UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Organized Electric Markets	Docket Nos. RM07-19-000 and AD07-7-000

**REQUEST FOR REHEARING
OR CLARIFICATION OF THE
TRANSMISSION ACCESS POLICY STUDY GROUP**

Pursuant to Commission Rule 713, 18 C.F.R. § 385.713, and Section 313 of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*, the Transmission Access Policy Study Group ("TAPS") requests rehearing and clarification of Order No. 719, the Commission's Final Rule in the above-captioned proceeding.[1] TAPS supports many of the Commission's objectives and a number of the actions taken in the Final Rule in pursuit of those objections. However, we have serious concerns that several of its actions intended to promote demand response will have adverse consequences that the Commission has not recognized or adequately addressed. In other areas (including RTO responsiveness and reducing the delay for disclosure of bid information), we believe the Commission has not gone far enough to foster accountability and transparency.

IDENTIFICATION OF ERRORS

Pursuant to Rule 713(c)(1), 18 C.F.R. § 385.713(c)(1), TAPS identifies the following errors:

1. The Final Rule erroneously imposes requirements regarding the sale of retail non-consumption by individual retail customers and Aggregators of Retail Customers ("ARC") that exceed the Commission's jurisdiction under Section 201 of the FPA.

[1] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), 125 F.E.R.C. ¶ 61,071 (2008) ("Order No. 719").

2. The Final Rule errs by establishing a default regimen that authorizes the sale of retail non-consumption in wholesale markets with no evidence that applicable electric retail regulatory authority laws and regulations allow such sales, and without requiring adequate safeguards to assure that such sales facilitated and effected by RTOs are legal under applicable laws and regulations.

3. The Commission errs by establishing a new retail demand response regimen without substantial evidence that the requirements of this regimen can reasonably be implemented; with no assessment of its negative impact on the existing demand response programs of load-serving entities ("LSE"), which use demand response to reduce costs to all of their customers by reducing planning reserve requirements and avoiding or defering generation investment; and without substantial evidence demonstrating that the new retail demand response regimen will perform as well as or better than existing LSE-based demand response programs.

4. The Final Rule erroneously ignores the concerns of commenters and impermissibly fails to address the defects of its demand response program on grounds that a different regulatory authority may prevent the wholesale sales by retail customers that the Rule authorizes.

5. The Final Rule errs by failing to provide substantial evidence of benefits justifying the significant disruptions to wholesale and retail service that will be caused by its new retail demand response regimen, including the modification of LSE and RTO metering, billing, and settlement processes; the potential for substantial, unpredictable load variation for LSEs; an erosion of the accuracy of the real-time price and consumption information that wholesale customers currently rely on; and potential LSE exposure to a variety of unjust and unreasonable charges based on events over which they have no operational control.

6. The Final Rule erroneously claims that no action affecting retail jurisdictions is being taken, ignoring the significant new burdens that the Final Rule will impose on LSEs to either accommodate the Final Rule, or to enact legislative or regulatory opt-outs from participation; the Commission's failure to analyze these impacts on small entities violates the Regulatory Flexibility Act ("RFA").

7. The Final Rule errs by failing to adopt either the alternative opt-in structure for retail participation in its demand response system, or a minimum threshold for requiring opt-out regulatory action, both of which were suggested by commenters and which would alleviate the undue burdens on hundreds of municipal systems that the Final Rule's opt-out demand response program imposes.

8. The Final Rule errs by making it optional, rather than mandatory, for RTOs to require that entities bidding retail demand response into wholesale markets certify that such demand response is permissibly bid and aggregated under the laws and regulations of the relevant electric retail regulatory authorities.

9. The Final Rule errs by failing to direct RTOs to provide detailed, real-time or near real-time information to affected LSEs on the identity of individual retail customer loads involved and the amount of such retail demand response for each billing interval, in order to enable LSEs to assure that the underlying sales of retail "non-consumption" are authorized by law and to enable appropriate treatment in the retail rates of the host LSE.

10. It was error for the Final Rule to direct RTOs to eliminate price/bid caps, without substantial evidence that lifting such caps will attract investment in generation and demand response sufficient to protect consumers from market power, that the Final Rule's new requirements will change the existing elasticity of demand response, or that consumers will be able to protect themselves from high prices; this directive is inconsistent with the FPA requirement that the Commission ensure all rates are just and reasonable.

11. The Final Rule erred in finding, without substantial evidence, that existing market rules are unjust and unreasonable, and by ignoring variables compromising the effectiveness of the demand response regime thereby violating the Commission's statutory obligation to ensure that the regime of the Final Rule protects consumers completely from excessive rates and charges.

12. The Commission erroneously ignores the comments of TAPS and others regarding the defects of the four scarcity pricing approaches delineated in the NOPR, notwithstanding the Commission's finding that each of these approaches can be just and reasonable, where the four approaches fail to protect consumers from market power, are premised on unsupported assumptions about the bidding behavior or consumers, require the adoption of particular wholesale market structures that have not been established in all RTOs, and may encourage gaming.

13. The Final Rule errs by failing to adopt the National Rural Electric Cooperative Association's ("NRECA") alternative approach (proposing to remove bid caps for demand response resources during emergency situations, provided that the higher bids for demand response do not set the market clearing price for all resources) and by suggesting that the NRECA proposal would be considered by the RTO, when the Commission failed to modify its regulatory text to accommodate the NRECA approach, and imposed new criteria that would bar such consideration. The Final Rule also errs by ignoring TAPS Comments demonstrating that this approach will neither incent generators to create emergencies, nor exact the same degree of extreme hardship on consumers that elevating market clearing prices will do, and explaining that the NRECA Approach would enable the Commission to test its assumptions regarding the availability of demand response and develop the evidentiary basis to support lifting price caps.

14. The Final Rule errs by abandoning the NOPR's comparability criteria, and imposing additional criteria requiring comparability in treatment of and compensation to all resources. In so doing, the Rule creates a potential barrier to NRECA's proposal, and adds to the burden on both consumers and the economy by enhancing compensation

of generators during operating reserve shortages even where such generators have not contributed to addressing the emergency.

15. The Commission erred by failing to adopt strengthened requirements, as recommended by TAPS and others, for the factual showing that RTOs must make regarding their scarcity pricing proposals under the Final Rule. The requirements erroneously rejected by the Commission would have required RTOs to evaluate statistics on scarcity conditions; market power risks; the effectiveness and adequacy of demand response in mitigating market power; the potential for the exercise of market power by entities holding demand response resources, especially those with both generation and demand response resourses; the effectiveness of RTO market mitigation in scarcity conditions; and the cost-effectiveness of the Final Rule's scarcity pricing requirement.

16. The Final Rule erroneously fails to clarify the definition of "Operating Reserve Shortage," which should be revised to restrict scarcity pricing to emergencies.

17. In light of the wealth of evidence showing the benefits of and the absence of adverse consequences of (1) unmasking, and (2) shorter lags on the release of bid and offer data, the Final Rule's failure to address that evidence and refusal to further reduce the three-month lag on release of bid and offer data, and its maintenance of the masking of identities, erroneously and unreasonably impairs the operation of the markets the Commission is seeking to enhance.

18. The Final Rule errs by failing to require that RTOs post mission statements making them accountable to consumers for meeting the FPA's purpose of ensuring that consumers pay the lowest possible reasonable rates for reliable service.

19. The Final Rule erroneously fails to adopt TAPS' suggested measures to ensure RTO responsiveness and accountability, including, *inter alia*, benchmarking studies, performance measures, and cost-benefit analyses.

STATEMENT OF ISSUES

Pursuant to Rule 713(c)(2), 18 C.F.R. § 385.713(c)(2), TAPS provides the following statement of issues:

1. Did the Final Rule erroneously impose requirements regarding the sale of retail non-consumption by individual retail customers and Aggregators of Retail Customers that exceed the Commission's jurisdiction under Section 201 of the FPA? FPA § 201(a), 16 U.S.C. § 824(a); *N.Y. v. FERC*, 535 U.S. 1, 20 (2002); *FPC v. Conway Corp.*, 426 U.S. 271, 277 (1976).

2. Did the Final Rule err by establishing a default regimen that authorizes the sale of retail non-consumption in wholesale markets with no evidence that applicable electric retail regulatory authority laws and regulations allow such sales, and without

requiring adequate safeguards to assure that such sales facilitated and effected by RTOs are legal under applicable laws and regulations?

3. Did the Commission err by establishing a new retail demand response regimen without substantial evidence that the requirements of this regimen can reasonably be implemented; with no assessment of its negative impact on the existing demand response programs of LSEs, which use demand response to reduce costs to all of their customers by maintaining reliability, reducing planning reserve requirements, and avoiding or defering generation investment; and without substantial evidence demonstrating that the new retail demand response regimen will perform as well as or better than existing LSE-based demand response programs? ISO-New England Demand Response Programs: CMEEC Experience, at 3, CMEEC Loads and Resources—August 2, 2006, Attachment B to TAPS ANOPR Comments (Sept. 14, 2007), *available at* eLibrary Accession No.s 20070914-5137; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,283, P 29, n.26, *reh'g granted in part*, 125 F.E.R.C. ¶ 61,061 (2008).

4. Did the Final Rule erroneously ignore the concerns of commenters and impermissibly fail to address the defects of its demand response program on grounds that a different regulatory authority may prevent the wholesale sales by retail customers that the Rule authorizes? *Time Warner Entm't Co. v. FCC*, 56 F.3d 151, 173-74 (D.C. Cir. 1995).

5. Did the Final Rule err by failing to provide substantial evidence of benefits justifying the significant disruptions to wholesale and retail service that will be caused by its new retail demand response regimen, including the modification of LSE and RTO metering, billing, and settlement processes; the potential for substantial, unpredictable load variation for LSEs; an erosion of the accuracy of the real-time price and consumption information that wholesale customers currently rely on; and potential LSE exposure to a variety of unjust and unreasonable charges based on events over which they have no operational control? Fed. Energy Regulatory Comm'n, *Assessment of Demand Response & Advanced Metering 2007 Staff Report* 7 (2007) ("*2007 FERC Staff Assessment*"), http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,283 at P 29, n.26, *reh'g granted in part*, 125 F.E.R.C ¶ 61,061 (2008).

6. Did the Final Rule erroneously claim that no action affecting retail jurisdictions is being taken, ignoring the significant new burdens that the Final Rule will impose on LSEs to either accommodate the Final Rule, or to enact legislative or regulatory opt-outs from participation? Did the Commission's failure to analyze these impacts on small entities violate the Regulatory Flexibility Act? 5 U.S.C. § 601-12; 13 C.F.R. § 121.201; Public Utility Regulatory Policies Act of 1978 ("PURPA") § 3(9), 16 U.S.C. § 2602(9); Energy Polict Act ("EPAct") § 1252(b)(3)(i), 16 U.S.C. § 2625(i); PURPA § 102(a), 16 U.S.C. § 2612(a); *Aeronautical Repair Station Ass'n v. FAA*, 494 F.3d 161, 177 (D.C. Cir. 2007); *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 342 (D.C. Cir. 1985); FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1); *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027, 1044, *modifed in other part*, 195 F.3d 4 (D.C. Cir. 1999), *aff'd in part and rev'd in part*, 531 U.S. 457 (2001).

7. Did the Final Rule err by failing to adopt either the alternative opt-in structure for retail participation in its demand response system, or a minimum threshold for requiring opt-out regulatory action, both of which were suggested by commenters and which would alleviate the undue burdens on hundreds of municipal systems that the Final Rule's opt-out demand response program imposes? 5 U.S.C. § 601-12; 13 C.F.R. § 121.201; Public Utility Regulatory Policies Act of 1978 ("PURPA") § 3(9), 16 U.S.C. § 2602(9); EPAct § 1252(b)(3)(i), 16 U.S.C. § 2625(i); PURPA § 102(a), 16 U.S.C. § 2612(a).

8. Did the Final Rule err by making it optional, rather than mandatory, for RTOs to require that entities bidding retail demand response into wholesale markets certify that such demand response is permissibly bid and aggregated under the laws and regulations of the relevant electric retail regulatory authorities? Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266, at 12,462 (Mar. 15, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,241, P 1521 ("Order No. 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,261, *order on reh'g*, Order 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 F.E.R.C. ¶ 61,299 (2008), *review docketed*, No. 08-1278(D.C. Cir. filed Aug. 22, 2008); Order No. 890 *pro forma* OATT § 29.2(viii).

9. Did the Final Rule err by failing to direct RTOs to provide detailed, real-time or near real-time information to affected LSEs on the identity of individual retail customer loads involved and the amount of such retail demand response for each billing interval, in order to enable LSEs to assure that the underlying sales of retail "non-consumption" are authorized by law and to enable appropriate treatment in the retail rates of the host LSE?

10. Was it error for the Final Rule to direct RTOs to eliminate price/bid caps, without substantial evidence that lifting such caps will attract investment in generation and demand response sufficient to protect consumers from market power, that the Final Rule's new requirements will change the existing elasticity of demand response, or that consumers will be able to protect themselves from high prices? Was this directive inconsistent with the FPA requirement that the Commission ensure all rates are just and reasonable? *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984); Partial Dissent of Commissioner Kelly to Order No. 719, at 1-2; *Gainesville Utils. Dep't. v. Fla. Power Corp.*, 402 U.S. 515, 528 (1971); *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959); Standard and Poor, *Makeover for California's Power Markets* by David Bodek (July 1, 2004); Technical Conference, *Transmission Independence and Investment* and *Pricing Policy for Efficient Operation and Expansion of the Transmission Grid*, Nos. AD05-5-000 and PL03-1-000, Tr. 37-38 (Larson, Trimaran Capital Partners) (Apr. 22, 2005), *available at* eLibrary Accession No. 20050422-4031; Technical Conference, *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, No. PL04-2-000, Tr. at 149 (Anderson, John Hancock Financial Services) (Feb. 4, 2004), Tr. at 153 (Baliff, Credit Suisse First Boston Corporation), Tr. at 262 (Newman, Warburg Pincus), *available at* eLibrary Accession No. 20040204-0444;

Synapse Energy Economics, Inc., *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers* at 32 (Feb. 5, 2006) (prepared for American Public Power Association), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2007-02.APPA.LMP-Electricity-Markets.06-060-Report.pdf; *2007 FERC Staff Assessment* at 7.

