maximum continuous thrust, and deceleration to ground idle.

(2) The throttle movement from ground idle to rated takeoff or maximum continuous thrust and from rated takeoff thrust to ground idle should be not more than one (1) second, except that, if different regimes of control operations are incorporated necessitating scheduling of the thrust-control lever motion in going from one extreme position to the other, a longer period of time is acceptable, but not more than two (2) seconds. The throttle movement from rated maximum continuous thrust to ground idle should not be more than five (5) seconds.

(3) The time durations for each cycle associated with either takeoff or maximum continuous thrust segments must include all maximums allowed in the TCDS and expected service operation, and must include the following cycles:

(i) Three (3) cycles of 5 minutes each and one (1) cycle of 10 minutes at the takeoff thrust.

(ii) Three (3) cycles of 30 minutes each at the maximum continuous thrust.

Issued in Burlington, Massachusetts, on November 8, 2017.

Robert J. Ganley,

Manager, Engine and Propeller Standards Branch, Aircraft Certification Service.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM16–5–001; Order No. 831–A]

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

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Order on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission is granting in part and denying in part requests for rehearing and clarification of its determinations in Order No. 831, which amended its regulations to address incremental energy offer caps in markets operated by regional transmission organizations and independent system operators.

DATES: This rule is effective January 16, 2018.

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SUPPLEMENTARY INFORMATION:

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I. Introduction

1. On November 17, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 831.[1] Order No. 831 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 are one of the components used to calculate locational marginal prices (LMPs). California Independent System Operator Corporation (CAISO), ISO New England Inc. (ISO–NE), Midcontinent Independent System Operator, Inc. (MISO), New York Independent System Operator, Inc. (NYISO), and Southwest Power Pool, Inc. (SPP) currently have a $1,000/MWh cap on incremental energy offers (offer cap), and PJM Interconnection, L.L.C. (PJM) currently has an offer cap of $2,000/MWh on cost-based offers.[2]

2. In Order No. 831, the Commission amended its regulations to require that each regional transmission organization and independent system operator (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) cap verified cost-based incremental energy offers at $2,000/MWh when calculating LMPs (hard cap).[3] Resources with verified cost-based incremental energy offers above $2,000/MWh will be eligible to receive uplift.[4] In response to comments on the Notice of Proposed

[1] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 81 FR 87,770 (Dec. 5, 2016), FERC Stats. & Regs. ¶ 31,387 (2016) (Order No. 831).

[2] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at PP 11–13.

[3] *Id.* P 1.

[4] *Id.* P 78.

Rulemaking,[5] the Commission clarified that each RTO/ISO or Market Monitoring Unit must verify that any incremental energy offer above $1,000/MWh reasonably reflects the associated resource's actual or expected costs, as opposed to only the resource's actual costs, prior to using that offer to calculate LMP.[6]

3. With respect to treatment of cost-based incremental energy offers above $2,000/MWh, the Commission stated that it expects RTOs/ISOs to use such offers to determine merit-order dispatch, and it cited PJM as an example of an RTO/ISO that 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 LMP.[7] The Commission found that imports should be permitted to offer above $1,000/MWh, but will not be subject to verification.[8] Finally, while Order No. 831 did not require RTOs/ISOs to include an adder above cost in cost-based incremental energy offers above $1,000/MWh, the Commission stated that if an RTO/ISO chooses to retain existing rules that allow for an adder above cost or proposes any new adders above cost, such adders may not exceed $100/MWh.[9] However, in Order No. 831, the Commission did not require RTOs/ISOs to change the costs they currently include in cost-based incremental energy offers, and it did not address whether verifiable opportunity costs are subject to the $100/MWh limit on adders.

4. On December 19, 2016, the Commission received four requests for rehearing and/or clarification of Order No. 831 which raise issues related to the structure of the offer cap, the verification requirement, and the costs included in cost-based incremental energy offers. TAPS filed a request for rehearing and clarification. NYISO filed a request for clarification and, alternatively, request for rehearing. AMP/APPA filed a request for rehearing. Exelon filed a motion for clarification and request for rehearing.[10] For the reasons discussed below, we grant in part and deny in part the requests for rehearing and clarification.

II. Discussion

A. Offer Cap Structure

5. The requests for rehearing and clarification regarding the offer cap structure focus on the level of the hard cap and the implementation of the hard cap.

1. Hard Cap Level

a. Request for Rehearing

6. TAPS seeks rehearing and argues both that the $2,000/MWh hard cap level established by the Commission is not supported by substantial evidence, and that the $1,724/MWh offer cited in Order No. 831 was not a legitimate cost-based incremental energy offer.[11] Rather, TAPS states, the $1,724/MWh offer was the estimated cost of a resource calculated according to PJM's Cost Development Guidelines, but the actual cost of that resource was less than $1,500/MWh. TAPS argues that, given the large discrepancy between estimated and actual costs, it was inappropriate for the Commission to rely on an estimated $1,724/MWh offer as the basis for the $2,000/MWh hard cap level. TAPS asserts that, even if it was appropriate for the Commission to rely upon estimated costs, the Commission should not have used the $1,724/MWh level, since it was estimated using a methodology that is not compliant with Order No. 831. TAPS contends that the Commission should instead set the hard cap level at $1,500/MWh or, alternatively, at $1,800/MWh if the Commission determines that there was a legitimate cost-based incremental energy offer of $1,724/MWh.[12] TAPS also argues that the Commission failed to meaningfully address the analytical evidence TAPS presented in its comments supporting a $1,500/MWh hard cap.[13]

b. Determination

7. We deny TAPS' request for rehearing of the $2,000/MWh level of the hard cap. In Order No. 831, the Commission determined that a hard cap was necessary to limit any adverse impact on LMPs due to imperfect information about a resource's short-run marginal costs that might arise during the verification process.[14] The Commission also recognized that a hard cap that is too low might suppress LMPs below the marginal cost of production.[15] In determining the $2,000/MWh level of the hard cap, the Commission therefore struck a balance between competing goals: (1) Limiting any adverse impacts on LMPs due to imperfect information during the verification process and (2) reducing the likelihood of suppressing LMPs below the marginal cost of production.

