, that current RTO/ISO offer caps should not be revised.[40] For example, several commenters assert that revising the offer cap is an overreaction to anomalous, infrequent, and/or transitory market and weather conditions that do not justify changing the offer cap. Steel Producers' Alliance observes that the current offer cap has only been an issue in a handful of instances, which it argues demonstrates that the offer cap is set at the appropriate level and performing as intended.[41] APPA, NRECA, and AMP assert that the offer cap issues described in the NOPR are merely hypothetical, and that there is insufficient evidence that current offer caps are unjust and unreasonable.[42]

23. Some commenters disagree with the NOPR's preliminary finding that offer caps are unjust and unreasonable because they can suppress LMPs below the marginal cost of production. For example, ODEC argues that a higher cap is unnecessary because LMPs are lower in PJM than they were when PJM's current higher offer cap was adopted.[43] Other commenters argue that LMPs above $1,000/MWh do not send a useful price signal to consumers,[44] and may in fact harm consumers because most demand for electricity is inelastic, or unresponsive to price changes.[45] These commenters argue that, because most demand is inelastic, raising the offer cap would lead to market power abuses and transfer payments from load to generators.[46] For example, Industrial Customers argue that resources can take advantage of inelastic demand and exercise market power to obtain prices above competitive levels.[47] The New York Commission argues that without sufficient competition, including from demand response, raising the offer cap will not change behavior in NYISO and will only increase prices and burden ratepayers.[48] The New York Commission asserts that the Commission should not revise the offer cap until more effective demand response resources can participate in NYISO's real-time energy market.[49]

24. Many commenters argue that the current offer caps in RTOs/ISOs should be maintained because they protect consumers from excessive LMPs that result from market power abuse.[50] For example, NY Department of State argues that the offer cap benefits consumers by shielding customers from high real-time LMPs or market manipulation.[51] Similarly, TAPS states that the current offer caps act as a critical safety valve to protect consumers from excessive prices.[52] Industrial Customers assert that increasing the offer cap above $1,000/MWh would raise consumers' costs to hedge electricity procurements.[53] Industrial Energy Consumers stress that offer caps are essential for consumers to be confident that rate structures are fair and nondiscriminatory.[54]

25. Some commenters argue that current offer caps do not suppress LMPs in a manner that impacts resource investment decisions. AF&PA asserts that periodic and unpredictable price spikes have limited value in sustaining resource viability or inducing consumers to make long term behavioral changes.[55] Similarly, TAPS argues that allowing offers above $1,000/MWh to set the LMP would not have a practical impact on resource investment decisions because, even if the offer cap were raised, the LMP would remain the same in the vast majority of hours. TAPS adds that no resource owner would base its capital investments on the hope that LMPs will be extremely high for just a few hours every year.[56]

26. Some commenters argue that offer cap waivers are the best remedy to address issues associated with the offer cap.[57] For example, Industrial Energy Consumers state that the Commission adequately addressed the isolated Polar Vortex event by granting either temporary, limited waivers, or uplift payments, thereby sending the correct price signal for investment.[58] AF&PA supports current Commission protocols of waivers and other reforms that allow generators to recover verifiable costs in certain situations, and supports the expansion and streamlining of these protocols.[59]

3. Generally Applicable Offer Cap Reforms

27. In addition to the four preliminary findings stated above,[60] the Commission also stated in the NOPR that the lack of a uniform offer cap has the potential to exacerbate seams issues between neighboring RTOs/ISOs.[61] The Commission recognized in the NOPR that the proposed reforms could result in neighboring markets having different effective offer caps in a given interval because the marginal cost of production in one RTO/ISO may differ from neighboring markets due to resources with different short-run marginal costs being on the margin in those markets.[62] The Commission preliminarily found, however, that these differences will not adversely affect seams because the differences would be driven by actual costs and not by offer caps artificially suppressing LMPs. The Commission stated that, to the extent incremental energy offers can be verified, a reform applicable to all RTOs/ISOs that allows cost-based incremental energy offers to exceed $1,000/MWh would enhance

[37] ISO–NE Comments at 1–3.

[38] ISO–NE Market Monitor Comments at 12–14 (citing ISO–NE Market Rule 1, Appendix A, Section III.A.15).

[39] SPP Market Monitor Comments at 8–9.

[40] *See generally* APPA, NRECA, and AMP Comments at 5–8; AF&PA Comments at 2–3; CAISO Comments at 2; Industrial Customers Comments at 3–9; Industrial Energy Consumers Comments at 2; ISO–NE Market Monitor Comments at 12–14; NY Department of State Comments at 3–5; NYPSC Comments at 1, 4; Steel Producers' Alliance Comments at 2–3; ODEC Comments at 3–5; PG&E Comments at 1–2; PJM Joint Consumer Advocates Comments at 2–4; SPP Market Monitor Comments at 2, 6, 12–13; TAPS Comments at 1, 4–7.

[41] Steel Producers' Alliance Comments at 2.

[42] APPA, NRECA, and AMP Comments at 9–13.

[43] ODEC Comments at 3–4.

[44] NY Department of State Comments at 3; New York Commission Comments at 5–6.

[45] AF&PA Comments at 2–3; Industrial Energy Consumers Comments at 2; Industrial Customers Comments at 10; PJM Joint Consumer Advocates Comments at 4; TAPS Comments at 6, 12.

[46] Direct Energy Comments at 3–5; Industrial Customers Comments at 10; NY Department of State Comments at 3; TAPS Comments at 3.

[47] Industrial Customers Comments at 10.

[48] New York Commission Comments at 5–6.

[49] New York Commission Comments at 6.

[50] Industrial Customers Comments at 3, 10–11; Industrial Energy Consumers Comments at 2; TAPS Comments at 1, 8–12, NY Department of State Comments at 4.

[51] NY Department of State Comments at 4.

[52] TAPS Comments at 1.

[53] Industrial Customers Comments at 20.

[54] Industrial Energy Consumers Comments at 2.

[55] AF&PA Comments at 2–3.

[56] TAPS Comments at 6–7.

[57] AF&PA Comments at 6–7; Industrial Energy Consumers Comments at 2; Steel Producers' Alliance Comments at 2–3.

[58] Industrial Energy Consumers Comments at 2.

[59] AF&PA Comments at 6.

[60] *See supra* P 2.

[61] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 70.

[62] *Id.* P 71.

market efficiency and mitigate the potential for seams issues.[63] The Commission sought comment on these preliminary findings and other seams issues related to this proposal.

28. The majority of commenters agree with the NOPR's proposal to make a change in the offer cap across all RTOs/ISOs in order to avoid seams issues,[64] and several commenters generally agree with the importance of mitigating seams issues.[65] For example, the IRC notes the importance of uniformity in the treatment of offer caps, particularly in neighboring RTOs/ISOs.[66] NYISO supports a uniform RTO/ISO offer cap and argues that, in areas with a common fuel source, differing offer caps in neighboring regions could lead to restricted fuel procurement in the region with the lower offer cap.[67] MISO asserts that without a common offer cap, tight operating conditions could provide counterproductive arbitrage opportunities.[68] The ISO–NE Market Monitor notes that different offer caps in neighboring regions could be detrimental to ISO–NE's ongoing efforts to develop a clearing mechanism to select external resources in economic merit order.[69]

29. The PJM Market Monitor states that the proposal's impact on seams would be consistent with efficient markets whereby energy would flow to where it is valued most.[70] EEI argues that the actual effect of the NOPR on seams would be determined by market forces and the marginal cost to operate the system.[71]

30. With respect to the Western Electricity Coordinating Council (WECC), CAISO and Exelon argue that the Commission must address how it will ensure consistency between the proposed offer cap in CAISO and the existing $1,000/MWh offer cap in WECC.[72] CAISO and Exelon observe that, in instituting the existing offer cap in WECC, the Commission recognized the interdependency between CAISO and WECC and therefore stated that it would be unjust and unreasonable to have different offer caps in these two regions.[73] CAISO further asserts that for those RTOs/ISOs, such as CAISO, that do not share a seam with another RTO/ISO, the Final Rule should allow these RTOs/ISOs to demonstrate that raising the offer cap is unnecessary.[74]

31. Some market participants support the NOPR's applicability to all RTOs/ISOs in theory, but argue that the effect on seams would depend on implementation. The Delaware Commission cautions that the degree to which the verification of cost-based offers above $1,000/MWh is sufficiently rigorous will determine the effect on seams and that this will not be known until implementation.[75] ISO–NE agrees that consistent energy offer caps are important to prevent flows that run contrary to reliability needs, but argues that the NOPR's actual effect on seams is unknown because real-time cost verification for imports is not possible.[76] PJM Joint Consumer Advocates argue that the Commission's proposal could exacerbate seams because shortage pricing mechanisms vary across RTOs/ISOs.[77] Industrial Energy Consumers note that allowing different offer caps in adjacent markets could create seams issues.[78]

32. Other commenters argue that there should be regional flexibility in implementing an offer cap. PG&E argues that a one-size-fits-all solution for all RTO/ISO markets is not appropriate.[79] As noted above, the NY Transmission Owners suggest that different hard caps in different regions might be justified, so long as regions that are dependent on the same gas supply coordinate their caps.[80] Direct Energy supports the NOPR's proposal for verified cost-based offers above $1,000/MWh, but argues that individual RTOs/ISOs should be able to set offer caps above $1,000/MWh in recognition of regional differences.[81]

33. APPA, NRECA, and AMP assert that the NOPR runs counter to the Commission's usual practice of recognizing and accommodating regional differences.[82] APPA, NRECA, and AMP state that a concern over seams is not adequate justification for the rule because it fails to account for regional differences, and because the Commission determined that the need for an increase in the offer cap outweighed seams issues when it approved PJM's $2,000/MWh offer cap.[83]

B. Determination

34. Based on our analysis of the record, we adopt the preliminary findings in the NOPR, and conclude that the offer caps currently in effect in RTOs/ISOs are unjust and unreasonable. We find that the currently effective offer caps may prevent a resource from recovering its short-run marginal costs, which could result in that resource operating at a loss.[84] We also find that the $1,000/MWh offer caps in effect in some RTOs/ISOs may suppress LMPs below the marginal cost of production given that recent history demonstrates that resource short-run marginal costs can exceed $1,000/MWh.[85] We also find that preventing resources from including all of their short-run marginal costs in their incremental energy offers when those costs exceed $1,000/MWh may discourage resources that are not subject to must-offer requirements from offering their supply to the RTO/ISO energy market. Finally, preventing resources from including their short-run marginal costs in their incremental energy offers when those costs exceed $1,000/MWh may also prevent the RTO/ISO from dispatching the most efficient resources when several resources have short-run marginal costs above $1,000/MWh.

35. We disagree with commenters who argue that there is no need to reform the offer cap or that the problems described in the NOPR are hypothetical and that insufficient evidence exists to

[63] *Id.* P 48.

[64] *See generally* Dominion Comments at 8; Competitive Suppliers Comments at 23, 25; EEI Comments at 4; Exelon Comments at 22–23; MISO Comments at 19; NESCOE Comments at 2; PJM Power Providers Comments at 6–7; OMS Comments at 4; PJM/SPP Comments at 2–3; IRC Comments at 3; NY Department of State Comments at 6; NYISO Comments at 9–10; ISO–NE Market Monitor Comments at 14; Steel Producers' Alliance Comments at 3–4. Some of these commenters express conditional or qualified support of the NOPR and/or propose alternative offer caps.

[65] Industrial Customers Comments at 21, 24; Midcontinent Joint Consumer Advocates Comments at 9–10; TAPS Comments at 21–22.

[66] IRC Comments at 1, 3.

[67] NYISO Comments at 10.

[68] MISO Comments at 19.

[69] ISO–NE Market Monitor Comments at 14.

[70] PJM Market Monitor Comments at 12.

[71] EEI Comments at 4.

[72] CAISO Comments at 14; Exelon Comments at 22.

[73] CAISO Comments at 14 (citing *Western Electric Coordinating Council,* 133 FERC ¶ 61,026 (2010)); Exelon Comments at 22 (citing *Western Electric Coordinating Council,* 131 FERC ¶ 61,145 (2010)).

[74] CAISO Comments at 2, 4.

[75] Delaware Commission Comments at 14–15.

[76] ISO–NE Comments at 9.

[77] PJM Joint Consumer Advocates Comments at 6–7.

[78] Industrial Energy Consumers Comments at 2.

[79] PG&E Comments at 1–2.

[80] NY Transmission Owners Comments at 4–5.

[81] Direct Energy Comments at 5–6.

[82] APPA, NRECA, and AMP Comments at 5–6.

[83] *Id.* at 6 (citing PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 55). Additionally, APPA, NRECA, and AMP argue that the fact that PJM has this higher offer cap and it has not resulted in seams issues proves that concerns over seams are purely hypothetical. *Id.*

[84] As discussed above, the Commission has previously accepted temporary changes to tariff provisions in MISO that enabled resources to receive uplift for short-run marginal costs above the $1,000/MWh offer cap. However, cost recovery through uplift is only guaranteed if a resource experiences short-run marginal costs above $1,000/MWh during the time period for which the Commission has accepted tariff revisions related to the offer cap. *See supra* P 14. Currently, resources in many RTOs/ISOs do not have the opportunity to recover short-run marginal costs above $1,000/MWh without a tariff modification.

[85] PJM 2014/15 Offer Cap Order, 150 FERC ¶ 61,020 at P 6.

conclude that the current offer caps are unjust and unreasonable. As discussed in the NOPR, three RTOs/ISOs made filings with the Commission (two on multiple occasions) to address issues related to the level of the offer cap.[86] The waiver requests and high natural gas costs experienced during the Polar Vortex, which could have caused some resources to experience costs above $1,000/MWh, demonstrate that the deficiencies of current offer caps, in particular the $1,000/MWh offer cap, are concrete rather than hypothetical.

36. Without Commission action to remedy these deficiencies, some resources could be forced to operate at a loss and some resources would be discouraged from offering their supply to the grid when it is most needed. A central tenet of sound wholesale electric market design is that resources must have an opportunity to recover their costs, so the question left to the Commission is how to provide that opportunity for cost recovery when short-run marginal costs exceed the $1,000/MWh offer cap. We have essentially two choices to enable resources to recover short-run marginal costs above $1,000/MWh: To allow cost recovery through energy prices or through uplift. Short-run marginal costs, which resources include in the incremental energy component of their supply offers, are typically used to calculate LMP. As noted above,[87] ensuring that LMPs reflect the marginal cost of production sends critical information to market participants, improves transparency, and generally results in more efficient outcomes in RTO/ISO energy markets. We find that recovery through energy prices, in most circumstances, will provide the additional benefit that LMPs reflect the marginal cost of production, will increase transparency about the functioning of RTO/ISO energy markets, and will facilitate efficient dispatch of resources with short-run marginal costs above $1,000/MWh.[88] While we recognize that offer caps may not bind frequently, the Federal Power Act requires the Commission to ensure that rates are just and reasonable.

37. We also disagree with commenters that LMPs above $1,000/MWh do not send useful price signals to market participants because, in fact, the Commission has found on prior occasions that LMPs based on short-run marginal cost send efficient short-run and long-run signals to the market.[89] In the short-run, LMPs based on short-run marginal costs are an effective way to communicate information to market participants about the cost of providing the next unit of energy. For example, when LMPs are high, 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, LMPs based on short-run marginal costs can help to inform investment decisions.[90]

38. Furthermore, as noted by Competitive Suppliers and EEI, even if LMPs exceed $1,000/MWh for only a few hours during the year, the resulting LMPs in those hours could affect long-term price signals.[91] For all of these reasons, we conclude that the existing offer caps are not just and reasonable and, thus, need to be reformed.

39. With respect to the applicability of the reforms adopted in this Final Rule, we find that making the reforms applicable to all RTOs/ISOs will avoid seams issues that could arise if RTOs/ISOs had different offer caps.[92] We find that these offer cap reforms will also result in more economically efficient flows between RTOs/ISOs because transactions across RTO/ISO seams will occur based on economic merit rather than based on differences in the offer cap.[93]

40. We also find that continued use of temporary waivers related to the offer cap, as advocated by some commenters, is an inappropriate remedy for problems associated with current offer caps in RTOs/ISOs. The reforms adopted in this Final Rule will provide more certainty to market participants and reduce the administrative burden on RTOs/ISOs associated with requests for temporary waivers of various tariff provisions related to the $1,000/MWh offer caps prior to the start of every winter to ensure that resources are given the opportunity to recover their costs.[94] We also find that problems identified with the current offer caps are better addressed through a rulemaking rather than through continued use of either *ad hoc* actions to approve tariff waivers or temporary changes to tariff provisions to remedy issues associated with existing RTO/ISO offer caps.

41. We find that the reasons for requiring the proposed offer cap reforms apply equally to CAISO. As discussed above, the potential for resources to have short-run marginal costs above CAISO's current $1,000/MWh offer cap requires some action to ensure that resources have an opportunity to recover costs. As in other RTO/ISO markets, increasing the offer cap will improve price formation in CAISO at times when the short-run marginal costs of CAISO resources exceed $1,000/MWh. CAISO's lack of a seam with another RTO/ISO does not alter these effects. Contrary to the implication of CAISO's argument, as explained above, we are not relying on the avoidance of seams issues as the sole rationale for adopting this Final Rule. With respect to comments regarding the WECC offer cap, we find that this issue is unique to CAISO, and if CAISO finds that this Final Rule raises seams issues with WECC, it may raise such issues elsewhere.

IV. Offer Cap Reforms

42. Having concluded that the existing offer caps are not just and reasonable, section 206 of the Federal Power Act requires that the Commission determine the practices that are just and reasonable.[95] We direct each RTO/ISO to establish in their tariffs the following three requirements:

(1) A resource's incremental energy offer must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at $2,000/MWh. (Offer cap structure requirement)

(2) 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 offer may not be used to calculate Locational Marginal Prices and the resource would be eligible for a make-whole payment if

[86] NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 13–17.

[87] *See supra* P 5.

[88] We note that uplift is necessary in some circumstances. For example, resource start-up and no-load costs are not typically included in LMP, and some resources receive uplift to recover these costs.

[89] *PJM Interconnection, L.L.C.,* 110 FERC ¶ 61,053, at P 114 (2005) ("offers [in a competitive market] should set the market clearing price in order to send appropriate price signals about the need for new generation or enhanced load response"). PJM 2014 Offer Cap Order II, 146 FERC ¶ 61,078 at P 40 ("By limiting legitimate, cost-based bids to no more than $1,000/MWh, the market produces artificially suppressed market prices and inefficient resource selection").

[90] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 7.

[91] Competitive Suppliers Comments at 9; EEI Comments at 5.

[92] NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 70–71.

[93] *Id.* P 74.

[94] *Id.* PP 45, 49 (citing Notice Inviting Comments, Docket No. AD14–14–000 at 2).

[95] 16 U.S.C. 824e (2012).

that resource is dispatched and the resource's costs are verified after-the-fact. A resource would also be eligible for a make-whole payment if it is dispatched and its verified cost-based incremental energy offer exceeds $2,000/MWh. (Verification requirement)

(3) All resources, regardless of type, are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh. (Resource neutrality requirement)

43. The offer cap structure requirement is discussed in section IV.A. The verification requirement is discussed in section IV.B. The resource neutrality requirement is discussed in section IV.C.