11. Did the Final Rule err in finding, without substantial evidence, that existing market rules are unjust and unreasonable, and ignore variables compromising the effectiveness of the demand response regime thereby violating the Commission's statutory obligation to ensure that the regime of the Final Rule protects consumers completely from excessive rates and charges? *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959).

12. Did the Commission erroneously ignore the comments of TAPS and others regarding the defects of the four scarcity pricing approaches delineated in the NOPR, notwithstanding the Commission's finding that each of these approaches can be just and reasonable, where the four approaches fail to protect consumers from market power, are premised on unsupported assumptions about the bidding behavior of consumers, require the adoption of particular wholesale market structures that have not been established in all RTOs, and may encourage gaming? *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004), *cert. denied*, 127 S. Ct. 2972 (2007); *Wholesale Competition in Organized Electric Markets*, Nos. RM07-19 and AD07-7: Affidavit of Laurence D. Kirsch and Mathew J. Morey on Behalf of National Rural Electric Cooperative Association at 3 (April 23, 2008), *available at* eLibrary Accession No. 20080421-5223; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 684 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002); *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976).

13. Did the Final Rule err by failing to adopt the NRECA alternative approach (proposing to remove bid caps for demand response resources during emergency situations, provided that the higher bids for demand response do not set the market clearing price for all resources) and by suggesting that the NRECA proposal would be considered by the RTO, when the Commission failed to modify its regulatory text to accommodate the NRECA approach, and imposed new criteria that would bar such consideration? Did the Final Rule also err by ignoring TAPS NOPR Comments demonstrating that this approach will neither incent generators to create emergencies, nor exact the same degree of extreme hardship on consumers that elevating market clearing prices will do, and explaining that the NRECA Approach would enable the Commission to test its assumptions regarding the availability of demand response and develop the evidentiary basis to support lifting price caps? *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984); *2007 FERC Staff Assessment* at 7; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,172 (Wellinghoff, Comm'r, dissenting), *on reh'g*, 123 F.E.R.C. ¶ 61,297 (2008) (Wellinghoff, Comm'r, dissenting).

14. Did the Final Rule err by abandoning the NOPR's comparability criteria, and imposing additional criteria requiring comparability in treatment of and compensation

to all resources. In so doing, the Rule creates a potential barrier to NRECA's proposal, and add to the burden on both consumers and the economy by enhancing compensation of generators during operating reserve shortages even where such generators have not contributed to addressing the emergency?

15. Did the Commission err by failing to adopt strengthened requirements, as recommended by TAPS and others, for the factual showing that RTOs must make regarding their scarcity pricing proposals under the Final Rule -- requirements which would have required RTOs to evaluate statistics on scarcity conditions; market power risks; the effectiveness and adequacy of demand response in mitigating market power; the potential for the exercise of market power by entities holding demand response resources, especially those with both generation and demand response resourses; the effectiveness of RTO market mitigation in scarcity conditions; and the cost-effectiveness of the Final Rule's scarcity pricing requirement? *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984); 2007 FERC Staff Assessment at 7; *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,172, *on reh'g*, 123 F.E.R.C. ¶ 61,297 (2008) (Wellinghoff, Comm'r, dissenting).

16. Did the Final Rule erroneously fail to clarify the definition of "Operating Reserve Shortage," which should be revised to restrict scarcity pricing to emergencies?

17. In light of the wealth of evidence showing the benefits of and the absence of adverse consequences of (1) unmasking, and (2) shorter lags on the release of bid and offer data, did the Final Rule's failure to address that evidence and refusal to further reduce the three month lag on release of bid and offer data, and its maintenance of the masking of identities, erroneously and unreasonably impair the operation of the markets the Commission is seeking to enhance? U.S. Dep't of Justice & Fed. Trade Comm'n, *Horizontal Merger Guidelines*, §§ 2.11, 2.12 (1997), http://www.usdog.gov/atr/public/guidelines/horiz_book/hmg1.html; *In re High Fructose Corn Syrup Antitrust Litig.*, 295 F.3d 651 (7th Cir. 2002), *cert. denied*, 537 U.S. 1188 (2003); *Fed. Trade Comm'n v. Elders Grain, Inc.*, 868 F.2d 901 (7th Cir. 1989); *Hosp. Corp. of Am. v. Fed. Trade Comm'n*, 807 F.2d 1381 (7th Cir. 1986), *cert. denied*, 481 U.S. 1038 (1987); Critical Energy Infrastructure Information, Order No. 630-A, 68 Fed. Reg. 46,456, at 46,457 (Aug. 6, 2003), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,147, P 7 (to be codified at 18 C.F.R. pt. 388).

18. Did the Final Rule err by failing to require that RTOs post mission statements making them accountable to consumers for meeting the FPA's purpose of ensuring that consumers pay the lowest possible reasonable rates for reliable service? FPA § 205, 16 U.S.C. § 824d; *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959); *Fla. Power & Light Co. v. FERC*, 617 F.2d 809, 816 (D.C. Cir. 1980); *also FPC v. La. Power & Light Co.*, 406 U.S. 621, 631 (1972); *Pub. Sys. v. FERC,* 606 F.2d 973, 979 n.27 (D.C. Cir. 1979); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000), *aff'd sub nom. N. Y. v. FERC*, 535 U.S. 1 (2002); Promoting Transmission Investment through Pricing Reform, Order No. 679-A, 72 Fed. Reg. 1152, 1166 (Jan. 10, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,236, P 86 n.141, *clarified*, 119 F.E.R.C. ¶ 61,062 (2007).

19. Did the Final Rule erroneously fail to adopt TAPS' suggested measures to ensure RTO responsiveness and accountability, including, *inter alia*, benchmarking studies, performance measures, and cost-benefit analyses? Was the Rule's failure to impose such measures, and its reliance instead on stakeholders to ensure RTO accountability, inconsistent with the GAO report's findings faulting the Commission for over-reliance on stakeholders to raise concerns about RTO expenses and decisions? 16 U.S.C. § 824q(b)(4), as added by Section 1233 of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 958 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,061, P 34 (2008); 18 C.F.R. § 35.34(k)(7); U.S. Gov't Accountability Office, Report to the Committee on Homeland Security and Governmental Affairs, U.S. Senate, *Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance*, (2008), http://www.gao.gov/new.items/d08987.pdf.

ARGUMENT

I. DEMAND RESPONSE AND PRICING DURING PERIODS OF OPERATING RESERVE SHORTAGES IN ORGANIZED MARKETS

A. Wholesale Sales of Retail Customer Demand Response and Aggregators of Retail Customers

The Commission rules that RTO wholesale electricity markets must accept bids of retail customer demand response, from either retail customers or third-party ARCs, on the same basis as generation, unless the relevant electric retail regulatory authority's ("RERRA") laws or regulations expressly do not permit such transactions. 18 C.F.R. § 35.28(g)(1)(i)(A); 18 C.F.R. § 35.28(g)(1)(B)(*3*)(iii). TAPS filed comments on this proposal when it appeared in the NOPR,[2] explaining that the resulting demand response system was inferior to and would interfere with existing, LSE-administered demand response programs, and that the Commission's "opt-out" requirement would cause significant problems for LSEs—particularly small ones. TAPS attempted to work with

[2] Wholesale Competition in Regions with Organized Electric Markets, 73 Fed. Reg. 12,576 (proposed Mar. 7, 2008), IV F.E.R.C. Stat. & Regs. ¶ 32,628 ("NOPR").

the Commission to find solutions, and it proposed alternatives, including an "opt-in" structure for the requirement (at least as applied to small RRERAs), that would avoid these problems while meeting the Commission's goals. Nevertheless, the Final Rule adopts the NOPR's proposal with virtually no meaningful changes.

TAPS therefore seeks rehearing. Order No. 719 imposes a default rule that would undermine the rate structures and power supply decisions of regulated retail jurisdictions, encouraging retail customers to cherry-pick transactions—allowing a retail customer both: (1) to enjoy the rate protection of LSE aggregation and average cost rates whenever wholesale prices are high and it wants to consume electricity; *and* (1) to siphon off profits for itself based on selected high wholesale marginal prices when it decides not to consume electricity, shifting the burden of those high wholesale prices to the LSE's other retail customers. By decoupling the *responsibility* for serving retail load from the *authority* to schedule the portion of that load that will respond to price changes, the default rule will also increase LSE costs of providing service, and (except with respect to the limited circumstances where deviation penalties are excused) will impose RTO scheduling penalties on LSEs which cannot reasonably be expected to predict the scheduling decisions of individual retail customers and ARCs.

As discussed in greater detail below, TAPS urges the Commission to modify the existing, "opt-out" structure of the Rule's retail demand response and ARC requirements, by changing it to an "opt-in" structure (at least for small systems) to address the jurisdictional defects of the Final Rule; and to avoid undue burden to the hundreds of small RRERAs that would be required to pass new ordinances and coordinate with RTOs in order maintain the *status quo* with respect to the retail electric service they currently provide. On rehearing, the Commission should also address the impacts of its new retail demand response and ARC requirements on existing LSE-administered retail demand response programs; and to require that before implementing the Rule, the Commission (or individual RTOs) make an evidence-based factual determination that the significant burdens imposed by the Rule will be outweighed by the benefits that will be realized by the grid. The Final Rule should also be modified to require that ARCs and individual retail customers bidding retail demand response into wholesale markets provide detailed real-time or near-real-time information to the RTO and host LSEs to assure that the underlying sales of "non-consumption" are authorized by law and to enable appropriate treatment in the retail rates of the host LSE.

1. The Final Rule's Default Rule Oversteps the Commission's Jurisdiction

TAPS strongly supports the development of appropriate demand response programs and believes they are a crucial component of robust electricity markets. TAPS NOPR Comments[3] (at 14-16) provide examples of its members' demand response programs, which they use to maintain reliability, reduce planning reserve requirements, and avoid or defer generation investment—*i.e.*, to reduce costs to all of their customers.

The Final Rule's ARC and retail customer demand response requirements, however, overstep the Commission's jurisdiction under the Federal Power Act. The plain language of FPA § 201(a), 16 U.S.C. § 824(a), provides that the Commission's Part II jurisdiction is limited to "that part of [the business of transmitting and selling electric

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[3] Comments of the Transmission Access Policy Study Group (Apr. 21, 2008), *available at* eLibrary Accession No. 20080421-5189 ("TAPS NOPR Comments").

energy] which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," with the limitation that such jurisdiction shall "extend only to those matters which are not subject to regulation by the States." Retail customer demand response simply is not a sale of electric energy at wholesale in interstate commerce. The Commission cannot bootstrap its jurisdiction by erroneously claiming that the absence of consumption by such customers is the equivalent to the wholesale sale of electricity. On rehearing, the Commission should abandon its effort to do so.

Accepting the Final Rule's assertion that the absence of consumption must be treated the same as a sale of electricity creates even *more* jurisdictional problems for this Commission. The Final Rule cannot have it both ways: if sales of retail demand response—*i.e.*, non-consumption of retail electricity—are to be treated as wholesale sales of electricity subject to the Commission's jurisdiction, then the underlying purchase of electricity by the retail customer necessary to support this non-consumption transaction has *also* been converted into a wholesale electricity sale.[4] Viewed through this lens, the new ARC and retail demand response requirements amount to a ruling that retail customers purchasing electricity (or non-consumption) under rates that are not subject to FERC's jurisdiction are by default authorized to re-sell that electricity (or non-consumption) into wholesale markets, either directly or through a third-party.

[4] Indeed, as discussed below in Part I.A.3, to implement the default requirement of the Final Rule and avoid double-counting, it appears that LSEs could be forced to develop retail metering and billing protocols that expressly treat retail customer sales of 'non-consumption' into wholesale markets as purchases of electricity for resale.

The Commission lacks jurisdiction to modify retail electricity sales in this manner.[5] The whole point of retail sales is that they are sales of electricity to end-users—*i.e.*, *not* sales for re-sale. To the extent that what is at issue is the re-sale of retail electricity, there is no reason to believe the laws of each of the individual affected states, and the laws and regulations of every other RRERA, grant retail customers either title or a contract right to such undelivered retail electricity, allowing the customers to resell it. Or to the extent that non-consumption is the product, there is no reason to believe that RRERA laws and regulations impose an obligation on LSEs to provide energy that the retail customer—for whatever reason—has decided not to consume, so that the retail customer would have title to, and the right to sell, any such non-consumption.

By establishing a default rule that authorizes the sale of retail non-consumption in wholesale markets, the Final Rule erroneously seeks to exercise jurisdiction that the Commission simply does not have under the Federal Power Act. The Rule also intrudes into retail electric service rates by requiring RTOs to effect transactions that may be prohibited by state law, without first obtaining confirmation that such transactions are allowed under the underlying retail service. TAPS urges the Commission to remedy these basic jurisdictional defects by modifying the Rule, so that the ARC and retail customer demand response requirements apply only if an individual electric retail regulatory authority, pursuant to its retail rate authority, has expressly chosen to permit

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[5] *N.Y. v. FERC*, 535 U.S. 1, 20 (2002) ("FERC's jurisdiction over the sale of power has been specifically confined to the wholesale market"); *FPC v. Conway Corp.*, 426 U.S. 271, 276-77 (1976) (stating "[t]he Commission has no power to prescribe the rates for retail sales of power companies" and describing the Federal Power Act as specifically structured to "foreclose the possibility that the Commission would…regulat[e] the nonjurisdictional, retail price.")

sales of demand response by retail customers and expressly decided to allow the operation of ARCs within its retail jurisdiction.

2. The Final Rule Errs by Failing to Adequately Address the Impact on Existing Retail Demand Response Programs

As TAPS explained in its NOPR Comments (at 13-17), many LSEs have worked out tariffs and contractual arrangements with their largest customers regarding demand response programs that are different from and inconsistent with allowing the retail customer to receive generation and ancillary services payments through RTO markets for reducing demand. These LSE-based programs may provide the customer with demand charge reductions in exchange for permitting the LSE to interrupt it under certain circumstances (*e.g.*, when needed to keep the lights on, or if the LSE's total load exceeds a certain level), treating the demand response as a reduction in the load the LSE is required to serve for reliability, power supply planning, and resource adequacy purposes—not just as real-time energy or operating reserves. TAPS asked the Commission to take care not to trample on these contractual and tariff arrangements, and reliability-based programs. In response, the Final Rule simply states that "the continuing role of the relevant retail electric regulatory authority adequately addresses these concerns." Order No. 719, P 157. The Commission makes no independent assessment of the impact on existing LSE-administered demand response programs.

