DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–17–000; Order No. 745]

Demand Response Compensation in Organized Wholesale Energy Markets

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Final rule.

SUMMARY: In this Final Rule, the Federal Energy Regulatory Commission (Commission) amends its regulations under the Federal Power Act to ensure that when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (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 described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). This approach for compensating demand response resources helps to ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources, thus ensuring just and reasonable wholesale rates.

DATES: *Effective Date:* This Final Rule will become effective on April 25, 2011. Dates for compliance and other required filings are provided in the Final Rule.

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

I. Introduction

1. This Final Rule addresses compensation for demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized wholesale energy markets, *i.e.,* the day-ahead and real-time energy markets. As the Commission has previously recognized, a market functions effectively only when both supply and demand can meaningfully participate. The Commission, in the Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010, proposed a remedy to concerns that current compensation levels inhibited meaningful demand-side participation.[1] After nearly 3,800 pages of comments, a subsequent technical conference, and the opportunity for additional comment, we now take final action.

[1] *Demand Response Compensation in Organized Wholesale Energy Markets,* Notice of Proposed Rulemaking, 75 FR 15362 (Mar. 29, 2010), FERC Stats. & Regs. ¶ 32,656 (2010) (NOPR).

2. We conclude that when a demand response [2] resource [3] participating in an organized wholesale energy market [4] 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 described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP).[5] The Commission finds that this approach to compensation for demand response resources is necessary to ensure that rates are just and reasonable in the organized wholesale energy markets. Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.[6]

3. This cost-effectiveness condition, as determined by the net benefits test described herein, 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 the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test described herein 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.

4. To implement the net benefits test described herein, we direct each RTO and ISO 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 beyond 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. This price level is to be updated monthly, by each ISO or RTO, as the historic data and relevant supply conditions change.[7]

5. This Final Rule also sets forth a method for allocating the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.

6. The tariff changes needed to implement the compensation approach required in this Final Rule, including the net benefits test, measurement and verification explanation and proposed changes, and the cost allocation mechanism must be made on or before July 22, 2011. All tariff changes directed herein should be submitted as compliance filings pursuant to this Final Rule, not pursuant to section 205 of the Federal Power Act (FPA).[8] Accordingly, each RTO's or ISO's compliance filing to this Final Rule will become effective prospectively from the date of the Commission order addressing that filing, and not within 60 days of submission.

7. In addition, we believe that integrating a determination of the cost-effectiveness of demand response resources into the dispatch of the ISOs and RTOs may be more precise than the monthly price threshold and, therefore, 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. However, we acknowledge 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, we require 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 directs each RTO and ISO to file the results of this study with the Commission on or before September 21, 2012.[9]

II. Background

8. Effective wholesale competition protects customers by, among other things, providing more supply options, encouraging new entry and innovation, and spurring deployment of new technologies.[10] Improving the competitiveness of organized wholesale energy markets is therefore integral to the Commission fulfilling its statutory mandate under the FPA to ensure

[2] Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. 18 CFR 35.28(b)(4) (2010).

[3] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5).

[4] The requirements of this final rule apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response, NYISO's Emergency Demand Response Program, and PJM's Emergency Load Response Program. This Final Rule also does not apply to compensation in ancillary services markets, which the Commission has addressed elsewhere. *See, e.g., Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

[5] LMP refers to the price calculated by the ISO or RTO at particular locations or electrical nodes or zones within the ISO or RTO footprint and is used as the market price to compensate generators. There are variations in the way that RTOs and ISOs calculate LMP; however, each method establishes the marginal value of resources in that market. Nothing in this Final Rule is intended to change RTO and ISO methods for calculating LMP.

[6] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[7] In its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule.

[8] 16 U.S.C. 824d (2006).

[9] We note that this report is for informational purposes only and will neither be noticed nor require Commission action.

[10] *See, e.g., Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, at P 1 (2008) (Order No. 719); *see also Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at P 1 (1999), *order on reh'g,* Order No. 2000–A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington* v. *FERC,* 272 F.3d 607, 348 U.S. App. DC 205 (DC Cir. 2001).

supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[11]

9. As the Commission recognized in Order No. 719, active participation by customers in the form of demand response in organized wholesale energy markets helps to increase competition in those markets.[12] Demand response, whereby customers reduce electricity consumption from normal usage levels in response to price signals, can generally occur in two ways:
(1) Customers reduce demand by responding to retail rates that are based on wholesale prices (sometimes called "price-responsive demand"); and
(2) customers provide demand response that acts as a resource in organized wholesale energy markets to balance supply and demand. While a number of States and utilities are pursuing retail-level price-responsive demand initiatives based on dynamic and time-differentiated retail prices and utility investments in demand response enabling technologies, these are State efforts, and, thus, are not the subject of this proceeding. Our focus here is on customers or aggregators of retail customers providing, through bids or self-schedules, demand response that acts as a resource in organized wholesale energy markets.