A. Offer Cap Structure

1. NOPR Proposal

44. In the NOPR, the Commission proposed the following offer cap structure requirement:

> *A resource's incremental energy offer used for purposes of calculating Locational Marginal Prices in energy markets must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer.*[96]

The Commission sought comments on this proposed offer cap structure requirement and whether a hard cap that limited the incremental energy offers used to calculate LMPs would be necessary. The Commission also sought comment on whether the level of the hard cap should be $2,000/MWh or another value.[97]

2. Comments

45. Comments about the proposed offer cap structure focus on two key areas: (1) Whether incremental energy above $1,000/MWh should be cost-based; and (2) how LMPs should be calculated when resource short-run marginal costs exceed $1,000/MWh, including whether resources with costs above $1,000/MWh should be compensated through higher LMPs or through uplift, whether a hard cap is necessary, and the appropriate level of any hard cap.

a. Whether Incremental Energy Offers Above $1,000/MWh Should be Cost Based

46. Commenters differed on the proposal to limit incremental energy offers above $1,000/MWh to cost-based incremental energy offers. Some commenters support this proposal and argue that it is appropriate to limit incremental energy offers that are *not* cost-based to $1,000/MWh as a backstop mitigation measure.[98] As discussed further below,[99] many commenters support the verification requirement proposed in the NOPR and stress that incremental energy offers above $1,000/MWh must be cost-based incremental energy offers before such offers are eligible to calculate LMPs.[100]

47. Regarding offer caps in general, MISO states that the offer cap is currently necessary because demand in RTO/ISO energy and ancillary service markets is inelastic and also because they serve as a safety net.[101] MISO adds that offer caps should be set high enough so as not to interfere with valid market dynamics.[102] NY Transmission Owners maintain that the $1,000/MWh offer cap is an important backstop to protect consumers from the exercise of market power should mitigation fail.[103]

48. Some commenters argue that the $1,000/MWh threshold, above which a resource's incremental energy offer submitted to the RTO/ISO must be cost-based, is too high. The Delaware and New Jersey Commissions recommend that in PJM, all incremental energy offers above $400/MWh be verified before such offers are eligible to set LMP,[104] and the Pennsylvania Commission asks the Commission to carefully consider the threshold above which incremental energy offers are verified.[105] The PJM Market Monitor states that there is no reason that $1,000/MWh should be the dividing line between incremental energy offers that can include markups and incremental energy offers that must be cost-based, and that the threshold could be lowered to $500/MWh in PJM noting that only 0.17 percent of all offers were above $400/MWh in 2015.[106]

49. Exelon states that while it supports removing the offer cap completely, if the Commission finds that incremental energy offers above a certain threshold must be cost-based,[107] Exelon recommends a $2,000/MWh threshold which it states is above a recent fully supported cost-based incremental energy offer of $1,724/MWh seen in PJM in 2014.[108] Exelon also recommends that this threshold be reevaluated on a triennial basis to ensure it reflects market realities.[109]

50. Other commenters support an absolute cap on the incremental energy offers, even if a resource's short-run marginal costs exceed that cap.[110] Industrial Customers also claim that if incremental energy offers above $1,000/MWh are permitted, resources would have no incentive to minimize their fuel costs because they would recover all of their costs if they were dispatched by the RTO/ISO.[111] Potomac Economics states that resources should be prohibited from submitting incremental energy offers above $2,000/MWh, and claims that without such an absolute cap, natural gas prices could be bid up to extraordinary levels.[112]

51. However, several commenters state that resources should be able to submit incremental energy offers that reflect their short-run marginal costs, even if those offers exceed $1,000/MWh.[113] For example, CEA argues that it is prudent to modify current offer caps to allow resources to submit incremental energy offers above $1,000/MWh when fuel and other inputs cause the marginal cost of production to exceed $1,000/MWh.[114] PJM Power Providers argue that raising the offer cap is important because it would allow energy clearing prices to reflect market conditions and provide stability to consumers and suppliers by eliminating the need for *ad hoc* waivers.[115]

52. Some commenters argue that offer caps that limit the incremental energy offers that resources can submit should

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[96] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 53.

[97] *See id.* P 55.

[98] MISO Comments at 7; NY Transmission Owners Comments at 2–3.

[99] *See infra* PP 100–101.

[100] *See generally* NYISO Comments at 2; SCE Comments at 1–2; PG&E Comments at 3; NY Transmission Owners Comments at 3; Golden Spread Comments at 3; Delaware Commission Comments at 11; TAPS Comments at 12; NESCOE Comments at 3.

[101] MISO Comments at 7.

[102] *Id.* at 7.

[103] NY Transmission Owners Comments at 2–3.

[104] Delaware Commission Comments at 4–7; New Jersey Commission Comments at 9.

[105] Pennsylvania Commission Comments at 10–13.

[106] PJM Market Monitor Comments at 2.

[107] Exelon refers to this threshold as a ''market-based offer cap.'' *See, e.g.,* Exelon Comments at 1, 7–10.

[108] Exelon Comments at 9–10.

[109] *Id.* at 10.

[110] Industrial Customers Comments at 10; Potomac Economics Comments at 7.

[111] Industrial Customers Comments at 19.

[112] Potomac Economics Comments at 7. Potomac Economics is the external independent market monitor for NYISO, MISO, and ISO–NE. ISO–NE and NYISO also have internal Market Monitoring Units.

[113] *See generally* Competitive Suppliers Comments at 12–14; Dominion Comments at 3–4; EEI Comments at 3–4; Golden Spread Comments at 1; MISO Comments at 6; NY Transmission Owners Comments at 3; OMS Comments at 3; PJM/SPP Comments at 6; PJM Market Monitor Comments at 1; Six Cities Comments at 2.

[114] CEA Comments at 3–4.

[115] PJM Power Providers Comments at 1–2 (citing NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 14, 16, 17).

be increased [116] or removed entirely.[117] For example, API and the Texas Commission argue that the offer cap should be raised significantly.[118] The Texas Commission asserts that MISO's offer cap should be raised significantly to provide greater assurance of resource adequacy, reduce administrative complexity, and minimize uplift charges.[119]

53. MISO states that it does not oppose the NOPR proposal to revise the offer cap because the proposal will allow market clearing prices to more accurately reflect the true marginal cost of production while protecting consumers from the effects of manipulation and improving price transparency, and the proposal should also reduce uplift payments.[120] However, MISO urges the Commission to consider whether the offer cap proposal in the NOPR is an appropriate long-term approach and states that it could support a gradual relaxation of offer caps to allow market forces to respond accordingly.[121]

54. PJM Power Providers assert that resources should be able to submit cost-based incremental energy offers that reflect all short-run marginal costs.[122] Competitive Suppliers and Exelon argue that the offer cap should be removed entirely, or raised to avoid adverse impacts on the market.[123] According to Competitive Suppliers, significant improvements in electricity markets and market monitoring have occurred since the $1,000/MWh offer cap was put in place nearly 20 years ago.[124] Competitive Suppliers also argue that, given these improvements, the offer cap should be removed, or if that approach is not taken, the verification process should involve minimal distortions.[125]

b. How LMPs Should Be Calculated When Resource Short-Run Marginal Costs Exceed $1,000/MWh

55. Several commenters discuss how LMPs should be calculated when resource short-run marginal costs exceed $1,000/MWh, with some commenters arguing that LMPs should rise to reflect the marginal cost of production and others arguing that resources with short-run marginal costs above $1,000/MWh should be compensated outside of the market through uplift rather than through higher LMPs. Commenters also discuss the need for a hard cap and the appropriate level for any hard cap.

i. Whether To Compensate Resources With Costs Above $1,000/MWh Through Uplift or Higher LMPs

56. As noted above,[126] several commenters state that incremental energy offers above $1,000/MWh should be used to calculate LMPs because the resulting LMPs will better reflect the marginal costs of production.[127] MISO states that permitting cost-based incremental energy offers above $1,000/MWh to set LMPs should improve price transparency and should reduce uplift payments.[128] EEI states that competitive wholesale electricity markets should provide accurate price signals and that cost-based incremental energy offers above $1,000/MWh should be used to calculate LMPs because LMPs should reflect the marginal cost of operating the system, which will promote efficient operation, resource accuracy, and result in savings for consumers.[129]

57. However, other commenters argue that incremental energy offers above $1,000/MWh, even if they are cost-based, should not be able to set LMP.[130] For example, Industrial Customers argue that letting incremental energy offers set LMP would be a windfall to resources.[131] Many commenters argue that uplift or temporary waivers should be used to account for instances when resources' short-run marginal costs exceed the offer cap. Some commenters argue that rather than letting incremental energy offers above $1,000/MWh set LMP, resources with costs above the $1,000/MWh offer cap should be compensated through uplift.[132] For example, the New York Commission argues that an uplift mechanism could ensure that generators can recover all short-run marginal costs.[133] KEPCo/NCEMC asserts that if cost-based incremental energy offers above $1,000/MWh are based on inaccurate fuel cost estimates, there may be no means of remedying the effects on the markets.[134] KEPCo/NCEMC add that uplift is a more cost effective way to ensure both resource cost recovery and just and reasonable prices.[135] Industrial Customers assert that uplift is preferable to using incremental energy offers above $1,000/MWh to calculate LMP because uplift payments ensure cost recovery and can be limited to the resources that are necessary to balance supply and demand, rather than compensating all resources.[136]

ii. Whether To Adopt a Hard Cap

58. Comments differ on the need for a hard cap that would limit the incremental energy offers RTOs/ISOs use to calculate LMPs, a limit referred to herein as a hard cap. Many commenters support a hard cap,[137] and some argue that a hard cap serves as an important backstop mitigation measure to address concerns about the competitiveness of natural gas markets or as a means to protect consumers from unreasonably high LMPs.[138]

59. CAISO, ISO–NE, and NYISO support a hard cap. CAISO asserts that, assuming it were able to verify cost-based offers above $1,000/MWh, a hard cap is necessary if the Commission permits resources to submit incremental energy offers above $1,000/MWh.[139] CAISO adds that a hard cap may help mitigate price spikes in fuel markets.[140] ISO–NE supports a hard cap established at a fixed level and argues that any new offer cap should be imposed in a straightforward manner such that market participants know the level of

[116] API Comments at 3, 8, 13; Exelon Comments at 7; OMS Comments (on behalf of Public Utility Commission of Texas (Texas Commission), referring to MISO's $1,000/MWh offer cap) at 3 n. 7; NEI Comments at 2, 4–5.

[117] NEI Comments at 2, 4–5; Competitive Suppliers Comments at 4–5, 7, 13–15; Exelon Comments at 9–10.

[118] API Comments at 3, 8, 13; OMS Comments (on behalf of Texas Commission) at 3 n.7.

[119] OMS Comments (on behalf of Texas Commission) at 3 n.7.

[120] MISO Comments at 6.

[121] *Id.* at 7.

[122] PJM Power Providers Comments at 2.

[123] Competitive Suppliers Comments at 4–5, 8, 14; Exelon Comments at 10.

[124] Competitive Suppliers Comments at 8, 14–15.

[125] *Id.* at 4–5.

[126] *See supra* P 17.

[127] CEA Comments at 3–4; Competitive Suppliers Comments at 9–13; EEI Comments at 3; Exelon Comments at 5–7; Powerex Comments at 6; PJM Providers Group Comments at 2; Golden Spread Comments at 1; MISO Comments at 6; PJM/SPP Comments at 1–2.

[128] MISO Comments at 6.

[129] EEI Comments at 3–4.

[130] APPA, NRECA, and AMP Comments at 8–10; Industrial Customers Comments at 9; NY Department of State Comments at 3; ODEC Comments at 3; PJM Joint Consumer Advocates Comments at 5; TAPS Comments at 5–6; Steel Producers' Alliance Comments at 3.

[131] Industrial Customers Comments at 9.

[132] APPA, NRECA, and AMP Comments at 8, 13–14, 16; Industrial Customers Comments at 8–9, 23–24; KEPCo/NCEMC Comments at 4; TAPS Comments at 5–6; New York Commission Comments at 6–7; SPP Market Monitor Comments at 2, 4, 6–7; Industrial Energy Consumers Comments at 2.

[133] New York Commission Comments at 6–7.

[134] KEPCo/NCEMC Comments at 4.

[135] *Id.* at 4.

[136] Industrial Customers Comments at 8–9.

[137] ISO–NE Comments at 3; ISO–NE Market Monitor Comments at 12; Joseph Margolies Comments at 8; NYISO Comments at 7; SPP Market Monitor Comments at 2, 13; TAPS Comments at 7.

[138] Direct Energy Comments at 3–5; Industrial Customers Comments at 12; ISO–NE Comments at 3; Joseph Margolies Comments at 3; Potomac Economics Comments at 7; NY Department of State Comments at 3; TAPS Comments at 7.

[139] CAISO Comments at 10. As noted in P 20, *supra,* CAISO opposes raising CAISO's current $1,000/MWh offer cap.

[140] *Id.* at 10. CAISO refers to the hard cap as a "secondary hard cap."

the offer cap with certainty when making advance fuel supply arrangements.[141] NYISO asserts that a hard cap will protect the market from the inadvertent submission of offers above the cap, create bounds for offers that are difficult to verify, and prevent potential attempts to exercise market power that are not otherwise addressed by existing mitigation rules.[142] While MISO takes no position on a hard cap as discussed further below,[143] MISO states that a hard cap is easier to integrate with other market design elements because it is more challenging to establish the appropriate levels for other market elements, such as MISO's Operating Reserve and Transmission Constraint demand curves, without a hard cap because the maximum incremental energy offers would not be limited to a pre-defined value.[144]

60. Potomac Economics, and the ISO–NE and PJM market monitors stress the need for the hard cap to address concerns about uncompetitive conditions in natural gas markets when natural gas supplies are scarce.[145] Potomac Economics contends that during natural gas shortages, natural gas markets have two dominant customer types: Local gas distribution companies and natural gas generators.[146] Potomac Economics states that natural gas generators are frequently the marginal buyers since local gas distribution companies will not interrupt supply to their customers at any price. Potomac Economics asserts that without a hard cap, natural gas prices could be bid up to extraordinary levels because local distribution companies are guaranteed to recover their cost, regardless of how high.[147] The PJM Market Monitor also states that vertically-integrated utilities with a gas marketing function could have the incentive to exercise market power in natural gas markets during extreme conditions in an effort to exercise market power in electricity markets.[148]

61. The ISO–NE Market Monitor also asserts that natural gas markets lack structural measures to prevent the exercise of market power. According to the ISO–NE Market Monitor, the offer cap in electricity markets can impact prices in natural gas markets when natural gas supplies are scarce because natural gas resources, particularly resources with must-offer requirements, are the marginal customers in natural gas markets and thus have a significant impact on natural gas prices.[149]

62. Although the PJM Market Monitor argues that, in the absence of market power, there should be no absolute cap on the short-run marginal costs reflected in an incremental energy offer,[150] the PJM Market Monitor opines that the removal of hard caps in electricity markets should be considered in light of the competitiveness of natural gas markets. The PJM Market Monitor asserts that it is essential that market participants have confidence in the competitiveness of natural gas markets before removing hard caps in electricity markets.[151]

63. The ISO–NE, PJM, and SPP market monitors also explain that when natural gas supplies are scarce, open exchanges for natural gas, such as the Intercontinental Exchange (ICE), tend to have low liquidity and wide bid-ask spreads. These market monitors state that it can be difficult to verify the short-run marginal cost of natural gas resources during periods when open natural gas exchanges have low liquidity because natural gas resources may purchase natural gas bilaterally rather than through the exchanges, and therefore the bid and ask spreads and settled transactions observed on the open exchanges may not represent the costs of the natural gas resources that make bilateral natural gas purchases. Furthermore, when liquidity in the open exchanges is low and the bid-ask spreads are wide, the ISO–NE, PJM, and SPP market monitors explain that there may be little basis on which to verify a resource's natural gas procurement costs.[152]

64. The New Jersey Commission and NY Transmission Owners also argue that a hard cap is necessary to address issues related to the interactions between the gas and electricity markets.[153] NY Transmission Owners explains that resource owners with costs above $1,000/MWh that also own infra-marginal resources may benefit from paying more for natural gas which in turn increases LMPs and thus the revenues that infra-marginal resources receive.[154] NY Transmission Owners further states that it will be difficult for market monitors to ascertain whether the price a resource has paid for natural gas reflects its expectations about the electricity market or an attempt to impact LMPs, and suggests that a hard cap can address these issues.[155] The New Jersey Commission similarly states that, absent a hard cap, market power in natural gas markets could drive up cost-based incremental energy offers in electricity markets and increase LMPs.[156]

65. The SPP Market Monitor states that it would prefer to maintain SPP's existing $1,000/MWh offer cap, but if it is to be revised, it would prefer a new fixed hard cap to serve as a backstop market power mitigation measure during periods of market anomalies when existing measures may fail to protect consumers.[157]

66. Comments from other stakeholders generally support a hard cap to protect customers against market power abuse.[158] For example, the Ohio Commission asserts that if the Commission does not require PJM and the PJM Market Monitor to jointly review these cost-based energy offers, the $2,000/MWh hard cap in PJM should remain to protect against market power concerns and unverified price increases.[159] Industrial Customers argue that the offer cap works in tandem with market power mitigation measures to prevent excessive prices when supplies are tight given that demand is inelastic.[160]

67. Some commenters argue that a hard cap is necessary to protect customers from unjust and unreasonable prices resulting from market aberrations or other events when RTOs/ISOs fail to function properly.[161] For example, TAPS asserts that removing the offer cap entirely would result in the Commission failing to meet its statutory duty to protect against excessive prices,[162] and it argues that the hard cap provides crucial damage control to shield consumers from unreasonably high prices.[163] Industrial Customers argue that the hard cap helps discipline generator fuel procurement costs, stating that full cost recovery would significantly reduce incentives for

[141] ISO–NE Comments at 2–3.

[142] NYISO Comments at 8.

[143] *See infra* P 69.

[144] MISO Comments at 13.

[145] ISO–NE Market Monitor Comments at 13–14; Potomac Economics Comments at 7; PJM Market Monitor Comments at 4.

[146] Potomac Economics Comments at 7.

[147] *Id.*

[148] PJM Market Monitor Comments at 4.

[149] ISO–NE Market Monitor Comments at 13–14.

[150] PJM Market Monitor Comments at 1.

[151] *Id.* at 4.

[152] ISO–NE Market Monitor Comments at 8; PJM Market Monitor Comments at 6; SPP Market Monitor Comments at 7.

[153] NY Transmission Owners Comments at 3–4; New Jersey Commission Comments at 9.

[154] NY Transmission Owners Comments at 4.

[155] *Id.*

[156] New Jersey Commission Comments at 9.

[157] SPP Market Monitor Comments at 6, 13.

[158] *See generally* Direct Energy Comments at 4–5; Ohio Commission Comments at 6–7; Industrial Customers Comments at 10–11; TAPS Comments at 8–10; New Jersey Commission Comments at 7.

[159] Ohio Commission Comments at 6–7.

[160] Industrial Customers Comments at 10–11.

[161] TAPS Comments at 8–9; Industrial Customers Comments at 19–20.

[162] TAPS Comments at 10 (citing *FERC* v. *Elec. Power Supply Ass'n,* 136 S. Ct. 760, 764 (2016)).