8. The overall offer cap structure set forth in Order No. 831 and the overall market structure of RTOs/ISOs in which the offers arise affected the balance struck by the Commission in setting the level of the hard cap. The hard cap does not stand alone, meaning that it is not the only way of ensuring that an offer does not reflect the exercise of market power and that the price resulting from an incremental energy offer is just and reasonable. In balancing the competing goals, the Commission effectively recognized that the hard cap serves as a backstop to the mitigation established through both the cost-based requirement and the verification process—the other elements of the offer cap structure. The cost-based offer requirement serves a ''mitigation function'' [16] by requiring incremental energy offers above $1,000/MWh be cost-based. The verification requirement also addresses market power concerns.[17] The hard cap ''limit[s] the adverse impact that any imperfect information about resources' short-run marginal costs during the verification process could have on LMPs.'' [18] The Commission factored in these two other elements of the offer-cap structure in balancing the competing goals to set the level of the hard cap.

9. In setting that level, the Commission also considered the overall market structure of RTOs/ISOs—a structure designed to ensure that markets are competitive and not subject to the exercise of market power, through for instance, existing market power mitigation processes.[19] The hard cap

[5] *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 PP 3 (2016) (NOPR).

[6] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 139.

[7] *Id.* P 90.

[8] *Id.* P 192.

[9] *Id.* P 207.

[10] The Independent Market Monitor for PJM (PJM Market Monitor) filed an answer to Exelon's motion for clarification and request for rehearing. MISO filed comments in support of NYISO's request for clarification and, alternatively, request for rehearing. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure prohibits answers to requests for rehearing. 18 CFR 385.713(d)(2) (2017). We therefore reject the answer of the PJM Market Monitor. We will treat MISO's comments as an answer and as a result reject them.

[11] TAPS Request for Clarification/Rehearing at 2 (citing *Pac. Gas & Elec. Co.* v. *FERC,* 373 F.3d 1315 (D.C. Cir. 2004); *Canadian Ass'n of Petroleum Producers* v. *FERC,* 254 F.3d 289 (D.C. Cir. 2001) (*Canadian Ass'n of Petroleum Producers*)).

[12] *Id.* at 5–11.

[13] *Id.* at 10 (citing *Canadian Ass'n of Petroleum Producers,* 254 F.3d at 299 (an agency's ''failure to respond meaningfully'' to objections raised by a party renders its decision arbitrary and capricious)).

[14] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 87.

[15] *Id.* P 91.

[16] *Id.* P 83.

[17] *Id.* P 139.

[18] *Id.* P 87.

[19] *Cf. id.* PP 85–90. Additionally, all six RTOs/ISOs have market power mitigation rules designed to prevent market participants from exercising market power. *See, e.g.,* California Independent System Operator Corporation, eTariff, 39; ISO New

also serves as backstop to those existing market mitigation processes.[20]

10. Based on the record, the Commission set the level of the hard cap to $2,000/MWh. The Commission determined that $2,000/MWh was the level that short-run marginal costs would rarely exceed.[21] The cost-based incremental energy offer of $1,724/MWh referenced in Order No. 831, and which TAPS questions, regardless of the methodology by which it was derived, was only one point of reference for the Commission within the context of the broader record. Specifically, the Commission also examined the evidence in the record regarding high natural gas prices that occurred during the Polar Vortex when some resources experienced short-run marginal costs above $1,000/MWh.[22]

11. The alternative $1,500/MWh and $1,800/MWh hard cap levels that TAPS proposed would result in a balance different than the one chosen by the Commission. Lower hard cap levels such as these would increase the likelihood of suppressing prices below the marginal cost of production and would thereby run contrary to the Commission's price formation efforts to ensure that LMPs reflect the short-run marginal cost of the marginal resource. We therefore reject TAPS' request for rehearing and the alternative hard cap levels proposed. As stated above, we continue to find that the $2,000/MWh hard cap reasonably balances reducing the likelihood of suppressing LMPs while limiting any adverse impact on LMPs from imperfect information about resources' short-run marginal costs during the verification process.

12. Further, we reject TAPS' argument that the Commission failed to meaningfully address its $1,500/MWh alternative proposal. The Commission addressed this alternative in adopting the $2,000/MWh hard cap.[23] In any event, in a rulemaking, the Commission need not respond to every comment or analyze every alternative. Rather, the Commission must respond to ''comments which, if true. . .would require a change in an agency's proposed rule.'' [24] The Commission's determination regarding the $2,000/MWh hard cap is not invalidated merely because there may be a reasonable alternative.[25]

2. Implementation of the Hard Cap

a. Requests for Rehearing/Clarification

13. NYISO seeks clarification that Order No. 831 does not require that incremental energy offers above $2,000/MWh be used to determine merit-order dispatch in all RTOs/ISOs, and, in the alternative, seeks rehearing on this issue.[26] NYISO states that, to the extent the Commission intended to establish a requirement, the Commission did not seek comment on the requirement in the NOPR, did not demonstrate that the requirement must be imposed on all RTOs/ISOs in order to ensure just and reasonable rates, and did not consider the burdens the requirement would impose on NYISO.[27]

14. NYISO asserts that such a requirement would introduce foreign market design elements into NYISO that were developed by PJM to be compatible with its own pricing method, market rules, and software.[28] Specifically, NYISO explains that PJM's design accommodates discrepancies between schedules and price, using a secondary *ex post* process to determine LMPs that is separate from the process for determining resource schedules. However, NYISO states that it uses a common *ex ante* process to determine both locational based marginal prices (LBMPs) and resource schedules. NYISO asserts that, because its process utilizes the same offers for scheduling and pricing, it would be challenging to allow resources to be committed and scheduled based on validated incremental energy offers above $2,000/MWh, but then cap the offers for purposes of calculating LBMPs and ancillary services prices. According to NYISO, this would require resource-intensive and potentially costly software changes, make validation of prices and schedules more complex, and require NYISO to redirect resources from other efforts that are more certain to benefit consumers and markets. Additionally, NYISO contends that implementing an offer cap that only limits the offer prices used to determine LBMPs can lead to a divergence between resource schedules and prices that can harm market participants.[29]

