

137 FERC ¶ 61,215
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized
Wholesale Energy Markets

Docket No. RM10-17-001

ORDER NO. 745-A

ORDER ON REHEARING AND CLARIFICATION

(Issued December 15, 2011)

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Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

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1. In this order the Commission denies rehearing of Order No. 745 (Final Rule),¹ and grants in part and denies in part clarification regarding certain provisions of the order. Order No. 745 amended Commission regulations to require that a demand response resource participating in an organized wholesale energy market must be compensated for the service it provides at the market price for energy when the demand response resource has the capability to balance supply and demand as an alternative to a generation resource and when the dispatch of demand response resource is cost-effective.

I. Introduction

2. On March 15, 2011, the Commission issued Order No. 745, a Final Rule amending its regulations under the Federal Power Act (FPA) regarding demand response compensation in the Regional Transmission Organization (RTO) and Independent System Operator (ISO) day-ahead and real-time organized wholesale energy markets. The Commission determined that the Final Rule would help improve the functioning and competitiveness of organized wholesale energy markets, thereby ensuring just and reasonable rates in those markets. In the Final Rule, the Commission requires each RTO and ISO in which demand response participates in its energy market to pay a demand

¹ *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011).

response resource the market price for energy, also referred to as the locational marginal price (LMP), when two conditions are met. First, the demand response resource must have the capability to balance supply and demand as an alternative to a generation resource. Second, dispatch of the demand response resource must be cost-effective as determined by a net benefits test.²

3. The Commission in the Final Rule also provided guidance about the net benefits test that it required RTOs and ISOs to include in their respective compliance filings, and on the formulation of such a test. As explained in the Final Rule, the net benefits test begins with an analysis of a RTO's or ISO's historical supply curves grouped into monthly periods, from which a threshold point can be calculated. This threshold point corresponds to a point on the supply curve at which the benefit to load from the reduced LMP resulting from dispatching demand response resources exceeds the increased cost to load associated with the billing unit effect. The Commission stated in the Final Rule that it expects that the net benefits test would be satisfied, thereby requiring payment of LMP, where the supply curve is shaped such that small decreases in generation that is used to serve load will result in price decreases sufficient to offset the billing unit effect.

4. The Commission also required each RTO and ISO to review their current measurement and verification requirements in light of the changes in this Final Rule and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed.

5. Finally, the Final Rule set forth cost allocation requirements applicable to the costs incurred by RTOs and ISOs when paying demand response compensation. The Commission noted that, as a result of the billing unit effect, the difference between the amount owed by the RTO or ISO to both generation and demand response resources, and the revenue derived from load, results in a negative balance that must be addressed through cost allocation. Allocation of costs, as explained by the Final Rule, is reasonable when costs are allocated proportionally to all entities that purchase from the relevant

² The Commission explained that a net benefits test is necessary because the dispatch of demand response resources may result in an increased cost per unit to load associated with the decreased amount of load that pays for the cost of energy purchased in the organized wholesale energy market. The Commission further explained that when the LMP is reduced and consumers realize a cost savings because of the participation of demand response resources in the energy market, and where this cost savings is of a sufficient amount to overcome the total amount that consumers pay for demand response resources at the LMP and the effect of the reduced quantity of load paying for the purchased supply resources, such a purchase of demand response resources is cost-effective.

energy market in the area(s) that benefit from the lower LMPs that result from demand response resource participation in the organized wholesale energy markets.

II. Requests for Rehearing and Clarification

6. The following entities have filed timely requests for rehearing of the Final Rule: Edison Electric Institute (EEI); Electric Power Supply Association (EPSA), Independent Power Producers of New York, Inc. (IPPNY), Electric Power Generation Association (EPGA), and New England Power Generators Association, Inc. (NEPGA) (collectively, Competitive Supplier Associations or CSA); EPSA, American Public Power Association (APPA), EPGA, and National Rural Electric Cooperative Association (NRECA) (collectively, Joint Petitioners); Midwest Transmission Dependent Utilities (Midwest TDUs); Organization of MISO States (OMS); PJM Power Providers Group (P3); and PPL Parties. The following entities have filed timely requests for clarification and/or rehearing of the Final Rule: California Department of Water Resources State Water Project (SWP); California Independent System Operator Corporation (CAISO);³ Demand Response Supporters (DR Supporters);⁴ Public Utilities Commission of the State of California (CPUC); Midwest ISO Transmission Owners (Midwest ISO TOs); and Old Dominion Electric Cooperative (ODEC), APPA, and NRECA (collectively, Joint Parties). The Illinois Commerce Commission (ICC) filed a timely request for clarification.

7. Occidental Permian Ltd. and Occidental Chemical Corporation (collectively, Occidental), filed a motion for leave to answer and answer responding to the request for clarification or rehearing filed by the DR Supporters.⁵ ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) Participants Committee filed a motion for leave to answer and answer responding to the request for clarification filed by the ICC and the request for clarification or rehearing filed by the DR Supporters.⁶

³ California Independent System Operator Corporation (CAISO) requests that the Commission issue a substantive order within 30 days after the April 14, 2011 deadline for petitioners to file requests for rehearing. The Office of the Secretary issued an Order Granting Rehearing for Further Consideration on May 13, 2011. Accordingly, CAISO's issues are addressed in this order.

⁴ Members of the Demand Response Supporters include: American Forest & Paper Association, Consumer Demand Response Initiative, EnerNOC, Inc., Project for Sustainable FERC Energy Policy, and Viridity Energy, Inc.

⁵ Occidental Permian Ltd. and Occidental Chemical Corporation (Occidental) April 29, 2011 Answer.

⁶ ISO New England Inc. (ISO-NE) April 29, 2011 Answer.

Viridity Energy, Inc. filed a motion for leave to answer and answer responding to the request for rehearing filed by EEI, the request for clarification or rehearing filed by the CPUC, and the request for clarification and rehearing filed by CAISO.⁷ The Industrial Energy Consumer Group (IECG) filed a motion for leave to answer and answer to the motion for leave to answer and answer filed by ISO-NE.⁸ The NEPOOL Participants Committee filed an answer responding to the motion for leave to answer and answer filed by IECG.⁹ Wal-Mart Stores, Inc., along with a collection of retail end-use customer demand response participants, filed a letter supporting the Final Rule, and answering the request for clarification or rehearing filed by the CPUC and the request for clarification and rehearing filed by CAISO.¹⁰

8. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2011), prohibits an answer to a request for rehearing. Accordingly, the answers from Occidental, ISO-NE and NEPOOL Participants Committee, Viridity, and Wal-Mart Stores, Inc. are rejected. IECG's and NEPOOL Participants Committee's answers to an answer are dismissed.

9. CAISO filed a motion to lodge, and an errata to that motion, seeking to include in the record a CAISO Market Surveillance Committee opinion regarding the Final Rule, as well as a concurring opinion by Steven Stoft of the Market Surveillance Committee, both issued on June 6, 2011, to supplement its request for clarification and rehearing.¹¹ CAISO notes that it included a draft of the opinion in its request for clarification and rehearing, indicating that it would supplement the filing with the final opinion once issued. CAISO indicated that it was unable to submit the final opinion with its request for clarification and rehearing because the Market Surveillance Committee procedures require draft opinions to be posted before they may be finalized.

10. We deny CAISO's motion to lodge. Although CAISO indicated in its request for clarification and rehearing that a final version of the Market Surveillance Committee opinion would be forthcoming, the draft submitted with the request for clarification and rehearing bears little resemblance to the final opinion submitted on June 22, 2011. The

⁷ Viridity Energy, Inc. (Viridity) May 6, 2011 Answer.

⁸ Industrial Energy Consumer Group May 13, 2011 Answer.

⁹ New England Power Pool (NEPOOL) Participants Committee May 24, 2011 Answer.

¹⁰ Wal-Mart Stores, Inc. June 8, 2011 Letter.

¹¹ CAISO June 22, 2011 Motion to Lodge.

draft opinion included with the request for clarification and rehearing was two pages long. The final opinion submitted with the motion to lodge consists of 21 pages, and the Stoft opinion, which was not included with the request for clarification and rehearing, is an additional 24 pages. The CAISO filing does not respond to any arguments raised by other parties on rehearing, but rather adds supplemental material to its rehearing request, more than two months following the deadline for filing requests for rehearing. As such, we will reject it as an out-of-time rehearing request.¹²

III. Discussion

A. Commission Jurisdiction and Authority to Regulate Demand Response Resources

11. In the Final Rule, the Commission explained that it has jurisdiction over demand response in the organized wholesale energy markets due to the direct effect demand response resources have on wholesale energy prices.¹³ The Commission stated that its actions in issuing the Final Rule arise out of its responsibility to ensure just, reasonable, and not unduly discriminatory or preferential wholesale energy market rates.¹⁴ The Commission further noted that the Final Rule does not affect a state's authority over retail rates, nor does it preclude state-administered demand response programs.¹⁵ Lastly, the Commission stated that its actions are consistent with the policy set forth by Congress calling for the removal of barriers to demand response resource participation in the energy markets.¹⁶

1. Requests for Rehearing

12. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 request rehearing arguing that the Commission does not have jurisdiction over the compensation paid to demand response providers.¹⁷ The petitioners argue that demand response providers' actions,

¹² *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,018, at P 19-21 (2011).

¹³ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 112.

¹⁴ *Id.* P 115.

¹⁵ *Id.* P 114.

¹⁶ *Id.* P 113.

¹⁷ Joint Petitioners Request for Rehearing at 7; Midwest TDUs Request for Rehearing at 8; PPL Parties Request for Rehearing at 7; P3 Request for Rehearing at 5-6.

characterized by the petitioners as retail non-purchases, are not wholesale sales as described in section 201(b)(1) of the FPA.¹⁸ The petitioners assert that because sections 205¹⁹ and 206²⁰ of the FPA apply only to actions subject to the Commission's jurisdiction, the Commission is powerless to act on demand response compensation.²¹ The petitioners analogize demand response services to non-jurisdictional retail rates applicable to retail purchases and conclude that demand response compensation falls within the realm of state jurisdiction.²²

13. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 assert that the Commission, by way of its order in *EnergyConnect, Inc. (EnergyConnect)*,²³ has previously established that demand response providers are not engaged in a sale for resale of energy back into the energy market, and therefore are not subject to the Commission's jurisdiction because the terms of section 201(b)(1) are not met.²⁴

14. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that the Commission is in error to the extent that it believes it has jurisdiction over demand response compensation through the "affecting" clause of sections 205(a) and 206(a) of the FPA.²⁵ The petitioners argue that Commission jurisdiction, obtained where certain rules and regulations affect rates or charges pertaining to the wholesale sale of electric energy, is not broad enough to overcome the fact that demand response is not a jurisdictional sale

¹⁸ 16 U.S.C. § 824(b)(1) (2006).

¹⁹ 16 U.S.C. § 824d.

²⁰ 16 U.S.C. § 824e.

²¹ Joint Petitioners Request for Rehearing at 7; Midwest TDUs Request for Rehearing at 8; PPL Parties Request for Rehearing at 7-8; P3 Request for Rehearing at 5-6.

²² Joint Petitioners Request for Rehearing at 7.

²³ *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010) (*EnergyConnect*).

²⁴ Joint Petitioners Request for Rehearing at 6; Midwest TDUs Request for Rehearing at 9; PPL Parties Request for Rehearing at 7-8; P3 Request for Rehearing at 5.

²⁵ Joint Petitioners Request for Rehearing at 8-9; Midwest TDUs Request for Rehearing at 10-11; PPL Parties Request for Rehearing at 8; P3 Request for Rehearing at 5.

under section 201(b)(1) of the FPA.²⁶ As stated by the Joint Petitioners, the terms of sections 205(a) and 206(a) do not trump those of section 201(b)(1).²⁷

15. Joint Petitioners request rehearing arguing that that Commission is prohibited from regulating non-jurisdictional entities (demand response resources) through the exercise of its authority over public utilities (RTOs and ISOs).²⁸ The petitioners assert that the Commission is attempting to indirectly, and wrongly, exercise authority over demand response resources, entities it claims are non-jurisdictional under section 201(b)(1) of the FPA, by requiring RTOs and ISOs to pay demand response resources the LMP.²⁹ Joint Petitioners also assert that prior case law concerning Commission jurisdiction over capacity markets is unresponsive in the context of the Final Rule.³⁰ Joint Petitioners further argue that demand response resources, when offered into the organized wholesale energy market, have no greater effect on the rates generated by the market, than does the cost of cement, steel, or coal.³¹ Petitioners' reasoning is that if the Commission were able to assert jurisdiction over demand response compensation in this manner, then it would also be able to do so with respect to any other non-jurisdictional factor that may affect rates.

16. Joint Petitioners also argue that that the Commission may not assert jurisdiction over demand response compensation even where demand response compensation is construed as a component of a jurisdictional, market-based rate for energy in organized markets.³² Joint Petitioners assert that demand response does not qualify for Commission review even under a situation where the Commission may review a non-jurisdictional rate that is a component of a jurisdictional rate.

17. Petitioners assert that the Commission does not have implied jurisdiction over demand response compensation because “[demand response] is a retail non-purchase, and

²⁶ Joint Petitioners Request for Rehearing at 9; Midwest TDUs Request for Rehearing at 10.

²⁷ Joint Petitioners Request for Rehearing at 9.

²⁸ Joint Petitioners Request for Rehearing at 9.

²⁹ *Id.*

³⁰ *Id.* at 9-10.

³¹ *Id.* at 11.

³² *Id.* at 12.

retail rates have traditionally been subject to State or local regulation.”³³ The petitioners argue that courts are reluctant to infer jurisdiction in an agency over an area it seeks to regulate where the area to be regulated has traditionally been regulated by the states.³⁴

18. Joint Petitioners and Midwest TDUs argue that the Commission erred in citing the Energy Policy Act of 2005 (EPAAct 2005)³⁵ as support for its jurisdiction to regulate demand response compensation.³⁶ The petitioners argue that EPAAct 2005 is a mere policy statement, and does not expand the Commission’s jurisdiction or authority to implement that policy.³⁷

19. Joint Petitioners, Midwest TDUs, CAISO, and CPUC argue that the Commission is interfering with existing retail demand response programs, and therefore is intruding on state jurisdiction.³⁸ Midwest TDUs argue that this constitutes a barrier, in the form of a financial disincentive, to participation in retail demand response programs.³⁹

2. Commission Determination

20. We deny the requests for rehearing regarding the Commission’s jurisdiction over demand response participation in organized wholesale energy markets. We continue to find that Commission regulation of demand response participation in the organized wholesale energy markets and the market rules governing that participation is essential to the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable.

³³ Joint Petitioners Request for Rehearing at 13.

³⁴ *Id.*

³⁵ Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005) (EPAAct 2005).

³⁶ Joint Petitioners Request for Rehearing at 14; Midwest TDUs Request for Rehearing at 11-12.