10. As the Commission stated in Order No. 719,[13] and emphasized in the NOPR,[14] there are several ways in which demand response in organized wholesale energy markets can help improve the functioning and competitiveness of those markets. First, when bid directly into the wholesale market, demand response can facilitate RTOs and ISOs in balancing supply and demand, and thereby, help produce just and reasonable energy prices.[15] This is because customers who choose to respond will signal to the RTO or ISO and energy market their willingness to reduce demand on the grid which may result in reduced dispatch of higher-priced resources to satisfy load.[16] Second, demand response can mitigate generator market power.[17] This is because the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high.[18] Third, demand response has the potential to support system reliability and address resource adequacy [19] and resource management challenges surrounding the unexpected loss of generation. This is because demand response resources can provide quick balancing of the electricity grid.[20]

11. Congress has recognized the importance of demand response by enacting national policy requiring its facilitation.[21] Consistent with that policy, the Commission has undertaken several reforms to support competitive wholesale energy markets by removing barriers to participation of demand response resources. For example, in Order No. 890, the Commission modified the *pro forma* Open Access Transmission Tariff to allow non-generation resources, including demand response resources, to be used in the provision of certain ancillary services where appropriate on a comparable basis to service provided by generation resources.[22] Order No. 890–A further required transmission providers to develop transmission planning processes that treat all resources, including demand response, on a comparable basis.[23]

12. In Order No. 719, the Commission required RTOs and ISOs to, among other things, accept bids from demand response resources in their markets for certain ancillary services on a basis comparable to other resources.[24] The Commission also required each RTO and ISO "to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage," [25] for purposes of encouraging existing generation and demand resources to continue to be relied upon during an operating reserve shortage, and encouraging entry of new generation and demand resources.[26]

13. Additionally, in recent years several RTOs and ISOs have instituted various types of demand response programs. While some of these programs are administered for reliability and emergency conditions, other programs allow wholesale customers, qualifying large retail customers, and aggregators of retail customers to participate directly in the day-ahead and real-time energy markets, certain ancillary service markets and capacity markets.[27]

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[11] 16 U.S.C. 824d (2006); Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 1.

[12] *See* Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 48.

[13] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292, at P 48 (2009).

[14] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 4.

[15] For example, a study conducted by PJM, which simulated the effect of demand response on prices, demonstrated that a modest three percent load reduction in the 100 highest peak hours corresponds to a price decline of six to 12 percent. ISO–RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets, found at *http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf.*

[16] *Id.* ("Demand response tends to flatten an area's load profile, which in turn may reduce the need to construct and use more costly resources during periods of high demand; the overall effect is to lower the average cost of producing energy.").

[17] *See* Comments of NYISO's Independent Market Monitor filed in Docket No. ER09–1142–000, May 15, 2009 (Demand response "contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other market costs, and mitigates supplier market power.").

[18] *Id.*

[19] *See* ISO–RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at *http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_DR_Report_101607.pdf* ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings * * *.").

[20] For instance, in ERCOT, on February 26, 2008, through a combination of a sudden loss of thermal generation, drop in power supplied by wind generators, and a quicker-than-expected ramping up of demand, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded quickly, bringing ERCOT back into balance. Oak Ridge Nat'l Lab., Nat'l Renewable Energy Lab., Tech. Rep. NREL/TP–500–43373, ERCOT Event on Feb. 26, 2008: Lessons Learned (Jul. 2008).

[21] *See* Energy Policy Act of 2005, Public Law 109–58, § 1252(f), 119 Stat. 594, 965 (2005) ("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.").

[22] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 887–88 (2007), *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[23] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 216.

[24] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 47–49.

[25] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 194.

[26] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 247.