[163] *Id.* at 9–10.

generators to minimize their costs if these costs can be passed on to consumers.[164]

68. Commenters opposed to the inclusion of a hard cap on offers used to calculate LMPs generally argue that any cap would artificially suppress LMPs and increase uplift payments.[165] PJM/SPP state that there should not be a hard cap on cost-based offers used to calculate LMPs provided that appropriate verification processes are in place to ensure cost-based incremental offers reflect legitimate costs.[166] PJM/SPP also assert that a hard cap can create unhedgeable uplift payments.[167] PJM Power Providers assert that resources should be able to submit cost-based incremental energy offers that reflect their short-run marginal costs and that those offers should be able to set the LMP.[168]

69. MISO states that it does not have a strong preference on the imposition of a hard cap and notes that the same benefits and drawbacks that exist for the current $1,000/MWh hard cap (in some markets) would apply to any new hard cap.[169] MISO identifies two drawbacks of a hard cap: (1) A hard cap could suppress LMPs below the marginal cost of production; and (2) a special uplift mechanism would be needed for offers that exceed the hard cap.[170] MISO states that a hard cap may not be necessary because the verification requirement safeguards the market and states that the limitations and implementation costs associated with a hard cap would likely overshadow the benefits.[171]

70. Exelon and EEI oppose a hard cap, arguing that it is important for LMPs to be as consistent as possible with the marginal cost of operating the system and that, therefore, resources should always be permitted to offer their costs, and that such offers should always be eligible to set LMP.[172] As noted above, Competitive Suppliers assert that the offer cap should be removed entirely.[173]

71. Additionally, some commenters opposed to a hard cap assert that existing market monitoring and mitigation measures, as well as the proposed verification requirement for cost-based incremental energy offers above $1,000/MWh, render a hard cap unnecessary and duplicative.[174] For example, Dominion states that a hard cap is not necessary for cost-based incremental energy offers because market power concerns are not relevant for cost-based incremental energy offers as offers based on resource costs do not constitute an exercise of market power.[175]

72. Commenters disagree about the appropriate level for any new hard cap. ISO–NE states that it does not have evidence to substantiate a specific recommendation for the level of any new hard cap.[176] NYISO states that the Commission should hold a technical workshop to determine the appropriate level of the hard cap that analyzes the elasticity of the fuel markets, including natural gas markets, and fuel prices at various demand levels.[177]

73. Potomac Economics states that the $2,000/MWh level approved in PJM would be a reasonable hard cap for all RTOs/ISOs in the Eastern Interconnect.[178] However, Potomac Economics states that the Commission should adopt a $2,000/MWh cap that not only caps the incremental energy offers eligible to set LMP but also prevents resources from recovering incremental energy costs above $2,000/MWh.[179] Potomac Economics adds that the loss of generation resulting from any natural gas resources that do not procure natural gas during natural gas shortages due to such a cap will not substantially increase the probability of an electric outage.[180]

74. TAPS argues that offers above $1,500/MWh should not be used to calculate LMPs because a MISO analysis indicated that natural gas resources in MISO would have a marginal cost below $1,138/MWh if natural gas prices reached $65/MMBtu and that more than 98 percent of MISO's gas capacity would have a marginal cost below $1,500/MWh if gas prices reached $100/MMBtu.[181] TAPS further argues that $2,000/MWh is too high and that the value was not supported by PJM other than as a compromise between PJM stakeholders.[182] Midcontinent Joint Consumer Advocates argue that a $2,000/MWh hard cap is unreasonably high and could cause prices to rise up to $2,000/MWh.[183]

75. As noted above, some commenters support a $1,000/MWh hard cap on the incremental energy offers that are used to calculate LMPs.[184] For example, APPA, NRECA, and AMP assert that the hard cap should be set to $1,000/MWh in all RTOs/ISOs, including PJM, which currently has a $2,000/MWh hard cap.[185] Direct Energy and NY Transmission Owners state that different hard caps across RTOs/ISOs may be justified given differences in regional natural gas prices, but add that RTOs/ISOs with the same natural gas supply should have the same hard cap.[186] Additionally, APPA, NRECA, and AMP, ODEC, PJM Joint Consumer Advocates, and Steel Producers' Alliance all ask the Commission to reinstate PJM's previous $1,000/MWh offer cap.[187] ODEC and PJM Joint Consumer Advocates state that although they supported the consensus position on PJM's current $2,000/MWh offer cap as an interim measure, they state that they were awaiting Commission action on offer caps and do not support such a cap as a long-term policy.[188] ODEC and PJM Joint Consumer Advocates argue that the $2,000/MWh offer cap on cost-based offers is no longer necessary and that a $1,000/MWh offer cap is more appropriate because new measures, such as PJM's new capacity construct and additional measures implemented in response to the Polar Vortex, will ensure that prices remain at reasonable levels.[189]

76. Dominion states that the NOPR proposal will result in more accurate price signals and a better understanding of the true costs of serving demand, reduce uplift during stressed periods, and allow customers to more effectively hedge the costs of reliability through market participation.[190] NESCOE states

[164] Industrial Customers Comments at 19–20.

[165] Competitive Suppliers Comments at 12–15; Dominion Comments at 4; Exelon Comments at 21–22; Golden Spread Comments at 2; PJM/SPP Comments at 6; EEI Comments at 7.

[166] PJM/SPP Comments at 6.

[167] *Id.*

[168] PJM Power Providers Comments at 2.

[169] MISO Comments at 13.

[170] *Id.*

[171] MISO Comments at 13.

[172] Exelon Comments at 21; EEI Comments at 4.

[173] Competitive Suppliers Comments at 13.

[174] Competitive Suppliers Comments at 14; PJM/SPP Comments at 6; Dominion Comments at 4.

[175] Dominion Comments at 4.

[176] ISO–NE Comments at 3.

[177] NYISO Comments at 8.

[178] Potomac Economics Comments at 7–8.

[179] *Id.* at 8. Potomac Economics notes that its recommendation would require modifying PJM's current offer cap, which permits resources to recover costs above PJM's $2,000/MWh hard cap.

[180] *Id.*

[181] TAPS Comments at 10–11. TAPS uses the phrase ''hard offer cap,'' which could indicate that RTOs/ISOs should limit offers to $1,500/MWh for purposes of calculating LMPs or that resources should not be able to submit incremental energy offers above $1,500/MWh.

[182] *Id.* at 11.

[183] Midcontinent Joint Consumer Advocates Comments at 4.

[184] New Jersey Commission Comments at 8–9; TAPS Comments at 10–11; APPA, NRECA, and AMP Comments at 8–9.

[185] APPA, NRECA, and AMP Comments at 9.

[186] Direct Energy Comments at 3–4; NY Transmission Owners Comments at 5.

[187] APPA, NRECA, and AMP Comments at 7; ODEC Comments at 3–5; PJM Joint Consumer Advocates Comments at 2–4; Steel Producers' Alliance Comments at 5.

[188] ODEC Comments at 3; PJM Joint Consumer Advocates Comments at 2.

[189] ODEC Comments at 5; PJM Joint Consumer Advocates Comments at 2–3.

[190] Dominion Comments at 3.

that the offer cap reforms proposed in the NOPR appear to appropriately balance price formation issues, seams issues, and the potential for market power abuse while allowing for regional variation in implementing consumer protection mechanisms.[191]

3. Determination

77. The Commission is adopting aspects of the offer cap structure set forth in the NOPR, which caps a resource's incremental energy offer used for purposes of calculating LMPs in day-ahead and real-time energy markets at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. Based on the comments received in this proceeding, the Commission is also adopting a hard cap as part of this Final Rule.[192] Although a resource may submit a cost-based incremental energy offer above $2,000/MWh, the hard cap will prohibit the use of such offers above $2,000/MWh when calculating LMPs. As discussed further in section IV.B below, incremental energy offers above $1,000/MWh must be verified before they are used to calculate LMPs. As noted above, RTOs/ISOs must cap verified cost-based incremental energy offers at $2,000/MWh when calculating LMPs.

78. As a result of this Final Rule, an RTO/ISO will treat resources' incremental energy offers differently, depending on the level of the offer itself. Each RTO/ISO shall treat incremental energy offers below $1,000/MWh as it currently does. Such offers: (1) Are subject to existing RTO/ISO market power mitigation procedures and are not required to be cost-based; and (2) may be used to calculate LMPs. A resource may only submit an incremental energy offer equal to or above $1,000/MWh if the offer is cost-based, that is, if the offer accurately reflects that resource's actual or expected short-run marginal costs. For an incremental energy offer equal to or above $1,000/MWh and less than or equal to $2,000/MWh, the RTO/ISO or Market Monitoring Unit must verify that the offer is cost-based before the RTO/ISO may use the offer to calculate LMPs. For an incremental energy offer above $2,000/MWh, the RTO/ISO or Market Monitoring Unit must also verify that the offer is cost-based. Cost-based incremental energy offers in excess of $2,000/MWh will be capped at $2,000/MWh for purposes of calculating LMPs. As such, the $2,000/MWh hard cap places an upper limit on the incremental energy offers that the RTO/ISO can use to calculate LMPs.[193] We note that the resulting LMPs may exceed $2,000/MWh due to losses and congestion. Additionally, resources with verified cost-based incremental energy offers above $2,000/MWh will be eligible to receive uplift.

79. After consideration of the record in this proceeding, including responses to the question we asked about the need for a hard cap, we adopt a modified version of the offer cap structure proposed in the NOPR. This modified version recognizes the practical issues raised by commenters. While a hard cap may diminish the ability to fully address the shortcomings of the current offer caps identified above[194] in all circumstances, we find that, on balance, a hard cap is necessary to reasonably limit the adverse impact that imperfect information about a resource's short-run marginal costs during the verification process could have on LMPs.

80. First, the offer cap structure will reduce the likelihood that the $1,000/MWh offer cap in effect in some RTOs/ISOs[195] will suppress LMPs below the marginal cost of production. Ideally, LMPs in RTO/ISO energy markets should reflect the short-run marginal cost of the marginal resource. Under the offer cap structure adopted in this Final Rule, cost-based incremental energy offers up to $2,000/MWh that have been verified by either the RTO/ISO or Market Monitoring Unit as being a reasonable reflection of a resource's actual or expected short-run marginal cost may be used to calculate LMPs.

81. Second, the offer cap structure and associated uplift payments discussed further in section IV.B below give resources the opportunity to be compensated for the short-run marginal costs they incur to provide service, which achieves the price formation goal of ensuring that resources have an opportunity to recover their costs.

82. Third, the offer cap structure adopted in this Final Rule will encourage a resource to offer supply to the market when it is needed most. A resource that is compensated for its costs has an incentive to offer its supply into the market even when those costs are high, which often occurs when supplies are tight. Fourth, the offer cap structure enables RTOs/ISOs to dispatch the most efficient set of resources when resources' short-run marginal costs exceed $1,000/MWh.

83. We also find that the offer cap structure will mitigate market power associated with incremental energy offers above $1,000/MWh, as some commenters suggest. The requirement that incremental energy offers above $1,000/MWh be cost-based retains the backstop mitigation function that current offer caps play in existing RTO/ISO market power mitigation because incremental energy offers that are not cost-based may not exceed $1,000/MWh. A cost-based incremental energy offer is based on the associated resource's short-run marginal cost, which constitutes a competitive offer free from the exercise of market-power.

84. Revising the offer cap to permit cost-based incremental energy offers up to $2,000/MWh to set LMP will reduce the likelihood that the offer cap will suppress LMPs below the marginal cost of production. Permitting cost-based incremental energy offers up to $2,000/MWh to set LMP will also reduce uplift associated with the current offer caps, which will be beneficial to the market because uplift payments are less transparent to market participants than LMPs that reflect the marginal cost of production. Therefore, we disagree with arguments that all resources with short-run marginal costs above $1,000/MWh should be compensated through uplift rather than through the LMP. As discussed further below, we adopt a hard cap and provide cost recovery for resources with short-run marginal costs above $2,000/MWh to address practical concerns raised about the offer verification process. As discussed further below, some resources may not know their actual short-run marginal costs at the time they submit cost-based incremental energy offers.[196] Accordingly, the RTO/ISO or Market Monitoring Unit will have to verify that such offers reasonably reflect the associated resource's expected short-run marginal costs, which necessarily involves an estimate. Furthermore, the information that RTOs/ISOs and/or Market Monitoring Units have to estimate and/or verify the short-run marginal costs of some resources may be imperfect. For example, as noted above, information about the short-run fuel costs of certain natural gas-fired resources may be limited when natural gas supplies are scarce because publicly available natural gas indices may not be representative of the price that such resources actually pay for fuel.[197] Given

[191] NESCOE Comments at 2.

[192] The hard cap was not included in the proposal set forth in the NOPR, but the Commission sought comment on it. *See* NOPR, FERC Stats. & Regs. ¶ 32,714 at P 55.

[193] The $2,000/MWh hard cap requires that the cost-based incremental energy offers that RTOs/ISOs may use to calculate LMPs may not exceed $2,000/MWh.

[194] *See supra* P 2.

[195] Specifically CAISO, ISO–NE, MISO, NYISO, and SPP.

[196] *See infra* PP 105–108.

[197] *See supra* P 63.

these limitations, we find it is appropriate to include a hard cap to ensure that LMPs calculated based on verified cost-based incremental energy offers above $1,000/MWh are just and reasonable.

85. We disagree with Industrial Customers that resources would have no incentive to minimize their fuel costs if the offer cap is above $1,000/MWh because, in the absence of market power, resources have an incentive to compete with other resources in order to clear the RTO/ISO day-ahead and real-time energy markets. Any resource that is able to procure natural gas at a cost less than the cost that sets the LMP will earn a profit and thus has a strong incentive to manage its fuel procurement.

86. However, as part of the offer cap structure, we will require a hard cap of $2,000/MWh on offers that are used to calculate LMPs. Under the hard cap, an RTO/ISO must place an upper limit, or hard cap, on the cost-based incremental energy offers that it uses to calculate LMPs.[198] To implement the hard cap, we modify the offer cap structure requirement proposed in the NOPR and adopt the following offer cap structure requirement:

A resource's incremental energy offer must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. *For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at $2,000/MWh.*

87. We find that a hard cap is necessary for two primary reasons. First, a hard cap will address the fact that RTOs/ISOs and/or Market Monitoring Units may have imperfect information about resources' short-run marginal costs during the verification process. As discussed further in section IV.B below, several commenters note that there may be imperfect information associated with the verification of cost-based incremental energy offers above $1,000/MWh prior to the market clearing process because some of those offers will be based on a resource's estimate of its costs and RTOs/ISOs or Market Monitoring Units may not have perfect information with which to estimate those costs. Additionally, as noted by market monitors, when natural gas spot market prices rise to levels that could result in the short-run marginal costs of some natural gas-fired resources exceeding $1,000/MWh, over-the-counter natural gas markets often lack liquidity or have wide bid-ask spreads, which can make verification challenging, particularly verification of expected costs. At those times, a market participant's expected costs could vary significantly from its actual costs. Although, as discussed further below, only verified cost-based incremental energy offers above $1,000/MWh may be used to calculate LMPs subject to the $2,000/MWh hard cap. We find that, on balance, a hard cap will reasonably limit the adverse impact that any imperfect information about resources' short-run marginal costs during the verification process could have on LMPs.

88. Second, we agree with MISO that a hard cap will be easier to integrate with other market constructs that place caps or upper bounds on various market elements (*e.g.,* penalty factors associated with shortage pricing or violating transmission constraints).

89. We are not persuaded by comments that a hard cap is duplicative of existing market power mitigation rules because existing market power mitigation provisions in most RTOs/ISOs only apply under certain circumstances, whereas this Final Rule essentially mitigates all incremental energy offers above $1,000/MWh to a level based on short-run marginal costs. Additionally, as noted above, the hard cap is necessary to address concerns about the imperfect information that RTOs/ISOs and/or Market Monitoring Units have about resources' short-run marginal costs during the verification process.

90. Having determined that a hard cap is necessary, we find that $2,000/MWh is a just and reasonable level for that hard cap based on the record in this proceeding. Historically, high natural gas prices during the Polar Vortex resulted in at least one resource with a cost-based incremental energy offer of $1,724/MWh.[199] Based on this experience and noting that it occurred in an otherwise low natural gas price environment, we expect that resources may experience costs that approach but are unlikely to exceed $2,000/MWh. With a hard cap of $2,000/MWh, we find that resources will be able to recover those costs and that LMPs will reflect marginal costs.[200] The Commission has previously relied upon high and volatile natural gas prices as a justification for increasing offer caps.[201] This $2,000/MWh level was also generally supported by Potomac Economics.[202] With respect to treatment of cost-based incremental energy offers above $2,000/MWh, we expect RTOs/ISOs to use such offers to determine merit-order dispatch. We note that the Commission allowed this approach when accepting PJM's current offer cap structure, in which PJM uses cost-based incremental energy offers above $2,000/MWh to determine merit order dispatch but limits cost-based incremental energy offers to $2,000/MWh for purposes of calculating LMPs.[203]

91. We recognize that a $2,000/MWh hard cap leaves some possibility for price suppression when the marginal cost of production legitimately exceeds $2,000/MWh. However, by allowing verified cost-based incremental energy offers in the $1,000/MWh–$2,000/MWh range to set LMPs, we significantly reduce the likelihood of such price suppression, and we find this balanced approach just and reasonable.

92. We decline to hold a technical workshop as suggested by NYISO or a triennial review as suggested by Exelon to determine an appropriate level for the hard cap because there is sufficient evidence in this record to support $2,000/MWh as a just and reasonable value. Based on the record, we decline to adopt a lower hard cap level, such as the $1,500/MWh value TAPS proposes, because this level is demonstrably lower than cost-based incremental energy offers observed during the Polar Vortex. Additionally, the PJM Market Monitor reported that on 54 occasions in early 2015, resources submitted cost-based incremental energy offers at prices above $1,000/MWh.[204]

[198] We note that PJM currently permits resources to submit cost-based incremental energy offers above its current $2,000/MWh hard cap, and PJM may use such offers to dispatch resources. However, incremental energy offers are capped at $2,000/MWh for purposes of calculating LMPs. *See* PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289.

[199] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 13 (citing PJM 2014 Offer Cap Order I, 146 FERC ¶ 61,041 at P 2).

[200] *See Envtl. Action, Inc.* v. *FERC,* 939 F.2d 1057, 1064 (D.C. Cir. 1991) (''it is within the scope of the agency's expertise to make such a prediction about the market it regulates, and a reasonable prediction deserves our deference notwithstanding that there might also be another reasonable view.''). *See also Michigan Consol. Gas Co.* v. *F.E.R.C.,* 883 F.2d 117, 124 (1989) (''It is also quite clear FERC may make predictions—''[m]aking . . . predictions is clearly within the Commission's expertise'' and will be upheld if ''rationally based on record evidence.'') (citing *East Tennessee Natural Gas Co.* v. *FERC,* 863 F.2d 932, 938–39 (1988) (citing *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 1008 (1987)).

[201] *See California Indep. Sys. Operator Corp.,* 114 FERC ¶ 61,026, at P 25 (2006) (In CAISO, natural gas prices rose from $3–$4/MMBtu when the bid cap in CAISO was $250/MWh to $14/MMBtu. Based on this information, the Commission found ''that raising the bid cap is justified by the well-documented rise in gas prices'' and accepted CAISO's proposal to raise the bid cap from $250/MWh to $400/MWh.).

[202] Potomac Economics Comments at 8.

[203] PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 11.

[204] Monitoring Analytics, Report on PJM Energy Market Offers January 16 to March 31, 2015, at 2 (May 1, 2015), *available at http://*

93. With respect to APPA, NRECA, and AMP's argument that concerns over seams do not justify revising RTO/ISO offer caps, particularly because the Commission accepted PJM's current $2,000/MWh offer cap, we reiterate that the Commission's finding in that order was limited to the facts in that record. In accepting PJM's proposal, the Commission stated that it would not prejudge broader reforms in the price formation proceeding.[205]

94. We decline to hold, as CAISO suggests, a technical workshop on implementation challenges. We expect that any issues regarding the implementation of this Final Rule will be raised by RTOs/ISOs on compliance, and the Commission will address them at that time. We also decline to implement a $400/MWh cap on incremental energy offers that are not cost-based, as some commenters have suggested. We find that the fact that resources rarely submit incremental energy offers above $400/MWh does not indicate that allowing resources to submit incremental energy offers as high as $1,000/MWh which are not cost-based (referred to as ''market-based offers'' in PJM) will result in unjust and unreasonable rates.

95. In response to MISO's suggestion that future adjustments to the offer cap may be needed in response to market-based solutions that increase demand elasticity or resource mix changes, we decline to speculate as to what changes may or may not be necessary in the future.