The Commission cannot avoid addressing the defects of its new retail demand response regimen by asserting that a different regulatory authority, other than FERC, could issue a separate rule that prevents the wholesale sales by retail customers authorized by Order No. 719. *See*, *e.g.*, *Time Warner Entm't Co. v. FCC*, 56 F.3d 151, 173-74 (D.C. Cir. 1995) (holding that the FCC's default ratemaking methodology for cable operators was arbitrary and capricious, notwithstanding FCC's assertion that a disadvantaged cable operator could avoid the default methodology by adopting cost-of-service ratemaking as an alternative). The Commission has an independent obligation to fully justify the default requirements established by the Final Rule. It was error to impose the new requirements without substantial evidence that they can be reasonably implemented and will achieve the Commission's goals, and without first evaluating the impact of the requirements on existing, LSE-administered demand response programs.

Those impacts are substantial. The demand response of ARCs and individual retail customers bidding into wholesale markets will be unpredictable and based on individual market participant reactions to volatile prices in RTO day-ahead and real-time markets. In contrast, LSEs can integrate their retail demand response programs into their power supply planning, and through that process deliver significant value to all of their customers by avoiding or deferring generation investment. Some TAPS members have been able to avoid purchases of a block of power for the peak season by implementing programs that commit retail customers to interruptions when directed by the LSE.[6] In addition, because those interruptions are predictable and can be expressly tied to triggers coordinated with the LSE's power supply resource plans, LSEs can get additional value for all of their customers by integrating demand response into their planning and avoiding the need to carry planning reserves for interruptible load. Indeed, the Commission itself

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[6] For example, to avoid committing to a peak block of power for the summer season, TAPS member CMEEC called on its demand response customers to reduce load even *before* prices reached "scarcity" levels. *See* ISO-New England Demand Response Programs: CMEEC Experience, at 3, CMEEC Loads and Resources—August 2, 2006 (graph showing that CMEEC called upon its demand response when prices were not much more than $180/MWh, several hours *before* prices climbed to the $1000/MWh level). This presentation is appended to TAPS ANOPR Comments as Attachment B (*available at* eLibrary Accession No. 20070914-5137).

has recognized the important role of demand response in reducing an LSE's load subject to resource adequacy requirements.[7]

In contrast, the Final Rule gives the major benefits of retail demand response to only the few retail customers who choose to make sales into wholesale markets, allowing them to "skim the cream": arbitraging the price difference between the lower retail rates they pay to their LSEs and, selectively, the highest energy prices from the RTO's wholesale markets if they happen to be willing to drop load in some hours when wholesale prices are high; but enjoying the protection of LSE power supply planning and aggregation and average cost rates when they do not want to lower their consumption while wholesale prices are high. Meanwhile, by siphoning off retail demand response into the RTO's wholesale energy and ancillary services markets, LSEs will lose the planning benefits that an LSE-administered demand response program would normally provide. An LSE would need to include the full loads of its retail customers who sell into wholesale markets or contract with ARCs—*i.e.*, without any allowance for the demand response being sold into the wholesale market—in its planning for firm power supply, as well as carry full planning reserves to meet that load. The value to the LSE and its other customers of avoiding peak block generation investments and additional reserves would be lost.

The Final Rule's focus on RTO-spot-price-driven demand response also ignores and could undermine LSE-based demand response programs that seek continuous, long-

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[7] For example, under the Midwest ISO's conditionally-approved Resource Adequacy Requirement, an LSE may deduct certain demand response resources from the firm load for which it must meet the MISO-established planning reserve margin. *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,283, P 29, n.26, *reh'g granted in part*, 125 F.E.R.C. ¶ 61,061 (2008).

term reductions in energy consumption. Some LSE-based demand response programs include subsidies to encourage retail customers to adopt energy efficient technologies that can produce continuous, long-lasting energy savings that benefit consumers and the environment by significantly reducing the total MWhs of energy consumed. Under the Final Rule, however, adopting such energy efficiency technologies would likely *reduce* the amount of demand response that a retail customer would have available to sell into RTO spot markets, by changing the baseline used to calculate the amount of demand response available when prices are high. By authorizing retail customers to sell their non-consumption at high spot prices, the Final Rule changes the financial calculation for retail customers considering demand response, reducing the incentive to the LSE or customer to make the capital investments necessary to achieve significant, permanent reductions in electricity usage, in favor of short-term, peak-hour reductions that garner premium payments from ARCs and the wholesale market.

The public interest is not served by undermining highly valuable, LSE-organized demand response programs by establishing a regulatory preference for third-party and spot-market-price-driven demand response programs. As TAPS recommended in its NOPR Comments, the Final Rule should be modified to make clear that it will not undermine or require any change to an existing aggregation program that already functions well. While TAPS appreciates the Commission's desire to promote demand response, existing programs should be respected.

3. Impact on Wholesale and Retail Rates, Metering, and Billing Protocols

The Final Rule fails to provide record evidence sufficient to justify the very significant disruptions to wholesale and retail service that will be created by authorizing retail customers to sell their demand response in wholesale RTO markets. The Final Rule provides little evidence to support its apparent assumption that the new demand response regimen it orders will perform as well, or better than, existing LSE-based demand response programs. To the contrary, as TAPS pointed out in its NOPR Comments (at 15-16), the Commission's own studies indicate that "economic" demand response programs (like those promoted by the Commission's new requirements) typically have a *lower* response rate than reliability-based programs.[8]

Notwithstanding the fact that its purported demand response benefits are unproven, the Final Rule is certain to impose substantial new burdens on RTOs, LSEs, and relevant electric retail regulatory authorities. The Final Rule provides that "[a]n RTO or ISO *may* place appropriate restrictions on any customer's participation in an ARC-aggregated demand response bid to avoid counting the same demand response resource more than once." Order No. 719, P 158j (emphasis added). Failure to avoid double-counting would obviously distort the RTO market price signals that are at the heart of the Final Rule's new demand response regimen, and it would be a clear invitation for gaming. Any system implemented to avoid double-counting, however, could require major modifications to both: (1) RTO metering and settlement protocols; and (2) the metering and billing protocols of LSEs whose retail customers are bidding into the RTO's wholesale markets.

[8] The 2007 FERC Staff Assessment of Demand Response and Advanced Metering (at 7) found load reductions in demand bidding programs of only 4-19% of enrolled demand response resources. It distinguished between "economic" (demand bidding) demand response (which is not as effective, *i.e.*, <20% response rate) and "reliability-based" demand response (which has a much higher response rate—62% and 83% in the programs reported in the 2007 FERC Staff Assessment). Indeed, in the experience of TAPS members, such reliability-based programs have a response rate in excess of 90%.

a) Effects on Wholesale Rate Design

To implement the Final Rule, RTOs will need to implement systems to assure that specific retail customers have not sold their demand response to multiple entities, or, if a retail customer has, to confirm that the magnitude of the demand response sold to each entity bidding into the wholesale market on behalf of the retail customer sums to less than the total retail demand response available from (and provided by) that customer.

In addition, if a retail customer or ARC is given credit for demand response energy, someone else will have to be charged for that energy—even though existing meters will not show that the energy has been delivered to any wholesale customer. Because the host LSEs' wholesale meters will automatically reflect the reduced energy consumption claimed by the retail customer or ARC in the wholesale electricity market, RTOs appear to have two choices. They can: (1) uplift the costs of the retail customer or ARC-claimed demand response energy to some or all customers through an administrative charge; or (2) assign the costs of the energy to the LSE whose retail customer (either directly or through an ARC) is selling retail non-consumption into the energy market—*i.e.*, bill that LSE for both its actual energy consumption *and* the energy that its retail customers would have consumed, but for the retail demand response bid into the RTO's wholesale markets.

The latter option introduces new layers of complexity into the RTO metering, billing, and settlements process. For example, if a TDU with 100 MW of metered load in a given hour has a retail customer that has sold 5 MW of demand response energy into the RTO's energy imbalance market in that same hour, then to avoid double-counting the demand response that is already reflected in the LSE's metered load, the RTO would charge the LSE for 105 MWh of energy—*i.e.*, as if the 5 MWh of demand response energy had been purchased by the LSE, delivered to the retail customer, and then re-sold.[9]

Unless RTOs that adopt this approach simultaneously implement new systems to assign this phantom energy to specific LSEs and communicate the information to LSEs in real-time, LSEs that currently have access to real-time metering information they use to make wholesale power supply decisions will no longer be able to rely on those meters. The effect of the Final Rule could be to expose selected retail customers to wholesale market price signals, while *eroding* the accuracy of the real-time price and consumption information that wholesale customers currently rely on.

New operating protocols will also be necessary for LSEs that choose to use their resources to follow their load, or that are required by contract to do so. TAPS member Northern California Power Agency ("NCPA"), for example, is required by contract to follow its load and is subject to penalties if it fails to do so.[10] Basic load-following functions will be fundamentally undermined if LSEs can no longer rely on their wholesale meters for accurate information on the energy they are consuming and for which they will be billed by their RTOs.

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[9] Notwithstanding the Rule's general statements disfavoring the use of uplift charges (*see*, *e.g.*, Order No. 719, P 207), RTOs should be barred from imposing such phantom energy charges on LSEs for which the relevant electric retail regulatory authority has passed a law or regulation prohibiting sales of retail demand response in wholesale markets by individual retail customers or ARCs.

[10] *See*, *e.g.*, Metered Subsystem Aggregator Agreement ("MSSA") between the Northern California Power Agency and the California Independent System Operator ("California ISO"). The MSSA establishes the relationship between NCPA, its member Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto (a California Charter City) and Ukiah, the Plumas-Sierra Rural Electric Cooperative, and the Port of Oakland and the California Independent System Operator Corporation ("CAISO"), and was approved as a settlement agreement by this Commission on August 29, 2002. The MSSA is currently on file as Service Agreement No. 457 under the California ISO First Replacement Tariff Vol. No. 1.

Moreover, the Final Rule's retail demand response regimen, if successful, could introduce substantial, unpredictable load variation for LSEs. In addition to undermining existing RTO resource adequacy systems by diverting retail demand response to day-ahead and real-time wholesale electricity markets,[11] the Final Rule's new default regimen will expose LSEs to extra RTO charges for real-time operations—*e.g.*, for failure to accurately schedule. The Rule creates a limited exception that excuses deviation charges for LSEs that decrease load in periods when the RTO has called an operating reserve emergency. Order No. 719, P 111. However, if retail customer demand response causes an unexpected drop in an LSE's load during periods *other* than when the Final Rule's emergency exception is triggered, the LSE will be subjected to deviation charges if its real-time load is below its day-ahead load. Similarly, a decrease or increase[12] in an LSE's load, triggered by unexpected, market-price-driven retail customer demand response, could impose over- and under-scheduling charges on the LSE under the SPP Energy Imbalance Service tariff.[13] Where LSEs have no operational control over the retail customer demand response being sold into wholesale generation markets, the imposition of such charges under RTO tariffs is unjust and unreasonable.

b) Effects on Retail Rates

Any new phantom wholesale energy charges introduced to implement the Final Rule's retail demand response system will also require significant modifications to the retail rates that LSEs charge. It is possible that some LSEs might choose to uplift such

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[11] *See*, *e.g.*, n.7, *supra*.

[12] *E.g.*, at the conclusion of the period when the demand response bid was activated.

[13] *See* Sections 5.3 and 5.4 of Attachment AE to the Southwest Power Pool, FERC Electric Tariff, Fifth Revised Volume No. 1 (subjecting LSEs whose load deviates from schedules by more than 4% or 2 MW

charges to all of their customers. Principles of cost causation, however, would require that LSEs assign those charges only to the retail customers whose decision to sell their demand response into the wholesale market caused the LSE to incur those costs in the first place. Accordingly, unless the purpose of the Final Rule's demand response requirement is to mandate a beggar-thy-neighbor demand response system in which each retail customer's demand response is designed to *increase* the costs of the LSE's other retail customers, the Final Rule should be modified to require that if RTOs choose *not* to uplift all retail customer/ARC demand response energy costs to all wholesale customers, the retail customer/ARC must provide near-real-time information to all affected LSEs on the specific retail customers that have provided demand response to the wholesale market, and the amount of that demand response in each billing interval.[14]

The bottom line is that implementation of the Final Rule to accommodate wholesale demand response bids by selected retail customers will require the expenditure of enormous resources by RTOs and LSEs for theoretical, but uncertain benefits for the grid as a whole, especially as compared to existing LSE-administered demand response programs. Some retail regulatory authorities may be able to avoid the retail-level problems by not participating in the Rule's new retail demand response system. RTOs, however, will necessarily incur significant costs to design brand new systems to accommodate, track, and verify retail customer demand response as required by the Final Rule. Based on the evidentiary record of the proceeding, the Final Rule's new retail demand response regimen, particularly with its strict RTO mandate and deadlines and its

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to such charges in certain circumstances) *available at* http://www.spp.org/publications/SPP_Tariff.pdf.

[14] In any event, this information will also be necessary to assure that individual retail customers and ARCs

default authorization of wholesale sales of retail demand response and ARCs in all retail regulatory jurisdictions, is unreasonable. It should be modified on rehearing to direct RTOs to evaluate the efficacy of such bid-based programs, especially given the adverse impacts on LSE-administered demand response programs, and to implement them only if that evaluation demonstrates that the benefits outweigh the costs. In addition, the structure of the Commission's ARC/retail customer demand response regimen should be modified so that it applies only to those retail jurisdictions that expressly choose to participate.

4. The Rule Errs in Concluding That No Burden is Placed on Small Systems for Purposes of the Regulatory Fairness Act

The Final Rule requires RTOs to accept ARC bids "unless the laws or regulations of the relevant electric retail regulatory authority *expressly* do not permit a retail customer to participate" (18 C.F.R. § 35.28(g)(1)(B)(*3*)(iii), emphasis added); and it requires RTOs to accept retail demand response bids in ancillary services markets "unless not permitted by the laws or regulations of the relevant electric retail regulatory authority" (18 C.F.R. § 35.28(g)(1)(i)(A). The Rule defines relevant electric regulatory authority as the "the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission." Order No. 719, P 158.