[27] Other demand response programs allow demand response to be used as a capacity resource and as a resource during system emergencies or permit the use of demand response for synchronized reserves and regulation service. *See, e.g., PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331 (2006); *Devon Power LLC,* 115 FERC ¶ 61,340, *order on reh'g,* 117 FERC ¶ 61,133 (2006), *appeal pending sub nom. Maine Pub. Utils. Comm'n* v. *FERC,* No. 06–1403 (D.C. Cir. 2007); *New York Indep. Sys. Operator, Inc.,* 95 FERC ¶ 61,136 (2001); *NSTAR Services Co.* v. *New England Power Pool,* 95 FERC ¶ 61,250 (2001); *New England Power Pool and ISO New England, Inc.,* 100 FERC ¶ 61,287, *order on reh'g,* 101 FERC ¶ 61,344 (2002), *order on reh'g,* 103 FERC ¶ 61,304, *order on reh'g,* 105 FERC ¶ 61,211 (2003); *PJM Interconnection, L.L.C.,* 99 FERC

14. To date, the Commission has allowed each RTO and ISO to develop its own compensation methodologies for demand response resources participating in its day-ahead and real-time energy markets. As a result, the levels of compensation for demand response vary significantly among RTOs and ISOs.[28] For example, PJM Interconnection, L.L.C. (PJM) pays the LMP minus the generation and transmission portions of the retail rate.[29] ISO New England Inc. (ISO–NE) and New York Independent System Operator, Inc. (NYISO) pay LMP when prices exceed a threshold level, with the levels differing between the RTOs.[30] The Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) demand response programs [31] pay LMP for demand response resources in the day-ahead and real-time energy markets.[32] The California Independent System Operator Corporation (CAISO) pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying resources to provide day-ahead and real-time energy.[33] CAISO also provides for demand response resources to participate in its Participating Load program, which enables certain resources to provide curtailable demand in the CAISO market. CAISO pays nodal real-time LMP for its Participating Load program. The Southwest Power Pool, Inc. (SPP) has filed revisions to its tariff to facilitate demand response in the Energy Imbalance Service Market.[34]

III. Procedural History

15. As noted above, the Commission issued the NOPR in this proceeding on March 18, 2010.[35] The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The Commission sought comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.[36]

16. After receiving the first round of comments, the Commission issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference (Supplemental NOPR) in this proceeding on August 2, 2010.[37] The Supplemental NOPR sought additional comment on: Whether the Commission should adopt a net benefits test for determining when to compensate demand response providers, and, if so, what, if any, requirements should apply to the methods for determining net benefits; and what, if any, requirements should apply to how the costs of demand response are allocated. The Commission further directed Staff to hold a technical conference focused on these two issues, which occurred on September 13, 2010.[38]

IV. Discussion

17. Based upon the record in this proceeding, the Commission herein requires greater uniformity in compensating demand response resources participating in organized wholesale energy markets. This Final Rule also addresses the allocation of costs resulting from the commitment of demand response, directing that such costs be allocated among those customers who benefit from the lower LMP resulting from the demand response.

A. Compensation Level

1. NOPR Proposal

18. The NOPR proposed to require RTOs and ISOs to pay the LMP in all hours for demand reductions made in response to price signals. The NOPR sought to provide comparable compensation to generation and demand response providers, based on the premise that both resources provide a comparable service to RTOs and ISOs for purposes of balancing supply and demand and maintaining a reliable electricity grid.[39] Also as stated in the NOPR, the proposed compensation level was designed to allow more demand response resources to cover their investment costs in demand response-related technology (such as advanced metering) and thereby facilitate their ability to participate in organized wholesale energy markets.[40] The Commission sought comments on the compensation proposal and, in particular, on the comparability of generation and demand response resources; alternative approaches to compensating demand response in organized wholesale energy markets; whether payment of LMP should apply in all hours, and, if not, any criteria that should be used for establishing hours when LMP should apply; and whether to allow for regional variations concerning approaches to demand response compensation.

19. In the Supplemental NOPR, the Commission sought additional comments and directed staff to hold a technical conference regarding various net benefits tests. In particular, the Commission sought comment on:

¶ 61,227 (2002); *California Independent System Operator Corp.,* 132 FERC ¶ 61,045 (2010).

[28] *See New England, Inc.,* Docket No. ER09–1051–000; *ISO New England, Inc.,* Docket No. ER08–830–000; *Midwest Indep. Transmission Sys. Operator, Inc.,* Docket No. ER09–1049–000.

[29] *See* sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[30] For example, under ISO–NE's Real-Time Price Response Program, the minimum bid is $100/MWh and a demand response resource is paid the higher of LMP or $100/MWh. For the Day-Ahead Load Response Program, the minimum offer level is calculated on a monthly basis and is the Forward Reserve Fuel Index ($/MMBtu) multiplied by an effective heat rate of 11.37 MMBtu/MWh. The maximum offer level is $1,000/MWh. *See* sections III.E.2.1 and III.E.3.2 of Appendix E of the ISO New England Transmission, Markets and Services Tariff. NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. *See* section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

[31] Midwest ISO FERC Electric Tariff characterizes Demand Response Resources (DRR) as either DRR-Type I or DRR-Type II. DRR-Type I are capable of supplying a specific quantity of energy or contingency reserve through physical load interruption. DRR-Type II are capable of supplying energy and/or operating reserves over a dispatchable range. *See* sections 39.2.5A and 40.2.5 of the Tariff.