15. In addition, NYISO requests clarification that RTOs/ISOs are permitted to apply the same offer cap to both incremental energy and minimum generation offers,[30] and in the alternative seeks rehearing on this issue. Currently, NYISO's tariff applies a $1,000/MWh offer cap to all day-ahead and real-time energy offers, including minimum generation offers. NYISO argues that applying different offer caps to incremental energy offers and minimum generation offers could incentivize suppliers to artificially shape their offers to conform to the different offer caps rather than offer in a manner that accurately reflects a resource's costs, which would result in less optimal commitment, dispatch, and pricing. Furthermore, NYISO states that if minimum generation offer caps are lower than incremental energy offer caps, generators may not offer to supply energy if they do not expect to be able to recoup their costs.[31] NYISO also states that the Commission previously granted waiver of the $1,000/MWh offer cap on both incremental energy offers and minimum generation offers in

England Inc., Markets and Services Tariff, Market Rule 1, Appendix A; Midcontinent Independent System Operator, Inc., FERC Electric Tariff, Module D; New York Independent System Operator, Inc., Market Administration and Control Area Services Tariff, Attachment H; PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT, Tariff Operating Agreement, Attachment M; and Southwest Power Pool, Inc., OATT, Sixth Revised Volume No. 1, Attachment AF.

[20] *Cf. id.* P 89.

[21] *See id.* n.200 (citing *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. *FERC,* 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)))).

[22] *Id.* P 92.

[23] *Id.*

[24] *American Min. Congress* v. *EPA,* 907 F.2d 1179, 1187–88 (D.C. Cir. 1990) (*American Min. Congress*) (citing *Thompson* v. *Clark,* 741 F.2d 401, 408 (D.C. Cir. 1984) (*Thompson*); *ACLU* v. *FCC,* 823 F.2d 1554, 1581 (D.C. Cir.1987) (*ACLU*)).

[25] *See United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1169–70 (D.C. Cir. 1996) (*United Distribution Cos.*) (''FERC correctly counters that the fact that AEPCO may have proposed a reasonable alternative . . . is not compelling. The existence of a second reasonable course of action does not invalidate an agency's determination.'').

[26] *See* Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 90 (''With respect to the 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. . . .'' '').

[27] NYISO Request for Clarification/Rehearing at 5, 11–13.

[28] NYISO also maintains that RTOs/ISOs do not need to have identical software or market rules, and that the practical ability to implement software changes justifies accommodating regional circumstances. *Id.* at 6 (citing *N.Y. Indep. Sys. Operator, Inc.,* 142 FERC ¶ 61,202, at PP 24–26 (2013); *N.Y. Indep. Sys. Operator, Inc.,* 133 FERC ¶ 61,246, at P 25 (2010)).

[29] *Id.* at 7–11.

[30] In NYISO, the first block in a resource's incremental energy offer is called a ''minimum generation bid'' and includes the costs a resource incurs to operate at its economic minimum operating level. NYISO, *Manual 11—Day-Ahead Scheduling Manual,* Sec. 4.3.3. (October 2016) *http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/dayahd_schd_mnl.pdf.*

[31] NYISO Request for Clarification/Rehearing at 13–15.

response to spikes in natural gas costs caused by the Polar Vortex.[32]

b. Determination

16. Regarding NYISO's concerns on economic merit-order dispatch, we clarify that Order No. 831 did not require cost-based incremental energy offers above $2,000/MWh to be used to determine economic merit-order dispatch. We recognize that some RTO's/ISO's existing commitment, dispatch, and pricing algorithms are structured differently, and the Commission in Order No. 831 did not require RTOs/ISOs to change their current practices or software to use cost-based incremental energy offers above $2,000/MWh for determining economic merit-order dispatch. However, in the event that RTOs/ISOs must select from several offers above $2,000/MWh, we encourage RTOs/ISOs to make those selections on a least-cost basis when possible, in order to minimize the cost to serve load.

17. We also clarify that application of the offer cap and verification requirement adopted in Order No. 831 to minimum generation offers, as NYISO requests, is appropriate. Applying different offer caps to minimum generation and incremental energy offers could give resources the incentive to shape their offers in a manner that does not reflect their costs.[33] Furthermore, this application is consistent with prior Commission orders regarding NYISO's offer cap discussed above.[34]

B. Verification Requirement

18. The requests for rehearing regarding the verification requirement focus on the use of expected costs in the verification requirement and whether to subject imports to the verification requirement.

1. Expected Costs

19. The requests for rehearing regarding expected costs include the definition of expected costs and whether they should be included in the regulatory text as well as market power concerns related to the use of expected costs in the verification process.

a. Definition and Regulatory Text

i. Requests for Rehearing

20. AMP/APPA seek rehearing of Order No. 831, arguing that the Commission was arbitrary and capricious because it failed to provide a reasonable justification for allowing sellers' expected costs to set LMP, and that the Commission also unjustifiably expanded the definition of cost-based offers to include ''expected'' costs. According to AMP/APPA, in order for LMPs to send accurate signals regarding the actual cost of producing energy, LMPs should be based on actual costs. AMP/APPA argue that, since some commenters stated that pre-verification of actual costs would not be possible, the Commission should have concluded that offers above $1,000/MWh should not set LMP, and instead, required such costs to be recovered via uplift.[35]

21. Exelon requests rehearing of the fact that the regulatory text does not include the ''actual or expected'' phrase when it describes the costs to be verified. Exelon argues that the current regulatory text fails to adequately capture the Commission's intent described in the preamble, specifically that costs may be either actual or expected. Exelon asserts that, in order to avoid confusion and also satisfy due process and regulatory notice requirements, the Commission should amend the regulatory text to specify that the verified costs can be ''actual or expected.'' [36]

ii. Determination

22. We disagree with AMP/APPA's argument that the use of expected costs in the verification process to set LMPs was arbitrary and capricious, and thus deny its request for rehearing. The record demonstrates that certain natural gas resources do not know their actual short-run marginal costs at the time they submit their incremental energy offers, and thus it is just and reasonable, and consistent with current practice, for such resources to offer based on their expected costs.[37] Given this record, the Commission appropriately responded to the many comments filed by clarifying in Order No. 831 that market participants could offer based on expected costs. In circumstances when actual costs are not known, a resource offer based on expected short-run marginal cost constitutes a competitive offer. Further, contrary to AMP/APPA's assertion, in Order No. 831 the Commission did not expand the definition of the specific types of short-run marginal costs that a resource could include in its cost-based incremental energy offer above $1,000/MWh, but rather, the Commission stated that it expected that the RTO/ISO would build on its existing mitigation processes for calculating or updating cost-based incremental energy offers. Further, in Order No. 831, the Commission required an RTO/ISO to explain in its compliance filing what factors it will consider 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. Thus, the Commission was not arbitrary and capricious because its decision to permit verified expected costs above $1,000/MWh to set LMP is consistent with current RTO/ISO practices that allow cost-based incremental energy offers to be based on expected, rather than actual costs, as demonstrated in the record.[38]