Notwithstanding the Final Rule's assertion that the Commission is "mindful of the comments that allowing ARCs to bid into the wholesale energy market without the

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do not bid retail demand response into wholesale markets from areas that do not allow permit such sales.

relevant electric retail regulatory authority's express permission may have unintended consequences" (*id.* P 155), the Rule does not clearly eliminate the NOPR's requirement that such authorities must provide the RTO "explicit notification … in order to disqualify a bid from an ARC that includes the demand response of that authority's retail customers" (NOPR P 90; *see also* Order No. 719, P 129). Although the Commission repeatedly asserts that the Final Rule places no burden on electric retail regulatory authorities, because "we will not require a retail electric regulatory authority to make any showing or take any action in compliance with this rule"[15] (Order No. 719, P 155; *see also id.* PP 53, 602), the Rule *also* requires that RTOs "should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority" (*id.* P 49 n.78). Given the new default rule directing RTOs to facilitate and effect sales of retail demand response, the latter requirement means that such transactions will occur *unless* an RTO receives express notification from someone else. Because the Final Rule allows, but does not require, that ARCs certify they are selling retail demand response only from jurisdictions that allow such sales (*id.* P 158), the Rule appears to leave the ultimate notification responsibility with the relevant electric retail regulatory authorities.

It is disingenuous for the Commission to pretend that no action affecting electric retail regulatory authorities is being taken, or that the Final Rule places no burden on such entities. The jurisdiction of states and other electric retail regulatory authorities to establish the rates, terms, and conditions of retail service are not contingent on whether their decisions have been communicated to an RTO. However, to maintain the *status quo*

[15] This assertion likewise ignores the significant new burdens, described in detail in Parts I.A.2 and I.A.3, that implementation of the Final Rule will impose on LSEs.

and prevent an RTO from facilitating and effecting transactions that may already be implicitly prohibited under their existing laws and regulations, the Final Rule appears to require every electric retail regulatory authority located in an organized market, regardless of size, to go through a legislative process to address, expressly, whether the retail demand response sales defined by the Final Rule may be bid into RTO ancillary services markets, and whether third party ARCs may aggregate the retail demand response of LSEs within the jurisdiction. In addition, absent an optional RTO decision to require ARCs and individual retail customers to certify that they are selling demand response only from retail jurisdictions that allow such transactions, the Final Rule would apparently leave it to each relevant electric retail regulatory authority to ensure that someone notifies the RTO that such transactions are prohibited. Also, even if an RTO chooses to require certification by ARCs and retail customers, the Final Rule, by failing to impose clear enforcement requirements on the RTO, appears to leave enforcement to the RERRA. A small system that has decided not to permit ARCs or retail demand response bids into wholesale ancillary service markets, for example, might be required to monitor and challenge the bids and certifications submitted to RTOs by ARCs, to assure that they do not include demand response from retail customers within its jurisdiction.

TAPS believes that this burden is undue and urges the Commission to modify the default ARC requirement, so that participation in the program by retail electric authorities is on an “opt-in” basis, rather than an “opt-out” basis. For most municipal systems (and especially for those are not in a retail access state or have that opted out of retail competition pursuant to the applicable laws of a retail access state), it is reasonable to presume that the exclusive right and obligation to serve to its citizens and ratepayers with electricity at retail includes the right to aggregate their customers' willingness not to purchase such electricity—*i.e.*, to aggregate their demand response. We expect, however, that few municipal electric systems will have "expressly" addressed that specific issue in their laws and regulations because third-party ARCs and bidding retail demand response directly into wholesale markets as generation are new concepts. As TAPS explained in its NOPR Comments (at 17-21), requiring the city council of every municipal electric system in an RTO to expressly address the issue through legislation or regulation, even where the municipal does not allow retail access, is a huge undertaking. For example, TAPS member AMP-Ohio includes 123 municipal electric systems in MISO and PJM; TAPS member Indiana Municipal Power Agency serves 51 municipal electric systems in MISO and PJM; TAPS member Wisconsin Public Power Inc. serves 50 municipal electric systems in MISO; and the list goes on. Many of these systems are very small. Getting the city council of each such municipal to explicitly address the retail demand response bidding and ARC issues would be a Herculean task. Nor is the city council necessarily the pertinent regulatory body.[16]

This burden on small utilities is why Congress requires the Commission to make a Regulatory Flexibility Act ("RFA") certification as to the impact on entities whose total electric output does not exceed 4 million MWh. *See* 5 U.S.C. § 601-12; 13 C.F.R.

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[16] Many electric municipal systems have utility boards that set retail rates and other regulatory policies. Municipal members of a joint action agency are often under very long-term full-requirements contracts, which support the joint action agency's bonds and enable them to carry out their assigned power supply and load aggregation functions. Joint action agencies are governed by their members, who sit on their board, which plays a regulatory function by setting the wholesale rates for the municipal members (which comprise the bulk of municipal members' retail rates) and establishing other pertinent policies. The joint action agency is typically the interface with the RTOs, who often have no contact with the individual municipal members.

§ 121.201 n.1.[17] The Final Rule (PP 602-05) recognizes this obligation, but treats the Rule as directly affecting only RTOs, ignoring the clear effects on relevant electric retail regulatory authorities.

Having used the availability of a legislative or regulatory "out" as justification for its incursion into the domain of state-regulated retail electricity sales and its potential disruption of municipal demand response programs, the Commission cannot then pretend that the efforts required of small utilities to avail themselves of such an "out" do not exist. Similarly, the Commission may not ignore the significant burdens, described above in Parts I.A.2 and I.A.3, that will be placed on LSEs to implement the Final Rule should they elect *not* to obtain legislative or regulatory outs. FERC's repeated assertions that it is not impacting small entities do not make it so. By imposing responsibilities on small entities, the Final Rule implicates the RFA's requirements. *See Aeronautical Repair Station Ass'n, Inc. v. FAA*, 494 F.3d 161, 177 (D.C. Cir. 2007) (Although regulations "are immediately addressed" to other entities, the "Final Rule *imposes responsibilities* directly on the contractors and subcontractors and they are therefore parties affected by and regulated by it" for RFA purposes) (emphasis added).[18]

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[17] This same concern is reflected in PURPA's restrictions on "non regulated electric utilit[ies]" (PURPA § 3(9), 16 U.S.C. § 2602(9); *see* NOPR P 88 n.92) required to investigate and issue a decision on such issues as "whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs." EPAct § 1252(b)(3)(i), 16 U.S.C. § 2625(i), amending PURPA § 115. Only non-regulated electric utilities with retail sales of more than 500 million kWh must go through that process. *See* PURPA § 102(a), 16 U.S.C. § 2612(a).

[18] TAPS notes that while FERC's claim in *Mid-Tex Electric Cooperative, Inc. v. FERC*, 773 F.2d 327, 342 (D.C. Cir. 1985), quoted in Order No. 719, P 603, that "virtually all of the public utilities that it regulates do not fall within the meaning of the term 'small entities'" might not have been disputed in 1985, Congress has since granted FERC limited jurisdiction over many of the small utilities that are at issue here. *See* FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1).

American Trucking Associations, Inc. v. EPA,[19] which the Commission cites to support its failure to conduct required RFA analysis, is inapposite. In that case, whether the small entities at issue would actually be burdened by the Environmental Protection Agency's action was dependent on the intermediate, discretionary action of the states. *Id.* at 1044. As a result, the EPA was not required to conduct an RFA analysis of these burdens. *Id.* Here, in contrast, the RTOs have no such discretion to mitigate the impacts of the Commission's directive, which itself requires LSEs to either: (1) invest in the legislative and/or regulatory procedures necessary to obtain an explicit "out" and enforce it (*e.g.*, by notifying the RTO and somehow monitoring ARC and retail customer certifications and bids for infringement of that law); or (2) undertake the implementation burdens necessary to accommodate ARCs and retail customers directly bidding retail demand response into wholesale markets. *American Trucking Associations* does not relieve FERC of its obligations under the RFA.

TAPS suggests that the Commission can achieve its objective of ensuring that RTOs accept ARC bids where regulators are willing to permit third-party ARCs by: (1) replacing the "unless" clause of 18 C.F.R. § 35.28(g)(1)(B)(*3*)(iii) with "if the relevant electric retail regulatory authority expressly permits a retail customer to participate"; and (2) replacing the "unless" clause of 18 C.F.R. § 35.28(g)(1)(i)(A) with "if permitted by the laws or regulations of the relevant electric retail regulatory authority." These provisions would invite relevant electric regulatory authorities to contact the RTO to provide notification of such permission. Absent such explicit

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[19] *Am. Trucking Ass'ns, Inc. v. EPA*, 175 F.3d 1027, 1044, *modified in other part*, 195 F.3d 4 (D.C. Cir. 1999), *aff'd in part and rev'd in part*,. 531 U.S. 457 (2001).

notification that permission has been granted, the RTO would presume that sales of retail demand response in RTO markets are not permitted and an ARC cannot lawfully aggregate retail load within the . This modification would ensure that any relevant electric retail regulatory authority that wished to allow third-party demand response aggregation could do so, without unduly burdening hundreds of municipals.

In addition, this change to the Final Rule, by making it easier for RRERAs to join at their own pace, will allow such programs to build credibility and could significantly reduce administrative burdens in the long-run. Little is currently known about the effectiveness of the new retail demand response bidding programs required by the Rule, and few retail customers have expressed an interest in participating. Meanwhile, the impacts and costs for LSEs of allowing retail demand response and third-party ARCs could be very significant.[20] If forced to make a choice today, many relevant electric retail regulatory authorities will take the immediate, pre-emptive step of passing opt-out legislation. If an LSE's retail customers later decide, once everyone has gained experience with wholesale bidding of retail demand response and third-party ARCs, that they *do* want to participate in the RTO's retail demand response regime, either directly or through a third-party ARC, extensive work will be necessary to undo those laws and regulations.

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[20] As discussed in Part I.A.2 above, the loss of control over its retail customer's demand response could impair the LSE's ability to plan for its load and harness that demand response to reduce the costs of serving all of its customers. Permitting retail customer demand response and third-party ARCs will also significantly affect billing, metering, and settlement for the municipal system at both the wholesale and retail level. *See* Part I.A.3 above. Municipals that allow individual retail customers and third-party ARCs to sell retail demand response into wholesale markets may be subject to phantom energy charges, based on the RTO's determination of the energy that those retail demand responders would otherwise have consumed; and they will be exposed to deviation charges (*e.g.*, if ARC-aggregated load causes an unexpected drop in an LSE's load during periods other than when the Final Rule's emergency exception on deviation charges is triggered, or if a retail-demand-response-triggered decrease or increase in an LSE's

At minimum, any affirmative regulatory action requirement should be restricted to systems that are larger than the RFA threshold. Only systems with a total electric output exceeding 4 million MWh should need to go through the process of expressly opting-out of the Final Rule's retail demand response and ARC requirements. An alternative threshold would be those municipals with retail sales of more than 500 million kWh, as used in PURPA. Limiting application of the Final Rule's requirements in this manner would minimize the burden on small systems associated with either implementation of the Rule or compliance with its "express[]" prohibition requirement, consistent with the Rule's RFA Certification. *See* Order No. 719, PP 588-92.

5. The Final Rule Should Clarify and Address Basic Implementation Issues and Information Requirements Related to Retail Demand Response Bids and ARCs

The Final Rule makes it optional for RTOs to require that entities bidding retail demand response into RTO markets certify that the retail loads and demand response at issue are permissibly bid and aggregated under relevant electric retail regulatory authority laws and regulations. Order No. 719, P 158. That requirement should be mandatory. Even assuming that it is clear which LSEs allow retail demand response sales and ARCs, neither the RTO, nor the relevant electric retail regulatory authority, is in a position to police whether all retail demand response being bid into RTO wholesale markets is from retail jurisdictions where such sales are permitted. It may be difficult, if not impossible, for either RTOs or RRERAs to identify, independently, whether improper sales or aggregation is occurring; placing policing responsibility on such entities is therefore impractical and unfair.

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load triggers over- and under-scheduling charges (*see* Part I.A.3.a) above)).

In contrast, the entities bidding retail demand response into the RTO wholesale markets are in the best position to identify the specific retail loads and customers involved and to verify that such bids are permitted by the relevant electric retail regulatory authority. ARCs and other entities bidding retail demand response into RTO markets should therefore be required to certify that their sales are permitted, much like network customers must provide certification to support designation of network resources.

Under Order No. 890, network customers must attest, for each network resource identified for designation, that: (1) the transmission customer owns or has committed to purchase the designated network resource; and (2) the designated network resource meets the requirements for designated network resources.[21] Transmission providers must terminate network resource designation requests that do not contain the proper attestation,[22] and designation of a network resource that does *not* meet these criteria is a tariff violation that may be the basis for the assessment of civil penalties.[23] In the same way, individual retail customers and ARCs should be required to certify that their bids and sales of retail demand response into wholesale markets are permitted under applicable law, and submission by such entities of ineligible demand response bids should be a tariff violation.

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[21]Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266, at 12,462 (Mar. 15, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,241, P 1521 ("Order No. 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,261, *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 F.E.R.C. ¶ 61,299 (2008), *review docketed*, No. 08-1278 (D.C. Cir. filed Aug. 22, 2008); Order No. 890 *pro forma* OATT § 29.2(viii).

[22] Order No. 890, P 1522.

[23] *Id*. P 1523.

In addition, because wholesale sales of retail demand response will affect the scheduling and resource planning of the LSEs that serve the retail customers providing demand response (and, as discussed above in Part I.A.3, may affect the wholesale metering, billing, and settlement for those LSEs), the Final Rule should direct RTOs to provide detailed information to affected LSEs on: (1) the identity of all individual retail customer loads involved (even if aggregated by an ARC); and (2) the amount of such demand response for each billing interval. This information on the specific sources of retail demand response should be provided by the RTO in real-time or near-real-time, depending on how the RTO's ARC system is designed. It must also be sufficient to assure that all affected LSEs: (1) know the amounts of energy for which they will be billed in real-time, so that the LSE can respond to wholesale price signals appropriately; and (2) have the information they need to assure that their retail rates are just and reasonable, and that any increased wholesale charges attributable to retail demand response being sold in the wholesale market can be assigned to the retail customers who are responsible for those charges. Such provisions will not prevent harm to LSEs from the reduced ability to plan and schedule accurately. However, they would at least make it possible for LSEs to allocate equitably any RTO deviation penalties resulting from wholesale sales of demand response by retail customers or ARCs during periods when the RTO has not declared an operating reserve emergency, or from unpredictable load swings caused by Imbalance Energy scheduled by such entities directly with the RTO; RTO charges to LSEs for energy that was not consumed, but for which a retail customer is claiming payment for non-consumption; and other LSE costs associated with retail demand response transactions in wholesale markets.