[32] *See* Charges and Payments for Purchases and Sales for Demand Response Resources. Midwest ISO FERC Electric Tariff, section 39.3.2C.

[33] *See* section 11.2.1.1 IFM Payments for Supply of Energy, CAISO FERC Electric Tariff. CAISO notes that for a Proxy Demand Resource that is made up of aggregated loads, the Resource is paid the weighted average of the LMPs of each pricing node where the underlying aggregate loads reside. *See CAISO,* 132 FERC ¶ 61,045, at P 26 n.14 (2010).

[34] The Commission has directed SPP to report on ways it can incorporate demand response into its imbalance market. *Southwest Power Pool, Inc.,* 128 FERC ¶ 61,085 (2009). As of September 1, 2010, SPP has submitted seven informational status reports regarding its efforts to address issues related to demand response resources. In orders addressing SPP's compliance with Order No. 719, the Commission also directed SPP to make another compliance filing addressing demand response participation in its organized markets. *Southwest Power Pool, Inc.,* 129 FERC ¶ 61,163, at P 51 (2009). On May 19, 2010, SPP submitted revisions to its Open Access Transmission Tariff in Docket Nos. ER09–1050–004 and ER09–748–002 to comply with the Commission's requirements established in Order Nos. 719 and 719–A. These filings are pending before the Commission.

[35] NOPR, FERC Stats. & Regs. ¶ 32,656.

[36] *See* Appendix for a list of commenters.

[37] *Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference,* 75 FR 47499 (Aug. 6, 2010), 132 FERC ¶ 61,094 (2010) (Supplemental NOPR).

[38] *See* Notice of Technical Conference (Aug. 27, 2010).

[39] NOPR, FERC Stats. & Regs. ¶ 32,656 at P 15.

[40] *Id.* at P 16.

whether the Commission should adopt a net benefits test applicable in all or only some hours and what the criteria of any such test would be; how to define net benefits; what costs demand response providers and load serving entities incur and whether they should be included in a net benefits test; whether any net benefits methodology adopted should be the same for all RTOs and ISOs; proposed methodologies for implementing a net benefits test and the advantages and limitations of any proposed methodologies.[41] The September 13, 2010 Technical Conference included an eleven-member panel discussion of net benefits tests representing a wide range of interests and viewpoints.[42] The Commission subsequently received additional written comments addressing these issues.

2. Comments

(a) Capability of Demand Response and Generation Resources To Balance Energy Markets

20. Various commenters address the comparability of demand response and generation resources for purposes of compensation in the organized wholesale energy markets. To begin, numerous commenters address the physical or functional comparability of demand response and generation, agreeing that an increment of generation is comparable to a decrement of load for purposes of balancing supply and demand in the day-ahead and real-time energy markets.[43] Equating generation and demand response resources, Dr. Alfred E. Kahn states:

> [Demand response] is in all essential respects economically equivalent to supply response * * * [so] economic efficiency requires * * * that it should be rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is, all resources—energy saved equivalently to energy supplied—* * * should receive the same market-clearing LMP in remuneration.[44]

Indeed, some commenters believe that, from a physical standpoint, demand response can provide superior services to generation, such as providing a quick response in meeting system requirements and service without having to construct major new facilities.[45] Occidental asserts that the fungibility of demand response and generation output creates greater operational flexibility that, in turn, offers RTOs and ISOs multiple options to solve system issues both in energy and ancillary service markets, and that the fungible nature of demand response and generation supports comparable compensation for each as proposed in the NOPR.[46]

21. Viridity states that attempts to distinguish the physical characteristics of generation and demand response ignore bid-based security-constrained economic dispatch as the foundation for LMP and are based on the assumption that the value of load management on the grid is limited to periods when the system is stressed, *i.e.,* traditional “super peak shaving.” Viridity states that, while these arguments might have been valid 15 years ago, today competitive markets can offer proactively-managed load control and comparable and non-discriminatory treatment of load-based energy resources. Therefore, Viridity asserts that all resources should be paid LMP if the grid operator accepts their bid to achieve grid balance.[47]