23. We grant Exelon's request to amend the regulatory text by adding the words ''actual or expected'' as suggested by Exelon. We agree that these revisions will provide more certainty to market participants and more clearly state the Commission's intention that both actual and expected costs over $1,000/MWh may be submitted for verification.

b. Market Power Concerns

i. Requests for Rehearing

24. AMP/APPA seek rehearing contending that Order No. 831 is arbitrary and capricious because it fails to address market power concerns that may arise if resources exaggerate expected costs included in cost-based incremental energy offers above $1,000/MWh.[39] According to AMP/APPA, there are strong incentives for an owner of a fleet of resources, for example, to inflate expected costs of one resource during a constrained period in order to increase earnings for all of its resources. AMP/APPA further argue that there is an opportunity to inflate costs because natural gas prices are higher during constrained periods, and this is also when the price of natural gas is less transparent because the price paid by a market seller for gas on the bilateral market is farthest away from index prices.[40]

25. AMP/APPA further assert that Order No. 831 failed to address whether

[32] *Id.* at 13 (citing *N.Y. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,061, at PP 2–4, 20 (2014)).

[33] *See id.* at 14.

[34] *See supra* P 15.

[35] AMP/APPA Request for Rehearing at 9–13 (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (*Motor Vehicle Mfrs. Ass'n*); *United Distrib. Cos.*, 88 F.3d at 1169).

[36] Exelon Request for Clarification/Rehearing at 6–8 (citing *U.S.* v. *Chrysler Corp.*, 158 F.3d 1350 (D.C. Cir. 1998); *Upton* v. *SEC*, 75 F.3d 92 (2d Cir. 1996); *General Electric Co.* v. *EPA*, 53 F.3d 1324 (D.C. Cir. 1995)).

[37] *See* Order No. 831, FERC Stats. & Regs. ¶ 31,387 at PP 104–108.

[38] *See id.* PP 106–107.

[39] AMP/APPA Request for Rehearing at 13–16 (citing *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43).

[40] *Id.* at 13–15 (citing Joint Comments of PJM and SPP, Docket No. RM16–5–000, at 10–11 (filed Apr. 4, 2016); Comments of ISO–NE Market Monitor, Docket No. RM16–5–000, at 7 (filed Apr. 4, 2016)).

allowing offers above $1,000/MWh to set LMP could lead to market power concerns in the natural gas market.[41] In support of this position, AMP/APPA reference the PJM Market Monitor's comments in the Order No. 831 proceeding stating that removing the offer cap entirely could exacerbate market power in the natural gas markets and also impact electricity markets.[42] AMP/APPA further note that the Internal Market Monitor for ISO–NE (ISO–NE Market Monitor) stated that, in ISO–NE., raising the offer cap could expose the energy markets to uncompetitive conditions in the natural gas markets.[43] AMP/APPA therefore propose that offers above $1,000/MWh should be based upon actual costs in order to be used to set LMP, since the use of expected costs can exacerbate market power concerns, but offers above $1,000/MWh based on expected costs should be recovered via uplift.[44]

26. AMP/APPA seek rehearing of Order No. 831, arguing that the Commission's use of expected costs in setting LMP was arbitrary and capricious, and that the Commission did not explain its departure from relevant precedent.[45] Specifically, AMP/APPA argue that allowing expected costs to be used to verify cost-based incremental energy offers above $1,000/MWh contravenes the Federal Power Act (FPA) and is inconsistent with precedent requiring certain safeguards when granting market-based rates. AMP/APPA maintain that the Commission's authority under the FPA to grant market-based rate authority has been upheld in court because the Commission periodically conducts *ex ante* examinations of a public utility's market power as well as enforceable *ex post* reporting.[46] According to AMP/APPA, however, Order No. 831 never requires RTOs/ISOs or Market Monitors to ensure that the market-clearing LMPs resulting from a seller's offer exceeding $1,000/MWh are actually cost-based. AMP/APPA assert that permitting verification based on expected costs does not meet the *ex post* reporting requirement that would allow the Commission to determine whether these expected costs and resulting market-clearing prices are just and reasonable. AMP/APPA therefore conclude that Order No. 831 is unlawful because the Commission cannot rely on market forces to regulate rates in lieu of imposing reporting requirements on generators.[47]

ii. Determination

27. We deny AMP/APPA's request for rehearing and alternative proposal regarding market power concerns and the use of expected costs. We disagree with AMP/APPA that incremental energy offers above $1,000/MWh based on expected costs present market power concerns; the verification requirement in Order No. 831 was specifically designed to address market power concerns and ensure that all incremental energy offers above $1,000/MWh are indeed cost-based. Pursuant to the verification requirement, resources may only submit incremental energy offers above $1,000/MWh if they are cost-based, and the RTO/ISO or Market Monitoring Unit must verify that any such offer reasonably reflects that resource's actual or expected short-run marginal costs. Incremental energy offers above $1,000/MWh may not be used to calculate LMPs if such offers cannot be verified by the RTO/ISO or Market Monitoring Unit prior to the market clearing process. In Order No. 831, the Commission specifically found 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.''[48] The verification requirement in Order No. 831 is therefore designed to prevent the concerns AMP/APPA raise about resources including ''inflated'' or ''exaggerated'' expected costs in cost-based incremental energy offers above $1,000/MWh.