B. Scarcity Pricing During Operating Reserve Shortages

1. The Final Rule's Scarcity Pricing Requirement is Not Consistent with Statutory Requirements

The Final Rule (PP 192-93) finds that "existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust, unreasonable, and may be unduly discriminatory," and requires RTOs to eliminate "artificial bid caps" (P 180) that fail to reflect "the true value of energy" (P 193):

> Without accurate prices that reflect the true value of energy, we cannot expect the optimal integration of demand response into organized markets.

Id. The Final Rule's directive views high prices as beneficial because they may deter consumption and spur investment in technology that allows consumers to respond to prices. *Id.* P 203. It concludes that market power need not be considered as part of the rulemaking because the compliance filings will have to address market power. *Id.* P 194. Notwithstanding arguments of TAPS and others that the very high prices its Rule is imposing could seriously harm consumers that lack the ability to respond, the Final Rule makes clear that RTOs cannot tie implementation to benchmarks that would delay implementation for more than a few years. *Id.* P 258.

As TAPS noted in its NOPR Comments (at 24-27), the Final Rule's proposals suffer from a basic lack of evidence that existing offer/bid caps in fact limit demand response, that lifting such caps will attract investment in generation and demand response sufficient to protect consumers from market power, and that consumers will be able to protect themselves from high prices for an essential commodity. Particularly as this country faces a massive financial meltdown from undue reliance on inadequately regulated market forces, this Commission should not act to remove price caps without concrete evidence that they are impeding integration of demand response.[24]

The Final Rule's scarcity pricing proposals focus on price formation during scarcity conditions when additional supply is, at least in the short term,[25] unavailable so that any price response will come from changes in demand. When the Commission is relying upon demand to provide the competitive response necessary to keep rates just and reasonable, the FPA's commands still apply. There must be "empirical proof" that "existing competition would ensure that the actual price is just and reasonable." *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984). "[U]ndocumented reliance on market forces" is insufficient to satisfy the Commission's regulatory responsibilities." *Id.* at 1508. Nothing in the FPA evinces a willingness to allow very high prices (apparently without regard to level or the actual cost of providing the underlying electric service) to deter consumption of a service essential to our economic and social well-being.

The Commission, however, appears willing to move forward, relying on undocumented—indeed, theoretical—market forces. Commissioner Kelly's dissent echoes TAPS' concern that the Commission is putting the cart before the horse:[26]

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[24] The events of the past few months have brought home the dangers of dismantling regulatory safeguards based solely on the belief in the assumptions and theory of competitive markets. After years of opposing as unnecessary federal regulations that might have helped avert the current financial crisis, Federal Reserve Chairman Alan Greenspan recently observed that it is unreasonable to expect sellers to self-police market behavior—even if the sellers' failure to do so would threaten their own financial viability. According to Chairman Greenspan, "[t]hose of us who have looked to the self-interest of lending institutions to protect shareholder's equity, myself included, are in a state of shocked disbelief." Edmond L. Andrews, *Greenspan Concedes Error on Regulation*, New York Times, Oct. 24, 2008.

[25] In the long run and depending upon entry conditions, new generation may, in theory, respond to high prices and return them to just and reasonable levels.

[26] Partial Dissent of Comm'r Kelly Order No. 719, at 1-2 (footnote omitted).

> I recognize that the majority has good intentions in requiring RTOs/ISOs to make this filing. However, I believe that, prior to allowing energy supply offer caps and demand bid caps to rise or be eliminated, the necessary generation and demand response infrastructure must be in place to give consumers the ability to respond to higher prices. As Commission staff noted in the 2006 FERC Staff Demand Response Assessment, advanced metering currently has low market penetration of less than six percent in the United States. Without providing consumers with the ability to respond to rising prices, I view the decision to allow energy supply offer caps and demand bid caps to rise or be eliminated as irresponsible.

The Commission's attempt to stimulate demand response through unrestrained scarcity pricing is akin to allowing market-based rates without assurances of the open access transmission necessary for competing supply to restrain prices. Unlike its approach to market-based rates, however, the Commission would unleash market forces without making factual findings that the demand response necessary to restrain prices is ready, willing, and truly able to respond.

The Supreme Court has rejected seller claims justifying higher prices for electricity based upon the value ascribed to the product by the buyer, noting that a "focus on the willingness or ability of the purchaser to pay for a service is the concern of the monopolist, not of a governmental agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable price." *Gainesville Utils. Dep't. v. Fla. Power Corp.*, 402 U.S. 515, 528 (1971). Electricity service is not a Picasso painting up for auction at Sotheby's. It remains essential to the nation's economy and the lives of its residents, which explains why the Supreme Court in *Atlantic Refining* emphasized the requirement for service "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest." *See Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959). The Commission's value pricing policy, if adopted, could also lead to unconscionable results: should an isolated village in the Allegheny Mountains of Pennsylvania go without electricity during an emergency simply because consumers there cannot outbid those in a Philadelphia Main Line suburb?[27]

The Commission concedes that it does not yet have the facts to find that demand response levels are sufficient to discipline prices, basing the requirements of the Final Rule on belief and theory. It premises on belief its fundamental finding that existing rules that do not allow for prices to rise sufficiently during an operating reserve shortage to allow supply to meet demand are unjust and unreasonable:

> In particular, they *may* not produce prices that accurately reflect the value of energy and, by failing to do so, *may* harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.

Order No. 719, P 192 (emphasis added). The absence of factual findings is striking. *See*, *e.g.*, *id.* P 250 (evaluating the effect of the rule change is not needed because "[w]e are firmly of the opinion" that the changes will increase reliability).

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[27] As TAPS explained in its NOPR Comments (at 36-37), market forces may not always do a good job of assigning value to products such as reliable electricity. The 2007 *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* of the Electric Energy Market Competition Task Force (on which a Commission representative served and to which several other Commission staff contributed) stated (at 54 n.148):

> It is important to note that competition in wholesale electric markets may not lead to an efficient allocation of resources involving the services that prevent network collapse. Where there are "public good" aspects to the delivery of a good or service, such as with reliability, regulation may be the best way to ensure that the correct level of the good or service is provided. In some circumstances, however, market remedies may be available that are superior to regulation.

(Apr. 6, 2007), http://www.ferc.gov/legal/fedsta/ene-pol-act/epact-final-rpt.pdf. As the Task Force *Report* suggests, an approach where individual consumers are assigning value to electricity may actually lead to a misallocation of this essential resource.

Moreover, the Final Rule's conjectures about expected market response do not reflect TAPS members' day-to-day experiences with wholesale markets. For example, the Commission says: "Further, by artificially capping prices, price signals needed to attract new market entry by both supply and demand-side resources are muted and long-term resource adequacy may be harmed." Order No. 719, P 193. This observation fails to confront evidence that high spot market prices do not correlate with entry in RTO markets. Rating agency reports,[28] testimony at Commission technical conferences,[29] and

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[28] For example, Standard and Poor's July 1, 2004 Report by David Bodek, *Makeover for California's Power Markets*, explains:

> Pricing data associated with hourly nodal prices should provide market signals for use in planning for investment in transmission and new generation. Yet, generators may realize that the benefits will be ephemeral. Once generators build capacity in a load pocket to address transmission congestion issues, prices will likely reach equilibrium levels that could remove the economic incentives created by locational marginal pricing. Therefore, generators may forego developing fixes if their investments might fail to provide them with economic benefits commensurate with development risks throughout the asset's life. The same argument also could be extended to developing transmission.

[29] *See*, *e.g.*, Technical Conference, *Transmission Independence and Investment* and *Pricing Policy for Efficient Operation and Expansion of the Transmission Grid*, Nos. AD05-5-000 and PL03-1-000, Tr. 37-38 (Larson, Trimaran Capital Partners) (Apr. 22, 2005), *available at* eLibrary Accession No. 20050422-4031:

> So with respect to incentives, my issue with incentives as opposed to rate-based treatment is this: That does introduce uncertainty into it and it does increase the rate. If I need to be able to predict say LICAP for the next 20 years in New England, without the rules even being clear to me how it's being done right now, much less in five years, then I'm going to price that into the returns that I require for that type of transmission investment.
>
> On the other hand, if it's been determined that a project is in the interest of ratepayers and that, based upon a regulatory approval proceeding that it is almost certain that, given a rate-based treatment of a certain new asset, that the benefits are going to offset the cost of the allowed return by the new investor, then frankly, I'll invest in that at a much lower required return.
>
> It's the predictability of earnings. And the uncertainty is not the uncertainty of earnings in a project right now, at least with respect to the investments that we've considered; it's the uncertainty of there being a project at all.

See also Technical Conference, *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, No. PL04-2-000, Tr. at 149 (Anderson, John Hancock Financial Services) (Feb. 4, 2004), *available at* eLibrary Accession No. 20040204-0444:

> Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We're not in this to make a killing off of spiking peak power prices. We're putting capital into this business in opportunities that we think can provide long term stable reasonable returns and are on the low end of the risk adjusted spectrum.

empirical studies all have debunked the assumption that spot market pricing will bring about needed investment in generation and transmission. In *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*, for example, Synapse Energy Economics analyzed the siting of new generation and the location of generation retirements in PJM and concluded:

> We make the following observations of the effect of LMP price signaling as an incentive for new generation construction and retirement decisions in PJM:
>
> • Most of the new generation constructed in PJM has not been in the higher priced eastern regions; conversely, a large share of the retirements *has* been in high-priced regions.
>
> • Most of the new generation had been planned and constructed prior to the recent increase in electricity prices and, because it … utilizes mostly gas-burning technology, it is not benefiting from those prices;
>
> • Proposed new generation in the PJM queue continues to be disproportionately located in regions outside of the high-priced Eastern zones. In addition, PJM has proposed three new east-west transmission corridors pursuant to the 2005 Energy Policy Act, suggesting that they have perhaps minimal expectation that sufficient generation can or will be built in high priced regions and thus transmission is required for reliability assurance;
>
> • LMP price signals do not appear to be providing effective incentives to build and maintain generation where and when it is most needed.[30]

The testimony reflects the reality that LSEs, not to mention generation developers, see today: investors will not fund projects unless they are backed by long-term contracts. Tr. 153 (Baliff, Credit Suisse First Boston Corporation). In the words of one investment banker: "I think the economists like volatility, but the marketplayers don't." Tr. 262 (Newman, Warburg Pincus).

[30] Synapse Energy Economics, Inc., *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers* at 32 (Feb. 5, 2006) (prepared for American Public Power Association), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2007-02.APPA.LMP-Electricity-Markets.06-060-Report.pdf.

The Final Rule also fails to address existing evidence on the elasticity of "demand response resources." Notwithstanding the Final Rule's new requirement that RTOs treat demand response on a par with generation resources, those "demand response resources" will not generate any new electricity. "Demand response resources" are nothing more or less than a decrease in demand; and the price elasticity of "demand response resources" is the mirror image of the price elasticity of demand. Existing evidence indicates that the short-run demand curve for electricity is highly inelastic.[31] The Final Rule not only fails to address that evidence, it assumes the reverse, apparently based on a belief that the new requirements of the Final Rule will fundamentally change the short-run demand for electricity, making it much more elastic—a hypothesis that could certainly be tested without raising existing scarcity price/bid caps. Without evidence to support that belief, the decision to lift price/bid caps amounts to an unsupported reversal by rulemaking of the Commission's past decisions to impose such caps to assure just and reasonable rates and prevent market power abuse in specific markets, without a determination that the conditions requiring the imposition of those caps have been alleviated.

The Commission's contentions about the amount of demand response needed to restrain prices are similarly lacking in reliable evidentiary support. The Commission states that putting rules in place that "allow a fraction of the load to respond can have a

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[31] *See, e.g.*, Alfred E. Kahn, *et al.*, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" at 9, 12-13 (January 23, 2001) http://www.cramton.umd.edu/papers2000-2004/kahn-cramton-porter-tabors-blue-ribbon-panel-report-to-calpx.pdf (strategic withholding of supply possible even without high degree of industry-wide concentration, in part because of "the extreme inelasticity of demand in the short run"); *2007 FERC Staff Assessment* at 7 (finding load reductions in demand bidding programs of only 4-19% of enrolled demand response resources); James Bushnell, Christopher Knittel and Frank Wolak, *Estimating the Opportunities for Market Power in a Deregulated Wisconsin Electricity Market* at 3, 5, 14 (2000) (commissioned by Customers First!, a coalition that includes TAPS members WPPI and Madison Gas and Electric Company, http://www.customersfirst.org/pdf/MarketPowerPaper.pdf) ("Bushnell Study").

positive effect on system reliability and market demand and help reduce prices for all." Order No. 719, P 202. In support of its belief, the Commission cites the 2006 FERC Staff Report, Assessment of Demand Response and Advanced Metering that found that "[a]s little as five percent of load responding to a high price can avert a system emergency and *may* help to lower the market price." Order No. 719, P 202 n.278 (emphasis added) (citing Fed. Energy Regulatory Comm'n, *Assessment of Demand Response & Advanced Metering* (2006), http://www.ferc.gov/legal/staff-reports/demand-response.pdf). The Final Rule, which simply repeats language from the NOPR (P 111), fails to address the 2000 study, *Estimating the Opportunities for Market Power in a Deregulated Wisconsin Electricity Market*, that concluded that one third of the load in the Wisconsin Upper Michigan Subregion ("WUMS") would have to be dropped to mitigate market power.[32]

Nor can the Commission support its evidence-less findings that the current market rules that limit prices in operating reserve emergencies are unjust and unreasonable (Order No. 719, P 192), on the ground that it is not eliminating all market power mitigation (*id.* P 198), or that its approaches provide the potential for some caps, albeit at a higher level (*id.* P 201). The prices paid to a demand responder hardly assure a "safety net" to protect consumers, as the Final Rule claims. *Id.* P 200. Particularly where, as here, the implementation of that regimen depends on the uncertain cooperation of electric retail regulatory authorities in RTO regions *and* may prove ineffective even with their

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[32] The Bushnell Study looked at demand response in WUMS. Bushnell Study at 31-33. It concluded that 4,000 MW of load (or 1/3 of the total WUMS load) would have to be dropped to mitigate market power in that highly constrained and concentrated subregion. *Id.* at 33. This amount of demand response was termed "extremely unlikely." *Id.*

cooperation, the Final Rule's decision to lift existing price caps, regardless, plays a dangerous game of regulatory chicken where electric consumers are the ones who are really at risk. The FPA does not allow the Commission to treat consumers as guinea pigs. Rather, the Commission must ensure a "complete, permanent and effective bond of protection from excessive rates and charges." *Atl. Ref. Co.*, 360 U.S. at 388. If it acts without the requisite empirical proof, the Commission will fail to protect consumers.