22. At the same time, other commenters argue that generation and demand response are not physically equivalent, pointing out that demand response reduces consumption, whereas generators serve consumption.[48] They argue that a MW reduction in demand does not turn on the lights.[49] EPSA adds that a load reduction does not provide electrons to any other load and, instead, allows the marginal electron to serve a different customer.[50] Some commenters assert that a power system can function solely and reliably on generating plants and without any reliance on demand response, while the system cannot rely exclusively on demand response because demand response by itself cannot keep the lights on. Ultimately, some commenters point out, megawatts produced by generators need to be placed on the system in order for power to flow.[51] Battelle additionally argues that a reduction in consumption is not exactly the same as an increase in production, because elastic demand often comes with attendant future consequences, such as rebound, by virtue of substitution in time.[52]

23. Some commenters who argue that the physical characteristics of demand response are not comparable to generation frame their arguments in terms of the ability of the system operator to call on demand response and generation resources to provide balancing energy. They argue that generation resources provide superior service to demand response providers, positing that demand response is not intended for long periods of balancing needs,[53] and that, moreover, contracts with demand response providers limit the number of hours and times a customer may be called upon to curtail. For example, ODEC asserts that the degree of physical comparability depends on the extent to which demand response resources can be dispatched similar to a generator.[54] Calpine adds that traditional generators provide system support features that demand response cannot, such as ancillary services including governor response or reactive power voltage support, which are necessary for reliable operation of the electric system.[55]

24. Numerous commenters also address the comparability of demand response and generation in economic terms. For example, EEI states that, in finance terms, the demand response product is, unlike generation, essentially an unexercised call option on spot market energy, and the value of that option is well-established in finance theory as the value of the resource (LMP) minus the “strike price,” which EEI contends in this case is the retail tariff rate.[56] EEI and like-minded commenters support, therefore, alternative compensation for demand response to equal LMP minus the generation (or G) component of the retail rate.[57] They posit that payment of

[41] Supplemental NOPR, 132 FERC ¶ 61,094 at P 8–9.

[42] *See* Sept. 13, 2010 Tr.

[43] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 2); Verso May 13, 2010 Comments at 3–4; Occidental May 13, 2010 Comments at 11; Viridity June 18, 2010 Comments at 5.

[44] DR Supporters August 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

[45] Verso May 13, 2010 Comments at 3–4; Alcoa May 13, 2010 Comments at 9.

[46] Occidental May 13, 2010 Comments at 11.

[47] Viridity June 18, 2010 Comments at 5.

[48] ISO–NE May 13, 2010 Comments at 3.

[49] *See, e.g.,* APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2.

[50] EPSA May 13, 2010 Comments at 72.

[51] *See, e.g.,* PSEG May 13, 2010 Comments at 8.

[52] Battelle May 13, 2010 Comments at 3.

[53] AEP May 13, 2010 Comments at 7–8.

[54] ODEC May 13, 2010 Comments at 12.

[55] Calpine May 13, 2010 Comments at 4–5.

[56] EEI May 13, 2010 Comments at 4–5. *See also* Robert L. Borlick May 13, 2010 Comments at 4. Mr. Borlick argues that the correct price is LMP minus the Marginal Foregone Retail Rate (MFRR), describing the economically efficient price that should be paid to a demand response provider as “its offer price minus the price in its retail tariff at which it would have purchased the curtailed energy.” Mr. Borlick asserts that this amount accurately represents the forgone opportunity costs that result when a demand response provider reduces its load. *Id.*

[57] *See* May 13, 2010 Comments of: APPPA; AEP; The Brattle Group; Calpine; ConEd; Consumers Energy; CPG; Detroit Edison; Direct Energy; Dominion; Duke Energy; Edison Mission; EEI; EPSA; Exelon; FTC; GDF; NYISO on behalf of the

LMP without an offset for some portion of the retail rate does not send the proper economic signal to providers of demand response, because it fails to take into account the retail rate savings associated with demand response, and thereby overcompensates the demand response provider. As described by Dr. William W. Hogan on behalf of EPSA, this is sometimes called a double-payment for demand reductions, because demand response providers would "receive" both the cost savings from not consuming an increment of electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity.[58] Viewing LMP as a double-payment, these commenters argue that paying LMP will result in more demand response than is economically efficient.[59] For example, Dr. Hogan states that paying LMP might motivate a company to shut down even though the benefits of consuming electricity outweigh the cost at LMP.[60] Indeed, P3 argues that compensation in excess of LMP–G is unjust and unreasonable, because such a payment level imposes costs on customers that are not commensurate with benefits received.[61]

25. ISO–NE argues that paying full LMP to demand response providers without taking into account the bill savings produced by demand response provides a significant financial incentive to dispatch demand response with marginal costs exceeding LMPs. By dispatching higher-cost demand response, ISO–NE asserts, lower-cost generation resources are displaced.[62] At the same time, ISO–NE argues, generation is not dispatched and paid for only when the generation reduces LMP—generation is dispatched and paid for when it is cost-effective.[63]