28. We reject as unsupported AMP/APPA's claim that the Final Rule did not address concerns about market power in the natural gas market. The excerpts from the PJM Market Monitor's and ISO–NE Market Monitor's comments that AMP/APPA included in its request for rehearing expressed general concern about removing a hard cap in energy markets given potential concerns about market power in natural gas markets. However, Order No. 831 did not remove a hard cap in energy markets—it adopted a $2,000/MWh hard cap. As discussed above, we balanced several considerations in adopting a $2,000/MWh but the fact that a hard cap continues to remain in place addresses the comments AMP/APPA cites, to the extent there is market power in the natural gas markets. Additionally, the excerpt from the ISO–NE Market Monitor's comments cited by AMP/APPA discusses the relationship between natural gas markets and energy markets and expresses general concerns about limited transparency into the competitive conditions in natural gas spot markets. Again, the $2,000/MWh hard cap addresses this concern as it recognizes that the verification process required by Order No. 831 may be less effective during extreme conditions in the natural gas market.[49]

29. We deny AMP/APPA's request for rehearing regarding market-based rates because Order No. 831 does not depart from Commission precedent, and the Commission's action was not arbitrary and capricious. Contrary to AMP/APPA's claims, a market participant with market-based rate authority that submits a cost-based incremental offer above $1,000/MWh for a resource would continue to be subject to the existing reporting and other requirements that are imposed on entities with market-based rate authority,[50] consistent with the precedent cited by AMP/APPA. Further, contrary to AMP/APPA's assertions, the verification process specifically requires that the RTO/ISO or Market Monitoring Unit ensure that incremental energy offers are in fact cost-based, meaning that the offer must reasonably reflect that resource's actual or expected short-run marginal costs.[51]

[41] *Id.* at 15–16.

[42] *Id.* at 15 (citing PJM Market Monitor, Comments, Docket No. RM16–5–000, at 4 (filed Apr. 4, 2016)).

[43] *Id.* (citing ISO–NE Market Monitor, Comments, Docket No. RM16–5–000, at 3 (filed Apr. 4, 2016)).

[44] *Id.* at 17.

[45] *Id.* at 8 (citing *PSEG Energy Res. & Trade LLC* v. *FERC,* 665 F.3d 203, 208 (D.C. Cir. 2011); *Motor Vehicle Mfrs. Ass'n,* 463 U.S. at 43; *FCC* v. *Fox Television Stations,* 556 U.S. 502, 515 (2009)).

[46] *Id.* at 5 (citing *California ex rel. Lockyer* v. *FERC,* 383 F.3d 1006, 1013–14 (9th Cir. 2004)).

[47] *Id.* at 6–8 (citing *Blumenthal* v. *FERC,* 552 F.3d 875, 882–83 (D.C. Cir. 2009); *FPC* v. *Texaco,* 417 U.S. 380, 399 (1974)).

[48] *See* Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 144.

[49] *See id.* P 87.

[50] For example, entities with market-based rate authority must file Electric Quarterly Reports with the Commission, consistent with Order Nos. 2001 and 768. *Revised Public Utility Filing Requirements,* Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh'g denied,* Order No. 2001–A, 100 FERC ¶ 61,074, *reh'g denied,* Order No. 2001–B, 100 FERC ¶ 61,342, *order directing filing,* Order No. 2001–C, 101 FERC ¶ 61,314 (2002), *order directing filing,* Order No. 2001–D, 102 FERC ¶ 61,334, *order refining filing requirements,* Order No. 2001–E, 105 FERC ¶ 61,352 (2003), *order on clarification,* Order No. 2001–F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements,* Order No. 2001–G, 120 FERC ¶ 61,270, *order on reh'g and clarification,* Order No. 2001–H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements,* Order No. 2001–I, FERC Stats. & Regs. ¶ 31,282 (2008); *Elec. Mkt. Transparency Provisions of Section 220 of the Fed. Power Act,* Order No. 768, FERC Stats. & Regs. ¶ 31,336 (2012), *order on reh'g,* Order No. 768–A, 143 FERC ¶ 61,054 (2013). They must also timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting their market-based rate authority. 18 CFR 35.42 (2017).

[51] *See* Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 140 (''[A]n RTO/ISO or a Market

Continued

As discussed above, the record demonstrates that it is appropriate to use expected costs in the verification of cost-based incremental energy offers because when actual costs are not known, a resource offer based on expected short-run marginal cost constitutes a competitive offer.[52] In Order No. 831, the Commission stated that ''[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.'' [53] Therefore, the use of expected costs in the verification process does in fact allow the Commission to determine whether the resulting market clearing prices would be just and reasonable.

2. Verification of Imports

a. Request for Rehearing

30. TAPS seeks rehearing of Order No. 831's exemption of all imports from the verification requirement for incremental energy offers above $1,000/MWh and asserts that it is unjust and unreasonable and arbitrary, and that it puts internal and external resources on unequal footing.[54] According to TAPS, the Commission's finding that some imports are not resource-specific and therefore cannot have their costs verified does not support exempting all imports from the verification requirement. Therefore, TAPS proposes that only resource-specific imports whose costs are verified by the receiving RTO/ISO should be able to set LMP, while other imports with offers above $1,000/MWh that are not verified should receive uplift payments if their costs are verified after-the-fact. TAPS further argues that failing to verify the costs of imports presents a greater opportunity and incentive for generators to exercise market power. TAPS presents a hypothetical example of a market participant that owns generators both inside and outside of an RTO/ISO and asserts that such a market participant could use its external generators to make import offers above $1,000/MWh that its internal generators would not be permitted to make. TAPS states that, if the market participant's external resource sets the LMP in the RTO/ISO (*i.e.,* as an import), all of that market participant's internal resources would receive infra-marginal rents. According to TAPS, such behavior would be difficult to monitor because Order No. 831 does not require cost information from external resources. TAPS therefore argues that, on rehearing, the Commission should prevent import offers above $1,000/MWh from setting LMP in the importing RTO/ISO unless the import offer costs are verified in advance, and that the Commission should only permit uplift payments to imports that have been cost-verified after-the-fact.[55]

b. Determination

31. We deny TAPS' request for rehearing regarding the treatment of imports. In Order No. 831, the Commission found that exempting incremental energy offers from imports above $1,000/MWh from the verification requirement was justified because imports are not similarly situated to internal resources.[56] Because they are not similarly situated, it was not arbitrary or capricious to treat import offers from external resources differently than offers from internal resources. Specifically, the Commission found that internal resources and imports are not similarly situated because, based on the record,[57] it may be impossible to identify the costs underlying an import offer because they are not resource-specific. Further, Order No. 831 remains consistent with current market power mitigation measures in RTOs/ISOs that generally apply to internal resources but not to imports.