Before the Commission imposes the proposed scarcity compliance requirement, it should at least test its hypothesis that price/bid caps are interfering with the proper valuation of energy products, thus deterring demand response. TAPS supports the proposal made by the NRECA in response to the ANOPR[33] that would remove "bid caps for demand response resources during emergency situations, provided that those higher bids for demand response do not set the market clearing price for all resources."[34] NRECA goes on to explain that this could elicit additional demand response during emergencies and "by differentiating between the price received by demand resources and generation resources, it would appropriately treat demand response in these out-of-market situations as an operational tool for preserving reliability rather than as a pure market participant." *Id.* As discussed in Part I.B.3 below, as it now stands, the Final Rule would bar a measured approach that would enable the Commission to develop the evidentiary basis to support lifting price/bid caps.

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[33] Wholesale Competition in Regions with Organized Electric Markets, 72 Fed. Reg. 36,276 (proposed July 2, 2007), [2006-2007 Proposed Regs.] F.E.R.C. Stat. & Regs. ¶ 32,617 ("ANOPR").

[34] Rulemaking Comment of the National Rural Electric Cooperative Association at 16 (Sept. 14, 2007), *available at* eLibrary Accession No. 20070914-5111 ("NRECA Comments").

2. The Final Rule's Finding that its Four Approaches can be Just and Reasonable Fails to Address Arguments to the Contrary

After noting the concerns of TAPS and others with regard to the four approaches included in the NOPR, the Commission expressly refuses to address those concerns individually, "because we are not mandating one specific approach that all RTOs and ISOs must follow, and because each RTO and ISO must demonstrate that it currently complies with the rule or has a proposal that will put it in compliance." Order No. 719, P 235.

Given its finding that "[e]ach of the four suggested approaches can be fashioned in a reasonable way upon compliance to achieve the objectives of the reform required here" (*id.* P 234), the Commission cannot, as it has done here, simply ignore the comments of TAPS and others with respect to the four measures it is so endorsing. TAPS' concerns, which are set forth in our NOPR Comments at 41-44, are summarized below.

The first approach—raising energy bid caps and market-wide caps in an emergency—offers consumers no protection against market power exercise and thus would only produce unjust and unreasonable rates, absent meaningful market power mitigation. *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004), *cert. denied*, 127 S. Ct. 2972 (2007). If demand response is insufficient to restrain prices, the Commission would have to rely upon generators to limit their bids to non-exploitative levels. Generators have neither the ability nor the incentive to determine a price that is just and reasonable under scarcity conditions. The generator would need to figure out what the efficient market price is and then bid at that level. Because electricity markets can change dramatically from hour to hour, this is a near impossibility. Further, the generator is in no position to determine the value buyers place on keeping the lights on, assuming value pricing were permissible.

Even assuming the marginal generator could develop an accurate estimate, it has no incentive to do so where it has market power, which it almost always will have under scarcity conditions because of the absence of competing suppliers and of the very limited ability of load to reduce consumption. To the contrary, the theory of markets assumes that firms with market power may have strong incentives to exercise that power at the expense of consumers.[35] Indeed, to the extent that such firms have a fiduciary responsibility to their shareholders to maximize profits, they could arguably have a duty to do so, so long as the exercise of market power would not cause them to incur penalties or damage to their reputations in excess of the economic profits they earn. The price level that the generator finds most profitable may well be very different from the efficient price.[36] Nor is there any reason to further reward generators that, unless they have been withholding (thereby creating artificial scarcity), have already bid in whatever energy they can produce. This proposal is not consistent with the "Commission's core responsibility … to 'guard the consumer from exploitation by non-competitive electric

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[35] *See*, *e.g.*, Affidavit of Laurence D. Kirsch and Mathew J. Morey on Behalf of National Rural Electric Cooperative Association at 3, filed in this proceeding on April 23, 2008 (eLibrary Accession No. 20080421-5223); *cf. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 684 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002) (noting that "Utilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers.")

[36] Without the risk that load would decrease its demand substantially (enough to make the price increase unprofitable) in response to a high price and knowing that they must be called by the system operator to maintain reliable service in the load pocket, generators would have no incentive to "get the price right." Their only incentive would be to get the price high.

power companies.'" ANOPR P 5 (quoting *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976)).

The second approach—raising bid caps only for demand bids—also suffers from a lack of proof that consumers can effectively express a value for electricity and, even assuming they can, that the Commission could lawfully allow prices to be set by the highest bidder, as would be the case for the sale of a masterpiece painting. While this approach might raise fewer market power concerns than the first (because generation offer caps would remain in place), that ameliorating effect could be very limited if the market participant submitting a demand bid also had generation that could benefit from a price increase. If the higher price yielded additional revenues that exceeded the added cost to load associated with the price increase, the proposal would do little to discourage artificially high load offers.[37]

The third approach—relying on demand curve pricing for operating reserves—risks mandating a particular type of reform, *i.e.*, an RTO-run ancillary services market. If regions, such as SPP, want to move towards Day-2 or Day-2½ markets, that effort should originate with stakeholders, not regulators or RTO management.

The fourth approach would set market-clearing prices at the payment made to participants in an emergency demand response program.[38] This approach may set the

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[37] The Commission's "ballot box" observation (NOPR P 102) that this second approach received less support than the first approach proves only that the numerous generating interests preferred the first approach over the second. Given that the first approach would let them exercise market power, that preference is not surprising.

[38] The NOPR, at P 98 n.97, attempts to distinguish a "demand response bid" (4th approach) from a "demand bid" (2nd approach) by describing the "demand response bid" as "an offer by a purchaser to reduce its normal purchase by a given amount in return for compensation" and describing the "demand bid" as "an offer by a potential purchaser to buy a certain amount of energy at a given market price." Despite TAPS NOPR Comments (at 42-44) questioning the relationship, the Final Rule does not address clarify the

clearing price at the contractually established payment (*e.g.*, to an air conditioning load that responds in an emergency), perhaps determined by a regulatory body other than this Commission and outside the context of the RTO's market clearing mechanism. In addition, if a market participant that can control whether such load is made available has other resources in the market, whether generation or demand, that would benefit from a higher clearing price, it could take actions to place a region into a scarcity condition artificially to earn the extra revenues.

3. The Final Rule Should Have Adopted NRECA's Approach, or at least Modified its Regulatory Text and Criteria to Accommodate that Approach

As noted above and in our NOPR Comments (at 37-39), TAPS supports the NRECA proposal to remove "bid caps for demand response resources during emergency situations, provided that those higher bids for demand response do not set the market clearing price for all resources."[39] The Final Rule (P 231) briefly summarizes this proposal, as well as TAPS' view that the proposal, if properly implemented, should not incent generators to create emergencies because they will not profit from them and, although adding to the uplift consumers must bear, will not inflict the same degree of extreme hardship on consumers as elevating the market clearing price across wide swaths of the nation. Some TAPS members have instituted similar programs, compensating firm customers (as opposed to the interruptible customers that already receive a year-round demand charge credit for being interruptible under certain conditions) for reducing demand in severe emergencies. This approach would have potential benefits in

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relationship between the two approaches.

[39] NRECA Comments at 16.

emergencies, with fewer adverse consequences than the four approaches in the Final Rule.

As the Final Rule further describes (*id.*), TAPS viewed the NRECA proposal as enabling the Commission to obtain evidence regarding the prices demand resources require and whether bid caps are, in fact, interfering with the market's producing those prices. If demand response resources are willing to participate at prices lower than the current offer caps, it will indicate that the offer caps are not the problem. If demand resources require higher prices than available in the market, the Commission can determine whether such participation can be achieved at lower cost through uplift or by allowing the demand resources to set the clearing prices (assuming protections against market power exercise are in place).

TAPS (NOPR Comments at 38-39) expressed concern that the proposed regulation (18 C.F.R. § 35.28(g)(1)(iv)(A)), which requires rule changes "to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power," would preclude an RTO from proposing the NRECA approach, as well as other beneficial demand response programs.[40] To prevent foreclosure of beneficial programs that advance the Commission's goals, TAPS proposed modification of the regulatory text, as described in the Final Rule, P 231.

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[40] For example, the Midwest ISO's Commission-approved Ancillary Service Market allows for participation of certain demand response resources that do not set the market clearing price. This limitation was expressly recognized by the Commission in its order. *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 F.E.R.C. ¶ 61,172, P 188, *on reh'g*, 123 F.E.R.C. ¶ 61,297 (2008).

In the "Commission Determination" section that follows (pertaining to the Commission's four approaches), the totality of the discussion that presumably includes the NRECA approach is as follows (*id.* P 237):

> Several commenters offer alternative approaches to modifying shortage pricing rules. In the NOPR we asked commenters to provide us with, not just barriers, but potential solutions, and these commenters have done just that. While we will not adopt any of these proposed changes explicitly in this rule, we note that RTOs and ISOs and their stakeholders are free to consider these and other possible solutions and propose to us their own method of shortage pricing reform that satisfies the criteria as well as our four approaches.

The Final Rule's conclusory statement that RTOs are free to consider any of the proposals suggested and "propose to us their own method of shortage pricing reform that satisfies the criteria," *id.*, fails to address TAPS Comments that the NRECA approach is a more responsible first step to gaining the facts necessary to shape effective demand response programs than is relaxing mitigation to allow the market clearing price to rise above existing caps, thereby exposing consumers and our economy to severe harm. Nor does the Final Rule's discussion address TAPS' concern that consideration of the NRECA approach as a compliance option is barred by the regulatory text, absent modification.

The Final Rule's suggestion that NRECA's approach may be proposed by the RTO as compliance is further nullified by the Commission's revised criteria, with which any proposal would be required to comply. As revised, the criteria require "comparability in treatment of and compensation to all resources." *Id.* P 247. Because the NRECA proposal compensates demand resources for responding when all available generation has been dispatched, rather than compensating the generator for adding no additional generation to satisfy the shortage, it may not be considered to treat supply and demand resources comparably. The NOPR's "comparability" criteria, which focused on comparable treatment of demand resources (*see id.* P 239), would not have posed such a barrier.

Thus, the Commission should address the merits of NRECA approach, and find it preferable, and more consistent with the FPA's consumer protection mandate than the directives adopted in the Final Rule. At the very least, the regulatory text (18 C.F.R. § 35.28(g)(1)(iv)(A)) should be modified to accommodate NRECA's approach, as TAPS previously proposed:

> Commission-approved ISOs and RTOs must modify their market rules to allow (1) the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand or (2) payments to demand response resources. In either case, the rules must ~~so as to~~ maintain reliability while providing sufficient provisions for mitigating market power.

NOPR Comments at 3.

Finally, the NOPR's "comparability" criteria should be substituted for the Final Rule's comparability criteria. This change would not only accommodate the NRECA proposal, but it would avoid transforming this rulemaking from one designed to enhance demand response into one that enhances the compensation of generators during operating reserve shortages (even where they contribute nothing additional to address the emergency), adding to the burden on consumers and our economic well-being.

4. Additional Criteria are Needed to Make Meaningful the Commission's Claim to be Addressing Market Power and Provide Accountability

As noted in the Final Rule (P 245), TAPS NOPR Comments argued that the need for "empirical proof" that, with implementation of scarcity pricing, competition is sufficient to yield just and reasonable prices[41] requires the Commission to strengthen the factual showing that RTOs must make regarding scarcity pricing proposals to include:

> • Specific competitive analyses of market power risks during scarcity conditions;
>
> • Measures of whether demand response in the RTO region, in fact, mitigates market power;
>
> • Examination of the incentive and ability to withhold demand response to exercise market power, especially by market participants with generation;
>
> • Demonstration that the RTO's market mitigation measures target market power under scarcity conditions and are effective in doing so;
>
> • A determination that there is enough demand response, after considering its use for capacity reserves and ancillary services, to restrain prices during scarcity; and
>
> • Statistics on experienced and expected scarcity conditions to ensure that such conditions are rare.

TAPS NOPR Comments at 3, summarizing TAPS NOPR Comments at 24-29.

As described in the Final Rule (P 244), another commenter (PG&E) sought, among other things, to expand the criteria to include "a demonstration that any proposed market rule changes are cost effective, including an evaluation of the impact on reliability and an estimation of the cost of the program;" and "an assessment of the readiness of

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[41] *See Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d at 1510.

demand response programs that will be called upon to reduce the number and severity of shortage pricing events and help mitigate market power."

The Final Rule (P 250) finds PG&E's suggested additions "not needed," explaining:

> We are firmly of the opinion that the changes mandated in this Final Rule will increase system reliability by inducing additional response by demand- and supply-side resources and that RTO and ISO compliance will not result in a decrease in reliability. Second, requiring an explicit accounting of the costs of the program will not be included. We do not see the usefulness of this exercise. While there will be costs involved, the long-term benefits of maintaining grid reliability are evident.

While the Final Rule finds that specified suggestions of another commenter (North Carolina Electric Membership Corporation) to be explicitly or implicit included in the Final Rule's criteria (*id.* P 249), TAPS' suggestions are not identified as encompassed within those criteria or otherwise specifically discussed in the "Commission Determination" section. Rather TAPS' suggestions are apparently included among the additional criteria rejected by the Final Rule, supported by the following discussion (*id.* PP 252-53):

> We decline to accept all other suggested criteria because they would represent a level of burden to the RTO or ISO that would exceed the benefit of doing the analysis.
>
> We find that the criteria proposed in the NOPR, as modified above, are sufficient to show whether a region's proposed changes to its existing market rules meet the requirements of this rule, while protecting consumers from market power.