B. Cost Verification

1. NOPR Proposal

96. In the NOPR, the Commission proposed the requirement that cost-based incremental energy offers above $1,000/MWh be verified by the RTO/ISO or Market Monitoring Unit prior to being used to calculate LMPs (verification requirement).[206] The Commission proposed the following verification requirement:

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.[207]

97. The Commission reasoned that this requirement would ensure that the proposal results in LMPs that reflect the marginal cost of production during intervals when the marginal resource's short-run marginal cost exceeds $1,000/MWh. Further, in the NOPR, the Commission preliminarily found that the verification requirement was necessary to reduce the potential exercise of market power by resources, which could result in unjust and unreasonable rates.[208]

2. Comments

98. As discussed further below, the Commission received several comments about the proposed verification requirement. Comments about the proposed verification requirement focus on whether it is needed and what type of verification would be acceptable and feasible. A number of commenters generally support the proposed verification requirement, but they express concerns or seek clarification about the proposed verification requirement.[209]

a. Need for the Verification Requirement

99. Commenters disagree about whether the proposed verification requirement for cost-based incremental energy offers above $1,000/MWh is necessary to reduce the potential exercise of market power. Several commenters support the verification requirement,[210] some asserting that the verification requirement is a critical element of the proposal.[211]

100. OMS contends that the verification requirement protects retail consumers from unlimited and unjustified wholesale price increases.[212] The Delaware Commission and TAPS assert that the verification requirement is necessary to address market power concerns.[213] TAPS states that although it opposes revisions to the offer cap, the proposed verification requirement is needed to protect the integrity of the RTO/ISO markets and will help avoid litigation costs associated with re-running markets after-the-fact in the event that an LMP is subsequently found not to be cost-justified.[214] PG&E and SCE generally support the prevention of unverified incremental energy offers above $1,000/MWh from setting the LMP, although PG&E does not support the proposal overall.[215]

101. PJM Joint Consumer Advocates argue that the only way to protect consumers from unfair prices is to verify offers prior to the market clearing process and that fairness demands such a review, even if the verification process is technically complex. PJM Joint Consumer Advocates assert that market-based offers, which are not strictly tied to costs, should not be eligible to set LMP because they would unfairly inflate costs to consumers and result in a windfall for suppliers.[216]

102. Other commenters assert that the verification requirement is unnecessary [217] or unduly cumbersome.[218] Potomac Economics and PJM Power Providers argue that cost verification is unnecessary given other RTO/ISO market constructs.[219] Potomac Economics states that the justification for the proposed verification requirement is limited because competition is not diminished during the fuel price spikes that could cause a resource's short-run marginal costs to exceed $1,000/MWh. Potomac Economics also argues that existing RTO/ISO market power mitigation measures address market power concerns.[220] PJM Power Providers state that the verification requirement is unnecessary because resources have the incentive to submit incremental energy offers that reflect actual costs. PJM Power Providers assert that the threat of an investigation from the Commission's Office of Enforcement and possible associated fines incent good behavior and discourage the exercise of market power.[221] Industrial Energy Consumers also state that the NOPR could lead markets to become more complicated

www.monitoringanalytics.com/reports/Reports/2015/IMM_Informational_Filing_Docket_No_EL15-31-000_20150505.pdf.

[205] PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 55.

[206] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 56.

[207] *Id.*

[208] *Id.* P 57.

[209] ISO–NE Comments at 6; NYISO Comments at 2; PJM/SPP Comments at 2–3; TAPS Comments at 12.

[210] SCE Comments at 1–2; PG&E Comments at 1–3; NY Transmission Owners Comments at 3.

[211] Golden Spread Comments at 3; Delaware Commission Comments at 11; TAPS Comments at 12; NESCOE Comments at 3.

[212] OMS Comments at 3.

[213] Delaware Commission Comments at 11; TAPS Comments at 12–13.

[214] TAPS Comments at 12–13.

[215] PG&E Comments at 1–3; SCE Comments at 1–2.

[216] PJM Joint Consumer Advocates Comments at 5.

[217] Potomac Economics Comments at 12; PJM Power Providers Comments at 5.

[218] OMS Comments (on behalf of Texas Commission) at 3 n.7.

[219] Potomac Economics Comments at 12; PJM Power Providers Comments at 5.

[220] Potomac Economics Comments at 12.

[221] Exelon Comments at 9; PJM Power Providers Comments at 5 (citing *Public Citizen, Inc.* v. *Midcontinent Indep. Sys. Operator, Inc.,* 154 FERC ¶ 61,224, at P 88 (2016)).

and opaque, potentially leading to unintended consequences.[222]

b. Verification Standard

103. The Commission sought comment on the Market Monitoring Unit's or RTO's/ISO's ability to timely verify cost-based incremental energy offers above $1,000/MWh prior to the day-ahead or real-time market clearing process.[223] In response, the Commission received a wide array of comments about the feasibility of the proposed verification requirement and the challenges associated with implementing the requirement.

104. Many of the comments highlighted the difference between verification of *actual* costs and verification of *expected* costs. They noted that because verification has to occur before the market runs, verification of *actual* costs was more difficult than verification of *expected* costs. Indeed, several commenters contend that it is not possible prior to the market clearing process to verify that a resource's cost based-incremental energy offer equals that resource's *actual* costs.[224] Commenters raise two key obstacles to the verification of a resource's actual costs prior to the market clearing process: (1) Some natural gas resources do not know their actual costs at the time they submit offers; and (2) natural gas resource fuel costs are particularly difficult to verify during periods when natural gas supplies are scarce. Each obstacle is discussed in turn below.

i. Resource Cost Uncertainty When Submitting Offers

105. Many commenters, including RTOs/ISOs, market monitors, and generators, assert that because some resources, specifically natural gas resources, do not know their actual fuel procurement costs when they submit incremental energy offers to the RTO/ISO, it is impossible to verify the incremental energy offers of such resources prior to the market clearing process.[225]

106. ISO–NE, MISO, and PJM/SPP state that some natural gas resources have not procured fuel by the time that they submit incremental energy offers to the RTO/ISO markets, and thus ISO–NE and PJM/SPP state that such resources often submit offers based on the cost that the resources expect to pay for natural gas on the natural gas spot market.[226] For example, PJM/SPP state that some natural gas resources procure all or part of their natural gas requirements in the daily natural gas spot market, which is more volatile than month-ahead index prices because of changes in commodity prices and weather, as well as interstate natural gas pipeline capacity curtailments and maintenance activities.[227]

107. Comments from market monitors also suggest that some natural gas resources do not know their actual fuel costs at the time they submit offers.[228] For example, the ISO–NE Market Monitor states that natural gas resources that have not purchased natural gas in advance submit offers based on their best estimate of what they expect to pay for natural gas in real-time.[229] Potomac Economics and the ISO–NE Market Monitor state that resources submit initial incremental energy offers [230] or updates to their cost-based incremental energy offers [231] based on expected, rather than actual costs. Potomac Economics adds that such offers reflect a resource's expectation of its costs, and these costs may be subject to substantial uncertainty and thus cannot be verified in advance.[232] The ISO–NE Market Monitor, Potomac Economics, and the SPP Market Monitor conclude that strict verification of a resource's actual costs prior to the market clearing process is not possible.[233]

108. Generators also state that verification of actual costs may not be possible because some natural gas resources can only submit an estimate of their expected fuel costs.[234] For example, Exelon states that when a resource submits a day-ahead offer, which is due 24–48 hours prior to actual dispatch, that resource must consider numerous costs and may have to make complicated and somewhat imprecise judgments to predict future events, which makes it difficult to quantify and substantiate risks on either an before-the-fact or after-the-fact basis.[235] Additionally, EEI states that a resource that is not committed or not fully committed in the day-ahead market may not procure enough natural gas to meet its full output in the real-time market and may need to purchase fuel in the intra-day natural gas market where prices are significantly higher and more volatile than the day-ahead natural gas market.[236]

ii. Cost Verification During Peak Periods

109. Several commenters state that the challenges associated with pre-verification become more acute during stressed system conditions when natural gas supplies are limited, which is precisely when resources may have incremental energy costs above $1,000/MWh.[237]

110. PJM states that higher natural gas prices have led to higher cost-based incremental energy offers from resources, but verifying resource costs with natural gas price indices can be challenging because there is not a strong or straightforward correlation between changes in natural gas index prices and the magnitude of changes in cost-based offers, particularly when cost-based incremental energy offers in PJM are high.[238] ISO–NE argues that indices may not fairly represent the fuel prices that resources must pay, particularly when natural gas supplies are tight.[239] ISO–NE notes that there may be scant independent or timely information on natural gas resources' costs during such times.[240] Various commenters explain that during such times, natural gas resources must often purchase natural gas outside of the exchange trading platforms [241] through bilateral deals that are not reported on such exchanges, and that a significant amount of such purchases tends to make natural gas

[222] Industrial Energy Consumers Comments at 2.

[223] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 59.

[224] EEI Comments at 6; Exelon Comments at 11; IRC Comments at 2–3; ISO–NE Comments at 2, 6–7; MISO Comments at 9; PJM/SPP Comments at 12–13; Potomac Economics Comments at 3–4; SPP Market Monitor Comments at 9.

[225] Dominion Comments at 5; Exelon Comments at 16; ISO–NE Market Monitor Comments at 7; ISO–NE Comments at 6; MISO Comments at 9; PJM Market Monitor Comments at 6; PJM/SPP Comments at 10; Potomac Economics Comments at 3–5; SPP Market Monitor Comments at 9.

[226] ISO–NE Comments at 5; MISO Comments at 9; PJM/SPP Comments at 9.

[227] PJM/SPP Comments at 9–10.

[228] ISO–NE Market Monitor Comments at 7; Potomac Economics Comments at 4; SPP Market Monitor Comments at 9.

[229] ISO–NE Market Monitor Comments at 7.

[230] Potomac Economics Comments at 4.

[231] ISO–NE Market Monitor Comments at 7.

[232] Potomac Economics Comments at 4.

[233] ISO–NE Market Monitor Comments at 4; Potomac Economics Comments at 3–4; SPP Market Monitor Comments at 9.

[234] Dominion Comments at 5; Exelon Comments at 11–16.

[235] Exelon Comments at 11–17.

[236] EEI Comments at 5–6.

[237] *See generally* Dominion Comments at 4–5; PJM/SPP Comments 11; ISO–NE Comments at 4–5; SPP Market Monitor Comments at 7; PJM Market Monitor Comments at 6; EEI Comments at 6; Exelon Comments at 13–14; PJM Power Providers Comments at 3.

[238] PJM/SPP Comments at 11 (citing Attachment A). Attachment A presents an analysis of cost-based incremental energy offers and natural gas prices during the winters of 2013/14, 2014/15, and 2015/16. The analysis in Attachment A shows that for cost-based offers in the $500/MWh–$750/MWh range, the median gas price corresponding to the range of offers was $10.44/MMBtu in the 2013/14 winter, $15.62 MMBtu in the 2014/15 winter, and $3.75/MMBtu in the 2015/16 winter.

[239] ISO–NE Comments at 4–5.

[240] *Id.*

[241] Industrial Customers Comments at 16; ISO–NE Comments at 4–5; ISO–NE Market Monitor Comments at 8; PJM Market Monitor Comments at 6; SPP Market Monitor Comments at 7.

indices less representative of the price natural gas resources pay for natural gas.[242]

111. The ISO–NE., PJM, and SPP market monitors state that cost verification is most challenging when natural gas demand is high because of low liquidity and high bid-ask spreads for natural gas purchased on open exchanges such as the ICE.[243] For example, the PJM Market Monitor and the ISO–NE Market Monitor state that the natural gas market is least transparent on days with very high electric demand and that the ICE index is likely to be unsuitable for verification purposes because there are either no completed trades reported, a low number of completed gas trades (*i.e.,* low liquidity), or the bid-ask spread is so wide as to be meaningless.[244] The SPP Market Monitor states that the risk inherent in determining accurate fuel costs from natural gas indices is acceptable in most periods, but that the risk increases to unacceptable levels during extremely stressed fuel supply conditions.[245] Comments from generators also suggest that natural gas indices become less reliable during periods when natural gas supplies are limited and natural gas prices spike.[246] Dominion and Exelon assert that purchasing natural gas outside of an exchange through marketers or bilateral deals also increases the risks that a natural gas resource faces when it formulates its bid, and can increase the error associated with a resource's estimate of its actual costs.[247]

c. Feasibility of Verification Requirement

112. The Commission sought comment on the feasibility of the proposed verification requirement.[248] As discussed further below, ISO–NE, MISO, and NYISO state that current mitigation procedures could satisfy the proposed verification requirement if the Commission clarifies that the verification process can include expected, rather than actual, costs.[249] Several commenters express concerns that timely verification of a resource's actual short-run marginal costs is not possible within the timeframe of the RTO/ISO day-ahead and real-time market clearing process.[250]

113. For example, Potomac Economics states that time constraints will make the proposal infeasible if the proposed verification requires that resource cost data be collected and fully validated to actual cost prior to market clearing.[251] The ISO–NE Market Monitor states that the lack of solid information about natural gas prices on high-volatility, low-liquidity days makes validation of a resource's expected short-run marginal costs difficult, particularly if many resources seek to update their cost-based incremental energy offers.[252] The PJM Market Monitor notes that in PJM, a large volume of data, including information from approximately 420 gas-fired resources and about 35 gas trading points, must be processed to review cost-based incremental energy offers.[253] The SPP Market Monitor states that verification prior to market clearing may not be feasible in SPP given the tight timeline, particularly during sudden fuel shortages and fuel price spikes, and adds that it would need additional technical capabilities for such verification.[254] The SPP Market Monitor states that the proposal could also negatively affect RTO/ISO market monitors' ability to conduct timely market power mitigation under the proposed timeline because market monitors would be required to perform cost verification and market mitigation before completion of the market clearing process.[255]

114. Industrial Customers argue that market monitors cannot be expected to have the ability to assess the legitimacy of the cost component of resource offers in real-time.[256] Industrial Customers add that even if a resource has a natural gas invoice with a high price and provides it to the market monitor, this alone does not provide adequate consumer protection because the market monitor must investigate, understand, and accept the dynamics that led to that invoice.[257]

115. Citing CAISO's prior comments about practical implementation challenges associated with before-the-fact verification, Industrial Customers argue that the proposal in the NOPR may not be beneficial because pre-verification presents significant challenges given time constraints.[258] KEPCo/NCEMC states that RTOs/ISOs may not be in a position to verify cost-based incremental energy offers prior to market clearing without substantial investment in both new technology and significant changes to the existing RTO/ISO tariffs and business practice manuals.[259] KEPCo/NCEMC argues that the verification requirement involves substantial technological and regulatory costs for wholesale market participants, which KEPCo/NCEMC asserts are unwarranted given the limited nature of the problem with the current RTO/ISO offer caps.[260]

116. EEI maintains that the NOPR proposal is heavily dependent on having a verification process that is not so cumbersome as to prevent a resource's cost based incremental energy offer from being verified in time to be used in the LMP calculation. It argues that the use of make-whole payments would not serve the Commission's goal of having clearing prices that reflect the true marginal cost of production, taking into account all physical constraints.[261] NEI states that the manner in which the verification is performed is a key concern, and without a simple and efficient process, there is risk that the LMP will not reflect the true costs of operating the system because it will exclude offers above the cap. NEI maintains that an alternative approach would be warranted if market monitors cannot validate incremental energy offers in excess of $1,000/MWh quickly and efficiently.[262] Competitive Suppliers contend that the proposed verification requirement would result in cost-based offers above $1,000/MWh being unable to set the LMP because cost verification prior to the market clearing process is not possible.[263]

117. Competitive Suppliers argue that removing the offer cap entirely or increasing it significantly would alleviate any challenges inherent in a before-the-fact cost verification process.[264] Similarly, NEI states that instead of the verification requirement, the Commission should lift caps to a

[242] ISO–NE Market Monitor Comments at 8; PJM Market Monitor Comments at 6.

[243] ISO–NE Market Monitor Comments at 8; PJM Market Monitor Comments at 6; SPP Market Monitor Comments at 7.

[244] ISO–NE Market Monitor Comments at 7–8; PJM Market Monitor Comments at 6.

[245] SPP Market Monitor Comments at 7.

[246] EEI Comments at 6; Exelon Comments at 13–14; PJM Power Providers Comments at 3.

[247] Dominion Comments at 5; Exelon Comments at 13–14.

[248] NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 59, 73.

[249] *See infra* PP 126–127.

[250] Exelon Comments at 11; Industrial Customers Comments at 13–16; ISO–NE Market Monitor Comments at 9; Joseph Margolies Comments at 13; Potomac Economics Comments at 3–4; SPP Market Monitor Comments at 2, 7, 9.

[251] Potomac Economics Comments at 3–4.

[252] ISO–NE Market Monitor Comments at 9.

[253] PJM Market Monitor Comments at 7.

[254] SPP Market Monitor Comments at 2, 7, 9, 10–11.

[255] *Id.* at 9.

[256] Industrial Customers Comments at 14.

[257] Industrial Customers Comments at 19.

[258] *Id.* at 14–16 (citing CAISO Post-Technical Workshop Comments, Docket No. AD14–14–000, at 4–6 (Mar. 6, 2015)).

[259] KEPCo/NCEMC Comments at 5.

[260] *Id.*

[261] EEI Comments at 5.

[262] NEI Comments at 4.

[263] Competitive Suppliers Comments at 17–18.

[264] *Id.*

level that does not artificially constrain LMPs.[265]

118. Midcontinent Joint Consumer Advocates and TAPS argue that it is possible to perform the proposed cost verification prior to the market clearing process.[266] Midcontinent Joint Consumer Advocates state that the MISO Market Monitor has publicly confirmed its ability to verify offers prior to market clearing and that it currently tracks fuel prices that could be used to make adjustments to gas and fuel costs included in a MISO resource's cost-based incremental energy offer.[267] According to TAPS, MISO's current process for developing and updating cost-based incremental offers for resources is workable because the vast majority of resources will never experience cost levels close to $1,000/MWh, and the resources that are likely to reach such levels should have already provided the Market Monitoring Unit with up-to-date information about their heat rates, which will allow the Market Monitoring Unit to quickly calculate cost-based incremental energy offers for such resources.[268] TAPS states that MISO's current methodology for verification of cost-based incremental offers could be modified and adapted in all RTOs/ISOs.[269]

d. Uplift Payments

119. Several stakeholders commented on the after-the-fact review of costs in the event that the RTO/ISO or Market Monitoring Unit is unable to verify a resource's incremental energy offer above $1,000/MWh prior to the market clearing process.[270] MISO states that market participants should be required to consult with the Market Monitoring Unit before the submission of an offer in order for that market participant to be eligible for make-whole payments after-the-fact, and asserts that market participants should not be eligible for cost recovery above their offers just because in hindsight, their offers were below their actual costs.[271] PG&E states that if a cost-based incremental energy offer is verified after the market has run, energy cleared from such an offer should be compensated on an ''as bid'' basis.[272] PG&E maintains that if a cost-based incremental energy offer cannot be verified even after the market has run, then that resource's cleared energy should instead be compensated at the LMP.[273] PJM Power Providers and Competitive Suppliers assert that even after-the-fact verification of a resource's costs will be challenging, and, according to Competitive Suppliers, it will be particularly challenging for natural gas resources that have complex fuel supply arrangements.[274]

120. Competitive Suppliers state that in some instances, a resource may not be able to use the RTO's/ISO's verification process to set the market clearing price (for offers above $1,000/MWh) and in such rare cases, it may be necessary to compensate that resource through an uplift payment based on after-the-fact cost verification.[275] Competitive Suppliers assert that if a resource incurs justifiable and demonstrable short-run marginal costs, those costs should be recovered so that the resource does not operate at a loss and so that the resource is not discouraged from offering supply to the market.[276]

121. NEI states that, given that the Commission's price formation reforms are aimed at reducing the use of out-of-market payments, NEI is disappointed by the NOPR proposal to include uplift payments as a fall back if before-the-fact cost verification proves infeasible in practice.[277] However, Direct Energy states that if a resource's verified cost-based incremental energy offer exceeds the cap, that resource should be entitled to full cost recovery of RTO/ISO approved costs through uplift.[278]

e. Specific Proposals for the Verification Requirement

122. Given the concerns about verification of actual costs, several commenters, including RTOs/ISOs,[279] Market Monitoring Units,[280] and other stakeholders,[281] request that the Commission clarify that if it is not possible to verify a resource's actual costs prior to setting LMP, it will accept a process that verifies that a resource's incremental energy offer reasonably reflects that resource's expected costs.