³⁷ Joint Petitioners Request for Rehearing at 14; Midwest TDUs Request for Rehearing at 11-12.

³⁸ Joint Petitioners Request for Rehearing at 13; Midwest TDUs Request for Rehearing at 20-21; CAISO Request for Rehearing at 31-32; CPUC Request for Rehearing at 13-16.

³⁹ Midwest TDUs Request for Rehearing at 20.

21. Under section 201 of the FPA⁴⁰ the Commission has jurisdiction over the transmission of electric energy in interstate commerce, as well as the wholesale sale (or sale for resale) of electric energy in interstate commerce, and it has jurisdiction over all facilities used for such transmission or sale of electric energy. Section 201 also defines a public utility as “any person who owns or operates facilities subject to the jurisdiction of the Commission.”⁴¹ Sections 205⁴² and 206⁴³ of the FPA provide the Commission with jurisdiction over all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission. Those sections also provide the Commission with jurisdiction over all rules, regulations, practices, or contracts that affect jurisdictional rates, charges, or classifications.

22. In *EnergyConnect*,⁴⁴ the Commission found that a company engaged solely in offering demand response services would not be a public utility and would not be making wholesale sales of electric energy. However, the Commission also found that it would still have jurisdiction to regulate certain aspects of demand response “as a practice that affects rates in organized wholesale electric markets under sections 205(a) and (c) and section 206(a) of the FPA.”⁴⁵ In Order Nos. 719⁴⁶ and 719-A, the Commission reached the same conclusion, including with respect to its jurisdiction over demand response in RTO and ISO ancillary service markets. Speaking generally, the Commission found that within RTO and ISO markets, demand response “affects wholesale markets, rates, and practices.”⁴⁷

⁴⁰ 16 U.S.C. § 824.

⁴¹ 16 U.S.C. § 824(e).

⁴² 16 U.S.C. § 824d.

⁴³ 16 U.S.C. § 824e.

⁴⁴ *EnergyConnect*, 130 FERC ¶ 61,031.

⁴⁵ *Id.* P 32.

⁴⁶ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh’g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh’g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

⁴⁷ Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 46.

23. In support of this assertion of jurisdiction, the Commission in Order No. 719-A described a direct effect on wholesale prices caused by demand response participation in RTO and ISO markets.⁴⁸ The Commission stated that this direct effect occurs when demand response is offered directly into the wholesale market, causing a reduction in demand to occur, thereby resulting in a lower wholesale price.⁴⁹ In addition, the Commission found that such demand response participation helps to mitigate generator market power and strengthen system reliability.⁵⁰ Demand response resources that participate in a wholesale market, especially when market prices are high, tend to lower the market clearing price placing downward pressure on generator offer strategies by making it more likely that a higher offer from a generator will not be accepted when the market clears.⁵¹ Moreover, system reliability realizes a benefit because demand response generally can be dispatched by the system operator with a minimal notice period, helping to balance the electric system in the event that an unexpected contingency occurs.⁵²

24. The Final Rule reiterated many of these findings in explaining the Commission's basis for jurisdiction with respect to demand response participation in organized wholesale energy markets.⁵³ We now reaffirm our previous findings on how demand response has a direct effect on wholesale rates subject to Commission jurisdiction under FPA section 201(b)(1), as well as our conclusion that these findings support Commission jurisdiction with respect to demand response participation in the organized wholesale energy markets and the market rules governing that participation.⁵⁴

⁴⁸ *Id.* P 47.

⁴⁹ *Id.*

⁵⁰ *Id.*

⁵¹ *Id.* In addition, demand response can reduce transmission rates by relieving congestion on transmission lines that leads to higher transmission charges. In RTO and ISO markets, these higher transmission charges are reflected in the congestion costs that wholesale customers are required to pay.

⁵² Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 at P 47.

⁵³ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 112-15.

⁵⁴ The Commission's finding of this direct effect on wholesale rates is important in light of the statement of the U.S. Court of Appeals for the District of Columbia Circuit that the Commission is empowered under section 206 to assess practices that directly

(continued...)

25. This jurisdictional analysis is consistent with precedent in which the courts have found that the Commission has jurisdiction over aspects of RTO services that affect wholesale rates. For example, in *Connecticut Dep't of Pub. Util. Control v. FERC*,⁵⁵ petitioner challenged the Commission's authority to review, approve, or modify the Installed Capacity Requirement (ICR), a key input into ISO-NE's forward capacity market. Petitioner argued that any Commission-ordered increase in the ICR would be equivalent to the Commission directing the installation of new capacity, thereby violating the FPA's limit of Commission jurisdiction over generation facilities. The court rejected this argument, holding that the ICR is subject to the Commission's authority because it is a "practice affecting rates" under sections 205 and 206 of the FPA. Specifically, the court upheld the Commission's assertion of jurisdiction because it found that "[w]here capacity decisions about an interconnected bulk power system affect FERC-jurisdictional transmission rates for that system without directly implicating generation facilities, they come within the Commission's authority."⁵⁶ The court found that the ICR was not a direct regulation of generation, nor a requirement as to the amount of generation that had to be constructed.⁵⁷ Acknowledging that capacity is not electricity, the court nonetheless found that the Commission may "directly establish prices for capacity—or much the same, prices for failing to acquire enough capacity—even for the express purpose of incentivizing construction of new generation facilities."⁵⁸ These holdings reinforce well-established precedent with respect to Commission jurisdiction based on the "practice affecting rates" language of sections 205 and 206.⁵⁹ Similarly, if demand response

affect or are closely related to a public utility's rates and "not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so." *California Indep. Sys. Operator v. FERC*, 372 F.3d 395, 403 (D.C. Cir. 2004).

⁵⁵ *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009) (*Connecticut*).

⁵⁶ *Connecticut*, 569 F.3d at 484.

⁵⁷ *Id.* at 483.

⁵⁸ *Id.* at 482.

⁵⁹ *See Groton v. FERC*, 587 F.2d 1296, 1302 (D.C. Cir. 1978) (capacity deficiency charge, just as the capacity adjustment charge "must be deemed to be within the Commission's jurisdiction because it too represents a charge for the power and service the overloaded participant receives or it is at least a rule or practice affecting the charge for these services"); *Mississippi Industries v. FERC*, 808 F.2d 1525, 1542 (D.C. Cir. 1987) (while capacity allocation costs "do not fix wholesale rates, their terms do directly and significantly affect the wholesale rates at which the operating companies exchange

(continued...)

participation in the organized wholesale energy market “help[s] to find the right price,”⁶⁰ as the Commission has found repeatedly, then that demand response participation and the corresponding RTO and ISO market rules “would still amount to a ‘practice . . . affecting’ rates.”⁶¹

26. Joint Petitioners contend that the capacity market cases are not controlling because capacity markets are subject to Commission jurisdiction under section 201 of the FPA even though capacity itself is not mentioned. The Commission rejects this argument. Joint Petitioners fail to support their contention that some practices that directly affect jurisdictional rates but are not mentioned in section 201 (e.g., market rules with respect to capacity) are subject to the Commission’s jurisdiction, while other such practices affecting rates (e.g., market rules with respect to demand response participation in an organized wholesale energy market) are not. As discussed above, the Commission finds court precedent on capacity markets and the “practice affecting rates” language of sections 205 and 206 to be analogous to the issues presented here with respect to demand response participation in organized wholesale energy markets and the market rules of the various ISOs and RTOs that govern that participation.

27. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that section 201(b) of the FPA does not invest the Commission with jurisdiction over demand response compensation because demand response providers are not public utilities. In making this argument, petitioners rely on the Commission’s findings in *EnergyConnect*. Joint Petitioners, Midwest TDUs, PPL Parties, and P3 argue that the Commission cannot claim jurisdiction over demand response resources through section 205’s and 206’s “affecting” clause when section 201(b) has not been satisfied. The Commission rejects these arguments. The Commission’s findings that demand response does not involve a wholesale sale of energy, and that entities engaged solely in demand response are not

energy”); *Maine Pub. Utils. Comm’n v. FERC*, 520 F.3d 464, 479 (D.C. Cir. 2008), *rev’d in part sub nom. NRG Power Marketing, LLC v. Me. Pub. Utils. Comm’n*, 130 S. Ct. 693 (2010), *remanded*, *Me. Pub. Utils. Comm’n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010) (concluding that the Commission had jurisdiction over capacity markets, because the “the protracted litigation over Must-Run agreements, the locational installed capacity market, and the Forward Market is fundamentally a dispute over the rates that will be paid to suppliers of capacity.”).

⁶⁰ *Connecticut*, 569 F.3d at 485.

⁶¹ *Id.* The court in *Connecticut*, in fact, observed that one of the methods of responding to the incentives produced by increases in the ICR short of building new generation facilities included the use of “demand response contracts where users are compensated for committing to use less electricity during shortages.” *Id.* at 482.

public utilities, do not void the Commission's jurisdiction with respect to demand response participation in organized wholesale energy markets and the market rules of various RTOs and ISOs that govern that participation. As noted above, the Commission discussed this issue, as well as the Commission's jurisdictional conclusion with respect to the "practice affecting rates" language of sections 205 and 206, in detail in *EnergyConnect*.⁶² A demand response resource that, as discussed in *EnergyConnect*, may not be a public utility, nonetheless may choose to participate in the RTO- and ISO-administered organized wholesale energy markets, therefore making it a market participant. The Commission has repeatedly found that market rules governing such participation by demand response resources in an organized wholesale energy market are a practice that directly affects rates in those jurisdictional markets.⁶³ The rules regarding compensation required by the Final Rule are one example of those market rules. Much as the forward capacity markets at issue in the court cases discussed above determine rates to be paid to capacity resources, the organized wholesale energy markets determine the rates (market-clearing prices) that are paid to participants in those markets.

28. It is also relevant that in *Sacramento Municipal Utility District v. FERC*,⁶⁴ the court affirmed the Commission's jurisdiction to impose marginal line losses on a non-public utility. In that case, a non-public utility argued that by approving CAISO's assessment of marginal loss charges to transactions involving the non-public utility's use of transmission ownership rights, the Commission unlawfully dictated rates, terms or conditions of service to a non-public utility's use of its own transmission facilities and effectively compelled such entity to transfer control over its transmission facilities to the CAISO. The court found, to the contrary, that the charges assessed to the non-public utility involved nothing more than charges for using the CAISO's facilities. The court concluded that the Commission did not exceed its jurisdiction:

Far from compelling Imperial to become a participating transmission owner of [CAISO], FERC merely permitted the ISO to charge Imperial for the costs incurred by the ISO when Imperial conducts transactions that cause transmission losses on the ISO's grid. The Commission's proper exercise of its power to regulate [CAISO's] rates was not transformed into a

⁶² *EnergyConnect*, 130 FERC ¶ 61,031.

⁶³ As discussed above, the courts have recognized the breadth of the Commission's jurisdiction under sections 205 and 206 of the FPA. See *Connecticut*, 569 F.3d at 484-85; *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) ("there is an infinitude of practices affecting rates and service").

⁶⁴ *Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520 (D.C. Cir. 2010).

violation of its statutory jurisdiction by dint of its incidental effect on Imperial.⁶⁵

In *United Distribution Companies v. FERC*,⁶⁶ the court likewise affirmed the Commission's jurisdiction to regulate resales of natural gas transportation capacity by non-jurisdictional entities.⁶⁷ The court concluded that the Commission had jurisdiction because the "the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers."⁶⁸ Similarly, the Commission has jurisdiction over the way in which RTOs and ISOs operate jurisdictional markets, including the market rules that govern demand response participation in those markets, to assure that the rates resulting from those markets are just and reasonable.

⁶⁵ *Id.* at 536. See also *Transmission Agency of N. Cal. v. FERC*, 628 F.3d 538, 540 (D.C. Cir. 2010) (TANC) (finding Commission jurisdiction to regulate interconnections with non-public utilities when these transactions "impact the CAISO-controlled grid [and] only a party that chooses to use the CAISO-controlled grid is affected").

⁶⁶ *United Distribution Cos. v. FERC*, 88 F.3d 1105, 1151-1154 (D.C. Cir. 1996).

⁶⁷ *Id.*

⁶⁸ *Id.* at 1153. We also note the statement of the U.S. Supreme Court in *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 602-03 (1945), in interpreting a similar jurisdictional limitation in § 1(b) of the Natural Gas Act with respect to gathering:

That does not mean that the part of § 1(b) which provides that the Act shall not apply "to the production or gathering of natural gas" is given no meaning. Certainly that provision precludes the Commission from any control over the activity of producing or gathering natural gas. . . . We only decide that it does not preclude the Commission from reflecting the production and gathering facilities of a natural gas company in the rate base and determining the expenses incident thereto for the purposes of determining the reasonableness of rates subject to its jurisdiction.

See also *Northern Natural Gas Co. v. FERC*, 929 F.2d 1261, 1269 (8th Cir. 1991) (finding that *Colorado Interstate* also permits the Commission to directly regulate rates for transportation over a pipeline's own gathering facilities performed in connection with admittedly jurisdictional interstate transportation).

29. Joint Petitioners argue that demand response resources, when offered into the organized wholesale energy market, have no greater effect on the rates generated by the market than does the cost of cement, steel, or coal. Petitioners express concern that if the Commission may assert jurisdiction over demand response compensation, then it would also be able to do the same with respect to any other factor that may affect rates.

30. We disagree with Joint Petitioners' argument and find that demand response resources are not similar to an input cost for generation. A properly functioning market should reflect both the willingness of sellers to sell at a price and the willingness of buyers to purchase at a price. In an RTO- or ISO-run market, however, buyers are generally unable to directly express their willingness to pay for a product at the price offered. As discussed later, RTOs and ISOs cannot isolate individual buyers' willingness to pay which results in extremely inelastic demand. Including demand response as a resource in RTO and ISO markets provides a way for buyers to indicate the price at which they are willing to stop consumption.

31. We recognize that merely because an input to generation may affect a wholesale rate, our jurisdiction does not extend to the regulation of the input itself. Demand response resources that participate in an RTO- or ISO-administrated organized wholesale energy market, however, are not merely an input cost for generation that indirectly affects wholesale rates. Rather, in the circumstances covered by the Final Rule, demand response resources are direct participants in the organized wholesale energy markets over which we have jurisdiction (just as is generation), and that participation has a direct and substantial effect on rates in those markets.⁶⁹ In light of this distinction, we disagree with Joint Petitioners' claim that the Commission's actions in the Final Rule create a slippery slope that will lead to limitless Commission jurisdiction. As discussed above, the Commission's statutory authority extends to those rules, regulations, practices, or contracts that directly affect the jurisdictional rates charged by public utilities.

32. Joint Petitioners, Midwest TDUs, CAISO, and CPUC argue that the Commission is interfering with existing retail demand response programs and, therefore, is intruding on state jurisdiction. The Commission rejects this argument. As the Commission stated in the Final Rule, demand response is a complex matter that lies at the confluence of state and federal jurisdiction.⁷⁰ Respecting that state interest, the Commission made clear in the Final Rule that we are not intruding into the province of state regulation and are "not

⁶⁹ See *Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1282 (D.C. Cir. 2007) (affirming Commission's assertion of jurisdiction over interconnections with dual-use facilities, when the facilities are included in a jurisdictional rate and the transaction facilitates a wholesale sale of electric energy).