This Final Rule's conclusory statement is not sufficient to meet its reasoned decision-making requirements. Nor does it satisfy its statutory obligations, under

Farmers Union, not to rely on market forces without empirical proof that competition is sufficient to discipline rates to just and reasonable levels. To reject, as the Final Rule apparently does, the additional TAPS criteria of specific competitive analyses of market power risks during scarcity conditions as a "level of burden to the RTO or ISO that would exceed the benefit of doing the analysis" (Order No. 719, P 252) gives a green light to RTO compliance filings that will be plainly inadequate to demonstrate that consumers will be protected from market power during the very periods when the Rule requires scarcity pricing to be in effect.[42]

Similarly, the Final Rule's apparent dismissal of TAPS' suggestion (*id.* at 3) that the criteria require "[m]easures of whether demand response in the RTO region, in fact, mitigates market power" as an undue burden on RTOs severely undermines the Final Rule's reliance on demand response to mitigate market power as required to meet its statutory requirements for just and reasonable rates. *See id.* PP 190, 192-207; *see also id.* P 252. As TAPS NOPR Comments explained (at 31-32), in assessing the ability of demand response to mitigate market power, it is not enough to recite advanced metering or other demand response penetration or participation rates; demand response enrollment will not suffice if the demand does not respond during the time of need. As noted above, the *2007 FERC Staff Assessment* (at 7) found load reductions in demand bidding programs of only 4-19%, even though enrollment levels were considerably higher. Empirical evidence, such as critical loss analyses, is needed to assess the amount of demand response that can be depended upon to restrain prices during scarcity. The need

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[42] As explained in TAPS NOPR Comments (at 30-31), none of the usual metrics—pivotal supplier, market share, and the delivered price test ("DPT")—examine scarcity conditions specifically.

for a factual record assessing the degree to which demand response can effectively discipline prices before finding scarcity pricing reasonable was highlighted in Commissioner Wellinghoff's recent dissents from the Commission's orders regarding MISO's proposed ancillary services market.[43]

Before relying on demand response to mitigate market power, the Commission likewise should require the RTOs' market power analyses to examine the incentive and ability to withhold demand response, especially by market participants with generation, and require RTOs to demonstrate that they have market mitigation measures that are effective under scarcity conditions (*see* TAPS NOPR Comments at 32-33). This showing is particularly crucial given that the Final Rule supports lifting existing caps by relying (Order No. 719, P 195) on mitigation measures that apply only to generation resources deemed to have significant effects on transmission constraints.[44] Failure of the Commission to demand that RTOs show that all resources, whether generation or demand, that could affect prices under scarcity conditions are covered by mitigation measures, significantly undermines its claim that its scarcity pricing requirements ensure that market power is mitigated.

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[43] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,172 (2008) (Wellinghoff, Comm'r, dissenting) ("Without such a record indicating potential demand response to discipline bidding behavior, the reasonableness of Midwest ISO's overall proposal, and particularly its plans to implement scarcity pricing, is called into question."). In the recent rehearing order, 123 F.E.R.C. ¶ 61,297 (2008), Commissioner Wellinghoff again dissented, referring to his earlier dissent and faulting the failure to modify market rules that create barriers to participation of demand response.

[44] *See* Southwest Power Pool, FERC Electric Tariff, Fifth Revised Volume No. 1, Attachment AF, Section 3.2, *available at* http://www.spp.org/publications/SPP_Tariff.pdf; Midwest ISO, FERC Electric Tariff, Third Revised Volume No. 1, Module D, Section 63.4, *available at* http://www.midwestmarket.org/publish/Document/3b0cc0_10d1878f98a_-7d060a48324a/Modules.pdf?action=download&_property=Attachment.

The Commission also brushes aside as an undue burden TAPS' proposed additional criteria (TAPS NOPR Comments at 34-35), including the request for statistics on the number of hours when scarcity conditions arose or are expected to arise. Particularly in light of the Final Rule's refusal to tie the timing of implementation to benchmarks (Order No. 719, P 258), this decision inappropriately denies the public and the Commission the opportunity to realistically assess the impact on consumers and our economy of its scarcity pricing requirement and the justness and reasonableness of the resulting rates.

Finally, although TAPS did not initially suggest them, TAPS seeks rehearing of the Commission's rejection of the additional criteria proposed by PG&E, especially with regard to the cost effectiveness of the Final Rule's scarcity pricing requirement. The Final Rule (P 250) does not "see the usefulness of this exercise" because the Commission is of the "opinion" that scarcity pricing will yield long-term reliability benefits it finds "evident." Apparently, it doesn't matter how much it costs. The FPA plainly requires the Commission to do more to ensure just and reasonable rates. Indeed, the Commission's failure to require any accountability for the costs imposed by its scarcity pricing rule runs contrary to the recommendations of the GAO Report, [45]with which the Commission is stated to agree. *See* Part III.B below.

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[45] U.S. Gov't Accountability Office, Report to the Committee on Homeland Security and Governmental Affairs, U.S. Senate, *Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance* (2008), http://www.gao.gov/newitems/do8987.pdf ("GAO Report").

5. Failure to Clarify the Definition of Operating Reserve Shortage Leaves the Rule Overbroad and Ambiguous

TAPS NOPR Comments criticized the then-proposed regulatory definition of "operating reserve shortage" as overbroad:

> [T]he proposed definition of "operating reserve shortage" may be too broad for the intended purposes of permitting scarcity pricing only in "emergency" situations. *See, e.g.*, NOPR at P 123 ("Under the first approach, RTOs and ISOs would increase the energy supply offer caps and demand bid caps above the current levels only during an emergency."). As proposed, Section 35.28(b)(6) would read "An *operating reserve shortage* means a period when the amount of available supply falls short of demand plus the operating reserve requirement" (emphasis in original). But operating reserves are meant to be used, and such use in the ordinary course should not be deemed an operating reserve shortage triggering scarcity pricing, if operating reserves can readily be timely replenished. The definition should be refined to encompass only the (hopefully) rare shortage situation.

TAPS NOPR Comments at 39-40.

The Final Rule (P 231) notes TAPS' suggestion regarding the operating reserve shortage definition, but incorrectly ties this change to eliminating obstacles to adoption of the NRECA approach (discussed above), and does not address it in the related "Commission Determination" section. In a later section, the Final Rule includes a discussion of when scarcity pricing would be effective:

> As to when these pricing rules would go into effect, it is when the RTO or ISO has an operating reserve shortage. The reliability standards of the North American Electric Reliability Corporation, which have been approved by the Commission, or of other authorized reliability body, specify system operating reserve requirements, and these standards are well known to system operators such as RTOs and ISOs, as well as to the many stakeholders who helped develop them. The level of operating reserves required by the reliability standards depends on the characteristics of each system and cannot be correctly

> reduced to a single number that applies to every system, such as seven percent of peak load. Further, if we were to repeat the reliability standard definition here in our regulations, it would be cumbersome for reliability organizations to improve their definition of operating reserve requirements over time without also having to seek a change in our regulations. We find that this is the best definition of when these price reforms apply; we do not adopt a second, different definition, here, because having two definitions of operating reserve shortage would only cause confusion for system operators.

Order No. 719, P 251. The above-quoted discussion suggests that the Commission intended to leave the definition of operating reserve shortage to reliability standards, rather than adopt a second definition in this rule that could cause confusion. Nevertheless, the Final Rule does just that—adopting the NOPR's regulatory language defining operating reserve shortage, without even referring to reliability standards. "*An operating reserve shortage* means a period when the amount of available supply falls short of demand plus the operating reserve requirement."[46] Thus, the regulatory text appears inconsistent with the preamble.

In addition, the Final Rule's discussion does not address TAPS' never-referenced concern that the operating reserve shortage definition encompasses the commonplace situation where operating reserves are used (as they are meant to be, thus causing operating reserve levels to momentarily dip), but can be timely replenished, consistent with applicable reliability standards, and should not trigger scarcity pricing. The definition should be revised to restrict scarcity pricing to emergencies, as the

[46] Order No. 719, at 309.

Commission apparently intends,[47] *i.e.,* to instances where the RTO risks being unable to replenish operating reserves within the period specified in applicable reliability standards.

II. MARKET MONITORING POLICIES

A. The Commission Should Have Further Shortened the Time for Release of Bid Data

The NOPR had proposed to reduce the lag on release of bid and offer data from six to three months. After noting that some commenters asked that the lag be reduced, the Final Rule states, P 421:

> Our proposal cuts the current lag time for most RTOs and ISOs in half. Because this is a substantial change, RTOs and ISOs should become accustomed to the new release time and observe its effects before committing to an even shorter time. However, as we proposed in the NOPR, we permit the RTOs and ISOs to propose a shorter time, with accompanying justification, or a longer time of four months if they can demonstrate a collusion concern. Alternatively, they may propose an alternative mechanism if release of a report were otherwise to occur in the same season as reflected in the data. These options provide the flexibility requested by commenters.

The Final Rule includes no further explanation of its denial of TAPS' request that disclosure be required in a week or less. In addition, the Final Rule (P 423) retains masking of identities.

> We decline to establish a time period for the eventual unmasking of identities, but invite RTOs and ISOs to propose a period when such unmasking might be permitted, if they believe it to be desirable.

While the move from six to three months is in the right direction, neither the limitation of the reduction to three months, nor the continuation of masking, can be

[47] *See*, *e.g.*, *id.*, PP 165, 254.

squared with the wealth of data demonstrating the benefits, and absence of adverse consequences, of shorter release periods and elimination of masking. Given this evidence, the Commission's continued masking and undue caution in waiting to see the results of the three-month release period before going shorter unreasonably impairs the operation of the markets it is seeking to enhance.

TAPS NOPR Comments (at 53-57) describe successful models for making information, including bid-offer data, available on a real or close-to-real time basis. In other functioning, competitive electricity markets, market data is released routinely, and without the masking that FERC has required or approved to date. In the Australian National Electricity Market, for example, generating unit bid data is available on a next-day basis.[48] Likewise, the Balancing Mechanism Reporting System ("BMRS") website for the England and Wales market provides near real-time and historical data—including bid-offer data—on the National Grid Company's balancing of power flows in the electricity transmission system in England and Wales.[49] Data disclosures have not caused those markets to collapse.[50] On the contrary, competitive markets thrive on information, not secrecy. On the New York Stock Exchange, trade information is immediately available, and actions are traceable to those commanding the activity.[51]

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[48] This data is found at NEMMCO Market Management System (MMS) CSV Files, http://www.nemmco.com.au/data/csv.htm (last visited Nov. 16, 2008).

[49] On the BMRS website (http://www.bmreports.com), a wide range of data, including bid-offer data for each BM Unit, can be retrieved at http://www.bmreports.com/bwx_reporting.htm (last visited Sept. 14, 2007).

[50] *See, e.g.,* Comptroller and Auditor General, Nat'l Audit Office, *The New Electricity Trading Arrangements in England and Wales* (2003), http://www.nao.org.uk/publications/nao_reports/02-03/0203624.pdf.

[51] In other contexts, such as securities regulation, transparency is favored because it breeds investor confidence, strengthens capital markets and leads to economic growth. *See* Claire Moore Dickerson, *Ozymandias as Community Project: Managerial/Corporate Social Responsibility and the Failure of*

Faster release of more information does not necessarily raise collusion concerns and may well mitigate them. From antitrust law and economics, we know that concentration levels and ease of entry are leading factors affecting the ability of firms to collude. Other factors, such as information transparency, firm size, product homogeneity or heterogeneity, and prior evidence of coordinated activity, can play a role in specific cases, but are far from dispositive in all circumstances.[52] More information in the hands of a larger number of competitors reduces the value of the information as a coordination tool, because there is a greater likelihood that individual competitors will use the information to compete harder and better. On the other hand, if only a few players with a sufficiently large share of the market have access to information, the risks of collusion increase. Moreover, transparency rules can be refined to keep confidential, or delay the release of, information that is the most sensitive and otherwise not available.

In fact, the current approach involving a significant time delay likely increases collusion risks. The greatest danger to LMP market design involves generators that derive market power from their control of multiple resources, because the intellectual foundation for the single-price auction model assumes that each offeror owns only one asset.[53] Large generation-portfolio holders know their offers for each of their multiple

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Transparency, 35 Conn. L. Rev. 1035, 1052 (2003) (citing Bernard S. Black, *The Legal and Institutional Preconditions for Strong Securities Markets*, 48 UCLA L. Rev. 781, 786-87, 835-38 (2001) and Joel Seligman, *The Historical Need for a Mandatory Corporate Disclosure System*, 9 J. Corp. L. 1 (1983)).

[52] *See* Margaret C. Levenstein & Valerie Y. Suslow, *What Determines Cartel Success?* 44 J. Econ. Literature 43 (2006); *see also* U.S. Dep't of Justice & Fed. Trade Comm'n, *Horizontal Merger Guidelines*, §§ 2.11, 2.12 (1997), http://www.usdoj.gov/atr/public/guidelines/horiz_book/hmg1.html; *In re High Fructose Corn Syrup Antitrust Litig.*, 295 F.3d 651 (7th Cir. 2002), *cert. denied*, 537 U.S. 1188 (2003); *Fed. Trade Comm'n v. Elders Grain, Inc.*, 868 F.2d 901 (7th Cir. 1989); *Hosp. Corp. of Am. v. Fed. Trade Comm'n*, 807 F.2d 1381 (7th Cir. 1986), *cert. denied*, 481 U.S. 1038 (1987).

[53] *See* Robert C. McDiarmid, Lisa G. Dowden & Daniel I. Davidson, *A Modest Proposal: Revoke the Nobel Prize? Recognize the Limitations of Theory? Or Grant a License to Steal?* 14 Electricity J. 11 (2001).

resources. Further, sources like Genscape already sell information on generator operating status. Consequently, those that would use such information to manipulate markets or for other improper purposes[54] can already obtain it, and a three-month lag will not prevent them from doing so. Allowing RTOs to make it available for free and more quickly would have the salutary effect of enabling smaller market participants to compete on a level playing field, and enabling them and low-budget consumer representatives (*e.g.,* official state consumer advocates) to assist with market monitoring. The result should be more competitive markets than would otherwise be the case. The availability of data to sophisticated players clearly does not argue for greater protection of confidentiality, as the Final Rule seems to assume. Order No. 719, P 423.