123. Several commenters maintain that a prior-to-the-market-clearing verification process that requires cost-based offers be equal to actual costs will likely result in fewer incremental energy offers above $1,000/MWh that are eligible to set LMP.[282] For example, EEI states that its primary concern with the NOPR is the verification process and whether it is workable.[283] The ISO–NE Market Monitor and PJM/SPP state that there is a trade-off between the level of precision of the cost-based offer verification, the number of offers that will be eligible to set LMPs, and the level of uplift.[284]

124. Several commenters ask the Commission to indicate the types of verification processes it would accept.[285] ISO–NE., MISO, and NYISO state that their current process for developing and updating cost-based incremental energy offers, known as reference levels, could comply with the proposal as clarified to include estimated costs.[286]

125. CAISO states that the simplest method of verifying cost-based incremental energy offers would involve reviewing a broker quote or procurement invoice provided as evidence of a resource's costs, but CAISO questions whether such information would be sufficient.[287] CAISO predicts that incremental energy offers above $1,000/MWh are not likely to be eligible to set the clearing price in CAISO and that instead a resource with costs above $1,000/MWh would receive an uplift payment, assuming that the resource's costs were verified after-the-fact.[288]

126. PJM/SPP state that the principles outlined in the NOPR are sound, provided that the Final Rule allows RTOs/ISOs flexibility to design verification procedures that are consistent with current RTO/ISO rules.[289] PJM/SPP outline conceptual initial proposals for verification, but stress the need to provide RTOs/ISOs with latitude to develop the final verification process with stakeholders.[290] PJM presents a possible verification process that involves an automatic screen to filter out unreasonably high offers and to create a range of reasonableness based on an

[265] NEI Comments at 4.

[266] Midcontinent Joint Consumer Advocates Comments at 5; TAPS Comments at 13–15.

[267] Midcontinent Joint Consumer Advocates Comments at 5.

[268] TAPS Comments at 13–14.

[269] *Id.* at 14–15.

[270] Competitive Suppliers Comments at 19; MISO Comments at 10; PG&E Comments at 3; PJM Power Providers Comments at 4.

[271] MISO Comments at 10.

[272] PG&E Comments at 3.

[273] *Id.*

[274] Competitive Suppliers Comments at 19; PJM Power Providers Comments at 4.

[275] Competitive Suppliers Comments at 20–21.

[276] *Id.* at 21.

[277] NEI Comments at 4.

[278] Direct Energy Comments at 3.

[279] ISO–NE Comments at 4–7; NYISO Comments at 2; PJM/SPP Comments at 12–13.

[280] Potomac Economics Comments at 3–4; ISO–NE Market Monitor Comments at 4.

[281] EEI Comments at 6–7; Exelon Comments at 17.

[282] CEA Comments at 5; EEI Comments at 5.

[283] EEI Comments at 5.

[284] ISO–NE Market Monitor Comments at 5; PJM/SPP Comments at 13.

[285] CEA Comments at 6; IRC Comments at 2.

[286] ISO–NE Comments at 6; MISO Comments at 8; NYISO Comments at 2.

[287] CAISO Comments at 11.

[288] *Id.*

[289] PJM/SPP Comments at 2–3.

[290] *Id.* at 14–21.

index of natural gas prices, the bid/ask spread, and resource heat rates.[291] PJM states that the verification requirement could use a screening process that determines whether certain resources' incremental energy offers in a given area are within ten percent or $100/MWh of a benchmark offer based on a natural gas price index.[292] SPP states that it could develop additional rules that facilitate resources' submission of the fuel cost component of their cost-based incremental energy offers that is consistent with the resource's actual costs where possible, or that is a reasonably accurate representation of those costs. SPP states that given the need to approximate fuel costs that are difficult to verify, in most cases such a verification process could be subject to a reasonable margin of error.[293]

127. ISO–NE states that if its current cost verification process is acceptable to the Commission, then the offer cap proposal may be workable and would help improve price formation if high fuel prices cause generation costs to exceed $1,000/MWh.[294] MISO contends that its current process to establish and adjust cost-based offers can be used to verify incremental energy offers above $1,000/MWh.[295] NYISO also states that its current review process of a resource's incremental energy costs could be used to satisfy the proposed verification requirement.[296]

128. The ISO–NE Market Monitor states that the Commission should revise the proposed verification requirement to permit use of ISO–NE's current Commission-approved process where a resource can update its cost-based incremental energy offer, which occurs through a ''Fuel Price Adjustment.'' [297] The ISO–NE Market Monitor states that ISO–NE's Fuel Price Adjustment mechanism balances the desire to reflect resource costs in cost-based incremental energy offers, the limited information the ISO–NE Market Monitor has available to verify costs, and the need to deter abuse.[298] The ISO–NE Market Monitor explains that ISO–NE's market power mitigation software automatically calculates cost-based incremental energy offers for resources, which may be based on a day-ahead fuel price index.[299]

129. Potomac Economics states that MISO's current process for developing and updating reference levels would comply with a Final Rule which clarified that before-the-fact verification of a resource's expected costs is acceptable.[300] Potomac Economics explains that in MISO, cost-based offers are calculated on the day before every operating day based on next-day fuel price indices.[301] In real-time, the MISO Market Monitor (*i.e.,* Potomac Economics), reviews natural gas prices on ICE at various delivery points, and if natural gas prices rise significantly compared to the next-day fuel index, the MISO Market Monitor adjusts the cost-based incremental energy offers of any affected resources.[302] Potomac Economics adds that a MISO resource can also consult with the Market Monitor and request to raise its cost-based offer beyond this adjustment if the resource provides supporting information, which may or may not be approved.[303]

130. Potomac Economics explains that a NYISO resource may also request to update its cost-based incremental energy offer through a software process that automatically permits such an increase, provided the increase does not exceed a predetermined threshold.[304] Potomac Economics maintains that NYISO may need to adjust the validation threshold to account for periods of unusually high fuel price volatility, but that with such an adjustment, NYISO's current verification process could comply with the proposal.[305]

131. The PJM Market Monitor explains that resource owners in PJM are responsible for submitting their own cost-based offers and fuel cost policies, and that fuel costs are an essential part of the verification process.[306] The PJM Market Monitor states that it does not have the authority to tell a resource owner what its fuel cost is or what its offer should be, but it does have the authority to verify cost-based offers, to discuss cost issues with resource owners, and to refer resource owners to the Commission for rule violations and for the attempted or actual exercise of market power.[307] It states that it is essential that the Commission impose significant penalties for rule violations determined during the after-the-fact review. According to the PJM Market Monitor, a resource should be required to have in place a fuel cost policy that has been approved by both the PJM Market Monitor and PJM before the resource is able to submit an offer in excess of $1,000/MWh.[308] The PJM Market Monitor states that if a resource's cost-based incremental energy offer above $1,000/MWh is used in the market clearing process, the PJM Market Monitor would perform a timely after-the-fact review to determine whether a resource's offer was based upon the best information available at the time the resource submitted the cost-based incremental energy offer.[309] The PJM Market Monitor states that, in cases where an offer above $1,000/MWh is not permitted, the PJM Market Monitor would perform a timely after-the-fact review to determine the actual incurred costs of a resource, and uplift would be paid if the costs exceeded the market clearing price.[310] Any uplift payments for such offers would be based on the actual gas cost incurred. The PJM Market Monitor also recommends that the $1,000/MWh offer cap apply to a resource's ''operating rate,'' which is calculated by adding a resource's incremental offer to its no-load offer.[311]

132. The PJM Market Monitor also maintains that it is essential that any verification process include a rigorous and timely after-the-fact review and a requirement that a resource follows the cost-based offer submission rules and abides by its approved fuel cost policy. The PJM Market Monitor states that the verification process requires strong compliance incentives, and the Commission should impose significant penalties if a resource violates the cost-based incremental energy offer guidelines.[312]

133. Commenters representing generator and load interests also proposed verification processes. Competitive Suppliers and NEI state that lifting the offer cap to a level that does not artificially constrain LMPs is preferable to developing a verification process, as removing the cap allows the market price to convey accurate information of the state of the system even during high stress.[313]

[291] *Id.* at 15–16.

[292] *Id.* at 16–17.

[293] *Id.* at 19.

[294] ISO–NE Comments at 6.

[295] MISO Comments at 8.

[296] NYISO Comments at 3.

[297] ISO–NE Market Monitor Comments at 5–10.

[298] *Id.* at 5.

[299] *Id.* at 6.

[300] Potomac Economics Comments at 5.

[301] *Id.* at 4.

[302] *Id.* In MISO, cost-based offers are referred to as reference levels.

[303] *Id.* at 5.

[304] *Id.* NYISO states that a resource that updates the fuel type or fuel cost information associated with its cost-based incremental energy offer must make supporting documentation available for NYISO's review after-the-fact. *See* NYISO Comments at 4.

[305] Potomac Economics Comments at 6.

[306] PJM Market Monitor Comments at 4–5.

[307] *Id.* at 5.

[308] *Id.* at 6.

[309] *Id.* at 7–8.

[310] *Id.*

[311] *Id.* at 2.

[312] *Id.* at 7.

[313] Competitive Suppliers Comments at 18; NEI Comments at 4.

134. Competitive Suppliers prefer no verification requirement but contends that if the Commission requires that all cost-based incremental energy offers above $1,000/MWh be verified, the RTO/ISO and the generator should be able to identify a set of accepted criteria and data inputs such that resources can submit offers that can be accepted and thus eligible to set LMP.[314] Competitive Suppliers state that PJM's Cost Development Guidelines provide a means of verifying resource costs and may provide an alternative approach to the proposed verification requirement.[315]

135. Exelon proposes that the Commission require RTOs/ISOs to adopt tariff provisions that will permit timely review and approval of resources' cost-based offers based on a resource-specific ''safe harbor'' formula that is agreed upon in advance.[316] Exelon proposes that, at a minimum, the safe harbor formula should include a ten percent uncertainty component and a fuel cost component based on a daily natural gas index, natural gas adders, balancing costs, transportation costs, and a risk adder.[317]

136. Dominion supports a verification process that uses fuel estimates based on recent prices, historical prices during similar conditions, or a combination of both.[318] Dominion would support allowing market participants to submit cost-based offers within a reasonable range of a reference price that would be based on a historical fuel price index or an average of ask prices within a given fuel market, and that offers which fall in the range of that reference price and clear the market should be eligible to set LMP.[319]

137. The New Jersey and Pennsylvania Commissions and OPSI maintain that in order to implement the proposal in PJM, resources should be required to have a fuel cost policy approved by the Market Monitoring Unit prior to submission of cost-based incremental energy offers above $1,000/MWh.[320] The Pennsylvania Commission states that pre-approved resource fuel cost policies in PJM would speed up the verification process, foster market stability, and provide certainty to resources.[321] The New Jersey Commission and OPSI assert that resource fuel cost policies should be derived from a verifiable, algorithmic, and systematic approach consistent with the PJM Market Monitor's fuel cost policy guidelines.[322] The Delaware and Pennsylvania Commissions and OPSI argue that PJM should clarify the role of PJM and the PJM Market Monitor in the review and approval of fuel cost policies and assert that the PJM Market Monitor should have the authority to verify offers above $1,000/MWh.[323]

138. SCE argues that each RTO/ISO should utilize its own stakeholder processes to develop specific verification rules, which may reflect regional factors such as differences in market power mitigation processes and region-specific costs such as emissions and greenhouse gas costs.[324]

3. Determination

139. We adopt the NOPR proposal and clarify that each RTO/ISO or Market Monitoring Unit is required to verify that any incremental energy offer above $1,000/MWh reasonably reflects the associated resource's actual or expected costs prior to using that offer to calculate LMPs. We find that this verification requirement is necessary for incremental energy offers above $1,000/MWh because market power concerns are heightened when a resource's short-run marginal costs exceed $1,000/MWh.

140. Based on the record, it is not practical to require that RTOs/ISOs or Market Monitoring Units verify a resource's actual costs in all circumstances because a resource may not know its actual short-run marginal costs at the time it submits an incremental energy offer to the RTO/ISO for various reasons, including the timing of natural gas procurement. Accordingly, we clarify that an RTO/ISO or a Market Monitoring Unit must verify that cost-based incremental energy offers above $1,000/MWh reasonably reflect a resource's actual or expected costs. Under this requirement, the verification process for cost-based incremental offers above $1,000/MWh must ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs.

141. The RTO/ISO or Market Monitoring Unit, as prescribed in the RTO/ISO tariff and consistent with Order No. 719,[325] must verify the costs within a cost-based incremental energy offer above $1,000/MWh before that offer is used to calculate LMP, subject to the condition that such offers are capped at $2,000/MWh for purposes of calculating LMP.[326] To create such a verification process, we expect that the RTO/ISO would build on its existing mitigation processes for calculating or updating cost-based incremental energy offers.[327] However, we appreciate statements from RTOs/ISOs, market monitors, and others about potential verification processes for incremental energy offers above $1,000/MWh. We recognize that the verification process for incremental energy offers may be a fact-specific inquiry, and we have previously provided Market Monitoring Units with flexibility to make case-specific determinations.[328] Given the potential complexities involved in verifying incremental energy offers as well as the Commission's recognition of the need for proper mitigation methods in energy markets, we will require that RTOs/ISOs explain in their compliance filings what factors will be considered by the RTO/ISO or its Market Monitoring Unit in the verification process for cost-based incremental energy offers above $1,000/MWh and whether such factors are currently considered in existing market power mitigation provisions or whether new practices or tariff provisions are necessary given the verification requirement adopted in this Final Rule. Therefore, we disagree that the verification requirement is needlessly cumbersome because RTOs/ISOs may build on existing processes for market power mitigation.

142. Most RTOs/ISOs prohibit incremental energy offers above $1,000/MWh, a prohibition that some market

[314] Competitive Suppliers Comments at 19.

[315] *Id.*

[316] Exelon Comments at 11.

[317] *Id.* at 17–20 (citing Testimony of Leslie O. Dedrickson at 29–31).

[318] Dominion Comments at 5.

[319] *Id.*

[320] New Jersey Commission Comments at 12–13; Pennsylvania Commission Comments at 9; OPSI Comments at 7–9. This issue was also raised in comments in PJM's offer flexibility proposal in Docket No. ER16–372–000.

[321] Pennsylvania Commission Comments at 9.

[322] New Jersey Commission Comments at 13; OPSI Comments at 8 (citing Monitoring Analytics, Fuel Cost Policy Guidelines: Gas Replacement Cost (Sept. 24, 2015), *available at http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Fuel_Cost_Policy_Guidelines_20150924.pdf*).

[323] Delaware Commission Comments at 12; OPSI Comments at 7–9.

[324] SCE Comments at 1–2.

[325] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, FERC Stats. & Regs. ¶ 31,281, at PP 370–375 (2008), *order on reh'g,* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g,* Order No. 719–B, 129 FERC ¶ 61,252 (2009). *See also* 18 CFR 35.28(g)(3)(iii)(B) (2016).

[326] Pursuant to 18 CFR 35.28(g)(3)(iii)(B), either the internal or external market monitor can ''provide the inputs required to conduct prospective mitigation . . . including, but not limited to reference levels, identification of system constraints, and cost calculations.'' 18 CFR 35.28(g)(3)(iii)(B) (2016). However, prospective mitigation may only be carried out by an internal market monitor if the RTO/ISO has a hybrid Market Monitoring Unit structure. 18 CFR 35.28(g)(3)(iii)(D) (2016).

[327] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 63.

[328] *See New England Power Generators Association, Inc.* v. *ISO New England Inc.,* 144 FERC ¶ 61,157, at P 62 (2015).

monitors characterize as a backstop market power mitigation measure.[329] The offer cap adopted in this Final Rule retains the backstop function that the current $1,000/MWh offer cap plays in existing RTO/ISO market power mitigation because it limits incremental energy offers that are not cost-based to $1,000/MWh. Under this Final Rule, incremental energy offers below $1,000/MWh will remain subject to existing market power mitigation measures. However, this Final Rule will require that all incremental energy offers equal to and above $1,000/MWh be cost-based, which essentially requires mitigation of all incremental energy offers above $1,000/MWh.

143. In this way, the verification requirement requires RTOs/ISOs to make only an incremental change to their existing market power mitigation procedures because the market power mitigation provisions that apply to incremental energy offers below $1,000/MWh will be unchanged. While in this Final Rule we increase the offer cap for cost-based incremental energy offers, we also subject offers above $1,000/MWh to additional market power mitigation in the form of the verification requirement. The verification requirement is designed to ensure that a cost-based incremental energy offer above $1,000/MWh is not an attempt by the associated resource to exercise market power. The verification requirement is part-and-parcel with the increase of the offer cap for cost-based incremental energy offers. We find that it would be inappropriate to raise the offer cap without imposing a verification requirement. The verification requirement thus serves as an additional backstop market power mitigation measure.[330]

144. Contrary to Potomac Economics' assertion that competition is not diminished when short-run marginal costs rise above $1,000/MWh, we find that market power concerns are heightened during such periods because short-run marginal costs in this range may indicate that very few resources are available to provide additional supply. Supply may be limited during such periods because of fuel supply limitations or the physical limitations of resources (*e.g.,* ramping constraints). Accordingly, resources with available supply during such periods likely face little competition, particularly in real-time, and may therefore be able to exercise market power. We find that the verification requirement reasonably addresses market power concerns associated with incremental energy offers above $1,000/MWh because such offers will be required to be cost-based, which should deter attempts by resources to exercise market power.

145. As discussed above, this Final Rule will require RTOs/ISOs to limit incremental energy offers to $2,000/MWh when calculating LMPs, which may be below the cost-based incremental energy offer of a resource. Thus, we revise the verification requirement proposed in the NOPR as indicated below and add new language (underlined below) to account for any uplift associated with the $2,000/MWh hard cap and adopt the following verification requirement:

> 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 offer may not be used to calculate Locational Marginal Prices and the resource would be eligible for a make-whole payment if that resource is dispatched and the resource's costs are verified after-the-fact. *A resource would also be eligible for a make-whole payment if it is dispatched and its verified cost-based incremental energy offer exceeds $2,000/MWh.*

146. We will retain the proposal in the NOPR which ensures that, if a resource's incremental energy offer above $1,000/MWh is not verified but that resource is nonetheless dispatched, that resource would be eligible to receive an uplift payment to recover its verified costs. The basis of the uplift payment would be the difference between a given resource's energy market revenues and that resource's actual short-run marginal costs of the MWs dispatched, as verified after-the-fact by the RTO/ISO or Market Monitoring Unit.[331] We find that such uplift payments are necessary given the challenges associated with the verification processes, to ensure that resources have an incentive to offer into RTO/ISO energy markets, and to ensure that resources are compensated for the service they provide.

147. This Final Rule will permit regional variation in the process for treating incremental energy offers above $1,000/MWh that the RTO/ISO or Market Monitoring Unit cannot verify prior to the start of the market clearing process. For example, the RTO/ISO could have procedures to change the incremental energy offer to $1,000/MWh or to mitigate that offer to a level below $1,000/MWh pursuant to other applicable market power mitigation provisions.