⁷⁰ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 114.

regulating retail rates or usurping or impeding state regulatory efforts concerning demand response.”⁷¹ The fact that participation in a Commission-jurisdictional RTO or ISO market may indirectly affect incentives in a state demand response initiative does not deprive the Commission of the ability to act within the jurisdictional boundaries discussed above.

33. Joint Petitioners and Midwest TDUs claim that the Commission cannot rely on section 1252(f) of EAct 2005⁷² as a basis for its jurisdiction to regulate demand response compensation. Petitioners base their argument on *Comcast Corp. v. FCC*,⁷³ asserting that this statutory language is a mere policy statement and does not expand the Commission’s jurisdiction or authority to implement policy.

34. Neither the Final Rule nor this order relies on section 1252(f) of EAct 2005 as an independent basis for Commission jurisdiction. The court in *Comcast* recognized that while statements of Congressional policy do not establish jurisdiction, “statements of congressional policy can help delineate the contours of statutory authority.”⁷⁴ To that end, we cited section 1252(f) of EAct 2005 because it sheds light on the contours of the Commission’s statutory authority. Section 1252(f) of EAct 2005 states that it is the policy of the United States that unnecessary barriers to demand response participation in energy, capacity, and ancillary services markets shall be eliminated. No commenter in this proceeding questions that such markets, including the organized wholesale energy markets addressed in the Final Rule, are subject to the Commission’s jurisdiction.

35. In light of the Commission’s jurisdiction, under section 201 of the FPA, over rates established in the organized wholesale energy markets, and for the reasons discussed in detail above, the Commission concludes that demand response participation in the organized wholesale energy markets and the market rules governing that participation are “practices affecting rates” pursuant to sections 205 and 206 of the FPA.

⁷¹ *Id.*

⁷² EAct 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (“It is the policy of the United States that . . . unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets shall be eliminated.”).

⁷³ *Comcast Corp. v. FCC*, 600 F.3d 642 (D.C. Cir. 2010) (*Comcast*).

⁷⁴ *Comcast*, 600 F.3d at 654.

B. Demand Response Resource Compensation Level

36. Separate from its findings as to the basis for Commission jurisdiction with respect to demand response participation in the organized wholesale energy markets and the market rules governing that participation, the Final Rule requires that each RTO and ISO that has a tariff provision permitting demand response resources to participate as a resource in the energy market must pay to those demand response resources the market price when the demand response resource has the capability to balance supply and demand and when payment is cost-effective. The Commission found that LMP is the appropriate compensation level because LMP reflects the marginal value of the demand response resource to each RTO and ISO. The Commission explained that the market-clearing LMP is the appropriate compensation level where demand response resources are a cost-effective alternative to generation for balancing the energy market.⁷⁵

1. Requests for Rehearing

37. ICC requests clarification that the Commission is basing the comparability of demand response resources and generation resources on the competition of the two resources in the dispatch model, i.e., as they are used to balance electricity supply and demand in the economic dispatch and not based on economic comparability. ICC argues that demand response is not comparable to generation in terms of the aggregate economic impact, financial settlement, and incentives associated with compensation paid at LMP. ICC expresses concern that LMP compensation will cause demand response providers to disengage from economic production, whereas generation resources do not have the same incentive.⁷⁶

38. CSA, P3, and PPL Parties request rehearing arguing that demand response resources are not equivalent to generation in terms of physical characteristics, marginal value, planning, economics, performance requirements, operational security, penalties, and reliability services. CSA further argues that a demand response resource is not a resource like generation because it cannot power residences, commercial establishments or industrial facilities, and LMP payment to demand response resources, unlike LMP payment to generation, causes the RTO or ISO to incur a net loss.

39. Joint Parties request rehearing and clarification arguing that demand response resources and generation resources are not comparable, even for the purpose of balancing supply and demand, because demand response resources have less stringent performance requirements and do not have as a part of their core business the generation of electricity.

⁷⁵ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 47.

⁷⁶ Illinois Commerce Commission (ICC) Request for Rehearing at 5.

40. CSA, EEI, Midwest TDUs, Joint Parties, Organization of MISO States, PPL Parties, and P3 argue that the Final Rule conflicts with Commission efforts to promote competitive markets because, according to these petitioners, compensating demand response at LMP is a subsidy, or overcompensation, resulting in the suppression of LMPs in the energy market.⁷⁷

41. Petitioners explain that the suppression of LMPs will distort price signals, causing customers to reduce or increase their energy purchases at other than optimal levels.⁷⁸ CSA further asserts that a suppression of the LMP will delay the construction of new generation while accelerating the retirement of current facilities.⁷⁹

42. CSA further argues that the Final Rule is a violation of a regulated utility's right to just and reasonable compensation for jurisdictional wholesale sales.⁸⁰ CSA states that the Commission failed to quantify or identify the amount by which jurisdictional rates are excessive, or would be excessive, absent the Final Rule.⁸¹ CSA asserts that the Commission has improperly assumed that an increase in demand response resource participation leading to a lower market price for energy is "always better"⁸² without regard to whether the corresponding lower rate and reduced revenue for regulated entities will be compensatory or confiscatory. CSA asserts that the Commission, by mandating compensation at LMP, has violated the Takings Clause of the Fifth Amendment of the U.S. Constitution and failed to satisfy its duty under the FPA to ensure that rates for

⁷⁷ Competitive Power Supplier Associations (CSA) Request for Rehearing at 16, 40; Edison Electric Institute (EEI) Request for Rehearing at 13; Midwest Transmission Dependent Utilities (Midwest TDUs) Request for Rehearing at 15; American Public Power Association, National Rural Electric Cooperative Association, and Old Dominion Electric Cooperative (collectively, Joint Parties) Request for Rehearing at 18; Organization of MISO States (OMS) Request for Rehearing at 4; PPL Parties Request for Rehearing at 20; PJM Power Providers Group (P3) Request for Rehearing at 8.

⁷⁸ See, e.g., CSA Request for Rehearing at 44; EEI Request for Rehearing at 13.

⁷⁹ CSA Request for Rehearing at 43.

⁸⁰ CSA Request for Rehearing at 51 (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 607 (1944)).

⁸¹ *Id.* at 49.

⁸² *Id.* at 49-50.

jurisdictional sales are just and reasonable as to jurisdictional public utilities making those sales.⁸³

43. Petitioners rely on Dr. Hogan and others in support of their position that paying LMP is overcompensation.⁸⁴ EEI refers to Dr. Hogan's argument that a compensation payment of LMP causes a demand response resource to receive a double payment for its curtailment. Dr. Hogan contends that a double payment results from the fact that the demand response resource does not pay for the energy that it would have consumed and also receives full LMP compensation from the RTO or ISO for its curtailment. Likewise, EEI and Midwest TDUs cite Potomac Economics, Ltd. for the position that the Final Rule allows "[demand response] resource[s] to sell energy in the wholesale market that it is not required to purchase at the retail rate. Hence, one can clearly see in this case that the [demand response] resource is receiving a subsidy to curtail equal to the retail rate. This will manifest itself in potentially significant economic inefficiencies."⁸⁵

44. EEI argues that large industrial or commercial customers that use behind-the-meter generation to satisfy their energy needs can receive compensation in the amount of two times the LMP.⁸⁶ Large industrial customers with behind-the-meter generation that purchase their energy requirements at the LMP set in the relevant RTO or ISO energy markets have the option to self-supply when it is less expensive to do so.⁸⁷ EEI and CSA argue that customers with behind-the-meter generation that reduce their load on the grid and are paid LMP as a result actually realize a payment of twice the LMP because they also avoided purchasing the energy.⁸⁸ EEI states that in essence, the customer is a generator that is now directly competing with other wholesale generators.⁸⁹

⁸³ *Id.* at 50.

⁸⁴ EEI Request for Rehearing at 13-15; Joint Parties Request for Rehearing at 18; Midwest TDUs Request for Rehearing at 11.

⁸⁵ EEI Request for Rehearing at 14; *see also* Midwest TDUs Request for Rehearing at 11.

⁸⁶ EEI Request for Rehearing at 21.

⁸⁷ *Id.*

⁸⁸ EEI Request for Rehearing at 21; CSA Request for Rehearing at 24 n.80.

⁸⁹ EEI Request for Rehearing at 21.

45. CSA, EEI, and Joint Parties state that the Commission is erroneously relying on a presumption that compensation at LMP is the correct payment level.⁹⁰ CSA argues that the Final Rule relies on a number of faulty assumptions and policy judgments including: (1) current levels of demand response participation are inadequate; (2) current levels of compensation paid to demand response resources are inadequate; (3) paying LMP will mitigate barriers to entry faced by demand response resources; (4) the “required subsidy” should be equal to the avoided costs of retail purchases; and (5) standardization of demand response compensation is the only solution available.⁹¹

46. CSA, EEI, Midwest TDUs, Joint Parties, OMS and PPL Parties argue that paying LMP-G is the appropriate payment level because it accounts for the avoided cost that the retail customer retains by curtailing its consumption.⁹² Stated another way, EEI argues that a retail customer actually has a property right to consume energy, and that it is this property right, or call option, that it is selling to the RTO or ISO.⁹³ EEI states that the RTO or ISO should be required to pay for the market value of the call option, rather than the market value of the foregone energy.⁹⁴

47. Midwest ISO TOs and Joint Parties request rehearing arguing that the Commission erred in stating that factoring retail rates into wholesale compensation payments presents problems for state public utility commissions, ISOs, and RTOs.⁹⁵ Petitioners point out that several state public utility commissions, ISOs, and RTOs filed comments explaining that a methodology that properly accounts for “G” (generation) does not impose an administrative burden on the RTOs and ISOs, and does not improperly impact state public utility commissions. Petitioners further assert that the Commission’s observation that RTOs and ISOs do not subtract a cost component from the compensation paid to

⁹⁰ CSA Request for Rehearing at 28; EEI Request for Rehearing at 11; Joint Parties Request for Rehearing at 11.

⁹¹ CSA Request for Rehearing at 30.

⁹² CSA Request for Rehearing at 77-78; EEI Request for Rehearing at 11; Midwest TDUs Request for Rehearing at 18; Joint Parties Request for Rehearing at 17; OMS Request for Rehearing at 4; PPL Parties Request for Rehearing at 19; P3 Request for Rehearing at 14.

⁹³ EEI Request for Rehearing at 11.

⁹⁴ *Id.* at 12.

⁹⁵ Midwest ISO Transmission Owners (Midwest ISO TOs) Request for Rehearing at 20-21; Joint Parties Request for Rehearing at 18.

generators misses their point, because, while RTOs and ISOs pay generators full LMP, generators do in fact incur production costs that result in a reduced net compensation amount; in contrast they argue that demand response resources pay nothing for the “call option” associated with retail energy not consumed.⁹⁶

48. CSA, EEI, Midwest ISO TOs, and Joint Parties request rehearing arguing that the Final Rule does not establish a rational connection between the perceived problem and the Commission’s solution. Petitioners argue that the Final Rule does not explain how the barriers to entry that demand response resources face with respect to organized wholesale energy markets will be mitigated or resolved by requiring RTOs and ISOs to pay demand response resources the LMP.⁹⁷

49. CSA and EEI request rehearing arguing that the Final Rule will have the opposite of its intended effect because it will hinder the development of retail dynamic price responsive demand programs, along with other state reforms.⁹⁸ Their argument relies on the notion that paying LMP compensation is a subsidy that will inappropriately encourage demand response resource participation in wholesale, rather than retail, programs.

50. CSA, EEI, Midwest TDUs, Midwest ISO TOs, Joint Parties, PPL Parties, P3, and CAISO further assert that the Commission failed to address, or dismissed entirely, arguments opposing the LMP compensation level.⁹⁹ Petitioners emphasize arguments in favor of LMP-G and a region-by-region approach. Petitioners assert that the Commission fails to distinguish the standardization in the Final Rule from the region-by-region approach permitted by the Commission in Order No. 719.¹⁰⁰

⁹⁶ Midwest ISO TOs Request for Rehearing at 21.

⁹⁷ CSA Request for Rehearing at 28; EEI Request for Rehearing at 17-18; Midwest ISO TOs Request for Rehearing at 19; Joint Parties Request for Rehearing at 12-13.

⁹⁸ CSA Request for Rehearing at 46-47; EEI Request for Rehearing at 20.

⁹⁹ CSA Request for Rehearing at 25-26; EEI Request for Rehearing at 8-9; Midwest TDUs Request for Rehearing at 6; Midwest ISO TOs Request for Rehearing at 10; Joint Parties Request for Rehearing at 7; PPL Parties Request for Rehearing at 10; P3 Request for Rehearing at 7; CAISO Request for Rehearing at 48-49.

¹⁰⁰ Petitioners argue that Order No. 719 specifically directed RTOs and ISOs to develop technical requirements, tailored to their individual circumstances, to facilitate the participation of demand response resources in the ancillary services market. *See, e.g.,*

51. CSA requests rehearing arguing that the Final Rule makes the erroneous and unsupported suggestion that LMP compensation is needed because current RTO and ISO market power mitigation rules are inadequate.¹⁰¹ Petitioners argue that the Commission failed to engage in reasoned decision-making and cast doubt on RTO and ISO market rules that the Commission previously approved. Petitioners claim that paying LMP compensation will lead to a case of over-mitigation because energy markets will now be subject to both existing market manipulation rules and demand response resource participation resulting in suppressed LMPs. Petitioners state that the Commission's previous approvals of supplier market power rules were made without reference to the level of demand response participation in the market, thus demonstrating that demand response is not necessary to maintain fair and competitive markets.

52. Joint Petitioners, Midwest TDUs, PPL Parties, EEI, and P3 argue that the Commission failed to make a reasoned finding, as required by section 206 of the FPA, that the existing demand response compensation paid by RTOs and ISOs, on a region-by-region basis, is unjust and unreasonable.¹⁰²

53. CSA requests rehearing based on Dr. Hogan's testimony, arguing that the Final Rule will facilitate or mandate the exercise of buyer market power, including a buyers' cartel, which will lead to artificially-suppressed prices.¹⁰³ Petitioners assert that the Final Rule will facilitate buyer market power, artificially reducing prices below competitive levels.

2. Commission Determination

a. LMP Compensation

54. The Commission denies the requests for rehearing and affirms its finding that LMP is the appropriate compensation level for demand response resources for service

CSA Request for Rehearing at 73 (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 50, 59).

¹⁰¹ CSA Request for Rehearing at 54.

¹⁰² Electric Power Supply Association, American Public Power Association, Electric Power Generation Association, and National Rural Electric Cooperative Association (collectively, Joint Petitioners) Request for Rehearing at 8; Midwest TDUs Request for Rehearing at 11; PPL Parties Request for Rehearing at 11; EEI Request for Rehearing at 7; P3 Request for Rehearing at 12-13.