Further support for faster release of data may be found in the 2007 study, *Data Required for Market Oversight – A Concept Paper for the Electric Market Reform Initiative ("EMRI") of the American Public Power Association*, which William H. Dunn Jr. of Sunset Point LLC prepared ("Dunn Study").[55] Mr. Dunn's study recommended that unmasked RTO electric market offer and bid data should be released on the day after the operating day, and the unmasked physical operating characteristics of generation

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[54] Given the public availability of Genscape information and other means of acquiring information on a target plant's operating status, TAPS doubts there remains a homeland security basis for keeping such information non-public. If that case can be made, however, the proper response is to make the generator status information available to all industry stakeholders that demonstrate their bona fides as North American market participants. Critical Energy Infrastructure Information, Order No. 630-A, 68 Fed. Reg. 46,456, 46,457 (Aug. 6, 2003), [2001-2005 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,147, P 7 (to be codified at 18 C.F.R. pt. 388) ("[T]he Commission encourages these entities [RTOs and others] to provide information to legitimate requesters.").

[55] William H. Dunn, Sunset Point, LLC, *Data Required for Market Oversight – A Concept Paper for the Electric Market Reform Initiative ("EMRI") of the American Public Power Association* (2007), http://www.appanet.org/files/PDFs/dunn2007.pdf.

resources should be publicly available. Dunn Study at 1. The study concluded that the benefits of faster release far exceed any additional collusion risks (at 14):

> The possible benefits to be obtained by the posting of resource and load-specific offer and bid data on the day following the operating day appear to far exceed the risks of additional collusion by those market participants inclined to collude. In fact, such data posting may help expose efforts to manipulate market prices and, as a result, discourage such behavior. Such rapid data posting also has the potential to create confidence in the markets and expose what goes on in the black box, thereby increasing the pressure on: (i) market participants to behave; (ii) RTOs/ISOs to efficiently and economically operate the markets; and (iii) market monitors to detect anomalous behavior on the part of market participants and/or RTOs/ISOs.

Given the increased recognition, post-Wall Street meltdown, of the importance of transparency, the Commission should move more forcefully on rehearing to further reduce the lag time on release of bid and offer data, and reconsider its retention of masking.

III. RESPONSIVENESS OF RTOS AND ISOS TO STAKEHOLDERS AND CUSTOMERS

A. The Commission Should Require a Mission Statement that Holds RTOs Accountable to Consumers

In TAPS NOPR Comments, we urged the Commission to go beyond merely requiring the posting of *a* mission statement which, at the RTO's election, may include *some* purpose, principles, plus a generalized commitment to be responsive to all stakeholders and consumers, and to instead require each RTO to file a consumer-focused mission that makes it *accountable* to consumers for meeting the Federal Power Act's purpose of ensuring that electricity consumers pay the lowest possible reasonable rates for reliable service. The Final Rule (at P 553) notes TAPS NOPR Comments, but then ignores it in its ruling (*id.* P 556).

The only discussion provided by the Final Rule on this point is the statement: "We find that this requirement will improve communication between RTOs and ISOs and their stakeholders and the community at large, as well as provide a statement of goals by which the RTO's and ISO's progress may be judged." *Id.* P 557. If anything, that finding supports the need to make sure that the "goals by which the RTO's … progress may be judged" (*id.*) enable consumers to hold Commission-approved RTOs accountable for ensuring that the FPA's goals are accomplished—that electricity consumers pay the lowest possible reasonable rates for reliable service.

Under the FPA, wholesale competition and well-oiled markets are not ends in themselves. Rather, the end is the one articulated in Section 205: just and reasonable rates. 16 U.S.C. § 824d. To do so, the Commission must "curb abusive activities by public utilities … and … protect consumers of electrical services from excessive rates."[56] As the Supreme Court has explained, Congress intended jurisdictional sales "at the *lowest possible reasonable rate* consistent with the maintenance of adequate service in the public interest," and the Act was "framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges." *Atl. Ref. Co.*, 360 U.S. at 388 (emphasis added) (internal quotation omitted).[57] As recently reaffirmed by

[56]*Fla. Power & Light Co. v. FERC*, 617 F.2d 809, 816 (D.C. Cir. 1980) (citations omitted). *See also FPC v. La. Power & Light Co.*, 406 U.S. 621, 631 (1972) ("The Natural Gas Act of 1938 granted FPC broad powers to protect consumers against exploitation at the hands of natural gas companies.") (internal quotation omitted); *Pub. Sys. v. FERC,* 606 F.2d 973, 979 n.27 (D.C. Cir. 1979) ("Both the Natural Gas Act and the Federal Power Act aim to protect consumers from exorbitant prices and unfair business practices.").

[57] While *Atlantic Refining* arose under the Natural Gas Act, courts have "repeatedly recognized the similarity of the two statutes and held that they should be interpreted consistently." *Transmission Access*

the Commission, "In Order No. 2000 … the Commission's goal was to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service… ."[58]

The RTOs' mission must be clearly defined and specific, so that there is a standard to which the RTOs and their management can be held. Only a clear directive will be sufficient to reverse the current course, where TAPS members have heard RTO executives disclaim any obligation to have their actions guided by consideration of cost impact on consumers. It is apparent that RTO management views this Commission and state regulators as the only entities to which they are responsible and accountable.

The Commission will not fulfill its FPA obligation unless it clearly redefines the RTOs' mission to include provision of reliable service at the lowest possible reasonable rates, and requires RTOs to meet these goals. By establishing consumer value as a core goal of the RTOs, the Commission would focus the entire RTO organization on the achievement of this goal, aligning the RTOs' mission with the objectives of state regulators, federal policy makers, LSEs, and the consumers who ultimately bear the cost of the RTO's operations.

B. The Commission Should Require Measures to Ensure RTO Accountability

TAPS NOPR Comments (at 70-75) summarized the specific responsiveness and accountability proposals that were discussed in greater detail in our ANOPR Comments:

Policy Study Group v. FERC, 225 F.3d 667, 686 (D.C. Cir. 2000), *aff'd sub nom. N. Y. v. FERC*, 535 U.S. 1 (2002).

[58] Promoting Transmission Investment through Pricing Reform, Order No. 679-A, 72 Fed. Reg. 1152, 1166 (Jan. 10, 2007), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,236, P 86 n.141, *clarified*, 119 F.E.R.C. ¶ 61,062 (2007).

- Requiring independent, biennial study of all RTOs that benchmarks each RTO's operating costs, as well as the costs of particular RTO functions, against the costs of other RTOs and, where possible, against the costs of non-RTO transmission providers (*see* TAPS ANOPR Comments at 48).

- Requiring detailed, biennial, independent cost-benefit analyses (with results shown by state at delivery point levels) and RTO efficiency audits. These analyses should not be limited to production cost-savings, but instead measure achievement of the RTO mission–value via reduced consumer costs. Such value cannot be delivered unless (a) the RTO generates cost savings through efficiencies, and (b) those savings, or a very significant portion of them, are reflected in the delivered price of wholesale energy, or at least the prices charged load-serving entities (recognizing the state role in determining charges to end-users) (*see* TAPS ANOPR Comments at 48-49).

- Requiring RTOs to assess the cost/benefits of new initiatives or major rule changes *before* undertaking them, taking into account both RTO costs and costs to market participants, to track the actual costs and benefits of such implementation, and to be accountable for their projections (*see* TAPS ANOPR Comments at 49-50).

- Requiring annual public reporting of RTO performance measurements (with an opportunity for comment), as well as other mechanisms to hold RTOs accountable for performance measures, including: (1) success at relieving congestion costs (quantifying congestion costs and tracking the progress of congestion cost reduction efforts); (2) responses to interconnection and transmission requests (tracking associated backlogs and delays and the measures undertaken to eliminate them); (3) reliability and outage statistics; and (4) whether RTO transmission planning and expansion targets are met (including its obligations to plan and expand the transmission system to meet the reasonable needs of LSEs and to enable them to secure long-term rights for their long-term power supply arrangements) (*see* TAPS ANOPR Comments at 50-51).

- Requiring RTO senior management compensation to be tied to consumer-focused performance measures (*see* TAPS ANOPR Comments at 52-54):

    - achievement of the RTO's consumer-cost lowering mission;

    - independently-determined measures of customer satisfaction;

    - reductions in congestion costs;

    - RTO cost containment;

    - reduction in interconnection and transmission queues;

- meeting aggressive planning and construction targets;
- strategic planning and internal analyses that reflect a consumer-focused mission; and
- other objective measures of high quality service.

- Requiring advance stakeholder committee review of each RTO's annual budget, with a specific allowance for stakeholder rejection or modification of the budget where a substantial majority of stakeholder sectors agrees. If the RTO board believes that a modified budget jeopardizes its ability to meet its obligations, the board should be permitted to appeal to the Commission. Such an appeal should occur with sufficient time and factual support to permit the Commission to resolve the issue, with meaningful consideration of the stakeholder rejection, *before* the budget takes effect (*see* TAPS ANOPR Comments at 54-55).
- The annual budget review process should include capital budgets reflecting the total expected costs of a major project, rather than just the current year's cost for a multi-year project, with the cost-benefit process and tracking discussed above (*see* TAPS ANOPR Comments at 54-55).

In addition, TAPS NOPR Comments stressed the need to hold RTOs accountable for fulfilling obligations to plan and expand the transmission system to meet the reasonable needs of LSEs and to enable them to secure long-term rights for their long-term power supply arrangements, as Congress directed in Section 217(b)(4).[59] We noted that the task could not be "checked off" as accomplished by promulgation of the long-term rights rule.[60] Our concerns are heightened by recent orders that find RTOs not accountable for fulfilling the fundamental RTO responsibility of planning and directing the expansion of the grid to maintain deliverability of resources designated (with RTO approval) as a load-serving entity's network resources, so they can be counted toward

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[59] 16 U.S.C. § 824q(b)(4), as added by Section 1233 of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 958 (2005).

[60] *See* NOPR, P 22 ("The Commission has also acted to improve certainty in the cost of transmission for electric customers by creating rules for long-term transmission rights in Order No. 681 and 681-A.").

resource adequacy requirements.[61] Shifting the quintessential RTO/transmission provider burden[62] to customers (that are in no position to ensure long-term deliverability of their network resources) undermines the basic set of rights and obligations set forth in Order Nos. 888 and 890.

Without specifically noting TAPS' Comments on these matters, the Final Rule contents itself with requiring RTOs to make compliance filings to demonstrate responsiveness with reference to its four criteria, and refuses to include any measures to require RTOs to be accountable to consumers for the costs they impose. In addressing comments of APPA and others seeking a requirement for benchmarking studies, cost benefit analyses, and a moratorium on new RTO products and services, the Commission "declines to expand the scope of this proceeding to encompass topics not presented in the NOPR. RTOs and ISOs and their stakeholders may address these topics, if they so choose, through their own processes for evolving RTO and ISO services and markets." Order No. 719, P 573. In rebuffing Connecticut and Massachusetts municipals' suggestions for cost-containment measures and cost-benefit reviews of significant RTO actions, as well as suggestions of others for customer satisfaction surveys, the Commission leaves such matters to the RTO's collaborative process (*id.* P 515).

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[61] *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,061, P 34 (2008) ("While we recognize that the Midwest ISO has the obligation to facilitate generation interconnections and expansion planning, it cannot force utilities to build capacity. The Midwest ISO therefore cannot be required to build sufficient transmission capacity to ensure deliverability of all resources for their useful life.").

[62] Order No. 2000 expressly required that an RTO have authority to plan and cause expansion needed to provide transmission service (18 C.F.R. 35.34(k)(7)). Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,089, *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), [1996-2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,092, *appeal dismissed for want of standing sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

On rehearing, the Commission should reconsider its conclusion that the collaborative process and expanded provision for responsiveness to all stakeholders will ensure that Commission-approved RTOs are accountable to consumers, and facilitate the ability of the Commission to fulfill its FPA obligation of ensuring reliable service at the lowest possible reasonable rates. *See* Part III.A above. The recently released GAO Report confirms the need for the Commission to meaningfully address RTO accountability. The Report recognized the limitations of the stakeholder process and called for more active Commission oversight of RTO expenses and rates. *See* GAO Report, Executive Summary at 7. The GAO Report (at 41-44) faults the Commission for over-reliance on stakeholders to raise concerns about RTO expenses and decisions.

The Executive Summary (*id.* at 8) recommends that the Commission develop a consistent approach for regularly reviewing RTO budgets and the accuracy, completeness, and reasonableness of their Form 1s. This recommendation draws on Report findings that "FERC officials do not regularly compare expenses across RTOs or create expense benchmarks to use as an analytical tool…." *Id.* at 40-41. The Report further found (*id.* at 41):

> Without reviewing actual RTO expenses for reasonableness, FERC may not be as well positioned as it could be to ensure the rates RTOs charge to recover their expenses are just and reasonable and that RTO funds were spent according to how FERC and the stakeholders approved them to be.

The GAO also recommended that the Commission work with RTO stakeholders and experts "to develop standardized measures to track the performance of RTO operations and markets" for public report. *Id.* at 8. This recommendation draws from the Report's findings that the Commission should develop "a report or other assessment with comprehensive, standardized measures that Congress and the public could use to identify and track RTO performance." *Id.* at 55. It also is based on the Report's finding that the Commission has not examined where RTO projections of savings have in fact been realized. *Id.* Noting Commission comments that "RTOs are in a position of greater public trust than utilities" and its "unique expectations" that "creation of RTOs could lead to lighter regulation," the GAO nevertheless adheres to its recommendations for performance measures to improve RTO performance. *Id.* at 61.

The GAO Report states, "FERC reviewed a draft of this report and generally agreed with our report and recommendations." GAO Report, Executive Summary at 8. That agreement cannot be reconciled with the Final Rule's rejection of all suggestions for enhancing accountability, including TAPS' recommendations for benchmarking studies, performance measures, and cost-benefit analyses. It is also hard to square the Final Rule's reliance on the collaborative stakeholder process in lieu of more directly addressing accountability, given GAO Report findings as to the Commission's undue reliance on the stakeholder process to ensure RTO costs are just and reasonable.

On rehearing, the Commission should include additional accountability measures, such as those proposed by TAPS in its NOPR and ANOPR Comments, including accountability for RTO planning and directing the expansion needed to support long-term transmission rights and continued deliverability of designated network resources. At minimum, the Commission should promptly issue a new NOPR (if appropriate in a new proceeding) to more directly address RTO accountability.

CONCLUSION

For the reasons discussed above, the Commission should grant rehearing and clarification of the Final Rule.

Respectfully submitted,

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