C. Resource Neutrality

1. NOPR Proposal

148. In the NOPR, the Commission proposed the following resource neutrality requirement:

> All resources, regardless of type, are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh.[332]

The Commission reasoned that this requirement would ensure that the eligibility to submit cost-based incremental energy offers in excess of $1,000/MWh would not be applied in an unduly discriminatory or unduly preferential manner.[333] The Commission also stated that the proposed resource neutrality requirement is consistent with prior orders related to the offer cap in PJM and MISO.[334]

2. Comments

149. Several commenters support the proposed resource neutrality requirement.[335] For example, MISO supports the resource neutrality requirement and notes that the MISO tariff currently allows any resource, regardless of type, to establish a cost-based reference level.[336] MISO adds that some resources could be constrained by the $1,000/MWh cap because they may be unable to provide evidence of high fuel costs.[337]

150. Commenters disagree about whether demand response resources should be able to submit incremental energy offers above $1,000/MWh. Some commenters argue that demand response resources should be treated the same as other physical generation resources that provide offers.[338]

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[329] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 23.

[330] Moreover, existing Commission regulations establish that misrepresenting costs when submitting cost-based incremental energy offers as part of a supply offer may be in violation of 18 CFR 35.41(b) (2016) and 18 CFR 1c.2(a)(2) (2016).

[331] The Commission notes that the clarification regarding use of a resource's actual or expected short-run marginal costs during the verification process that occurs prior to the market clearing process is not applicable to such uplift payments. Any such uplift payment, which is paid after-the-fact, must be based on a resource's actual short-run marginal costs.

[332] NOPR, FERC Stats. & Regs, ¶ 32,714 at P 69.

[333] *Id.*

[334] *Id.* (citing MISO 2014/15 Offer Cap Order, 150 FERC ¶ 61,083 at P 16; PJM 2014/15 Offer Cap Order, 150 FERC ¶ 61,020 at P 39).

[335] EEI Comments at 1, 3; Ohio Commission Comments at 12; MISO Comments at 12.

[336] MISO Comments at 12 (citing MISO Tariff, Module D, 64.1.4.a, 64.3.a, and 64.1.4.h).

[337] *Id.*

[338] API Comments at 12–13; Competitive Suppliers Comments at 23–24; Exelon Comments at 23 (citing PJM Manual 11 2.3.3); Industrial Customers Comments at 28; PJM Market Monitor Comments at 12–13.

Additionally, MISO questions why a demand response resource should be prevented from submitting an offer at the same level (in $/MWh) as physical resources.[339]

151. However, other commenters argue that demand response should not be able to submit incremental energy offers above $1,000/MWh. PJM/SPP argue that the proposed offer cap revisions should not apply to demand response resources because demand response resource offers are intended to capture foregone commercial revenues, not the short-run marginal cost of reducing output.[340] ISO–NE asserts that a demand response resource's costs would be based on its marginal opportunity cost of foregone consumption, which could routinely exceed $1,000/MWh or $2,000/MWh, and that verifying such costs could not be accomplished on short notice. ISO–NE surmises that allowing demand resources to submit incremental energy offers above $1,000/MWh could create perverse incentives and may give physical resources the incentive to move behind the meter to exploit asymmetries in the application of the offer cap. Accordingly, ISO–NE requests that the Commission carefully consider its position on verification of the actual costs of demand response resources.[341]

152. The New Jersey Commission argues that in the absence of a comprehensive definition of short-run marginal costs for demand response resource offers, demand response resources should not be permitted to offer and set the market clearing price above the Commission's determined offer cap.[342] The Pennsylvania Commission asserts that demand response resources should not be eligible to set LMP and should be treated as price takers, asserting that such resources do not generally exhibit competitive behavior in energy markets because the energy revenues of such resources are *de minimis* relative to their capacity market revenues.[343]

153. Several commenters express concerns about whether RTOs/ISOs or Market Monitoring Units can verify the costs of demand response resources. For example, ISO–NE asserts that a demand response resource's costs would be based on that resource's marginal opportunity cost of foregone consumption and other information that is difficult to validate, particularly if the demand response resource's costs increase significantly from the prior day.[344] PJM/SPP state that it is not clear what demand response resource costs could be validated to justify an offer above the $1,000/MWh offer cap.[345] The Pennsylvania Commission states that with the limited exception of on-site backup generation costs, the incremental energy costs of demand response capacity resources are largely unknown.[346] ISO–NE urges the Commission to carefully consider whether the verification of actual costs should be imposed on a resource-neutral basis, and explains its concerns regarding its ability to timely verify the offers of demand response resources.[347] AEMA argues that it is impractical, if not impossible, to verify the costs of a demand response resource in the same manner as a physical generation resource, particularly before-the-fact.[348] AEMA also cites a prior Commission order on ISO–NE's Order No. 745 compliance where the Commission found that ''unlike with supply resources, it would be very difficult to develop a competitive offer or reference price to which to mitigate each demand response resource.'' [349] AEMA asserts that there is no need to create an additional verification requirement for demand response resources, because the Commission has recognized that comparability does not require identical treatment.[350]

154. AEMA requests that the Commission clarify that the offer cap proposed in the NOPR only impacts demand response resources that participate in energy markets and would not apply to demand resources that exclusively participate in capacity markets.[351] AEMA explains that demand response resources that participate exclusively in capacity markets do not make incremental energy offers. AEMA explains that capacity-only demand response resources are only dispatched on a reliability-based trigger that determines the price the demand resource is paid as opposed to an offer price-based trigger that does not represent the LMP at which the customer wishes to be dispatched, or the costs of the customer to curtail its load. AEMA asserts that forcing these resources to make ''incremental energy offers'' in the energy market would drive them away from participation.[352]

155. AEMA requests that the Commission continue to allow demand response resources to submit offers up to the offer cap in energy markets and not impose additional verification requirements on demand response resource energy market offers beyond what has already been accepted.[353] AEMA asserts that the Final Rule should not impact existing or proposed methods for monitoring and evaluating demand resource offers in energy markets or create additional verification hurdles for demand resource offers beyond those that currently exist.[354]

3. Determination

156. We adopt the NOPR proposal and find that resources with costs above $1,000/MWh should be able to submit cost-based incremental energy offers to recover their costs, regardless of the type of resource. Prohibiting a particular set of resources from submitting cost-based incremental energy offers above $1,000/MWh could preclude them from recovering their costs.

157. In the NOPR the term ''resource'' referred to all supply resources, including demand response resources, that offer incremental energy to RTO/ISO energy markets.[355] As such, a demand response resource that submits incremental energy offers to the energy market based on short-run marginal cost would be subject to the verification requirement if that incremental energy offer exceeds $1,000/MWh. For such a resource, the short-run marginal cost may equal its opportunity costs.

158. We recognize that the verification process for demand response resources will necessarily differ from the verification process for generation resources, as noted by ISO–NE and AEMA. The Commission has

[339] MISO Comments at 7.

[340] PJM/SPP Comments at 5.

[341] ISO–NE Comments at 7–8.

[342] New Jersey Commission Comments at 18.

[343] Pennsylvania Commission Comments at 14 (citing PJM, Demand Response Operations Market's Activity Report: February 2016 (Feb. 16, 2016), Fig. 23; Monitoring Analytics, LLC, State of the Markets Report for PJM, Vol. 1., Fig. 10 (Mar. 10, 2016)).

[344] ISO–NE Comments at 7–8.

[345] PJM/SPP Comments at 5.

[346] Pennsylvania Commission Comments at 14.

[347] ISO–NE Comments at 7–8.

[348] AEMA Comments at 7–8.

[349] *Id.* at 8 (citing *ISO New England Inc.,* 138 FERC ¶ 61,042, at P 138 (2012)).

[350] *Id.* at 8–9 (citing *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299, at P 216 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009); *Indep. Market Monitor for PJM* v. *PJM Interconnection, L.L.C.,* 155 FERC ¶ 61,059, at P 31 (2016) (''comparability does not require identical application to demand response resources and generation resources of PJM's offer cap and the must-offer requirement'')).

[351] *Id.* at 3.

[352] *Id.* at 3–5.

[353] *Id.* at 5–6.

[354] *Id.* at 2–3, 7–9.

[355] This is consistent with prior uses of the term. *See, e.g., Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 825, 81 FR 42,882 (June 30, 2015), FERC Stats. & Regs. ¶ 31,384, at P 98 (2016).

recognized that demand response resources should receive comparable, but not necessarily identical treatment to generation resources.[356] However, we decline AEMA's request to exempt demand response resources that submit incremental energy offers in RTO/ISO energy markets from any additional verification requirements associated with this Final Rule, because such an exemption does not constitute comparable treatment. However, as noted above,[357] this Final Rule does not prescribe how RTOs/ISOs should verify cost-based incremental energy offers above $1,000/MWh, including offers from demand response resources.

159. Finally, we find that the New Jersey and Pennsylvania Commissions' comments that demand response resources should not be able to set LMP are beyond the scope of this Final Rule, which only applies to incremental energy offers above $1,000/MWh, and not the general eligibility of demand response resources to set LMPs in RTO/ISO energy markets. We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets.

V. Other Issues

A. Virtual Transactions

160. Although the Commission preliminarily found in the NOPR that virtual supply offers and virtual demand bids (virtual transactions) could not provide a cost basis for offers above $1,000/MWh, it sought comment about whether prohibiting virtual transactions above $1,000/MWh could limit hedging opportunities, present opportunities for manipulation or gaming, create market inefficiencies, or have other undesirable consequences.[358]

1. Comments

161. CAISO states that virtual transactions do not face short-run marginal production costs and would thus be unable to justify costs above $1,000/MWh.[359] However, CAISO notes that if physical resources can submit incremental energy offers above $1,000/MWh, then virtual participants should also be able to bid above $1,000/MWh to arbitrage those physical offers.[360]

162. ISO–NE states that market participants should be able to submit virtual supply offers at levels as high as offers from physical resources to ensure that there is a liquid supply of offers that can compete with physical resources in the day-ahead market under all market conditions, which can reduce the potential exercise of market power during tight day-ahead conditions.[361] ISO–NE asserts that if the Commission adopts a new hard cap, there is no cost-basis or market power rationale to limit virtual supply offers below the level of any hard cap.[362]

163. PJM argues that virtual transactions should be permitted to exceed $1,000/MWh or be subject to a reasonableness screen because virtual transactions increase competition in the day-ahead markets and reduce market share, and thus reduce market power.[363] MISO states that prohibiting virtual transactions above $1,000/MWh could limit hedging opportunities which could increase the price differentials between the day-ahead and real-time energy markets.[364] MISO adds that revising the offer cap for virtual transactions could conceivably expose other market participants to high prices but notes that MISO already has mitigation measures in place for virtual transactions and that years of market experience have shown that such manipulation concerns are improbable.[365]

164. NYISO states that cost-based incremental energy offers, interchange transactions (*e.g.,* imports and exports), and virtual transactions should be capped at the level of the hard cap, which will allow market participants to continue to compete to the maximum extent practicable.[366] NYISO also argues that a hard cap is appropriate for virtual transactions because such transactions are based on price expectations as opposed to verifiable costs.[367] SPP states that it takes no position on the application of the proposed reforms to virtual transactions.[368]

165. Potomac Economics states that competitive virtual transactions should be permitted to exceed $1,000/MWh when real-time prices are expected to exceed $1,000/MWh.[369] Potomac Economics states that although virtual transactions do not have production costs, they do have marginal costs, and notes that the marginal cost of selling virtual energy in the day-ahead market is the expected cost of buying the energy in the real-time market.[370] Potomac Economics states that virtual transactions support the competitive performance of day-ahead markets and thus argues that it is important to structure the rules for virtual transactions in a manner that does not impede their participation in the market.[371]

166. Potomac Economics proposes that virtual transactions be permitted to exceed $1,000/MWh when real-time LMPs are expected to exceed $1,000/MWh for more than a specified period (*e.g.,* 30 minutes).[372] The PJM Market Monitor argues that market participants should not be permitted to submit virtual transactions above $1,000/MWh because increasing the offer cap on virtual transactions would create opportunities for the exercise of market power and manipulation of markets and permit resource owners to avoid the requirement that incremental energy offers above $1,000/MWh be cost-based.[373] The PJM Market Monitor states there is no evidence that virtual supply offers have increased competition or would increase competition in extreme circumstances.[374] The PJM Market Monitor recommends that if the Commission wishes to permit some virtual transactions to exceed $1,000/MWh, the Commission should: (1) Limit virtual transactions above $1,000/MWh to liquid trading hubs; (2) require market participants to explain why virtual offers or bids above $1,000/MWh are appropriate; and (3) subject such virtual transactions to a ''reasonableness screen'' and an after-the-fact review for whether they resulted in manipulation or market power.[375] The PJM Market Monitor states that the asserted benefits of virtuals with respect to hedging, competition, and price convergence have not been empirically established, and, thus, it is unnecessary to create

[356] *Demand Response Compensation in Organized Wholesale Energy Markets,* Order No. 745, FERC Stats. & Regs. ¶ 31,322, at P 66, *order on reh'g and clarification,* Order No. 745–A, 137 FERC ¶ 61,215 (2011) (''as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource.'').

[357] *See supra* P 141.

[358] NOPR, FERC Stats. & Regs ¶ 32,714 at PP 64, 73.

[359] CAISO Comments at 13.

[360] *Id.*

[361] ISO–NE Comments at 8.

[362] *Id.* at 8–9.

[363] PJM/SPP Comments at 27.

[364] MISO Comments at 18; *see also* PJM/SPP Comments at 27–28.

[365] MISO Comments at 18.

[366] NYISO Comments at 7–8.

[367] *Id.* at 7.

[368] PJM/SPP Comments at 28.

[369] Potomac Economics Comments at 10.

[370] *Id.*

[371] *Id.*

[372] *Id.* at 9–10.

[373] PJM Market Monitor Comments at 11; PJM Market Monitor Answer at 6.

[374] PJM Market Monitor Answer at 5.

[375] PJM Market Monitor Comments at 11–12.

market power risks when revising the offer cap.[376]

167. Separately, the PJM Market Monitor recommends that up-to-congestion transactions in PJM be excluded from any offer cap reforms stating that because up-to-congestion transactions are spread bids between nodes there is no reason to relax the current rules that govern such transactions.[377]

168. Several commenters argue that the Commission should allow virtual transactions to exceed $1,000/MWh.[378] Some commenters focus on the use of virtual transactions to hedge physical transactions and argue that virtual transactions should thus be subject to the same offer caps as physical resources.[379] Dominion states that in extreme winter conditions, a physical resource that faces a start-up risk and is likely to receive a day-ahead award may submit a virtual demand bid to hedge against the potential outage in real-time.[380] Exelon also argues that hedging the risk of physical transactions through virtual transactions is especially important when the system is stressed, and that doing so may improve market performance by converging day-ahead and real-time prices.[381] Competitive Suppliers assert that the same argument articulated in the NOPR for having a uniform offer cap across regions demands similar treatment of virtual transactions, imports, and emergency demand response across regions.[382]

169. Dominion states that limiting the ability to submit virtual transactions above $1,000/MWh to physical resources with verified cost-based incremental energy offers above $1,000/MWh in order to allow such resources to hedge would minimize concerns about market manipulation.[383] The PJM Market Monitor responds that Dominion's proposal creates a significant risk of manipulation because Dominion does not propose to limit the virtual bids to the cost-based offer of the generator.[384]

170. Several other commenters argue that virtual transactions should be prohibited from submitting transactions above $1,000/MWh.[385] For example, several commenters argue that virtual transactions should not be permitted to exceed $1,000/MWh because allowing transactions in this range could raise clearing prices without a commensurate increase in short-run marginal production costs.[386] Six Cities argues that permitting virtual transactions to submit offers above the $1,000/MWh cap would be inconsistent with the Commission's goals of allowing recovery of actual production costs in excess of the cap and establishing LMPs consistent with actual production costs under extreme market conditions.[387] TAPS argues that the Commission does not need to allow virtual transactions to exceed $1,000/MWh to encourage price convergence between the day-ahead and real-time markets.[388]

171. Some commenters argue, as the PJM Market Monitor does, that allowing virtual transactions above the $1,000/MWh cap could lead to undesirable consequences, such as creating the opportunity for market manipulation and the exercise of market power.[389] For example, SCE cautions that allowing virtuals above $1,000/MWh would undermine the purpose of having a backstop for existing market power mitigation rules.[390] APPA, NRECA, and AMP state that although they oppose the idea, any proposal to allow virtual transactions above $1,000/MWh must be accompanied by an assurance that the RTO/ISO and/or Market Monitoring Unit will be able to address any gaming or anti-competitive conduct.[391] PG&E asks that the Commission direct market monitors to study the potential impacts and gaming opportunities associated with permitting virtual transactions above $1,000/MWh before revising any caps on virtual transactions.[392] Midcontinent Joint Consumer Advocates state that while it generally supports applying the same offer cap to physical and virtual transactions, the issue should be monitored to ensure that inappropriate virtual transactions do not affect real-time energy prices.[393] The Delaware Commission recommends that virtual transactions in PJM be limited to $400/MWh.[394]

2. Determination

172. In light of the comments received and our adoption of a $2,000/MWh hard cap, we find that it is just and reasonable to permit market participants to submit virtual transactions up to $2,000/MWh. We do not require that virtual transactions be subject to the cost verification described above. Allowing virtual transactions above $1,000/MWh could improve price convergence between day-ahead and real-time markets.[395] An offer cap that is lower for virtual transactions than for physical resources could increase divergence between day-ahead and real-time LMPs. This finding is consistent with prior Commission precedent, which finds it is reasonable to permit market participants to submit virtual transactions at levels commensurate with the levels that real-time LMPs can reach.[396]

173. We find that market participants should be allowed to submit virtual transactions up to the hard cap, as they can today. As such, this Final Rule is therefore less likely to result in unintended consequences associated with capping virtual transactions at a level below the hard cap. For example, capping virtual transactions at $1,000/MWh when the incremental energy offers used to calculate LMPs are capped at $2,000/MWh could encourage some market participants to place virtual demand bids at $1,000/MWh, a transaction that may be profitable if real-time prices exceed $1,000/MWh but would not contribute to day-ahead and real-time price convergence.

174. Under this Final Rule, LMPs may rise above $1,000/MWh. By permitting virtual transactions to exceed $1,000/MWh, we preserve a market participant's ability to use virtual

[376] PJM Market Monitor Answer at 5.

[377] PJM Market Monitor Comments at 11; PJM Market Monitor Answer at 6.

[378] Competitive Suppliers Comments at 23–24; Dominion Comments at 7; Exelon Comments at 23–24; ISO–NE Comments at 8; PJM/SPP Comments at 27; SPP Market Monitor Comments at 12; NY Department of State Comments at 6.

[379] SPP Market Monitor Comments at 12; Competitive Suppliers Comments at 23–24; NY Department of State Comments at 6; Dominion Comments at 7.

[380] Dominion Comments at 7.

[381] Exelon Comments at 23–24.

[382] Competitive Suppliers Comments at 23.

[383] Dominion Comments at 7.

[384] PJM Market Monitor Answer at 6.

[385] APPA, NRECA, and AMP Comments at 19; Industrial Customers Comments at 28–29; Ohio Commission Comments at 14; New Jersey Commission Comments at 17–18; Six Cities Comments at 3.

[386] Industrial Customers Comments at 28–29; New Jersey Commission Comments at 17–18; Six Cities Comments at 3; Ohio Commission Comments at 14; TAPS Comments at 20–21.

[387] Six Cities Comments at 4.

[388] TAPS Comments at 21.

[389] APPA, NRECA, and AMP Comments at 19; ODEC Comments at 1; KEPCo/NCEMC Comments at 5; New Jersey Commission Comments at 18; PJM Market Monitor Comments at 11–12; TAPS Comments at 21.

[390] SCE Comments at 2.

[391] APPA, NRECA, and AMP Comments at 19.

[392] PG&E Comments at 3–4.

[393] Midcontinent Joint Consumer Advocates Comments at 9.

[394] Delaware Commission Comments at 14. The Delaware Commission recommends that in PJM, virtual transactions and incremental energy offers that are not cost-based be limited to $400/MWh.

[395] *PJM Interconnection, L.L.C.,* 139 FERC ¶ 61,057 (2012).