32. With respect to TAPS' proposed alternative which would prevent import offers above $1,000/MWh from setting LMP if the costs cannot be verified, we reject it because, as supported in the record,[58] we continue to find that such a prohibition could discourage imports at times when they are most needed to provide additional supply and increased competition.[59] Further, as the Commission explained in Order No. 831, such a prohibition could also result in uneconomic flows between RTOs/ISOs.[60]

33. In Order No. 831, the Commission also considered market power concerns similar to those raised by TAPS in its rehearing request, but did not find that they warranted requiring cost-verification for import offers above $1,000/MWh. The Commission explained that because ''market participants can import energy from adjacent markets and sell that energy in the RTO/ISO energy market . . . it is difficult for external resources in an adjacent market to withhold.'' [61] The hypothetical example TAPS presents in its request for rehearing does not persuade us otherwise. First, and as the Commission explained in Order No. 831, it is unlikely that a resource-specific import transaction can successfully withhold energy from the destination market because any resource-specific import transaction is also competing against an import transaction that simply buys from the export market at the prevailing export market price. Second, the import offer in that example would only benefit a market participant that owns a fleet of internal and external generation (which is online and being compensated at the LMP in TAPS' hypothetical example) if the import offer actually cleared the importing RTO/ISO's energy market. However, such an import offer would only clear this market at a price above $1,000/MWh if it were below the verified cost-based incremental energy offers of other internal resources and below other import offers. Thus, such an import would be beneficial to the importing RTO/ISO market as it would lower the clearing price compared to a situation without it. Therefore, TAPS' example demonstrates that imports can lower an importing RTO/ISO's LMP, which supports the Commission's rationale for allowing import offers above $1,000/MWh to set LMP.[62] For these additional reasons, we find that the regulations regarding the treatment of imports in Order No. 831 are just and reasonable and not arbitrary and capricious and reject TAPS' proposal to prevent import offers above $1,000/MWh from setting LMP in the importing RTO/ISO unless the import offer's costs have been verified. For similar reasons, we deny TAPS' proposal regarding uplift payments to imports. Finally, we note that in Order No. 831, the Commission stated it would consider RTO/ISO proposals under FPA section 205 to verify or otherwise review the costs of imports or exports and/or develop additional mitigation provisions for import and export transactions with offers above $1,000/MWh.[63]

Monitoring Unit must verify that cost-based incremental energy offers above $1,000/MWh reasonably reflect a resource's actual or expected costs.'').

[52] *See supra* P 22.

[53] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 83.

[54] TAPS Request for Clarification/Rehearing at 12–15.

[55] *Id.* at 12–16.

[56] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 195.

[57] *See, e.g., id.* PP 180, 183, 185.

[58] *See, e.g., id.* PP 179, 181, 188–189.

[59] *Id.* P 193.

[60] *Id.* P 194.

[61] *Id.* P 196.

[62] Order No. 831 does not apply to emergency purchases, such as emergency import purchases. *See id.* P 198.

[63] *Id.* P 197.

C. Costs Included in Cost-Based Incremental Energy Offers

1. Requests for Rehearing/Clarification

34. Exelon requests clarification, and alternatively rehearing, that the Commission did not intend to exclude any particular categories of variable costs, particularly those not tied to the price of the commodity associated with the resource's fuel supply. Exelon asserts that a resource's cost-based incremental energy offer is comprised not only of those costs linked to the price of fuel, but also of other variable costs, including but not limited to balancing costs and transportation costs. Exelon states that if the Commission does not grant its requested clarification, then it seeks rehearing on the basis that exclusion of other variable costs from cost-based incremental energy offers would lead to an unjust and unreasonable result.[64]

35. TAPS requests clarification, and alternatively rehearing, regarding whether opportunity costs may be recovered in addition to the $100/MWh adder.[65] TAPS asserts that in Order No. 831, the Commission did not respond to the arguments it raised in response to the NOPR, did not explicitly state whether the $100/MWh adder includes opportunity costs, and did not state whether RTOs/ISOs can allow opportunity costs when developing their verification methodologies. TAPS asks the Commission to clarify that if an RTO/ISO allows adders, the maximum total amount of such adders, including both opportunity costs and any other difficult-to-quantify costs, cannot exceed $100/MWh. TAPS asserts that, if the Commission intended to permit RTOs/ISOs to propose verification methodologies that allow for the recovery of opportunity costs in addition to the $100/MWh adder, the Commission should grant rehearing because opportunity costs should not be allowed under the ''extreme'' price levels at issue in this proceeding.[66]

36. NYISO requests that the Commission clarify that, when calculating uplift payments for the recovery of verified costs, only actual, documented out-of-pocket costs should be paid after-the-fact and that no risk-related adders or opportunity costs be allowed when cost information is not submitted in a sufficiently timely manner to permit review and verification. NYISO states that it is concerned that the submission of legitimate, verifiable costs that exceed the $1,000/MWh offer cap close in time to the day-ahead or real-time market close could deny NYISO sufficient time to perform cost verification. NYISO states that this could cause the resource's offer to be mitigated to a level that does not include the unverified, additional costs and could cause the resource to be committed when it would not have otherwise been or receive a larger schedule than it otherwise would have. NYISO asserts that its requested clarification would ensure all resources have an incentive to submit timely information to the RTO/ISO.[67]

2. Determination

37. We deny Exelon's request for clarification, and alternatively rehearing, regarding whether the verification requirement intended to exclude particular categories of actual or expected costs, particularly variable costs that are non-fuel related costs. In Order No. 831, the Commission neither required RTOs/ISOs to change the methodologies they currently use to develop cost-based offers in order to satisfy the verification requirement nor prescribed the specific types of short-run marginal costs that could be included in cost-based incremental energy offers above $1,000/MWh. We do not prejudge what types of costs RTOs/ISOs may propose as part of their compliance filings.