¹⁰³ CSA Request for Rehearing at 57-58.

provided in the organized wholesale energy markets when these resources have the capability to balance supply and demand as an alternative to generation and when dispatch of demand response is cost-effective as determined by the net-benefits test described in the Final Rule. The Commission continues to find, as explained in the Final Rule, that LMP is the appropriate compensation level when the aforementioned two conditions are satisfied because LMP reflects the marginal value of demand response resources and generation resources to each RTO and ISO.¹⁰⁴ The rehearing requests generally reiterate arguments that were considered in the Final Rule and, for the reasons stated therein, are rejected here.

55. As the requests for rehearing indicate, there continue to be diverging opinions, including among noted experts, regarding the appropriate level of compensation for demand response resources participating in the organized wholesale energy markets. In the face of diverging opinions, the Commission in the Final Rule observed that, as the courts have recognized, “issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission.”¹⁰⁵ The Commission also observed that, in making such judgments, it takes into account both the economic analysis of the markets subject to our jurisdiction, and the practical realities of how those markets operate.¹⁰⁶ With this framework in mind, the Commission on balance agreed with commenters that supported payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described in the Final Rule.

56. Petitioners argue on rehearing that demand response is not comparable to generation and contend that a number of differences justify paying demand response resources a different price than the market clearing price. We disagree. As the Commission explained in the Final Rule, a power system must be operated so that there is real-time balance of generation and load, supply and demand. When balancing supply and demand, an RTO or ISO therefore can rely on the dispatch of a generation resource to increase supply or a demand response resource to decrease demand.¹⁰⁷ Petitioners nonetheless argue that demand response resources are not physically comparable to

¹⁰⁴ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 47.

¹⁰⁵ *Id.* P 46 (citing *Elec. Consumer Res. Council v. FERC*, 407 F.3d 1232, 1236 (D.C. Cir. 2005); *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992)).

¹⁰⁶ *Id.* (citing *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 872 (D.C. Cir. 1993); *Vermont Dep’t of Pub. Serv. v. FERC*, 817 F.2d 127, 135 (D.C. Cir. 1987); *Columbia Gas Transmission Corp. v. FERC*, 750 F.2d 105, 112 (D.C. Cir. 1984)).

¹⁰⁷ *Id.* P 49.

generation because they do not produce electricity and cannot serve load. While we agree that demand response resources do not create electricity that can be used to serve load, that fact is not dispositive here. The electric industry requires near instantaneous balancing of supply and demand at all times to maintain reliability, and it is in that context that the Commission found that demand response can balance supply and demand as can generation when dispatched in the organized wholesale energy markets.¹⁰⁸ Because the balancing of generation and load when clearing the RTO and ISO day-ahead and real-time energy markets can be accomplished by changes in either supply or demand, demand response resources that clear in the day-ahead and real-time energy market should receive the same market-clearing LMP as compensation in the organized wholesale energy markets when those resources meet the conditions established in the Final Rule as a cost-effective alternative to the next highest-bid generation resources for purposes of balancing the energy market.¹⁰⁹

57. Petitioners also argue that demand response and generation do not have the same marginal value because demand response has less stringent performance requirements. In Order No. 719, the Commission refrained from assigning a strict definition to comparability; nevertheless, the Commission required that demand response resources be: (1) “technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules”¹¹⁰ Thus the Commission linked comparability to the technical capability of a demand response resource to provide a particular service, not to whether the performance requirements of a demand response resource are identical to a generation resource. While demand response and generation may not be identical resources in every respect, both types of resources are equally able to assist RTOs and ISOs in maintaining a balance between supply and demand when they meet an RTO’s or ISO’s requirements to deliver their product or service when and where needed on the margin. Commenters have not demonstrated that the differences between generation and demand response render one superior to the other for purposes of balancing the system.

58. Petitioners further argue that the Final Rule’s requirement to pay LMP compensation is a subsidy, double payment, or overcompensation, provided to demand response resources. Petitioners contend that paying LMP, rather than LMP-G, leads to distorted price signals and thus causes some customers to reduce energy usage to below-optimal levels, or others to increase usage to above-optimal levels. In the Final Rule, the Commission rejected these arguments and explained that demand response resources

¹⁰⁸ *Id.* P 56.

¹⁰⁹ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 54.

¹¹⁰ Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47.

participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described therein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP.¹¹¹ Moreover, petitioners' arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response discussed in the Final Rule and again below. In Order No. 719, the Commission found that allowing demand response to bid into organized wholesale energy markets "expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability."¹¹² Moreover, as Dr. Kahn noted in this proceeding, paying demand response LMP sets "up an arrangement that treats proffered reductions in demand on a competitive par with positive supplies; but the one is no more a [case of overcompensation] than the other: the one delivers electric power to users at marginal costs – the other – reductions in costs – both at competitively determined levels."¹¹³

59. Petitioners challenge the Commission's consideration of market imperfections caused by existing barriers to demand response as relevant to the level of appropriate compensation for demand response resources participating in the organized wholesale energy markets. We continue to find that the barriers to demand participation in the wholesale market, such as the lack of a direct connection between wholesale and retail prices, lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), lack of real-time information sharing, and the relative lack of sufficient retail metering technology,¹¹⁴ demonstrate that customers do not have the ability to respond to the often volatile price changes in the wholesale market and demonstrate the need for including demand response as part of wholesale market design. If the price responsiveness of demand is not fully reflected in the wholesale market, the price, a fortiori, will be higher than it would be in a competitive market.¹¹⁵ To establish just and

¹¹¹ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 61.

¹¹² *Id.* (citing Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154).

¹¹³ *Id.* (citing DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 9-10)).

¹¹⁴ *Id.* P 57. *See also* Monitoring Analytics, The Independent Market Monitor for PJM, Comments, Docket No. RM10-17-000, at 4-6 (filed May 13, 2010); Monitoring Analytics, Barriers to Demand Side Response in PJM, Docket No. ER09-1063-000 (filed July 1, 2009); Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>).

¹¹⁵ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 59.

reasonable prices under such circumstances, we find that the demand response that can participate in the wholesale market should be paid the marginal value of its contribution.

60. Some petitioners argue that the Commission improperly relied on a finding that insufficient demand response resources exist as a justification for paying LMP. The Final Rule was not based on a pre-determined assessment of the amount of demand response that is necessary in the market. Rather, given the barriers that clearly exist to full participation of demand in the wholesale market, the Commission determined that payment of LMP is appropriate as it represents the value of the contribution of demand to the market during those periods in which demand response provides net benefits.

61. The Commission similarly rejects arguments made by CSA, EEI, Midwest ISO TOs, and Joint Parties stating that the Commission failed to explain how paying compensation at LMP will help reduce barriers. As indicated above, the existence of barriers helps to explain why payment of LMP as the market value of demand response services helps to produce just and reasonable wholesale energy prices. Paying LMP to demand resources will help address the lack of a direct connection between wholesale and retail prices and the lack of dynamic retail prices by providing those customers that can respond to price signals with the accurate market price signal for such response. Paying LMP, the marginal cost of energy, when demand response is a capable alternative to a generation resource, also will encourage more demand-side participation. As stated in the Final Rule, more demand-side participation will cause wholesale and retail prices to converge on a price level reflecting demand's ability to respond to the marginal cost of energy.¹¹⁶

62. Lack of real-time information sharing and a lack of incentives to invest in enabling technologies can be addressed by making additional investment resources available to market participants.¹¹⁷ Paying the full marginal value of energy to demand response will provide the proper level of investment resources available for capital improvements.

63. The Commission acknowledged that noted experts differed on whether paying LMP in the current circumstances facing the wholesale electric market is a reasonable price. In determining that LMP is the just and reasonable price to pay for demand response, the Commission examined some of the previously recognized barriers to demand response that exist in current wholesale markets. These barriers create an inelastic demand curve in the wholesale energy market that results in higher wholesale prices than would be observed if the demand side of the market were fully developed. The Commission found that paying LMP when cost-effective may help remove these

¹¹⁶ *Id.*

¹¹⁷ *Id.* P 57 (quoting EnerNOC May 13, 2010 Comments at 4).

barriers to entry of potential demand response resources, and, thereby, help move prices closer to the levels that would result if all demand could respond to the marginal price of energy.¹¹⁸ Furthermore, the Commission found that since LMP reflects the marginal value of the demand response resource to the RTO or ISO, it is a just and reasonable rate to be paid to demand response resources. RTOs and ISOs already pay LMP compensation to generation resources because LMP represents their marginal value.¹¹⁹ Thus, demand response resources, where capable of balancing supply and demand as an alternative to generation and when dispatch of demand response resources is cost-effective, also should be compensated for the marginal value they provide. The Commission recognized that in some circumstances paying the LMP to demand response would not be cost-effective and therefore determined that payment of LMP in conjunction with a net benefits test will ensure a just and reasonable rate by resulting in the cost-effective dispatch of demand response resources.

64. Dr. Kahn took note of these considerations in supporting the payment of LMP without reduction:

These circumstances—specifically, the fact that pass-through of the LMP is costly and (perhaps) politically infeasible, the possibly prohibitive cost of the metering necessary to charge each ultimate user, moment-by-moment, the often dramatic changes in true marginal costs for each—can justify direct payment at full LMP to distributors and ultimate customers who promise to guarantee their immediate response to such increases in true marginal costs of supplying them.¹²⁰

Many of those seeking rehearing maintain that the only correct price to be paid load must reflect the savings load realizes from not having to purchase electricity. However, as the Commission found in the Final Rule, in circumstances in which the net benefits test is satisfied, paying LMP to demand response resources does not reflect a double payment;

¹¹⁸ *Id.* P 57-59 (recognizing factors unique to the electric industry, including the need for instantaneous balancing of supply and demand and that demand responsiveness to price changes is relatively inelastic).

¹¹⁹ *See* DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2).

¹²⁰ DR Supporters September 16, 2009 Comments filed in Docket No. EL-09-68-000 (Kahn Affidavit at 6).

indeed, where cost effective, demand response resources should be paid the same price received by generation.¹²¹

65. Moreover, the Commission pointed out, examining cost avoidance by demand response resources is not consistent with the treatment of generation. In the absence of market power concerns, the Commission generally does not examine each of the costs of production for individual resources participating as supply resources in the organized wholesale electricity markets.¹²² The Commission has long held that payment of LMP to supply resources clearing in the day-ahead and real-time energy markets encourages more efficient supply and demand decisions in both the short run and long run, notwithstanding the particular costs of production of individual resources.

66. EEI and CSA argue that the possibility that some demand resources that normally purchase energy needs from the RTO or ISO energy market may possess and run behind-the-meter generation in order to continue operation and still collect payments for demand response is a sufficient reason to avoid setting demand response compensation at LMP for all demand response. We do not agree that the existence of behind the meter generation or the potential manner in which behind the meter generation is treated by the RTOs and ISOs invalidates the payment of LMP. As discussed previously, in an RTO or ISO market, payment of LMP is the marginal value of a load reduction in the wholesale market and therefore is reasonable payment for such reduction. From the perspective of the grid, the manner in which a customer is able to produce such a load reduction from its validly established baseline (whether by shifting production, using internal generation, consuming less electricity, or other means) does not change the effect or value of the reduction to the wholesale grid.¹²³ Details associated with the use and measurement of

¹²¹ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 61.

¹²² Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 62. In this regard, we note that certain generators may receive benefits or savings in the form of credits or in other forms. In these cases, the generators realize a value of LMP plus the credit or savings, but ISOs or RTOs do not take such benefits or savings into account in determining how much to pay those resources. *See* Viridity Comments, at 8 (“examples of those benefits include tax credits for kilowatt-hours produced by generators combusting municipal solid waste and other specified generators under Section 45(a) of the Internal Revenue Code (“IRC”), reductions in fuel costs for generators combusting refined coal due to tax credits under Section 45(e)(8) of the IRC, and the value of renewable energy certificates earned by eligible generators under state renewable portfolio standards”); September 13, 2010 Tr. 67:3-14 (Mr. Peterson).

¹²³ The Final Rule required RTOs and ISOs to address measurement and verification issues in their compliance filings. Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 94. Additionally, the Commission’s anti-manipulation regulation continues (continued...)

behind the meter generation to facilitate demand response are already part of some RTO and ISO tariffs, and any changes to such rules are properly considered either as part of the individual RTO and ISO compliance filings or separate section 205 or 206 filings, as appropriate.

67. We reject the argument that suppression of the LMP will result in unjust and unreasonable prices for generation, causing delay in the construction of new generation while accelerating the retirement of current facilities. First, generation resources will not be subject to unfavorable treatment relative to demand response resources, because both types of resources will receive compensation at the LMP when the conditions of capability and cost-effectiveness are met. Demand response resource participation helps to balance supply and demand, helping to produce just and reasonable energy prices by lowering the amount of higher-cost generation dispatched to satisfy system demand.¹²⁴ Second, petitioners' argument ignores the fact that demand response resources increase competition among supply-side resources in the context of balancing supply and demand. In other words, the Final Rule ensures that RTOs and ISOs treat demand response resources in a manner similar to a generation resource that is introduced into a pool of supply-side resources. Accordingly, the Final Rule treats demand response as an alternative to generation in the context of balancing supply and demand in the energy market.

68. CSA's argument that paying LMP to demand response when cost-effective will result in prices that are too low from the supply standpoint, and even violative of the Fifth Amendment, is unconvincing. As explained above, paying LMP reflects the marginal value of a resource's contribution to the market, regardless of whether that resource provides generation or demand response. By ensuring that both types of resources, when dispatched, receive the same compensation for the same service, we expect the Final Rule to enhance the competitiveness of organized wholesale energy markets and result in just and reasonable rates in accordance with the Commission's mandate under the FPA.¹²⁵

to prohibit fraudulent demand response schemes in which no genuine load reduction occurs. 18 C.F.R. § 1c (2011); *see, e.g., North America Power Partners*, 133 FERC ¶ 61,089 (2010).

¹²⁴ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 10.

¹²⁵ The remedy for an alleged taking by the federal government lies in a suit brought in the United States Court of Federal Claims pursuant to the Tucker Act. 28 U.S.C. § 1346(a)(2) (2006); *see Wisconsin Valley Improvement Co. v. FERC*, 236 F.3d 738, 743 (D.C. Cir. 2001) (citing *Transmission Access Policy Study Group v. FERC*,

(continued...)

69. CSA, EEI, and Joint Parties argue that the Commission erroneously relies on a presumption that compensation at LMP is the correct payment level. The Commission, as described in the Final Rule, did not simply presume that LMP is the correct level. As detailed in the Final Rule, the Commission carefully considered the effects of demand response resources on the energy market and found that LMP is warranted when demand response resources can balance supply and demand and are determined to be cost-effective. Under these conditions—that are reasonably tailored to address the capabilities and effects of demand response—demand response resources should be paid the marginal value of energy.