26. Dr. Hogan further disputes arguments equating a MW of energy supplied to a MW of energy saved on economic grounds. Dr. Hogan draws a distinction between reselling something that one has purchased, and selling something that one would have purchased without actually purchasing it. Dr. Hogan argues that from the perspective of economic efficiency and welfare maximization, the aggregate effect of demand response is a wash producing no economic net benefit. Dr. Hogan asserts that Commission policy citing the benefits of price reduction in support of demand response compensation would amount to no less than an application of regulatory authority to enforce a buyers' cartel. He states that the Commission has been vigilant and aggressive in preventing buyers and sellers from engaging in market manipulation to influence prices, and it would be fundamentally inconsistent for the Commission to design demand response compensation policies that coordinate and enforce such price manipulation.

27. Dr. Hogan argues that the ideal and economically efficient solution regarding demand response compensation is to implement retail real-time pricing at the LMP, thereby eliminating the need for demand response programs. Realizing that this is unattainable at the present time, Dr. Hogan goes on to propose a next-best solution, which he believes is to pay demand response compensation in the amount of LMP–G, or some amount that simulates explicit contract demand response (such as "buy-the-baseline" approach discussed below). These options, he argues, more than paying LMP, better support notions of comparability between demand response resources and generation.[64]

28. The New York Commission, however, argues that requiring payment of LMP–G would result in an administrative burden of tracking retail rates for the multiple utilities, ESCOs and power authorities and create undue confusion for retail customers and administrative difficulties for State commissions and ISOs and RTOs.[65]

29. Consistent with Dr. Hogan's arguments, some commenters assert that demand response providers should actually own or pay for electricity prior to, what commenters characterize as, an effective reselling of the electricity back to the market in the form of demand response. For example, these commenters suggest that the demand response provider purchase the power in the day-ahead market and resell it in the real-time markets.[66] EPSA argues that there must be some purchase requirement or representative offset to allow a demand response provider to "sell" a commodity that it owns to the ISO or RTO.[67] EPSA argues that such a requirement would send an efficient price signal, reduce incentives for gaming the system, and help address difficulties with measurement and verification of a demand reduction. EPSA highlights an ISO–NE IMM recommendation that, if the Commission permits LMP payment, it should also adopt a "buy-the-baseline" approach requiring demand response resources to purchase an expected amount of energy consumption in the day-ahead energy market and subsequently sell any demand reduction from that level in the real-time market.[68]

30. Viridity, on the other hand, argues that forcing customers to buy and then resell electricity will lead to too little demand response and that adopting a "buy-the-baseline" approach would constitute an inappropriate exercise of Commission authority to effectively force parties into contracts. Viridity and DR Supporters state that any characterization of demand response as a purchase and then resale of energy is erroneous[69] and based on the flawed assumption that demand response resources are reselling energy. They state that the description of demand response as a reselling of energy has been correctly rejected by the Commission in *EnergyConnect,* where the Commission stated that it was establishing a policy of treating demand response as a service rather than a purchase and sale of electric energy.[70]

31. DR Supporters further argues that, despite claims to the contrary, paying full LMP to demand response providers does not constitute a subsidy for demand response any more than the remunerations of generators for the power that they sell. As Dr. Kahn states:

> Does this plan involve double compensation, as [Dr.] Hogan asserts, at the expense of power generators—of successful

ISO RTO Council; ICC; IPPNY; Indicated New York TOs; IPA; ISO–NE; Midwest TDUs; Mirant; Midwest ISO TOs; NEPGA; NYISO; ODEC; OMS; PJM; PJM IMM; P3; Potomac Economics; PG&E; Ohio Commission; Robert L. Borlick; Roy Shanker; and RRI Energy.

[58] *See* Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09–68–000.

[59] EPSA May 13, 2010 Comments at 23. *See also* May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6–8.

[60] Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, Oct. 29, 2009, submitted in Docket No. EL09–68–000. In Dr. Hogan's view, supply should produce when the price of electricity exceeds its cost of production and demand should decline to consume when the costs in terms of convenience of delaying use are less than the price of electricity.

[61] P3 June 14, 2010 Comments at 2, 7–8.

[62] ISO–NE May 13, 2010 Comments at 3–4.

[63] *Id.* at 28.

[64] Hogan Affidavit, ISO RTO Council May 13, 2010 Comments at 5.

[65] New York Commission May 13, 2010 Comments at 8.