38. We deny TAPS' request for clarification, and alternatively rehearing, regarding whether the $100/MWh limit on adders applies to opportunity costs. Opportunity costs are legitimate short-run marginal costs and not adders above cost. Cost-based incremental energy offers based on opportunity costs may currently set LMP in many RTOs/ISOs. Given that, in Order No. 831, the Commission did not require RTOs/ISOs to change the specific costs that they permit resources to include in cost-based incremental energy offers, resources in RTOs/ISOs that permit the use of opportunity costs in this manner may continue to do so after implementing Order No. 831. Because opportunity costs should be considered part of a cost-based incremental energy offer, whether or not the offer exceeds $1,000/MWh, verifiable opportunity costs should not be subject to the $100/MWh limit on adders above cost. We do not prejudge the validity of including verifiable opportunity costs in cost-based incremental offers above $1,000/MWh or the verification methods of such costs that RTOs/ISOs may propose as part of their compliance filings. We also reject TAPS' argument that the Commission failed to meaningfully address its arguments stating that opportunity costs should not be permitted at the ''extreme'' prices contemplated in this rulemaking.[68] As stated above, in a rulemaking, the Commission need not respond to every comment or analyze every alternative.[69] As explained here, opportunity costs are legitimate short-run marginal costs that should be considered part of a cost-based incremental energy offer, regardless of whether that offer exceeds $1,000/MWh. Some current RTO/ISO practices permit cost-based incremental energy offers based on opportunity costs to set LMP, and the Commission in Order No. 831 did not require RTOs/ISOs to change which costs they may include in cost-based incremental energy offers. Therefore, TAPS' comments would not have resulted in a change in the rule.

39. We grant NYISO's request for clarification regarding the calculation of uplift payments. Resources are only eligible to receive uplift payments to make them whole to, at most, their submitted cost-based incremental energy offers if the associated offer and cost information is submitted in a sufficiently timely manner and verified by the RTO/ISO, meaning offers and supporting information must be provided consistent with RTO/ISO offer submission guidelines and approved by the RTO/ISO or Market Monitoring Unit. Consistent with Order No. 831, the after-the-fact uplift payment that a resource would be eligible to receive if its cost-based incremental energy offer above $1,000/MWh is not verified prior to market clearing shall include only actual verifiable costs. We agree with NYISO that opportunity costs, like other costs, must be submitted in a timely manner. However, we clarify that if a resource avails itself of an RTO's/ISO's current rules to allow a resource to include opportunity costs in its cost-based incremental energy offer, then that RTO/ISO must give that resource an

[64] Exelon Request for Clarification/Rehearing at 4–6, 7–8 (citing *Motor Vehicle Mfrs. Ass'n,* 463 U.S. at 43; *NorAm Gas Transmission Co.* v. *FERC,* 148 F.3d 1158, 1165 (D.C. Cir. 1998); *PPL Wallingford Energy LLC* v. *FERC,* 419 F.3d 1194, 1198 (D.C. Cir. 2005)).

[65] TAPS Request for Clarification/Rehearing at 2 (citing *Canadian Ass'n of Petroleum Producers,* 254 F.3d 289).

[66] *Id.* at 16–18 (citing *PJM Interconnection, L.L.C.,* 126 FERC ¶ 61,145, at P 28 n.34 (2009) (''The opportunity cost associated with providing 'must run' output is the value associated with the lost opportunity to produce energy during a higher valued time period within the year.'')).

[67] NYISO Request for Clarification/Rehearing at 15–16.

[68] TAPS Request for Clarification/Rehearing at 17–18.

[69] *See supra* P 12 (citing *American Min. Congress,* 907 F.2d at 1187–88; (citing *Thompson,* 741 F.2d at 408; *ACLU,* 823 F.2d at 1581)).

opportunity to recover those opportunity costs through an uplift payment, subject to verification. We further clarify that a resource may not receive uplift payments for incremental energy costs in excess of the costs included in its verified incremental energy offer. That is, a resource may not submit a cost-based incremental energy offer based on expected costs prior to the market clearing process *and* subsequently receive uplift payments to make it whole to an offer above the $/MWh level(s) of its offer(s).[70] In this instance, allowing a resource to receive uplift in excess of its verified cost-based incremental energy offer could give that resource the incentive to submit offers that do not reflect its actual short-run marginal costs and could thus result in inefficient resource selection.

40. Further, such after-the-fact uplift payments may not include any adders above cost, including risk related adders, because actual costs are known after-the-fact.[71] This finding is consistent with Commission precedent regarding PJM's requests for waivers of certain tariff provisions related to its offer cap.[72]

III. Information Collection Statement

41. The Paperwork Reduction Act (PRA)[73] 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,[74] in turn, require approval of certain information collection requirements imposed by agency rules.

42. The Commission is amending its regulations to clarify what the Commission already required in Order No. 831—that either actual or expected costs included in incremental energy offers above $1,000/MWh may be submitted for verification. The Commission estimates that there will be no net change to burden.

43. Interested persons may obtain information on the reporting requirements by contacting: 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 requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to FERC–516C and OMB Control Number 1902–0287.

IV. Regulatory Flexibility Act Certification

44. The Regulatory Flexibility Act of 1980 (RFA)[75] 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. The Commission has determined that there will not be a significant impact on a substantial number of small entities, therefore these requirements under the RFA do not apply.

V. Document Availability

45. 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 FERC's Home Page (*http://www.ferc.gov*) and in FERC'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.

46. From FERC'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 excluding the last three digits of this document in the docket number field.

47. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC 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.*

VI. Effective Date

48. These regulations are effective January 16, 2018.

List of Subjects in 18 CFR Part 35

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

By the Commission.

Issued: November 9, 2017.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Regulatory Text

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. Revise § 35.28(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 actual or expected 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 actual or expected 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

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[70] For example, a resource may not submit a $2,300/MWh offer based on expected short-run marginal cost that is verified and clears the market and receive uplift associated with incremental energy costs above $2,300/MWh, even if that resource's actual short-run marginal cost, based on an after-the-fact review, is $2,500/MWh.