70. While Midwest ISO TOs and Joint Parties dispute whether calculating LMP-G would impose an administrative burden on RTOs and ISOs, the Commission's determination in the Final Rule did not rest primarily on the imposition of such a burden and thus their arguments do not supplant the primary reasoning upon which the Final Rule is based.

b. Effect on Retail Demand Response Programs

71. CSA and EEI argue that the Final Rule may have a detrimental effect on retail-level reforms, such as price-responsive demand programs. As stated in the Final Rule, the pricing reform adopted is directed at demand response participation in organized wholesale energy markets and aims to ensure that rates in those markets are just and reasonable. The Final Rule does not directly affect retail-level demand response programs, nor does it require that demand response resources offer into the wholesale market only. Indeed, the organized wholesale energy markets can and do operate simultaneously with retail-level programs, and each can inform the design of the other. As stated in the Final Rule, the Commission “is not regulating retail rates or usurping or impeding state regulatory efforts concerning demand response.”¹²⁶ The effect, if any, experienced by a retail-level program is incidental to the reforms adopted in the Final Rule.

c. Need for a Uniform Requirement

72. Several petitioners argue that the Commission failed to justify why a uniform rule for demand response compensation is needed. This argument is a corollary to the argument that the Commission did not satisfy the requirements of section 206 of the FPA

225 F.3d 667, 690 (D.C. Cir. 2000); *Railway Labor Executives' Ass'n v. United States*, 987 F.2d 806, 815-16 (D.C. Cir. 1993) (citing *Williamson County Regional Planning Comm'n v. Hamilton Bank*, 473 U.S. 172, 195 (1985)).

¹²⁶ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 114.

because it failed to make a finding that current demand response compensation is unjust and unreasonable. Therefore, we address them together.

73. The Commission complied with the requirements of section 206. The Commission, on its own motion, initiated the section 206 action that resulted in the Final Rule. In the Final Rule, we found that:

[W]hen a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable.¹²⁷

As explained in the Final Rule and affirmed above, LMP represents the marginal value of an increase in supply or a reduction in consumption at each node within an RTO or ISO, i.e., LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand. LMP has therefore been the primary mechanism for compensating generation resources clearing in the organized wholesale energy markets since their formation.¹²⁸ As a result, we continue to believe that requiring all RTOs and ISOs to pay demand response resources the LMP under the conditions set forth in the Final Rule is appropriate to ensure that those resources are compensated in a manner that reflects the marginal value of those resources to the RTO or ISO.

74. Petitioners state that the Commission, up to this point, evaluated RTO and ISO demand response programs on an individual basis and without reference to a standardized compensation level. We disagree. Order No. 719 was clear that demand response resources participating in competitive ancillary service markets would receive the market clearing price.¹²⁹ Petitioners state that the Final Rule is a departure from past Commission practice of encouraging regional variations in RTO and ISO market design. Petitioners cite Order No. 719 as an example of the Commission's support for regional variation, where it directed RTOs and ISOs to work with their stakeholders to address issues involving ancillary services markets. Again, we disagree. In Order No. 719, the Commission recognized the need for RTOs and ISOs to ensure that the technical requirements of allowing demand response resources to offer into the ancillary services

¹²⁷ *Id.* P 47.

¹²⁸ *Id.* P 120.

¹²⁹ Order No. 719, FERC Stats. & Regs. ¶ 31,281 P 47.

markets required each RTO and ISO to examine this question from their own unique perspective, given the differences in markets, but still required comparable pricing between demand response and other resources.¹³⁰ The Commission acknowledged in the Final Rule that it previously accepted a variety of RTO and ISO proposals for compensation for demand response resources participating in organized wholesale energy markets.¹³¹ Nonetheless, based on the record of the proceeding, and balancing the diverging opinions of noted experts, the Commission determined it was necessary in this instance to adopt a uniform compensation rule for demand response resources participating in the organized wholesale energy markets under the conditions set forth in the Final Rule. We are not convinced by petitioners that this decision was in error. Indeed, our action here is consistent with Order No. 719 that determined RTOs and ISOs must pay the market clearing price to all accepted bids in ancillary services markets.

75. Moreover, the Final Rule allows RTOs and ISOs to exercise discretion with respect to their demand response programs, while balancing the level of prescriptive detail. For example, the Final Rule recognizes that there will be “inherent differences” in the supply curves determined by each RTO or ISO under the net benefits test, and thus varying threshold prices among RTOs and ISOs, attributable to each region’s unique supply data, mathematical methods, generation mix, local generation heat rates, and fuel price indices.¹³² The Final Rule also recognized that RTOs and ISOs may have different cost allocation and measurement and verification programs. Each of these elements can be addressed on an individual basis through the RTO and ISO compliance filings.

d. Effect on Market Power

76. CSA argues that the Final Rule seeks to justify the payment of LMP on the ground that current generator market power mitigation rules are inadequate but failed to make a finding that existing market power mitigation rules indeed are inadequate. CSA also cautions that over-mitigation of market power is as harmful as under-mitigation.

77. CSA, however, misinterprets the Commission’s reference in the Final Rule to generator market power and the effect of demand response resources on it. The Final Rule states that “[r]emoving barriers to demand response will lead to increased levels of investment in and thereby participation of demand response resources (and help limit potential generator market power), moving prices closer to the levels that would result if

¹³⁰ Order No. 719, FERC Stats. & Regs. ¶ 31,281 *see, e.g.*, P 59.

¹³¹ *Id.* P 47.

¹³² *Id.* n.160.

all demand could respond to the marginal cost of energy.”¹³³ The Commission emphasized that it sought to facilitate greater competition, with the markets themselves determining the appropriate mix of resources needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets.¹³⁴ The Final Rule does not make a finding that existing generator market power mitigation rules are inadequate, nor was that issue the subject of the rulemaking. The reference to market power was to illustrate the general principle that the greater competition in the market helps to limit potential opportunities for the exercise of market power.

78. CSA further argues that the Final Rule facilitates the exercise of buyer market power. The Final Rule addresses arguments concerning a buyers’ cartel and cooperative price setting, finding that the requirements of the Final Rule do not convert the unit commitment process into collusion among bidders, whether generation or demand response.¹³⁵ CSA has not shown how buyers could in any way collude in setting bids or prices under the Final Rule. Moreover, the market rules implementing the requirements of the Final Rule must be approved by the Commission and demand response resources will be subject to those Commission-approved rules, just like any other participant in the organized wholesale energy markets.

e. Costs of Generation Resources

79. Midwest ISO TOs and Joint Parties argue that the Commission erred when it refused to account for the costs incurred by generator resources to produce electricity. They argue that because generator resources incur costs for fuel, plant operation, etc., when generating electricity, that they are entitled to LMP compensation. In contrast, they claim that because a demand response resource incurs no costs associated with providing its service to an RTO or ISO, that it should receive LMP-G compensation. Again we disagree.

80. As explained in the Final Rule, in the absence of market power concerns the Commission does not inquire into the costs or benefits of production for the individual resources, either generation or demand response resources, participating as supply resources in the organized wholesale energy markets.¹³⁶ Just as the Commission found with regard to arguments made in response to the NOPR, we conclude that petitioners

¹³³ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 59.

¹³⁴ *Id.*

¹³⁵ *Id.* P 65.

¹³⁶ *Id.* P 62.

have failed to justify why it would be appropriate for the Commission to continue to pay generation resources in a manner that reflects the marginal value of the service provided yet depart from this approach for demand response resources.

C. Net Benefits Test and Determination of the Threshold Price Level

81. In the Final Rule, the Commission found that when a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test, that demand response resource must be compensated for the service it provides to the energy market at the LMP.

82. The Commission stated that the cost-effectiveness condition, as determined by the net benefits test, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit (\$/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is because the use of demand resources produces both effects, a reduction in the use of generation and a reduction in load.¹³⁷ We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, generation resources do not produce this billing unit effect because they do not result in a decrease of billing determinants. To address this billing unit effect, the Commission in the Final Rule requires the use of the net benefits test to ensure that the overall benefit of reduced LMPs that result from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test is satisfied, and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.

83. To implement the net benefits test, the Commission directed RTOs and ISOs to make two compliance filings. First, each RTO and ISO is required to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective. The RTO or ISO should determine, based on historical data as a starting point and updated for changes in relevant supply conditions such as changes in fuel prices and generator unit availability, the monthly threshold price corresponding to the point along the supply stack at which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources.

¹³⁷ If the replacement of generation does not produce a reduction in the LMP (price per unit) then the effective unit price to each remaining customer would go up because the same resource cost is now spread over fewer megawatt hours.

84. Second, the Commission indicated that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the RTOs and ISOs may be more precise than the monthly price threshold. The Commission required each ISO and RTO to conduct a study to determine whether the net benefits test could be integrated into its dispatch. Those studies are required to be filed by September 21, 2012.

1. Requests for Rehearing

85. ICC asks whether the determination of the threshold price level should consider demand response resource offers individually, in aggregate, or by some other means.

86. CAISO and P3 argue the Final Rule is arbitrary and capricious and fails to demonstrate reasoned decision making because the net benefits test, which RTOs and ISOs universally opposed, is, according to these petitioners, unworkable. The petitioners state that the Commission ignored significant amounts of record evidence in imposing the net benefits test. Joint Parties also argue that the Commission's net benefits test does not resolve concerns that such a test would be difficult and costly to administer. Midwest TDUs similarly maintain a net benefits test that is too complicated to work. With respect to the integration of demand response into dispatch, Joint Parties quote Andy Ott of PJM Interconnection, L.L.C. (PJM) who, during the technical conference in this proceeding stated that, "an iterative process to look at impacts on market price, my opinion is that would be very costly and difficult to do, if we could even do it."¹³⁸ They further state that in requiring compliance filings for the monthly net benefits test, as well as the study of a dynamic process, the Commission did not consider or resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of complying with this aspect of the Final Rule is reasonable. They conclude that every indication from the record in this proceeding is that developing a net benefits methodology will be very difficult, if not impossible.

87. CAISO argues that implementing the net benefits test results in similarly-situated resources being treated differently.¹³⁹ For example, CAISO states that its tariff provisions governing demand response require that the same methodology be used to evaluate bids from both demand response resources and other supply resources. CAISO argues that the Final Rule requires CAISO to unduly discriminate against demand response resources because such resources must now pass the net benefits test. SWP similarly claims undue discrimination, contending that prior to the Final Rule, no market

¹³⁸ September 13, 2010 Tr. 82:16-21 (Mr. Ott).

¹³⁹ CAISO Request for Rehearing at 38.

participant offering in supply was required to make a showing that its offer is cost-effective.¹⁴⁰

88. CSA and Joint Parties maintain that the monthly net benefits test will not be sufficiently accurate to perform the function for which it was adopted. The petitioners cite to the Commission's acknowledgement that the test may result in Type I and Type II errors,¹⁴¹ resulting in circumstances where demand response resources may be dispatched even though doing so is not cost-effective.¹⁴²

89. Midwest ISO TOs maintain the net benefits test adopted by Order No. 745 ignores the fact that demand response will provide different benefits to different customers in different locations, and therefore the Final Rule is arbitrary and capricious because, they argue, it ignores significant arguments raised in NOPR comments and fails to articulate a rational connection between the facts found and the decision made.¹⁴³

90. Midwest TDUs state that the net benefits test will be biased because the "over compensation" required under the rule will result in shifting demand response from state programs to the federal program.¹⁴⁴ As a result, they contend the shift from retail to wholesale demand response programs would drive up the baseline from which the net benefits test measures costs and benefits in the wholesale market. Specifically, they assert that the net benefits test will show consumer cost "savings" associated with the non-consumption behavior that consumers are already enjoying at a lower cost, thus raising total consumer bills.

2. Commission Determination

91. We affirm our determination that a net benefits test is appropriate and workable. As the Commission explained in the Final Rule, dispatching demand response resources may result in an increased cost per unit to load associated with the decreased amount of load paying the bill (the billing unit effect), depending on the change in LMP relative to the size of the energy market. When reductions in LMP from implementing demand

¹⁴⁰ California Department of Water Resources State Water Project (SWP) Request for Rehearing at 10.

¹⁴¹ See Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 80.

¹⁴² CSA Request for Rehearing at 63; Joint Parties Request for Rehearing at 23-24.

¹⁴³ Midwest ISO TOs Request for Rehearing at 26-27.

¹⁴⁴ Midwest TDUs Request for Rehearing at 19-20.

response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss.¹⁴⁵ Therefore, we find no undue discrimination as alleged by CAISO, since there is a reasonable basis for paying demand response depending on whether it satisfies the net benefits test. When demand response produces a sufficient reduction in LMP to cover the increased billing costs imposed on remaining customers, it is beneficial to customers; when the reduction does not cover costs, the demand response is not beneficial.

92. We also find that it is similarly reasonable to differentiate between demand response and generation as to this issue since only demand response produces the billing unit effect.¹⁴⁶ As the Commission stated in the Final Rule, in the absence of the net benefits test, the RTO's or ISO's economic dispatch ordinarily would select demand response when it is the incremental resource with the lowest bid. However, if the avoided cost of the next unit of generation is not sufficient to offset the billing unit effect of the demand response resource, the decrease in LMP multiplied by the remaining load would not be greater than the costs of dispatching the demand response resource. In such a situation, dispatching the demand response resource would result in a higher price to remaining customers than the dispatch of the next unit of generation in the bid stack. While the demand response resource appears cost competitive in the dispatch order, selection of the demand response resource increases the total cost per unit to remaining load, and it would not be cost-effective to dispatch the demand response resource.¹⁴⁷

93. We reject the arguments that the net benefits test we are requiring is unworkable. In the Final Rule, we provided an explanation of how to conduct that test. Indeed, five of the six RTOs and ISOs (including CAISO) have submitted compliance filings related to the calculation of the price threshold and the implementation of the net benefits tests, with what they assert are workable versions of the net benefits test, contrary to CAISO,

¹⁴⁵ See Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 50.

¹⁴⁶ Undue discrimination does not exist when "a rational, non-discriminatory basis existed for the difference." *Consol. Edison Co. v. FERC*, 165 F.3d 992, 1013 (D.C. Cir. 1999); *Bethany v. FERC*, 727 F.2d 1131, 1139 (D.C. Cir. 1984) (the "mere fact of a rate disparity [between customers receiving the same service] does not establish unlawful rate discrimination" under the NGA, and that "rate differences may be justified and rendered lawful by facts – cost of service or otherwise").

¹⁴⁷ See Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 52.

P3, Joint Parties and Midwest TDUs' assertions.¹⁴⁸ The Commission will address implementation of the net benefits tests when it acts on those filings.