[396] *Id.* PP 123–126. In that order, the Commission found that ''if virtual traders and demand cannot submit higher bids in the day-ahead market [commensurate with the $/MWh value that real-time LMPs can reach if shortage pricing is in effect], that market may not converge with prices in the real-time market during times when PJM experiences shortage conditions in the real-time market.'' *Id.* P 124.

transactions to hedge its exposure to real-time LMPs above $1,000/MWh. Otherwise, if virtual transactions are limited to $1,000/MWh, as proposed in the NOPR, a market participant would be barred from placing virtual transactions commensurate with its market risks.

175. We also find that allowing virtual transactions above $1,000/MWh may add liquidity to day-ahead markets. Permitting virtual transactions in the $1,000/MWh—$2,000/MWh range could result in additional demand bids and supply offers (*i.e.,* virtual demand bids and virtual supply offers) and will thus allow virtual transactions to continue to perform the functions that they do today by adding liquidity to the day-ahead market.

176. We recognize that virtual transactions, by their nature, cannot be subjected to the type of cost-verification discussed above. However, in response to comments arguing that virtual transactions above $1,000/MWh will raise LMPs above verifiable costs and/or result in market power abuse, we note that Market Monitoring Units currently monitor for anti-competitive behavior by market participants. While they are not required to do so, if RTOs/ISOs determine that additional measures are necessary to address any concerns that arise from permitting virtual transactions up to $2,000/MWh, RTOs/ISOs may propose such additional measures in a separate filing under section 205 of the Federal Power Act.

177. Dominion proposes to limit the ability to submit virtual transactions above $1,000/MWh to physical resources that have cost-based offers above $1,000/MWh. We find that Dominion's proposal to limit virtual transactions to certain market participants would be unduly discriminatory. Such a limitation would treat market participants differently depending on whether they owned physical generation assets, and would be unduly discriminatory because it would limit the benefits of virtual transactions above $1,000/MWh to those participants with physical assets. Further, such a limitation could limit the other potential benefits of virtual transactions above $1,000/MWh, such as increased liquidity and increased convergence between day-ahead and real-time LMPs. Additionally, we find that the PJM Market Monitor's and Potomac Economics' proposals to limit virtual transactions above $1,000/MWh to certain time periods or certain locations lack sufficient detail and record evidence to make a finding that either proposal is just and reasonable. Finally, we clarify that this Final Rule does not apply to up-to-congestion transactions in PJM, because such transactions are spread bids and not virtual supply offers or virtual demand bids.

B. External Transactions

178. In the NOPR, the Commission stated that external RTO/ISO resources (*i.e.,* imports) would not be eligible to submit cost-based incremental energy offers above $1,000/MWh because RTO/ISO processes to develop cost-based incremental energy offers for mitigation purposes typically only apply to internal RTO/ISO resources.[397] The Commission added, however, that it would consider RTO/ISO proposals to verify cost-based incremental energy offers from external transactions in their respective compliance filings.[398] The Commission also sought comment on whether the offer cap proposal should apply to imports and whether a cost verification process for import transactions is feasible.[399]

1. Comments

179. CAISO maintains that the consistent treatment of internal resources and external resources (*e.g.,* imports) is key to an efficient market and to avoid unintended consequences.[400] CAISO surmises that capping import offers to a level below the cap that internal resource incremental energy offers are subject to could reduce supply offers from imports during periods when natural gas prices in the West rise to a level that would justify LMPs above $1,000/MWh.[401]

180. ISO–NE states that it cannot verify the costs associated with energy import transactions in real-time.[402] ISO–NE explains that an importer's actual cost to import power into ISO–NE from an adjacent market is the adjacent market's real-time LMP, which is determined at the same time as ISO–NE's LMP. ISO–NE adds that, given the lack of organized markets in some control areas adjacent to ISO–NE., it is unclear how actual costs would be verified for import transactions from those areas. Accordingly, ISO–NE requests additional guidance from the Commission about the application of the proposed rule to imports and exports.[403]

181. PJM asserts that non-emergency imports should be allowed to submit offers above $1,000/MWh to ensure that economic import transactions occur even when PJM LMPs exceed $1,000/MWh because such purchases and sales will benefit the market and provide electric supplies by allowing the lowest cost energy to serve customers.[404] PJM adds that imports may also defer operational emergency procedures in extreme situations.[405]

182. PJM explains that under PJM's current rules, economic transactions are capped at the maximum energy price (absent congestion and losses) of $2,700/MWh while emergency import transactions are not. PJM states that the value of lost load may exceed this level and states that PJM is thus willing to pay more than $2,700/MWh to procure emergency energy to prevent load shedding.[406] PJM notes that the verification of import's cost would have to follow a different process than internal resources because the resource behind the import is frequently unknown.[407]

183. SPP states that verifying the costs of imports could be problematic because it is difficult to obtain cost information from resources outside of SPP.[408] SPP asks the Commission to allow regional flexibility for this issue, noting that it would investigate the issue further in response to any Final Rule issued in this proceeding.[409]

184. According to the PJM Market Monitor, 99.99 percent of PJM imports are price takers but imports that are not price takers should continue to be limited to $1,000/MWh offers.[410] Potomac Economics contends that external transactions should be eligible to submit offers above $1,000/MWh when prices in the real-time market exceed $1,000/MWh for more than a specified period of time (*e.g.,* 30 minutes). Potomac Economics also asserts that Coordinated Transaction Schedules should be exempt from the proposed reforms because they reflect a forecast of the price spread between RTO/ISO markets and thus would not set the LMP in either market.[411]

185. The SPP Market Monitor states that the proposed offer cap requirements should apply to imports because imports have the same potential impact on LMPs as internal resources. However, the SPP Market Monitor acknowledges that it is more challenging to verify the offers of

[397] NOPR, FERC Stats. & Regs ¶ 32,714 at P 63.

[398] *Id.*

[399] *Id.* PP 63, 73.

[400] CAISO Comments at 13.

[401] *Id.*

[402] ISO–NE Comments at 9.

[403] *Id.*

[404] PJM/SPP Comments at 25.

[405] *Id.*

[406] *Id.* at 26 (citing PJM, Intra-PJM Tariffs, OATT, Tariff Operating Agreement, Attachment K–Appendix, section 3.2.3.A).

[407] *Id.*

[408] *Id.* at 27.

[409] *Id.*

[410] PJM Market Monitor Comments at 10.

[411] Potomac Economics Comments at 9–10.

imports as compared to offers from internal SPP resources because the SPP market monitor may have limited access to the cost data of external resources.[412]

186. Several commenters assert that imports should be able to offer above $1,000/MWh provided the costs in their offers are verified beforehand,[413] and some commenters say it is possible to develop a workable solution for such verification.[414] For example, the New Jersey Commission argues that imports that clear the PJM capacity auctions, which are pseudo-tied, will have short-run marginal production costs that are available for the market monitor to review, and should thus be permitted to offer into the PJM energy market above $1,000/MWh when their costs exceed $1,000/MWh.[415] Midcontinent Joint Consumer Advocates explain that offers from imports are provided in the day-ahead market and then only scheduled in real-time, and imports cannot set real-time LMPs in MISO.[416] However, Midcontinent Joint Consumer Advocates state that if imports are the source of higher prices in MISO markets, then it would be important to verify the costs of imports and in such cases, Midcontinent Joint Consumer Advocates would support verification for imports so that all suppliers are treated equally.[417] The Delaware Commission supports the NOPR proposal to require verification of exchange transactions provided the process in an exporting region is not less objective or rigorous than the process in the importing region.[418]

187. Powerex asks the Commission to consider adopting a verification process for external resources that is distinct from the process used for internal resources because the two resource types differ.[419] Powerex states that verifying external resource costs is challenging in WECC because large hydroelectric storage facilities in the Pacific Northwest do not have easily calculable and verifiable short-run marginal costs, and because CAISO does not require that import offers be associated with a specific resource.[420] As an alternative, Powerex suggests that the Commission could direct the RTOs/ISOs to implement an offer cap tied to prevailing market prices, such as capping offers from external resources at the higher of $1,000/MWh or 120 percent of the highest market price index report in the region for the previous seven days.[421] TAPS and APPA, NRECA, and AMP assert that the Commission should give individual RTOs/ISOs the discretion to determine whether to allow imports to submit cost-based incremental energy offers over $1,000/MWh.[422]

188. Several commenters argue that limiting external resources to $1,000/MWh offers may dissuade them from offering electricity to the RTO/ISO in periods when it is most needed.[423] For example, CEA states that in light of the Commission's price formation proceeding, there is no compelling reason to adopt an asymmetrical offer cap for internal resources and imports and questions the wisdom of excluding external transactions when price signals indicate scarcity and extreme conditions.[424] Powerex states that the Western Interconnection has a robust market for energy and ancillary services outside of CAISO and that non-CAISO resources may make the economically rational choice to sell power to a non-CAISO customer if CAISO has a lower offer cap compared to the non-CAISO WECC bilateral market.[425]

189. NYISO and Competitive Power Providers state that all market transactions, including imports and virtual transactions, should be capped at the level of the hard cap, which will allow for a greater degree of competition.[426]

190. Some commenters discussed emergency imports. For example, PJM Power Providers agrees with PJM that the Commission should not apply the proposed offer requirements to emergency imports because an offer cap on emergency energy or emergency load reductions would limit PJM's ability to procure sufficient resources and could threaten reliability.[427]

191. However, the PJM Market Monitor argues that emergency imports above $1,000/MWh should be subject to cost verification before they are eligible to set LMP in PJM and asserts that such imports currently have an unmitigated opportunity to exercise market power in PJM markets.[428] The PJM Market Monitor states that the rules of competitive markets should apply, even during emergency conditions.[429] The PJM Market Monitor adds that verifying the costs of emergency imports is feasible because they occur infrequently.[430] PJM Market Monitor asserts that PJM/SPP offer no rationale for exempting emergency imports from the proposed offer cap requirements, which the PJM Market Monitor states are most critical during emergency situations.[431]

2. Determination

192. We find that it is just and reasonable to permit economic exchange transactions (*i.e.,* imports and exports) to offer up to the level of the $2,000/MWh hard cap. We do not require that import or export transactions above $1,000/MWh be subject to the verification requirement prior to the market clearing process.

193. While in the NOPR the Commission proposed to make imports ineligible to offer above $1,000/MWh, *i.e.,* to prohibit imports from making such offers, we now are persuaded that such a prohibition could discourage imports at times when they are most needed. Imports benefit the market because they offer additional supply and increase competition. A prohibition on imports above $1,000/MWh would discourage external resources with short-run marginal costs above $1,000/MWh from supplying energy to the RTO/ISO market, even though the market is willing to purchase that supply, and such a prohibition would thus put upward pressure on energy prices. We applied this rationale above in adopting the offer structure requirement and find that it applies equally to imports. Additionally, similar to the rationale outlined above for virtual transactions, allowing imports to offer up to $2,000/MWh without cost verification is generally consistent with the current market structures in RTOs/ISOs, which typically allow imports to offer up to the same offer cap that internal RTO/ISO resources are subject to. A similar logic applies to export transactions.

194. Further, prohibiting imports from offering above $1,000/MWh could result in uneconomic flows between RTOs/ISOs. For example, if the LMP in one

[412] SPP Market Monitor Comments at 11.

[413] Delaware Commission Comments at 13; Midcontinent Joint Consumer Advocates Comments at 8; Ohio Commission Comments at 13; Six Cities Comments at 3.

[414] Midcontinent Joint Consumer Advocates Comments at 8; Six Cities Comments at 3; CEA Comments at 7–8.

[415] New Jersey Commission Comments at 18.

[416] Midcontinent Joint Consumer Advocates Comments at 8.

[417] *Id.*

[418] Delaware Commission Comments at 13.

[419] Powerex Comments at 7–8.

[420] *Id.* at 8–9.

[421] *Id.* at 9.

[422] TAPS Comments at 19–20; APPA, NRECA, and AMP Comments at 18–19.

[423] NY Transmission Owners Comments at 5–6; CEA Comments at 7–8; NY Department of State Comments at 5; Powerex Comments at 7–8.

[424] CEA Comments at 7–8.

[425] Powerex Comments at 7–8.

[426] Competitive Suppliers Comments at 23–24; NYISO Comments at 7.

[427] PJM Power Providers Answer at 6–7.

[428] PJM Market Monitor Comments at 11; PJM Market Monitor Answer at 2–3.

[429] PJM Market Monitor Answer at 2.

[430] PJM Market Monitor Comments at 11; PJM Market Monitor Answer at 3.

[431] PJM Market Monitor Answer at 3.

RTO/ISO is $1,500/MWh and an external resource would like to offer an import at a price of $1,400/MWh, a prohibition on import offers above $1,000/MWh would restrict that transaction and result in inefficient flows across RTO/ISO boundaries.

195. Additionally, we will not require import offers above $1,000/MWh be cost-verified and find that imports are not similarly situated to internal generation resources. Unlike incremental energy offers from internal resources, import offers are often not resource-specific and, thus, it is difficult—some commenters say impossible—to ascertain the underlying costs of most import offers. This approach is consistent with current market power mitigation measures in RTOs/ISOs that apply to internal resources but do not typically apply to imports.

196. Additionally, RTO/ISO market participants can import energy from adjacent markets and sell that energy in the RTO/ISO energy market. Therefore, it is difficult for external resources in an adjacent market to withhold because internal RTO/ISO resources can import energy from that adjacent market. Additionally, provided the adjacent market is competitive, which is expected if the adjacent market is an RTO/ISO with market power mitigation, it would be difficult for an external resource to exercise market power in the importing RTO/ISO.

197. Though it is not required, the Commission would consider proposals by RTOs/ISOs to verify or otherwise review the costs of imports or exports and/or develop additional mitigation provisions for import and export transactions above $1,000/MWh. Such proposals should be submitted in a separate filing under section 205 of the Federal Power Act.

198. We clarify that this Final Rule will not apply to Coordinated Transactions Schedules, which are spread bids as opposed to energy offers. Additionally, the Final Rule will not apply to emergency purchases, which would go beyond the scope of this Final Rule because such transactions are administratively priced rather than based on short-run marginal cost.

VI. Other Comments

199. The Commission also sought comment on various aspects of the verification process and the types of costs that should be considered in the verification. Specifically, the Commission sought comment on (1) whether the Market Monitoring Unit or RTOs/ISOs may need additional information to ensure that all short-run marginal cost components that are difficult to quantify, such as certain opportunity costs, are accurately reflected in a resource's cost-based incremental energy offer, and (2) to the extent that RTOs/ISOs currently include an adder above cost in cost-based incremental energy offers, whether such an adder is appropriate for incremental energy offers above $1,000/MWh.[432] Commenters also discussed the impact that the proposed offer cap reforms could have on other market constructs, such as shortage pricing.

A. Verification Requirement Details

1. Comments

200. Commenters express differing views on whether opportunity costs are legitimate costs, and if so, whether it is appropriate to include them within cost-based incremental energy offers. The PJM Market Monitor states that it currently calculates opportunity costs at the request of PJM members and does not need additional information about the details of opportunity costs.[433] The SPP Market Monitor explains that SPP currently allows an opportunity cost adder above mitigated offers, which would still be appropriate to include if costs exceed $1,000/MWh.[434]

201. Midcontinent Joint Consumer Advocates and TAPS oppose opportunity cost adders in the verification methodology for cost-based incremental energy offers above $1,000/MWh.[435] Midcontinent Joint Consumer Advocates add that if the Commission finds that opportunity costs may be recoverable, then the Market Monitoring Unit should review such costs to ensure they are just and reasonable.[436]

202. Commenters expressed a range of opinions regarding whether it is appropriate to account for cost uncertainty or other risks through an adder in cost-based incremental energy offers above $1,000/MWh. SPP takes no position on the appropriateness of the adder but argues that the different RTOs/ISOs should be allowed to develop verification rules that are consistent with their existing rules, including adders.[437] PJM, MISO, the PJM Market Monitor, and Potomac Economics support an adder of up to ten percent to account for uncertainty and risk.[438] The ISO–NE Market Monitor states that the primary function of a ten percent adder is to provide for errors or under-estimation of a resource's marginal cost and contends that the Commission should not require such an adder unless it identifies specific and valid costs that are unique to days with abnormally high natural gas prices.[439]

203. Dominion, Exelon, ODEC, and PJM support the inclusion of a ten percent adder to cost-based incremental offers.[440] Dominion and Exelon contend that a ten percent adder to cost-based incremental offers is appropriate because the adder accounts for some of the uncertainty that accompanies fuel cost estimation as well as dispatch instructions.[441] ODEC maintains that the ten percent adder in cost-based incremental energy offers is both justified and necessary in PJM and should not be removed because it accounts for the fact that some costs are unknown when PJM resources compute their cost-based incremental energy offers.[442] APPA, NRECA, and AMP state that adders above cost are not necessary when a resource's costs can be accurately verified prior to the market clearing process.[443]

204. However, the New Jersey Commission, Direct Energy, PG&E, TAPS, and Industrial Customers oppose including a ten percent adder in cost-based incremental energy offers above $1,000/MWh.[444] The New Jersey Commission argues that such an adder would simply afford the generators an additional ten percent margin of profit above their costs that consumers would fund.[445] TAPS and Industrial Customers state that the ten percent adder should not be included in incremental energy offers above $1,000/MWh because the

[432] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 73.

[433] PJM Market Monitor Comments at 8.

[434] SPP Market Monitor Comments at 10. The SPP Market Monitor notes that resources can use forecasted LMPs and production costs to estimate price-cost margins for each hour of the day to determine the opportunity cost component of the mitigated offer.

[435] Midcontinent Joint Consumer Advocates Comments at 6–7; TAPS Comments at 16.

[436] Midcontinent Joint Consumer Advocates Comments at 6–7.

[437] PJM/SPP Comments at 24.

[438] *Id.* at 22–23; MISO Comments at 15; PJM Market Monitor Comments at 9; Potomac Economics Comments at 7.

[439] ISO–NE Market Monitor Comments at 12

[440] Dominion Comments at 6; Exelon Comments at 20 (citing Testimony of Kevin A. Libby at 8–9 (Libby Test.)); ODEC Comments at 5–6; PJM/SPP Comments at 22.

[441] Dominion Comments at 6; Exelon Comments at 20 (citing Libby Test. at 8–9).

[442] ODEC Comments at 6 (citing PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 30).

[443] APPA, NRECA, and AMP Comments at 17.

[444] Direct Energy Comments at 5; PG&E Comments at 3; New Jersey Commission Comments at 17; TAPS Comments at 16; Industrial Customers Comments at 25–26 (citing PJM Market Monitor Comments, Docket No. ER14–1144, at 2, n. 5 (filed Mar. 26, 2015)).