[71] Order No. 831, FERC Stats. & Regs. ¶ 31,387 at P 146.

[72] In the 2015 PJM offer cap order, the Commission found that ''the 10 percent adder [above costs] is unjust and unreasonable as applied to ex post review of documented costs, because the cost [sic] are no longer uncertain.'' *See PJM Interconnection L.L.C.,* 153 FERC ¶ 61,289, at P 31 (2015). *See also PJM Interconnection, L.L.C.,* 149 FERC ¶ 61,059, at P 13 (2014).

[73] 44 U.S.C. 3501–3520.

[74] 5 CFR 1320 (2017).

[75] 5 U.S.C. 601–12.

resource's actual 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.

[FR Doc. 2017–24803 Filed 11–15–17; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

30 CFR Part 917

[KY–254–FOR; OSM–2011–0005; S1D1SSS08011000SX064A000189S180110; S2D2SSS08011000SX066A00018XS501520]

Kentucky Regulatory Program

AGENCY: Office of Surface Mining Reclamation and Enforcement (OSMRE), Interior.

ACTION: Final rule; approval of amendment.

SUMMARY: We are approving an amendment to the Kentucky regulatory program (hereinafter, the ''Kentucky program'') under the Surface Mining Control and Reclamation Act of 1977 (SMCRA or the Act). Kentucky submitted a proposed amendment to OSMRE that includes revisions to the Kentucky Revised Statutes (KRS) as authorized by House Bill 385 (HB 385), regarding bonding of surface coal mining and reclamation operations.

DATES: The effective date is December 18, 2017.

FOR FURTHER INFORMATION CONTACT: Robert Evans, Telephone: (859) 260–3900. Email: *bevans@osmre.gov.*

SUPPLEMENTARY INFORMATION:

I. Background on the Kentucky Program

Section 503(a) of the Act permits a State to assume primacy for the regulation of surface coal mining and reclamation operations on non-Federal and non-Indian lands within its borders by demonstrating that its program includes, among other things, State laws and regulations that govern surface coal mining and reclamation operations in accordance with the Act and consistent with the Federal regulations. See 30 U.S.C. 1253(a)(1) and (7). On the basis of these criteria, the Secretary of the Interior conditionally approved the Kentucky program on May 18, 1982. You can find background information on the Kentucky program, including the Secretary's findings, the disposition of comments, and conditions of approval of the Kentucky program in the May 18, 1982, **Federal Register** (47 FR 21404, 21434). You can also find later actions concerning Kentucky's program and program amendments at 30 CFR 917.11, 917.12, 917.13, 917.15, 917.16, and 917.17.

II. Description of the Proposed Amendment

On May 10, 2011, Kentucky submitted an amendment to OSMRE for approval that proposed bonding revisions to the KRS as authorized by HB 385, which passed during the State's regular 2011 legislative session. HB 385 was passed in response to OSMRE's findings in its January 5, 2011, National Priority Oversight Evaluation of the Adequacy of Kentucky Reclamation Performance Bond Amounts (National Oversight Study) report. In that report, OSMRE oversight and programmatic reviews identified that current reclamation performance bonds in Kentucky are not sufficient to complete the reclamation required in approved permits. On February 3, 2011, the Kentucky Department for Natural Resources (KYDNR) and OSMRE signed an Action Plan detailing the steps necessary for correcting identified bond calculation deficiencies. The Action Plan required KYDNR to complete revised bonding protocols by April 1, 2011, along with a timetable for implementation for new and existing permits. HB 385 amends Kentucky Revised Statutes 350.060 to provide that:

> Within thirty (30) days of a cabinet determination of a need to change a bond protocol currently in use, the cabinet shall immediately promulgate administrative regulations setting forth bonding requirements including, but not limited to, requirements for the amount, duration, release, and forfeiture of bonds. Bond protocols shall not be exempt from KRS 13A.100 and shall be established by promulgating administrative regulations under KRS Chapter 13A. Failure to include the formula for establishing the amount of the bond in any administrative regulation on bonding requirements shall be deemed a failure to comply with the prescriptions of this section and the administrative regulation shall automatically be declared deficient in accordance with KRS Chapter 13A.

We announced receipt of the amendment and asked for comments in a **Federal Register** notice published on August 15, 2011 (76 FR 50436). In the same document, we opened the public comment period and provided an opportunity for a public hearing or meeting. We did not hold a public hearing or meeting because no one requested one. The public comment period ended on September 14, 2011. We received comments from two organizations.

III. OSMRE's Findings

The following are the findings we made concerning Kentucky's proposed amendment under SMCRA at Section 509, 30 U.S.C. 1259 and the Federal regulations at 30 CFR 800.14 and 800.15.

KRS 350.060 (11) Processing Permit Applications

The new language in KRS 350.060 (11) is intended to ensure that bond protocol regulations include the formula for establishing the amount of the bond. Failure to do so would result in any administrative regulations or bonding requirements to be declared deficient automatically, in accordance with KRS Chapter 13A.

While these proposed State revisions have no direct Federal counterparts there is no provision in SMCRA or its implementing regulations that prohibits a State from requiring its bond protocols to be implemented solely as regulations. On their face, the proposed revisions are not inconsistent with Section 509 of SMCRA and 30 CFR 800.14, and we are therefore approving them, as noted below.

While HB 385 could be construed to require the KYDNR to implement all bond adjustments as regulations before the adjustments can be made, to do so would be inconsistent with the literal construction of the language of the bill. Therefore, we do not construe HB 385 to apply to individual bonding adjustments, or other individual bonding decisions.

Rather, we are approving the proposed amendment, in accordance with its plain language, which will not impede implementation of the requirement in Section 509 of SMCRA that ''[t]he amount of the bond shall be sufficient to assure the completion of the reclamation plan if the work had to be performed by the regulatory authority in the event of forfeiture.'' Nor will the proposed amendment impede the obligation of the regulatory authority to adjust the amount of bond in accordance with 30 CFR 800.15. Should we find, however, during oversight, that the amendment is being interpreted in a manner that would render it inconsistent with either Section 509 of