94. CSA and Joint Parties maintain that the Commission cannot justify implementing the net benefits test when the Commission itself recognized that it is not perfectly accurate. We recognize that the test we are requiring may result in instances both when demand response is not paid the LMP but would have been cost-effective and when demand response is paid the LMP but is not cost-effective; however, we find that the test we are requiring is reasonably calculated to identify the hours in which it is reasonable to pay demand response LMP for participation in the day-ahead and real-time energy markets.¹⁴⁹ As we acknowledged in the Final Rule, a more accurate method would be to include demand response, including the concomitant reduction in demand, as part of the RTO or ISO dispatch algorithm. However, it was not clear that RTOs and ISOs could implement the required changes to the dispatch algorithm, so as a practical accommodation we adopted a reasonable, and more easily administered mechanism for the net benefits test.

95. We deny Midwest ISO TOs' request for rehearing arguing that the net benefits test does not acknowledge the fact that demand response provides different benefits to different customers in different locations, and therefore the Final Rule is arbitrary and capricious. Midwest ISO TOs' argument is raised here in the abstract, however, we have specific compliance filings before us that propose methods of determining the price threshold based on historical data in the RTOs. Midwest ISO TOs' argument is more appropriate for the Midwest ISO Order No. 745 compliance filing, where we can

¹⁴⁸ We note that Southwest Power Pool, Inc. (SPP) did not submit a net benefits test in its Order No. 745 compliance filing because it argues that its existing demand response program is consistent with or superior to the demand response programs required by Order No. 745, and does not require a net benefits test to determine the hours when to pay full LMP to demand response resources because it pays full LMP in all hours. We will address the merits of that argument in the order on compliance. Likewise, we also addressed CAISO's, Midwest Independent Transmission System Operator, Inc's (MISO), and PJM's net benefits tests in their respective orders on compliance. See *CAISO*, 137 FERC ¶ 61,217 (2011); *MISO*, 137 FERC ¶ 61,212 (2011); *PJM*, 137 FERC ¶ 61,216 (2011).

¹⁴⁹ See *Batavia v. FERC*, 672 F.2d 64, 84 (D.C. Cir. 1982) (the billing design need only be reasonable, not theoretically perfect); *North Carolina v. FERC*, 112 F.3d 1175, 1190 (D.C. Cir. 1997) ("An agency need not have perfect information . . . [it] need only explain the evidence which is available, and . . . offer a rational connection between the facts found and the choice made." (internal quotation and citation omitted)).

determine whether the net benefits test filed by the Midwest ISO appropriately measures the benefits of demand response.

96. Midwest TDUs argue that demand response resources shifting from retail to wholesale demand response programs caused by “over compensation” would drive up the baseline from which the net benefits test measures costs and benefits in the wholesale market leading to phantom benefits. As discussed previously, we do not find that paying LMP is over compensation; rather, it fairly compensates demand resources at the marginal value of their contribution. The net benefits test determines whether paying demand response at the LMP is cost-effective. The Final Rule does not attempt to measure what would have happened in a retail program absent the wholesale program. Rather, it is focused on the net price effect of paying the demand response resources the LMP in the wholesale market.

97. We believe ICC is asking whether the RTO or ISO is supposed to consider small changes (1 MW) changes or the full amount of demand response when it looks for the point where the price elasticity of supply is one. This issue is more appropriately raised in the individual compliance filings in which the RTOs sought to comply with the requirement. Additionally, we note that the Commission’s directive to smooth the representative supply curve,¹⁵⁰ thus employing a calculus-based operation into the threshold determination which looks at very small movements along the supply curve when calculating the elasticity, addresses ICC’s concern.

D. Cost Allocation

98. The Final Rule explained that when a demand response provider curtails, the RTO or ISO experiences a reduction in load with a corresponding reduction in billing units through which the RTO or ISO derives revenue (billing unit effect). When the two conditions described in the Final Rule are met, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO or ISO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. Therefore, the Final Rule concluded that a method is needed to ensure that RTOs and ISOs recover the costs of obtaining demand response.¹⁵¹

99. The Final Rule requires each RTO and ISO to include in their compliance filing a proposed method of allocating the costs associated with demand response compensation

¹⁵⁰ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at n.161.

¹⁵¹ *Id.* P 99.

proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.¹⁵²

1. Requests for Rehearing

100. DR Supporters seeks clarification that the costs associated with demand response compensation include the costs of paying all resources LMP *and* the wholesale costs associated with deviations to the load of load serving entities (LSEs) who host demand response.¹⁵³ DR Supporters argues that the reduction in load attributable to demand response shows up as a deviation in the load of the LSE who hosts the demand response. DR Supporters therefore requests that the Commission explicitly define the need to settle at wholesale for deviations to LSE load caused by demand response as a cost associated with demand response compensation.¹⁵⁴

101. DR Supporters contends that LSEs scheduling load in the day-ahead market take on a binding settlement obligation for a specified amount of load, which is matched by an obligation to settle in real-time for deviations from load scheduled day-ahead.¹⁵⁵ DR Supporters argues that when negative real-time deviations arise from the operation of demand response that was scheduled as a day-ahead resource, a settlement imbalance

¹⁵² *Id.* P 102.

Since the dispatch of demand response resources affects the LMP charged, and will result in a lower LMP, the customers benefitting from that lower LMP depends upon transmission constraints, and the price separation such constraints cause within the RTO [or ISO]. In some hours in which transmission constraints do not exist, RTOs [and ISOs] establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic [area].

Id. P 100.

¹⁵³ DR Supporters Request for Rehearing at 4-6, 10-11.

¹⁵⁴ *Id.* at 2.

¹⁵⁵ *Id.* at 4-5.

results. According to DR Supporters, the ISO must collect enough money to not only pay all resources LMP, but also to settle for any negative real-time deviations caused by demand response scheduled day-ahead. DR Supporters argues that this collection is necessary to hold the LSE harmless and prevent the imposition of a penalty to LSEs whose customers engage in demand response.¹⁵⁶

102. CSA requests clarification, or rehearing, that the Final Rule requires that costs associated with demand response compensation should be allocated to net purchasers (i.e., market participants whose net cleared demand exceeds their net cleared supply).¹⁵⁷ CSA asserts that it is indisputable that market participants that self-supply their energy needs do not benefit from lower LMPs resulting from dispatching demand response, and, as such, should not be allocated any demand response costs.¹⁵⁸ CSA states that to allocate costs to an entity that does not benefit from demand response would be inconsistent with the reasoning in the Final Rule that costs associated with demand response compensation should be allocated among those who benefit from the resultant lower LMP. Furthermore, CSA argues that such cost allocation would also undermine the operation of the net benefits test by understating the billing unit effect by allocating costs to self-supply, which does not benefit from price decreases.¹⁵⁹

103. A number of parties request rehearing based on assertions that the cost allocation method approved in the Final Rule does not adequately account for operational realities,¹⁶⁰ is vague,¹⁶¹ or is too complicated to implement.¹⁶²

104. Joint Parties request rehearing arguing that the Commission failed to clarify the cost allocation methodology. Joint Parties argue that the Final Rule does not define “all entities” as well as the “area(s)” subject to paying for the demand response compensation. Nor does the Final Rule, according to Joint Parties, explicitly state whether the areas for cost allocation must follow the designation of LMPs and thus is not sufficiently clear.

¹⁵⁶ *Id.* at 5.

¹⁵⁷ CSA Request for Rehearing at 64.

¹⁵⁸ *Id.* at 65.

¹⁵⁹ *Id.* at 66.

¹⁶⁰ OMS Request for Rehearing at 7-8.

¹⁶¹ Joint Parties Request for Rehearing at 26-27.

¹⁶² EEI Request for Rehearing at 25.

Joint Parties request that the Commission clarify that it will address these issues on a case-by-case basis in the compliance filing.¹⁶³

105. OMS requests rehearing arguing that the Commission's determination to allocate the costs of load reductions across an indefinite region is not just and reasonable because the approved cost allocation provides no incentive for LSEs to improve their rate structures and, furthermore, the Final Rule is not clear with respect to how the regions to which costs will be allocated will be determined.¹⁶⁴ OMS argues the Final Rule does not describe how "relevant market area(s)" will be determined. OMS contends that by their very nature RTO energy markets are dynamic and the algorithms used to compute LMPs are complex. OMS believes it may be impossible to conduct an after-the-fact analysis to determine the effect of a load reduction on hundreds or thousands of pricing nodes in order to make a determination as to where and when nodal LMPs were affected by a load reduction.¹⁶⁵

106. EEI contends that the cost allocation methodology fails to account for the complexities that can arise from transmission congestion by overlooking the reality that demand response can relieve congestion, thereby changing the boundaries of one or more transmission congested areas.¹⁶⁶ EEI argues that the benefits to each wholesale buyer as a result of the demand response participation must be calculated through computer simulation of the counterfactual case of no demand response and compared with the actual case. EEI contends that allocating recovery of the demand response payments in proportion to wholesale buyers' benefits will then be complex and cannot be accomplished through the methodology in the Final Rule.¹⁶⁷ EEI reasserts its support for the bifurcated methodology¹⁶⁸ for cost allocation that the Commission argued in the Final

¹⁶³ Joint Parties Request for Rehearing at 27.

¹⁶⁴ OMS Request for Rehearing at 8.

¹⁶⁵ *Id.* at 7-8.

¹⁶⁶ EEI Request for Rehearing at 24-25.

¹⁶⁷ *Id.* at 25.

¹⁶⁸ Under a bifurcated methodology, a portion of the total cost is allocated to the load serving entity (LSE) that serves the demand response resource, while the balance is allocated to the remaining LSE(s) that serve the zone that harbors the demand response resource. *See, e.g.*, PJM May 13, 2010 Comments at 12; ISO-NE May 13, 2010 Comments at 5.

Rule represented an arbitrary division of cost responsibility without regard to the degree to which each received benefits.

107. Midwest TDUs request rehearing arguing that the Final Rule's cost allocation requirement is very difficult and time-consuming because it will require RTOs and ISOs to estimate, on an ongoing basis, hypothetical LMPs that would have existed but for the participation of demand response resources in the organized wholesale energy market.¹⁶⁹

108. ICC requests clarification that costs should be allocated according to the degree to which each load benefits from price reductions and not simply based on each benefiting load's portion of total load. ICC argues that when a transmission constraint exists, a demand response resource may reduce the price in one pricing node, but not at another. Furthermore, ICC contends that the magnitude of the price decrease at two pricing nodes that experience a price decrease may be significantly different.¹⁷⁰ Therefore, ICC argues that, in order to determine those entities that benefit from lower LMPs, the RTO or ISO must be able to identify which LMPs will be reduced when demand response participates.¹⁷¹ ICC states that in order to determine the pricing nodes at which LMPs are decreased, RTOs and ISOs need to simulate a scenario where demand response did not participate in order to determine the prices at each node under the assumption that demand response was not allowed to participate. The RTO or ISO could compare those prices to the actual prices to determine which pricing nodes actually benefited as a ratio of total benefits.

109. Midwest ISO TOs request rehearing arguing that Order No. 745 contravenes the Commission's cost causation policy that costs should be allocated to entities that cause or benefit from the incurrence of the costs.¹⁷² Midwest ISO TOs argue that the net benefits test established in the Final Rule ignores the fact that significant benefits of demand response are realized at the local or nodal level.¹⁷³ Midwest ISO TOs argue that a market-wide net benefits test allocates costs equally to all market participants, notwithstanding the fact that market participants located in the same area as the demand response resource will realize a greater benefit from the reduction in LMP resulting from

¹⁶⁹ Midwest TDUs Request for Rehearing at 14.

¹⁷⁰ ICC Request for Rehearing at 14.

¹⁷¹ *Id.* at 15.

¹⁷² Midwest ISO TOs Request for Rehearing at 27.

¹⁷³ *Id.*

the demand response resource's participation in the energy market.¹⁷⁴ Midwest ISO TOs assert that to the extent that the Final Rule ignores the locational impact that demand response has on different components of LMP and mandates allocation of costs based on a market-wide net benefits test, the Final Rule represents a lack of reasoned decision-making. Midwest ISO TOs request clarification that RTOs and ISOs can develop cost allocation mechanisms that consider the respective regional and localized benefits provided by deployment of demand response resources.¹⁷⁵

110. EEI requests rehearing arguing that the cost allocation methodology required in the Final Rule produces cross-subsidies among wholesale buyers and thus violates the cost causation principle of assigning costs in proportion to benefits received.¹⁷⁶ EEI further argues that the cost allocation methodology thwarts the ability of retail regulatory authorities to offset at the retail level what is, according to EEI, inefficient wholesale pricing because the cross-subsidies are broadly spread over LSE and retail jurisdictional boundaries.¹⁷⁷ Furthermore, EEI states that the cross-subsidies created by the cost allocation methodology effectively disconnect LSE payments for purchased energy from the payments their respective retail customers enjoy by providing demand response.¹⁷⁸ Thus, even if retail regulators could recapture the payments to these retail customers through retail rates, EEI believes doing so will not make their LSEs indifferent because of the cross-subsidies created by the Final Rule.¹⁷⁹

2. Commission Determination

111. The Commission denies the requests for rehearing and affirms its finding that each RTO and ISO allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response resource reduces the market price for energy at the time when the demand response resource is committed or dispatched. As the Commission explained in the Final Rule, when a demand response provider curtails, the RTO experiences a reduction in load with a corresponding reduction in billing units through

¹⁷⁴ *Id.* at 28.

¹⁷⁵ *Id.*

¹⁷⁶ EEI Request for Rehearing at 22.

¹⁷⁷ *Id.* at 23.

¹⁷⁸ *Id.* at 28.

¹⁷⁹ *Id.* at 29.

which the RTO derives revenue.¹⁸⁰ When the demand response resource has the capability to provide the service and when payment of the service is cost effective, however, the RTO must pay LMP to both generators and demand response providers for the resources that clear the energy market. The difference between the amount owed by the RTO to resources, including demand response providers, and the revenue it derives from load results in a negative balance that must be addressed through cost allocation. The Commission continues to find its cost allocation method just and reasonable as it will reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response.

112. We deny DR Supporters' request for clarification as to whether the demand response costs to be allocated by the Final Rule should include costs associated with deviations from day-ahead market commitments made by an LSE that supplies energy to demand response providers, which it incurred as a result of serving those demand response providers. However, DR Supporters' argument assumes that an LSE is obligated to procure its full load (without taking into account the reduction in load from demand response) thus leaving it with a potential deficiency that would carry over to the real-time market.¹⁸¹

113. DR Supporters recognize that different RTOs and ISOs treat real-time settlement imbalances differently at present, where these imbalances may be positive or negative. Because of the differences in the way RTO's or ISO's operate their energy markets, we cannot resolve this issue on a generic basis. To the extent DR Supporters or other parties raise this issue in the compliance filings, we will address the issue on a case-by-case basis in the individual compliance proceedings.