[445] New Jersey Commission Comments at 17.

adder does not constitute an actual cost.[446]

205. With respect to other short-run marginal cost components, the Pennsylvania Commission, CAISO, and Industrial Customers argue that a resource's permissible short-run marginal costs should not include unauthorized natural gas costs and natural gas pipeline penalties.[447] CAISO requests that the Commission convene a technical conference to discuss limitations in fuel markets and the appropriate parameters for determining prudently incurred costs.[448] Industrial Customers recount the Commission's reasoning that allowing recovery for costs and penalties of unauthorized gas consumption could jeopardize gas pipeline and transmission system reliability, and that generators would still have sufficient flexibility.[449]

206. The Commission also sought comment on whether the verification of physical offer components is necessary.[450] The ISO–NE Market Monitor states that ISO–NE's existing process to verify physical offer components takes significant time because such changes to physical offer parameters cannot be completed on the day that offers are due.[451] The ISO–NE Market Monitor advises the Commission to avoid imposing time limitations that interfere with the ISO–NE Market Monitor's ability to review and verify physical parameters before-the-fact.[452] The PJM Market Monitor requests that the Commission clarify that the cost-based offers contemplated in the NOPR include the same limits on offer parameters as all other cost-based offers.[453] Potomac Economics advises that any Final Rule not address physical parameters because additional verification of physical parameters is not needed, and the proposal only addressed incremental energy offers.[454] Midcontinent Joint Consumer Advocates note that physical offer components such as generation minimum and maximum levels are already known and reviewed by the Market Monitoring Unit, and therefore, there is no need for additional verification of physical offer components.[455]

2. Determination

207. Several commenters state that adders above costs should be included in cost-based offers to account for cost uncertainty or risk.[456] While we will not require RTOs/ISOs to include such an adder, if an RTO/ISO chooses to retain an adder above cost or proposes to include a new adder above cost in cost-based incremental energy offers above $1,000/MWh, such adders may not exceed $100/MWh. On balance, we find that limiting adders above cost to $100/MWh is just and reasonable because as clarified above, the verification process may involve reviewing a resource's expected, rather than actual, costs, which could involve the use of imperfect information. Given that practical reality, we find that it is necessary to place an upper bound on the level of adders above cost when incremental energy offers exceed $1,000/MWh in order to ensure that cost-based incremental energy offers above $1,000/MWh reasonably and accurately reflect actual or expected short-run marginal cost.[457] The Commission has previously found in PJM that adders above cost are unjust and unreasonable as applied to an after-the-fact review of documented costs because the costs are no longer uncertain.[458] Applying that same reasoning here, if a resource receives uplift after-the-fact because that resource's cost-based incremental energy offer above $1,000/MWh could not be verified prior to the market clearing process or because its cost-based incremental energy offer exceeded $2,000/MWh, the uplift payments that the resource receives should not include any adders above costs. As noted above, after-the-fact uplift would be based on a resource's actual costs.[459]

208. Based on the record before us, we will not require that additional information on short-run marginal cost components be provided to the RTO/ISO or Market Monitoring Unit. Furthermore, we will not prescribe the manner in which RTOs/ISOs or Market Monitoring Units verify cost-based incremental energy offers above $1,000/MWh. As indicated in the NOPR, RTOs/ISOs use different processes to develop and update the incremental energy offers used for mitigation and differ in how they define the components of cost-based incremental energy offers.[460] While we are taking no action at this time on these issues and comments, we do not prejudge what RTOs/ISOs may file with the Commission in the future. Accordingly, the Final Rule will not require verification of physical offer parameters or financial offer components other than the incremental energy offer.

B. Impact of Offer Cap Reforms on Other Market Elements

209. The Commission recognized in the NOPR that revising the offer cap may impact other RTO/ISO market elements that depend on the offer cap, such as shortage pricing levels or various penalty factors.[461]

1. Comments

210. Four RTOs/ISOs commented that RTO/ISO market elements other than the offer cap may need to be revised if the offer cap is revised. CAISO states that it will face significant implementation challenges if it changes its current $1,000/MWh offer cap because the administrative penalty prices CAISO uses in its market model to indicate that constraints have been relaxed, such as the power balance constraint, are based on the offer cap.[462]

211. PJM states that it would likely need to adjust shortage pricing rules in PJM in light of any Final Rule on offer caps.[463] SPP states that it would likely need to revise its scarcity prices and violation relaxation limits to prevent instances in which LMPs exceed scarcity values.[464] MISO states that it may need to revise its Operating Reserve Demand Curve, $3,500/MWh LMP cap, and Transmission Constraint Demand Curves if MISO's $1,000/MWh offer cap is revised.[465]

212. APPA, NRECA, and AMP and ODEC state that any Final Rule

[446] TAPS Comments at 16; Industrial Customers Comments at 25–26 (citing PJM Market Monitor Comments, Docket No. ER14–1144, at p. 2, n. 5 (filed Mar. 26, 2015)).

[447] Pennsylvania Commission Comments at 5, 10; CAISO Comments at 11–12; Industrial Customers Comments at 26.

[448] CAISO Comments at 12.

[449] Industrial Customers Comments at 26–27 (citing *N.Y. Indep. Sys. Operator, Inc.,* 154 FERC ¶ 61,111, at P 1 (2016)).

[450] NOPR, FERC Stats. & Regs. ¶ 32,714 at P 73.

[451] ISO–NE Market Monitor Comments at 10.

[452] *Id.* at 11.

[453] PJM Market Monitor Comments at 2–3.

[454] Potomac Economics Comments at 11 (citing Potomac Economics Post-Technical Workshop Comments. Docket No. AD14–14–000, at 5 (filed Feb. 24, 2015)).

[455] Midcontinent Joint Consumer Advocates Comments at 6.

[456] *See supra* P 203.

[457] The Commission notes that it previously accepted adders above costs in PJM that exceed $100/MWh. However, after reviewing the record before us in this proceeding, we find that it is just and reasonable to limit the adder to $100/MWh. *See* PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 31.

[458] PJM 2015 Offer Cap Order, 153 FERC ¶ 61,289 at P 31 (citing *PJM Interconnection, L.L.C.,* 149 FERC ¶ 61,059 at P 13).

[459] *See supra* P 146.

[460] NOPR, FERC Stats. & Regs. ¶ 32,714 at PP 61–62.

[461] *Id.* P 72.

[462] CAISO Comments at 14–17. CAISO requests that, prior to issuing the Final Rule, the Commission conduct a technical conference to better understand the challenges of implementation. CAISO Comments at 3, 17.

[463] PJM/SPP Comments at 28.

[464] *Id.* at 29.

[465] MISO Comments at 3–5.

regarding offer caps should be restricted to changing the offer cap and not address potentially associated issues such as scarcity pricing.[466] In contrast, PG&E recommends that before allowing the offer cap to rise above $1,000/MWh, the Commission and the individual RTOs/ISOs should determine all related changes to the markets that would be needed to ensure that the markets would function properly.[467]

2. Determination

213. An RTO/ISO may file, pursuant to section 205 of the Federal Power Act, to propose modifications to shortage prices or other market elements that require revision in light of the offer cap reforms adopted in this Final Rule. However, we do not require such modifications to comply with this Final Rule. We find that it is not appropriate to determine in this Final Rule the changes that individual RTOs/ISOs should make to market elements that are not the subject of these reforms.

VII. Requests Beyond the Scope of This Proceeding

A. Comments

214. Commenters raised issues that are not discussed above and that are outside the scope of this rulemaking. Several commenters argue that the focus of the recommendations in the NOPR is too narrow. API recommends that the Commission look for ways to encourage the appropriate integration of new technologies, including quickly ramping gas-fired generation technology, to meet rapidly changing grid-conditions and allow prices in real-time markets to better reflect the true state of grid reliability at a given moment while addressing any remaining concerns of market power abuse.[468] API further recommends that the Commission initiate an examination of opportunity costs and risk premiums, inclusive of a wider range of resources, in wholesale energy market offer pricing and how they may or may not be considered by various RTO/ISO market rules.[469]

215. The PJM Market Monitor argues that because gas is the only fuel likely to result in offers greater than $1,000/MWh, the removal of any cap on short run marginal cost therefore relies on the competitiveness of the gas markets.[470] The PJM Market Monitor suggests that a reconsideration of the structure and design of the gas market and the potential for a gas market RTO/ISO is a longer term solution to address issues of transparency and market power in the gas market.[471]

216. The Pennsylvania Commission states that the Commission should direct PJM and other RTO/ISO stakeholders to develop a ‘‘circuit breaker’’ provision to cap energy market revenue during uncontrollable and sustained outage events.[472] The Pennsylvania Commission states that during sustained outages, price signals in energy markets become irrelevant, and the main consideration is the time required to repair infrastructure as opposed to the economic theory behind energy markets.[473] The Pennsylvania Commission also recommends that the Commission direct PJM to introduce some level of aggregate market power mitigation or impose a screen for aggregate market power in the PJM day-ahead and real-time markets.[474] PJM Joint Consumer Advocates argue that shortage prices in PJM should be revised to represent customers' willingness to pay,[475] and the Ohio Commission states that scarcity pricing may no longer be necessary in light of this Final Rule.[476]

217. Industrial Customers argue that increases to the current $1,000/MWh offer cap should be explored simultaneously with the elimination of capacity markets, and that the Commission could act more methodically to explore ways to improve capacity market competitiveness and transparency.[477]

B. Determination

218. We appreciate the concerns raised by numerous commenters requesting that the Commission undertake various initiatives, as set forth above. However, we find that the requested initiatives go beyond the scope of this rulemaking, which only addresses incremental energy offers above $1,000/MWh. Accordingly, we will not address those concerns here.

VIII. Information Collection Statement

219. The Paperwork Reduction Act (PRA)[478] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB's regulations,[479] in turn, require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collection(s) of information unless the collection(s) of information display a valid OMB control number.

220. In this Final Rule, we are amending the Commission's regulations to improve the operation of organized wholesale electric power markets operated by RTOs/ISOs. We require that each RTO/ISO (1) cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (2) when calculating LMPs, RTOs/ISOs shall cap verified cost-based incremental energy offers at $2,000/MWh. The reforms required in this Final Rule would require a one-time tariff filing with the Commission due 75 days after the effective date of this Final Rule to implement these reforms. We anticipate the reforms required in this Final Rule, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those RTOs/ISOs that believe that they already comply with the reforms required in this Final Rule, they could demonstrate their compliance in the compliance filing required 75 days after the effective date of this Final Rule in this proceeding. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[480]

221. In the NOPR, the Commission sought comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens, including the use of automated information techniques. Specifically, the Commission sought detailed comments on the potential cost and time necessary to implement aspects of the reforms proposed in the NOPR, including (1) software and business processes changes, including market power mitigation; (2) increased time spent validating cost-based incremental energy offers; and (3) processes for RTOs/ISOs to vet proposed changes amongst their stakeholders. The Commission also stated that although it did not expect other entities to incur

[466] ODEC Comments at 1; APPA, NRECA, and AMP Comments at 20–21.

[467] PG&E Comments at 2.

[468] API Comments at 2–3.

[469] *Id.* at 8.

[470] PJM Market Monitor Comments at 4.

[471] *Id.* at 6.

[472] Pennsylvania Commission Comments at 5–7.

[473] *Id.* at 8.

[474] *Id.* at 13–14.

[475] PJM Joint Consumer Advocates Comments at 5–6.

[476] Ohio Commission Comments at 14–15.

[477] Industrial Customers Comments at 29–30.

[478] 44 U.S.C. 3501–3520.

[479] 5 CFR 1320 (2016).

[480] 44 U.S.C. 3507(d).

compliance costs as a result of the reforms proposed in the NOPR, it sought detailed comments on whether other entities, such as load-serving entities, would incur costs as a result of the reforms proposed in the NOPR. The Commission received no comments in response to these questions.

Burden Estimate and Information Collection Costs: The Commission believes that the burden estimates below are representative of the average burden on respondents, including necessary communications with stakeholders. The estimated burden and cost for the requirements contained in this rule follow.[481] The Commission notes that these cost estimates below do not include costs for software or hardware or for increased time spent validating cost-based incremental energy offers above $1,000/MWh.[482] Software or hardware upgrades may not be required.

FERC–516, AS MODIFIED BY FINAL RULE IN DOCKET RM16–5–000

	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) × (2) = (3)	Average burden (hours) & cost per response (4)	Total annual burden hours & total annual cost (3) × (4) = (5)	Cost per respondent ($) (5) ÷ (1)
One-Time Tariff Filings (Year 1).	6	1	6	500 hrs.; $37,000 [483]	3,000 hrs.; $222,000	$37,000

Cost to Comply: The Commission has projected the total cost of compliance, all within four months of a Final Rule plus initial implementation, to be $222,000. After Year 1, the reforms in this Final Rule, once implemented, would not significantly change existing burdens on an ongoing basis.

The Commission notes that these estimates do not include costs for software or hardware. Software or hardware upgrades may not be required.

Title: FERC–516C,[484] Electric Rate Schedules and Tariff Filings.

Action: Proposed revisions to an information collection.

OMB Control No. 1902–0287.

Respondents for this Rulemaking: RTOs/ISOs.

Frequency of Information: One-time.

Necessity of Information: The Federal Energy Regulatory Commission approves this rule to improve competitive wholesale electric markets in the RTO/ISO regions.

Internal Review: The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

222. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov*, Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–0710, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include FERC–516C and OMB Control No. 1902–0287.

IX. Regulatory Flexibility Act Certification

223. The Regulatory Flexibility Act of 1980 (RFA) [485] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

224. This rule would apply to six RTOs/ISOs (all of which are transmission organizations). The average estimated annual cost to each of the RTOs/ISOs is $37,000, all in Year 1. This one-time cost of filing and implementing these changes is not significant.[486] Additionally, the RTOs/ISOs are not small entities, as defined by the RFA.[487] This is because the

[481] The RTOs/ISOs (CAISO, ISO–NE., MISO, NYISO, PJM, and SPP) are required to comply with the reforms in this Final Rule.

[482] The Commission expects that the validation of cost-based incremental energy offers above $1,000/MWh would be an infrequent occurrence. To the extent that the Market Monitoring Unit or the RTO/ISO spends time validating these offers, the Commission estimates such time to be *de minimis.*

[483] The estimated hourly cost (salary plus benefits) provided in this section is based on the salary figures for May 2015 posted by the Bureau of Labor Statistics for the Utilities sector (*available at http://www.bls.gov/oes/current/naics2_22.htm#13-0000*) and scaled to reflect benefits using the relative importance of employer costs in employee compensation from June 2016 (*available at http://www.bls.gov/news.release/ecec.nr0.htm*). The hourly estimates for salary plus benefits are:

Legal (code 23–0000), $128.94

Computer and mathematical (code 15–0000), $60.54

Information systems manager (code 11–3021), $91.63

IT security analyst (code 15–1122), $63.55

Auditing and accounting (code 13–2011), $53.78

Information and record clerk (code 43–4199), $37.69

Electrical Engineer (code 17–2071), $64.20

Economist (code 19–3011), $74.43

Management (code 11–0000), $88.94

The average hourly cost (salary plus benefits), weighting all of these skill sets evenly, is $73.74. The Commission rounds it to $74 per hour.

[484] The RM16–5–000 Final Rule reporting requirements should be submitted to FERC–516 (OMB Control No. 1902–0096). Currently, that information collection is under review for an unrelated activity. The FERC–516C is a temporary information collection. The reporting requirements of the RM16–5–000 Final Rule are being submitted to FERC–516C to ensure timely submission to OMB.

[485] 5 U.S.C. 601–12.

[486] This estimate does not include costs for software or increased time spent validating cost-based incremental energy offers. As stated above, the Commission expects that the validation of cost-based incremental energy offers above $1,000/MWh would be an infrequent occurrence. To the extent that the Market Monitoring Unit or the RTO/ISO spends time validating these offers, the Commission expects such time to be *de minimis.*

[487] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administrations' regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control

relevant threshold between small and large entities is 500 employees and the Commission understands that each RTO/ISO has more than 500 employees. Furthermore, because of their pivotal roles in wholesale electric power markets in their regions, none of the RTOs/ISOs meet the last criterion of the two-part RFA definition a small entity: ''not dominant in its field of operation.'' As a result, we certify that the reforms in this Final Rule would not have a significant economic impact on a substantial number of small entities.

X. Environmental Analysis

225. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[488] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the Federal Power Act relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[489]

XI. Document Availability

226. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

227. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

228. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

XII. Effective Date and Congressional Notification

229. These regulations are effective February 21, 2017. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Non-discriminatory open access transmission tariffs.

By the Commission.

Issued: November 17, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends part 35, chapter I, title 18, *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Amend § 35.28 by adding paragraph (g)(9) to read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(9) A resource's incremental energy offer must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at $2,000/MWh. 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 offer may not be used to calculate Locational Marginal Prices and the resource would be eligible for a make-whole payment if that resource is dispatched and the resource's costs are verified after-the-fact. A resource would also be eligible for a make-whole payment if it is dispatched and its verified cost-based incremental energy offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh.

The following appendix will not appear in the *Code of Federal Regulations.*

APPENDIX—LIST OF SHORT NAMES/ACRONYMS OF COMMENTERS

Short name/acronym	Commenter
AEMA	Advanced Energy Management Alliance.
AF&PA	American Forest & Paper Association.
APPA, NRECA, and AMP	American Public Power Association, National Rural Electric Cooperative Association and American Municipal Power, Inc.
API	American Petroleum Institute.
CAISO	California Independent System Operator Corporation.
CEA	Canadian Electricity Association.
Competitive Suppliers	Electric Power Supply Association, Independent Energy Producers Association, Independent Power Producers of New York Inc., New England Power Generators Association Inc., Western Power Trading Forum.
Delaware Commission	Delaware Public Service Commission.

entity (NAICS code 221121) to be 500 employees. *See* 5 U.S.C. 601(3), citing to Section 3 of the Small Business Act, 15 U.S.C. 632.

[488] *Regulations Implementing the National Environmental Policy Act of 1989,* Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[489] 18 CFR 380.4(a)(15) (2016).

APPENDIX—LIST OF SHORT NAMES/ACRONYMS OF COMMENTERS—Continued

Short name/acronym	Commenter
Direct Energy	Direct Energy Business, LLC, on behalf of itself and its affiliate, Direct Energy Business Marketing, LLC.
Dominion	Dominion Resources Services, Inc.
EEI	Edison Electric Institute.
Exelon	Exelon Corporation.
Golden Spread	Golden Spread Electric Cooperative, Inc.
Industrial Customers	Electricity Consumers Resource Council, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, American Chemistry Council, Association of Businesses Advocating Tariff Equity, Connecticut Industrial Energy Consumers, Illinois Industrial Energy Consumers, Indiana Industrial Energy Consumers, Inc., Louisiana Energy Users Group, Minnesota Large Industrial Group, Missouri Industrial Energy Consumers, Multiple Intervenors, New Jersey Large Energy Users Coalition, Wisconsin Industrial Energy Group, Inc.
Industrial Energy Consumers	Industrial Energy Consumers of America.
ISO–NE	ISO New England, Inc.
ISO–NE Market Monitor	ISO New England Inc. Internal Market Monitor.
IRC	ISO/RTO Council.
KEPCo/NCEMC	Kansas Electric Power Cooperative, Inc. and North Carolina Electric Membership Corporation.
Joseph Margolies	Joseph Margolies.
Midcontinent Joint Consumer Advocates.	Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, Minnesota Attorney General's Office.
MISO	Midcontinent Independent System Operator, Inc.
NEI	Nuclear Energy Institute.
NESCOE	New England States Committee on Electricity.
New Jersey Commission	New Jersey Board of Public Utilities.
NY Department of State	New York State Department of State Utility Intervention Unit.
NYISO	New York Independent System Operator, Inc.
New York Commission	New York State Public Service Commission.
NY Transmission Owners	New York Transmission Owners (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Power Supply Long Island, Rochester Gas and Electric Corporation).
ODEC	Old Dominion Electric Cooperative.
OMS	Organization of MISO States.
OPSI	Organization of PJM States, Inc.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
PG&E	Pacific Gas and Electric Company.
PJM/SPP	PJM Interconnection, L.L.C. and Southwest Power Pool, Inc. (Joint Comments).
PJM Joint Consumer Advocates	Delaware Division of the Public Advocate, Office of People's Counsel for the District of Columbia, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Kentucky Office of Rate Intervention, Office of Attorney General, Maryland Office of Peoples' Counsel, New Jersey Division of Rate Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Division of the Public Service Commission of West Virginia.
PJM Market Monitor	Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM.
PJM Power Providers	PJM Power Providers Group.
Potomac Economics	Potomac Economics, Ltd.
Powerex	Powerex Corp.
Ohio Commission	Public Utilities Commission of Ohio.
SCE	Southern California Edison Company.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
SPP	Southwest Power Pool, Inc.
SPP Market Monitor	Southwest Power Pool, Inc. Market Monitoring Unit.
Steel Producers' Alliance	Steel Producers' Alliance.
TAPS	Transmission Access Policy Study Group.

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