[66] *See, e.g.,* ISO–NE IMM May 13, 2010 Comments at 4–5; Midwest ISO TOs May 13, 2010 Comments at 14; PJM May 13, 2010 Comments at 5; and Duke Energy May 13, 2010 Comments at 2.

[67] EPSA June 30, 2010 Comments at 3.

[68] EPSA June 30, 2010 Comments at 23.

[69] Viridity Energy June 18, 2010 Comments at 25.

[70] DR Supporters Aug. 30, 2010 Reply Comments at 10 (citing *EnergyConnect, Inc.,* 130 FERC ¶ 61,031 at P 30–31 (2010)).

bidders promising to induce efficient demand curtailment and of consumers induced to practice it? Certainly not: The decrease in the revenue of the generators is (and consequent savings by consumers are) matched by the savings in their (marginal) costs of generating that power; the successful bidders for the opportunity to induce that consumer response are compensated for the costs of those efforts by the pool, whose (marginal) costs they save by assisting consumers to reduce their purchases.[71]

32. Viridity further disputes Dr. Hogan's argument that payment of LMP for demand response will distort an otherwise optimal market. Viridity posits that such arguments ignore dislocations in the wholesale power markets, the existence of market power that must be mitigated, imperfect information available to customers, barriers to entry and uneconomic resources dispatched to fulfill must-run requirements.[72] Viridity further states that Dr. Hogan's arguments fail to acknowledge the limits of the Commission's jurisdiction and widespread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation) and fail to account for any market benefits of demand response.[73] Finally, Viridity argues that Dr. Hogan's arguments fail to reflect the many complex interactions between price, equipment operational requirements, and customer processes, which point to a complex demand response decision.[74]

33. In addition to physical and economic comparability, some commenters contrast the environmental effects of generation and demand response resources. EDF notes that current market prices fail to internalize environmental externalities—including toxic air pollution, greenhouse gas pollution, and land and water use impacts—and other social costs. EDF asserts that the social impact of these environmental externalities is especially acute at peak times, positing that generation sources used for marginal supply at such times ("peaker plants") are among the oldest, dirtiest, and most inefficient in the fleet.[75] The American Clean Skies Foundation contends that fossil-fuel generators are typically mispriced because wholesale prices radically understate the full environmental and health costs associated with such generators.[76] Indeed, some commenters, such as Alcoa, argue that because demand response does not result in the external costs associated with generation (*e.g.,* greenhouse gas emissions), instead resulting in less greenhouse gas emissions than generation, it should be compensated at more than LMP.[77]

34. Taking the opposite view concerning environmental externalities, EPSA states that paying LMP for demand response will merely encourage load to switch to off-grid power (or behind-the-meter generation), while still being compensated, and that such behind-the-meter generation produces more greenhouse gases and other air emissions than electricity from the regional energy market.[78]

35. Some commenters discuss comparability of generation and demand response in terms of the market rules that apply to each resource, arguing that both resources should be comparably compensated only if the same rules for participation apply to both resources, and both resources are held to the same standards for dispatchability.[79] They also argue that similar penalty structures should apply to demand response resources as apply to generation, and that demand response participation must be subject to market monitoring.[80] Calpine adds that to the extent demand response resources are used and treated on par with generators for purposes of compensation, they should be subject to the same performance testing, penalties, and other similar requirements as generators.[81]

36. Some commenters address the comparability of demand response providers and generators in terms of maintaining system reliability. PIO argues that reductions in consumption provide additional reliability.[82] According to the NEMA, North American Electric Reliability Corporation (NERC) standards suggest that, from a reliability perspective, load reductions are equivalent or even superior to generator increases for balancing purposes. For example, while specific to the Western Interconnection, BAL–002–WECC–1 lists interruptible load as comparable to generation deployable within 10 minutes.[83] EPSA maintains that demand response resources are not full substitutes based on the nature of their participation and the rules applicable to each resource in the energy markets, pointing out, for example, that, unlike generators, demand response providers are not subject to regional and NERC mandatory reliability standards.[84]

37. On the other hand, PSEG argues that a MW of demand response does not make the same contribution towards system reliability as a MW of generation, because demand response committed as a capacity resource is only required to perform for a limited number of times over the peak period. PSEG refers to PJM's capacity market, for example, in which demand response only has to perform 10 times during the entire summer peak period, and then only for six hours per response. In contrast, PSEG argues, generators are available for dispatch, 24 hours a day, 365 days per year, except for a small percentage of time for forced and planned outages. PSEG further asserts that additional reliability standards—applicable to generating facilities, but not to demand response—increase the relative reliability value of generating resources to the system.[85]

(b) Appropriateness of a Net Benefits Test

38. Some commenters assert that demand response providers should be paid LMP only when the benefits of demand response compensation outweigh the energy market costs to consumers of paying demand response resources, *i.e.,* when cost-effective, as determined by some type of net benefits or cost-effectiveness test.[86] They maintain that paying LMP for demand response in all hours, including off-peak hours, might not result in net benefits to customers, because the payments might be substantially more than the savings created by reducing the clearing price at that time.[87] According to these commenters, net benefits are most likely to be positive and greatest when the supply curve is steepest, which typically occurs in highest-cost, peak

[71] DR Supporters Aug. 30, 2010 Reply Comments, Kahn Affidavit at 10.