114. Petitioners also challenge the allocation of costs associated with compensation for demand response resources to market participants that primarily self-supply. The cost allocation methodology required in the Final Rule is based upon the benefits of demand response to wholesale load. As explained in the Final Rule, and under the principle of cost causation, purchasers are allocated the costs of demand response because they receive a benefit through the lower LMP that results from demand response resource participation in the organized wholesale energy markets.¹⁸² We reiterate here that cost allocation proposals must satisfy the cost causation principle. However, we find that the record in this proceeding is insufficient to resolve on a generic basis the issue of cost allocation to participants that self-supply. We further find that the issue is better

¹⁸⁰ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 99.

¹⁸¹ DR Supporters Request for Rehearing at 7-8.

¹⁸² Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 100.

addressed in the individual RTO and ISO compliance proceedings, to the extent concerns have been raised there. We therefore deny the requests for rehearing on this issue.

115. The Commission also denies OMS' and Joint Parties' requests for rehearing regarding clarification and definition of the terms "all entities" and the "area(s)" subject to paying for the demand response compensation. The cost allocation methodology required by the Final Rule was designed to allow sufficient flexibility for each individual RTO and ISO to determine, in consultation with their stakeholders, an appropriate cost allocation methodology that complies with the Final Rule.¹⁸³ In this way, the Commission is allowing for regional variation in the determination of the "area(s)" in which market participants benefit from demand response participation based on the unique energy market design in each RTO and ISO. The Commission will analyze and evaluate each RTO's and ISO's proposed cost allocation methodology on a case-by-case basis in its compliance filing.

116. We further deny EEI's, OMS', and Midwest TDUs' requests for rehearing asserting that the cost allocation methodology prescribed in the Final Rule will be overly complex to implement. OMS argues that RTOs and ISOs will have to conduct after-the-fact analysis to determine the effect of demand response on hundreds or thousands of pricing nodes. EEI and Midwest TDUs claim that RTOs and ISOs will have to calculate hypothetical counterfactual LMPs that would have occurred with no demand response participation in order to determine the benefits of demand response participation.

117. The Final Rule requires no such specific actions on the part of RTOs and ISOs. The Final Rule allows each RTO and ISO to tailor its cost allocation methodology to the circumstances on its system.¹⁸⁴ Any issues with respect to the allocation of costs resulting from these proposals, or the feasibility of conducting the analysis, can be raised on a case-by-case basis in the compliance filing proceedings.

118. We deny ICC's, Midwest ISO TOs', and EEI's rehearing requests relating to the proper allocation of costs as more appropriately addressed in the individual compliance filing proceedings.

119. The Final Rule does not require, as ICC suggests, that RTOs and ISOs simulate a scenario to calculate what the prices at each node would have been if demand response had not participated in order to determine which pricing nodes actually benefited as a ratio of total benefits. Each RTO or ISO can propose a methodology that reasonably

¹⁸³ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 102.

¹⁸⁴ *Id.*

allocates the costs of demand response, consistent with the requirements of the Final Rule.¹⁸⁵

120. Finally, we reject Midwest ISO TOs' and EEI's requests for rehearing arguing that the cost allocation methodology prescribed by the Final Rule violates the cost causation policy which requires that costs should be allocated to those entities that benefit from the incurrence of the costs. Contrary to Midwest ISO TOs' and EEI's assertions, the cost allocation methodology prescribed in the Final Rule does not prevent an RTO or ISO from accounting for the regional or local benefits provided by deploying demand response resources. As the Final Rule explained, in some hours in which transmission constraints do not exist, RTOs establish a single LMP for their entire system (a single pricing area) in which case the demand response would result in a benefit to all customers on the system. When transmission constraints are present, however, LMPs often vary by zone, or other geographic areas.¹⁸⁶ The RTOs and ISOs need to look at their systems and determine what methodology best allocates cost to the customers benefitting from the lower LMP resulting from demand response.

E. Measurement and Verification

121. In the Final Rule, the Commission agreed with commenters that measurement and verification are critical to the integrity and success of demand response programs but found that, because it was not requiring payment of LMP in all hours, but, rather, subject to a net benefits test, the Final Rule did not directly implicate measurement and verification issues. Nevertheless, the Commission noted the importance of baseline calculation methodologies and the measuring and verifying of demand response resource performance. Therefore, the Final Rule directed each RTO and ISO to review their current requirements in light of the changes required therein and develop appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed. Each RTO and ISO was required to include as part of its compliance filing an explanation of how its measurement and verification protocols will continue to ensure that appropriate baselines are set, and that demand response will continue to be adequately measured and verified. Additionally, the Commission stated that each RTO and ISO should propose any changes necessary to ensure that their measurement and verification will adequately capture the performance or non-performance of each participating demand response resource, consistent with the Final Rule.

¹⁸⁵ *Id.*

¹⁸⁶ *Id.* P 100.

1. Requests for Rehearing

122. CSA and Midwest TDUs request rehearing arguing that the Commission's determination to adopt the Final Rule in the absence of measurement and verification standards capable of preventing gaming and manipulation is arbitrary and capricious. The petitioners argue that the Final Rule creates significant, and perhaps insurmountable, difficulties and costs for RTOs and ISOs in measuring customers' demand reductions and verifying that they have reduced consumption in response to price signals. The petitioners assert that current measurement and verification standards are not capable of performing the functions they are intended to serve, in particular preventing manipulation. The petitioners further assert that evidence in the record unequivocally indicates that current North American Energy Standards Board (NAESB) standards and RTO and ISO rules cannot prevent fraud and abuse. The petitioners conclude that the Commission's determination that RTOs and ISOs will be able to solve the problems created by the Final Rule regarding measurement and verification is arbitrary and capricious decision making.

2. Commission Determination

123. We deny the requests for rehearing on this issue. Petitioners reiterate the same general concerns regarding deficits in the RTO and ISO demand response measurement and verification programs as they did in their comments to the NOPR. In response, the Commission in the Final Rule required RTOs and ISOs to evaluate their measurement and verification protocols taking into account the effect of the Final Rule's directives and develop modifications as necessary, and include any such modifications in the required compliance filing. The Commission did not find that the compensation-related requirements of the Final Rule fundamentally changed the measurement and verification standards that the RTOs and ISOs have been using. Petitioners will have additional opportunities to address specific concerns about particular aspects of individual RTO or ISO measurement and verification programs in the compliance filing proceedings.¹⁸⁷

F. Study Regarding the Dynamic Implementation of the Net Benefits Test into the Dispatch Algorithm

124. In the Final Rule, the Commission stated that it believed that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of RTOs and ISOs may be more precise than the monthly price threshold and, therefore,

¹⁸⁷ In addition, we note that petitioners may participate in the proceedings considering NAESB Phase II measurement and verification standards development. *See* NAESB, Measurement and Verification of Demand Response Products Phase II Report, Docket No. RM05-5-020 (filed May 3, 2011).

provide the greatest opportunity for load to benefit from participation of demand response in the organized wholesale energy market administered by an RTO or ISO. The Commission acknowledged the position of several of the RTOs and ISOs that modification of their dispatch algorithms to incorporate the costs related to demand response may be difficult in the near term. In light of those concerns, the Commission required each RTO and ISO to undertake a study examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources the LMP results in net benefits to customers in both the day-ahead and real-time energy markets. The Commission directed each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.

1. Requests for Rehearing

125. ICC argues that, unlike in the case of the static model, in the dynamic model, demand-side bidders will not know whether their bids will be cost-effective when they place their bids. ICC states that bidders will have to include a risk premium to account for this uncertainty, which will lead to inefficient prices and levels of demand response resource participation in the RTO and ISO markets. Therefore, ICC asks the Commission to clarify that the dynamic cost-effectiveness model produces uncertainty regarding the offer level at which a demand response resource decides to submit its demand response. ICC also asks the Commission to clarify that this aspect of the dynamic model could have adverse impacts for the development of demand response in the RTO and ISO markets.

126. Joint Parties argue that the Commission's net benefits test does not resolve concerns that such a test would be difficult and costly to administer. Joint Parties cite to a statement by Andy Ott of PJM during the technical conference in this proceeding, "an iterative process to look at impacts on market price, my opinion is that would be very costly and difficult to do, if we could even do it." They further state that in requiring compliance filings for the study of a dynamic process, the Commission does not consider or resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of complying with this aspect of the Final Rule is reasonable. They conclude that every indication from the record in this proceeding is that development of a net benefits methodology will be very difficult, if not impossible, to do.

2. Commission Determination

127. ICC contends that the dynamic cost-effectiveness model will produce uncertainty regarding the level at which demand response resources will offer into the market, but the requirement in the Final Rule is simply that RTOs and ISOs make a compliance filing that includes the results of a study examining the requirements of, costs of, and impacts of implementing a dynamic cost-effectiveness model. The Commission does not expect that a demand response provider will know the magnitude of the billing unit effect

associated with its demand reduction *ex ante*, but if it bids its marginal opportunity cost (as we would expect in a competitive market), it will only be called when it is in the demand response provider's economic interest to reduce consumption. All resources, both supply side and demand side, face some degree of uncertainty as to whether they will be dispatched but if a resource bids its marginal opportunity cost it will not be dispatched unless it is in its economic interest. Furthermore, the Commission will not speculate, as ICC would have us do, as to the specific results that a dynamic cost-effectiveness model may produce. The Final Rule required the study to permit a further comprehensive evaluation of the impacts associated with implementing a dynamic approach, therefore we find it appropriate to refrain from making findings in response to ICC's assertions at this time.

128. We reject Joint Parties argument that in requiring compliance filings for the study of a dynamic process, the Commission did not consider or resolve whether the test is feasible for implementation or whether the cost and burden on RTOs and ISOs of complying with this aspect of the Final Rule is reasonable. Further exploration of these issues is precisely the reason the Final Rule required a study rather than imposing this condition at this time.¹⁸⁸ We are asking the RTOs and ISOs to study the feasibility and giving them sufficient time to do so; the RTOs and ISOs will assess the difficulty of implementing such a plan and report back to the Commission. The Commission can assess the feasibility of implementing a dynamic process in RTOs and ISOs after it receives the studies.

G. Applicability of Order No. 745 to Circumstances When it is not Cost-Effective to Dispatch Demand Response Resources

129. In the Final Rule, the Commission stated that it was not requiring the compensation of full LMP when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.¹⁸⁹ The Commission's findings in the Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.¹⁹⁰

1. Requests for Rehearing

130. ICC requests that the Commission clarify how the price threshold will work for a demand response resource that bids below the threshold. Specifically, ICC asks whether

¹⁸⁸ See Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 84.

¹⁸⁹ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 3.

¹⁹⁰ *Id.* P 3 n.6.

such a resource would be dispatched if the LMP were below the price threshold, but above the resource's bid. If so, ICC asks how such a demand resource should be compensated.

2. Commission Determination

131. As noted above, in Order No. 745 the Commission, acting pursuant to section 206 of the FPA, required each RTO and ISO to revise its tariff to pay a demand response resource the market price for energy (i.e., the LMP) when two conditions are met. First, the demand response resource must have the capability to balance supply and demand as an alternative to a generation resource. Second, dispatch of the demand response resource must be cost-effective as determined by a net benefits test.¹⁹¹ We clarify that pursuant to this section 206 directive, each RTO and ISO must revise its tariff to provide that when the LMP is greater than or equal to the threshold price, all demand resources that qualify for compensation¹⁹² will receive the LMP payment. The Commission's section 206 action in Order No. 745 did not extend, however, to situations where the LMP is not greater than or equal to the threshold price. Thus, if LMP is less than the threshold price, the Final Rule does not apply to determine the payment to a demand response resource, and any payment will be governed by the existing RTO or ISO tariff.

H. Effect of Order No. 745 on CAISO's Demand Response Programs

132. In the Final Rule, the Commission explained that the cost-effectiveness condition for dispatching and compensating demand response resources at the LMP, as determined by the net benefits test, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit (\$/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill.¹⁹³

133. The Commission further required each RTO and ISO to allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response

¹⁹¹ See *supra* P 54.

¹⁹² For example, a qualification may include a requirement that the demand response resource submit a successful supply offer, whether that successful bid is below, at or above the threshold price.

¹⁹³ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 3.

reduces the market price for energy at the time when the demand response resource is committed or dispatched.¹⁹⁴

1. Requests for Rehearing

134. Rehearing requests were received on three basic issues: the California Proxy Demand Resource Product, Reliability Demand Response Resource Products, and its Participating Load Program.

a. Proxy Demand Resource Product

135. CAISO and CPUC request clarification and rehearing that the Final Rule does not require any change to¹⁹⁵ nor does it expressly or implicitly modify or overturn¹⁹⁶ the default load adjustment feature of CAISO's FERC-approved demand response tariff provisions.¹⁹⁷ CAISO states that although the Final Rule contains no directives that squarely address the default load adjustment, or the wholesale double payment issue, it believes that the Final Rule could be read to indirectly require the elimination of it.¹⁹⁸ CAISO contends that the operation of the net benefits test, required in the Final Rule, appears to be inconsistent with the default load adjustment.¹⁹⁹ The net benefits test, described in the Final Rule, considers whether demand response resources should receive full LMP, based on a consideration of overall decreased energy cost spread over the decreased metered load, but the default load adjustment function of CAISO's existing market rules prevents a decrease in an LSE's metered load due to a cleared Proxy Demand Resource bid.

136. CAISO similarly requests clarification arguing that the provisions of the Final Rule relating to cost allocation could also be read as indirectly requiring elimination of the default load adjustment.²⁰⁰ CAISO argues that the cost allocation methodology for

¹⁹⁴ *Id.* P 102.

¹⁹⁵ CAISO Request for Rehearing at 21.

¹⁹⁶ Public Utilities Commission of the State of California (CPUC) Request for Rehearing at 5.

¹⁹⁷ *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,045 (2010).

¹⁹⁸ CAISO Request for Rehearing at 21-22.

¹⁹⁹ *Id.* at 21.

²⁰⁰ *Id.* at 23.

payments made to Proxy Demand Resources under the existing CAISO tariff satisfies and complies with the Commission's directive in the Final Rule because LMP payments made to Proxy Demand Resources are allocated to the load that benefits, i.e., to all load day-ahead and to deviations in real-time.²⁰¹

137. CAISO and the CPUC request rehearing arguing that the Final Rule does not include any factual or legal analysis as to why CAISO's FERC-approved Proxy Demand Resource is no longer just and reasonable and thus FERC's decision was arbitrary, capricious, and not the product of reasoned decision-making because FERC has failed to explain its inconsistency with its own precedent.²⁰²

b. Reliability Demand Response Products

138. CAISO and CPUC seek clarification as to whether Reliability Demand Response Resources are subject to the requirements of the Final Rule.²⁰³ CAISO states that this product occupies a gray area under the definition of programs subject to the Final Rule.²⁰⁴ According to CAISO, Reliability Demand Response Resources will be participating in the day-ahead and real-time energy markets administered by CAISO pursuant to bids submitted for their energy.²⁰⁵ CAISO states that the product is built on the same platform as, and will have many similarities to, the Proxy Demand Resource Product.²⁰⁶ However, CAISO states that its proposed tariff provisions for Reliability Demand Response Resources will provide compensation for demand response providing reliability and emergency relief in real-time.²⁰⁷

c. Participating Load Program

139. SWP seeks clarification or rehearing arguing that to the extent Order No. 745 imposes a net benefits test on demand response from Participating Loads, the order fails to address SWP's evidence and argument which it contends shows that a net benefits test

²⁰¹ *Id.* at 23-24.

²⁰² CPUC Request for Rehearing at 10-11; CAISO Request for Rehearing at 26.

²⁰³ CAISO Request for Rehearing at 32.

²⁰⁴ *Id.* at 33.

²⁰⁵ *Id.*

²⁰⁶ *Id.* at 15.

²⁰⁷ *Id.* at 33.

is not necessary for wholesale Participating Loads, which unlike retail demand response, do not use an administrative baseline against which curtailments are measured.²⁰⁸ SWP states that it requested an exemption from any net benefits test for wholesale demand response that, unlike retail demand response, is modeled as negative generation by CAISO, buys its baselines and is scheduled and settled at nodal LMP levels comparable to generation while retail load uses an averaged or zonal LMP.²⁰⁹

2. Commission Determination

140. We find that we cannot assess these individual aspects of CAISO's demand response program on rehearing in a Final Rule. Other parties need the opportunity to respond to these issues, which are best resolved in CAISO's compliance and Reliability Demand Response Resource proceedings.²¹⁰ These issues were raised by various parties in CAISO's compliance and Reliability Demand Response Resource proceedings, and the Commission will respond appropriately in those proceedings. Under the exercise of the Commission's authority under section 206 of the FPA, the Commission determined that any energy market demand response program is unjust and unreasonable if it does not pay LMP to demand resources when a net benefits test is satisfied and does not allocate costs appropriately to those parties that benefit from the reduction in LMP occasioned by the demand response. As discussed above, we had an adequate basis for making these determinations on a generic basis.

141. Whether the current contours of CAISO's demand response program meets these criteria can be determined only upon review of CAISO's compliance filing and the full record developed in that proceeding. For example, the Final Rule required that RTOs and ISOs allocate the costs of demand response to those parties that benefit from the reduction in LMP. We cannot determine on this record whether the existing cost allocation in the CAISO market meets these criteria. We similarly cannot determine whether CAISO's Reliability Demand Response Resource program or its wholesale Participating Load Program is covered by the Final Rule without the full record developed in the compliance filing and Reliability Demand Response Resource proceedings.

²⁰⁸ SWP Request for Rehearing at 4.

²⁰⁹ SWP Request for Rehearing at 5; *see also* SWP October 13, 2010 Comments at 2-3.

²¹⁰ CAISO's Reliability Demand Response Resource proposal is pending before the Commission in Docket Nos. ER11-3616-000 and 001.

I. Compliance with the Regulatory Flexibility Act

142. The Regulatory Flexibility Act of 1980²¹¹ (RFA) generally requires an administrative agency to perform an analysis of rulemakings that will have a significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rulemaking while minimizing any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.²¹² The SBA has established a size standard for electrical utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation, and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million MWh.²¹³

143. In the Final Rule, the Commission noted that the regulations promulgated in the Final Rule directly impact only RTOs and ISOs. Because RTOs and ISOs are not small entities as defined by the SBA, the Commission certified that the Final Rule would not have a significant economic impact on a substantial number of small entities.

144. Competitive Power Supplier Associations, PPL Parties, and P3 all assert that the Final Rule will, contrary to the Commission's assessment, have an impact on small entities as defined by the SBA. The petitioners assert that the Final Rule will affect small generators, marketers, LSEs, and demand response providers. The petitioners state that the Commission failed to recognize, simply ignored, or did not support its conclusion regarding the impacts that the Final Rule would have on small entities.²¹⁴

145. The only entities subject to the requirements of the Final Rule are the RTOs and ISOs, which as demonstrated in the Final Rule are not classified as small entities.²¹⁵ Furthermore, courts have held that the RFA does not require an agency to perform a regulatory flexibility analysis of impacts on small entities when a rule only indirectly

²¹¹ 5 U.S.C. §§ 601-612.

²¹² 13 C.F.R. § 121.101 (2011).

²¹³ 13 C.F.R. § 121.201, Sector 22 Utilities & n.1.

²¹⁴ Competitive Power Supplier Associations Request for Rehearing at 81; PPL Parties Request for Rehearing at 22; P3 Request for Rehearing at 16.

²¹⁵ Order No. 745, FERC Stats. & Regs. ¶ 31,322 at P 122-28.

impacts them.²¹⁶ In the context of the organized wholesale energy markets, any effects on other entities, such as generators or marketers, are indirect and are the result of competition in the energy market.

The Commission orders:

(A) The requests for rehearing are hereby denied, as discussed in the body of this order.

(B) The requests for clarification are hereby granted in part, and denied in part, as discussed in the body of this order.

By the Commission. Commissioner Moeller is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

²¹⁶ Indirect effects do not fall within the ambit of the RFA. *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027, 1044 (D.C. Cir. 1999), *aff'd in part and rev'd in part on other grounds*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457 (2001); *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 342-43 (D.C. Cir. 1985) (“Congress did not intend to require that every agency consider every indirect effect that any regulation might have on small businesses in any stratum of the national economy.”).

APPENDIX**List of Petitioners**

Abbreviation	Petitioner
CAISO	California Independent System Operator Corporation
Competitive Power Suppliers (CSA)	Electric Power Supply Association Independent Power Producers of New York, Inc. Electric Power Generation Association New England Power Generators Association, Inc.
CPUC	Public Utilities Commission of the State of California
DR Supporters	Demand Response Supporters (members include American Forest & Paper Association, Consumer Demand Response Initiative, EnerNOC, Inc., Project for Sustainable FERC Energy Policy, and Viridity Energy, Inc.)
EEI	Edison Electric Institute
ICC	Illinois Commerce Commission
Joint Parties	American Public Power Association National Rural Electric Cooperative Association Old Dominion Electric Cooperative
Joint Petitioners	Electric Power Supply Association American Public Power Association Electric Power Generation Association National Rural Electric Cooperative Association
Midwest ISO TOs	Midwest ISO Transmission Owners
Midwest TDUs	Midwest Transmission Dependent Utilities
OMS	Organization of MISO States

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P3	PJM Power Providers Group
PPL Parties	PPL Parties
SWP	California Department of Water Resources State Water Project

Parties Filing Answers

Abbreviation	Petitioner
IECG	Industrial Energy Consumer Group
ISO-NE	ISO New England Inc.
NEPOOL Participants Committee	New England Power Pool Participants Committee
Occidental	Occidental Permian Ltd. Occidental Chemical Corporation
Viridity	Viridity Energy, Inc.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in
Organized Wholesale Energy Markets

Docket No. RM10-17-001

(Issued December 15, 2011)

MOELLER, Commissioner, *dissenting*:

Demand response plays a very important role in markets by providing significant economic, reliability, and other market-related benefits when properly deployed.

However, it has become clear since the issuance of Order No. 745 that my earlier concerns in this proceeding were justified.¹ Namely, rather than impose a nationwide approach to demand response compensation, the Commission's objective of promoting demand response would have been better served if the regions were free to propose compensation methods that recognize the very real differences in the structures of the regional markets. In addition, the evidence now shows that the Net Benefits Test will be so costly to develop and so difficult to administer that it can be expected to result in an allocation of the costs of demand response to the parties that do not benefit from demand response.² Therefore, rather than continuing to pursue demand response compensation at full LMP only when the Net Benefits Test is passed, I would have changed that decision and put in its place compensation at LMP – G, where “G” is the avoided retail cost of generation.

While consumers may pay lower rates if some consumers voluntarily agree to use less electricity, the Federal Power Act requires this Commission to establish just and

¹ *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 (2011) (*Moeller Dissenting*) (“Order No. 745”).

² *See e.g.*, Requests for Rehearing, PJM Power Providers Group (P3) at 12; Organization of MISO States (OMS) at 4; California Department of Water Resources State Water Project (SWP) at 4 – 7; Old Dominion Electric Cooperative (ODEC), American Public Power Association (APPA), National Rural Electric Cooperative Association (NRECA) at 23 – 25; PPL Parties at 15 – 16.

reasonable rates that are not discriminatory.³ If the Commission requires the RTOs and ISOs to overcompensate for providing demand response, the resulting rates are both discriminatory and not just and reasonable.

The Case Has Not Been Made

Both the Final Rule and the current rehearing order fail to justify the imposition of a national standard for demand response compensation. Rather than address the legitimate concerns that were raised in this proceeding⁴ about (1) the difficulties with implementing this rule and (2) the disruptions to existing demand response programs, this order simply refers to the individual RTO and ISO compliance proceedings --- as if these problems were not fundamental to the viability of the rule.

As I recognized in my earlier dissent in this proceeding, organized markets have already demonstrated that they can develop demand response compensation rules. RTOs and ISOs have been working with their market participants through stakeholder processes to design demand response compensation rules that are tailored to suit the needs of their individual energy markets. I would have allowed these efforts to continue. However, despite warnings about disruptions from some parties,⁵ the majority is proceeding with generic rules that may actually discourage demand response products.

Furthermore, I would have accepted the Motion to Lodge submitted by CAISO⁶ and do not believe that sufficient rationale was given for denying the motion in this proceeding.⁷ The majority claims the request was made out-of-time, despite CAISO's internal procedures that require draft opinions to be posted before they are finalized. The motion by CAISO and its Market Surveillance Committee illustrates many of the difficulties stakeholders are having with their efforts to comply with this rule. By

³ 16 U.S.C. § 824d (2006).

⁴ See e.g., Requests for Rehearing, Midwest ISO Transmission Owners at 3; CAISO at 1 – 2; Edison Electric Institute (EEI) at 3; Competitive Power Supplier Associations (CSA) at 3; ODEC, APPA, NRECA at 5 – 11.

⁵ See California Independent System Operator Corporation (CAISO), Request for Rehearing, April 14, 2011 at 5, 29. See also Affidavit of Peter Scala on behalf of the California Public Utilities Commission (CPUC).

⁶ CAISO, Motion to Lodge, June 17, 2011 and Errata, June 22, 2011.

⁷ Order No. 745-A at P 9 – 10.

rejecting the motion, the majority did not counter the litany of arguments that assailed the workability of the final rule in CAISO.

The Net Benefits Test

As currently presented, the Net Benefits Test uses backward looking data to predict market rates a year later, when thousands of variables related to economic conditions and weather will surely result in different market rates and conditions. Therefore, it cannot define the benefits of demand response with any accuracy. As a consequence, the costs of demand response compensation will necessarily be inaccurate, and therefore, not just and reasonable. To be clear, I do not fault the RTOs and ISOs and their stakeholders who are trying to develop this unwieldy test. The difficulties inherent in developing a Net Benefits Test will be present regardless of whether the test for benefits is conducted dynamically⁸ or statically.

However, instead of acknowledging the overwhelming opposition—often by the very stakeholders tasked with developing the Net Benefits Test—the majority points to the fact that required compliance filings have been submitted and avoids addressing the substantive arguments about whether the Net Benefits Test is actually workable.⁹

Moreover, this order should have evaluated the costs of compliance, including the development of a static Net Benefits Test as well as studying and reporting on the development of a dynamic Net Benefits Test.¹⁰

While I would have preferred to allow the regions to continue to develop their own demand response compensation programs, absent that outcome, using LMP – G would have at least negated the need to develop and conduct the Net Benefits Test.¹¹

⁸ The unchallenged evidence in this case is that, “the ISO is unaware of a technological solution that exists and there is no reason to believe that it is practically possible for the ISO to incorporate a dynamic net benefits test as part of the ISO’s optimization in the foreseeable future.” *See* CAISO, Request for Rehearing at 40 – 41. *See also* Declaration of Khaled Abdul-Rahman on behalf of the California Independent System Operator Corporation.

⁹ Order No. 745-A at P 93.

¹⁰ Order No. 745-A at P 84. “The Commission required each ISO and RTO to conduct a study to determine whether the net benefits test could be integrated into its dispatch. Those studies are required to be filed by September 2, 2012.”

¹¹ “No such test would be necessary if instead a payment of LMP-G was made to
(continued...)

Demand Response Compensation

The order continues to effectively find that demand resources being compensated at the *value* of full LMP is not enough, so instead requires that demand resource be *paid* the full LMP *plus* be allowed to retain the savings associated with its avoided retail generation cost. Plainly speaking, this is overcompensation to demand response resources. And overcompensation cannot be just and reasonable. The majority insists that demand response is “comparable” to generation, and therefore, deserves the same amount and type of compensation as generation.¹² However, commenters have noted that by not accounting for the contributions of behind-the-meter generation, some demand response resources will receive a rate equal to double the LMP rate.¹³ Nothing distinguishes a generator that is behind-the-meter from one that is in front-of-the-meter such that it is just and reasonable to pay one generator double the rate that is paid to another.

Because measurement and verification is essential to the integrity and effectiveness of demand response compensation,¹⁴ it should have been more directly addressed in this order. Commenters raise valid concerns about the current lack of

fully verified DR. Genuine DR that can be profitable under this payment is efficient (increases market surplus) while any DR that cannot make money under that price reduces market surplus. With the correct payment, no separate screen, such as the Order’s benefit-cost test, is needed.” *See* CAISO Motion to Lodge, June 22, 2011, Exhibit A, “Opinion on Economic Issues Raised by FERC Order 745” at 12.

¹² *See* Order No. 745-A at P 56.

¹³ “For example, Severstal Steel’s Sparrows Point plant purchases its electricity directly from PJM’s day-ahead and real-time markets. The plant has a peak load of 230 MW and has 150 MW of [behind-the-meter generation] that it uses to reduce its purchases when PJM’s LMPs are greater than the running costs of its own generation. Clearly, Severstal Steel’s generators are directly competing with wholesale generators in the PJM footprint but they are being compensated exactly twice LMP for the energy that the wholesale generators can produce at half that price. Paying one generator twice the price that is paid to another generator for delivering an identical, fungible product is clearly unduly discriminatory.” Request for Rehearing, EEI at 21 (footnote omitted).

¹⁴ *See* Order No. 745 at P 93. *See also* Order No. 745-A at P 123.

effective measurement and verification standards, and about the cost and time needed to develop these standards.¹⁵ The order dismisses these concerns and passes off this challenge to the RTOs and ISOs to figure out measurement and verification in their compliance proceedings without regard to the costs of developing these programs.

For the reasons given, I cannot support this order as it violates the Commission's statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.

Philip D. Moeller
Commissioner

¹⁵ See Request for Rehearing, Midwest TDUs at 15. See also Request for Rehearing, CSA at 66 – 70. "...the Commission's decision to adopt the Final Rule, before meaningful measurement and verification standards have been developed, was arbitrary and capricious. The evidence in the record unequivocally indicates that current NAESB standards and ISO/RTO rules cannot prevent fraud and abuse."

Document Content(s)

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