[72] Viridity June 18, 2010 Comments at 13 ("Importantly, Dr. Hogan (and others) in opposing the proposed rulemaking fails to acknowledge the limits of the Commission's jurisdiction, and wide spread dislocations and distortions in virtually all economic aspects of relevant energy markets (including fuels, facilities, pricing, environmental attributes, information and participation)." (Affidavit of John C. Tysseling, PhD)).

[73] Viridity Reply Comments at 13.

[74] Viridity Reply Comments at 14.

[75] EDF Oct. 13, 2010 Comments at 2.

[76] American Clean Skies Foundation May 13, 2010 Comments at 4.

[77] Alcoa May 13, 2010 Comments at 9.

[78] EPSA May 13, 2010 Comments at 60.

[79] ODEC May 13, 2010 Comments at 12; Westar May 13, 2010 Comments at 5–6.

[80] *Id.*

[81] Calpine May 13, 2010 Comments at 5.

[82] PIO May 13, 2010 Comments at 8.

[83] NEMA May 13, 2010 Comments at 2.

[84] EPSA May 13, 2010 Comments at 7.

[85] PSEG May 13, 2010 Comments at 8.

[86] *See generally* May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

[87] Capital Power May 13, 2010 Comments at 5; P3 May 13, 2010 Comments at 5.

hours.[88] They argue that experience to date has shown positive benefits from demand response as a peak system resource, and that, during peak periods, the positive economics of demand response are generally very clear and a cost-benefit analysis may not be needed.[89] Furthermore, some commenters suggest that limiting the hours in which demand response resources are paid LMP could help establish better baselines for measuring whether a demand response provider has, in fact, responded.[90]

39. Some commenters who oppose paying LMP in all hours for demand response also suggest various approaches, including net benefits tests, for determining when LMP should apply. The stated purpose of any of these tests would be to determine the point at which the incremental payment for demand response equals the incremental benefit of the reduction in load; payment of LMP would apply only up to that point.[91]

40. Opposition to use of a net benefits test comes from several directions. Numerous commenters, primarily industrial consumers and some consumer advocates, argue that a net benefits test will reduce competition,[92] have a "chilling effect" on the development of demand response,[93] and be costly and complex to implement.[94] Some commenters further state that no net benefits test is needed because the merit-order bid stack and market clearing function in a wholesale market, by definition, assures that the benefits to the system of demand response exceed the costs, and that the resource that clears is the lowest cost resource; otherwise, demand response would not dispatch ahead of competing alternatives.[95]

41. Another set of commenters argues that a net benefits test is unnecessary and inappropriate for different reasons.[96] These commenters assert that a net benefits test would be very costly and difficult to implement, that RTOs and ISOs cannot implement a net benefits test,[97] and that such a test is unnecessary with the economically efficient compensation level for demand response resources.[98] According to Andy Ott of PJM, "[t]he implicit assumption in developing a benefits test for purposes of compensation would be that you could actually determine individual customers, whether they benefitted or not. That type of analysis would be very costly to implement."[99] Midwest ISO TOs further assert that it would be difficult to prescribe by regulation the hours in which demand response provides net benefits because system conditions and load patterns change across seasons and over time.[100] NEPGA argues that compensating demand response resources at LMP whenever a reduction in consumption suppresses energy prices enough to provide net benefits to load is neither just and reasonable, nor in the public interest.[101] NEPGA states that the Commission recognized in *Amaranth Advisors*[102] that, if prices are suppressed below competitive, market levels, society as a whole is worse off. According to NEPGA, the goal is to get the *right* price—the economically efficient price produced by competitive markets.

42. NYISO posits that a rule mandating payment of LMP–G avoids the need to develop a net benefits test. NYISO further states, however, that if the Commission decides to move forward with LMP for demand response, it should craft a net benefits test that minimizes any opportunities for distorting market prices or exploiting market inefficiencies. Citing support for Dr. Hogan's arguments, NYISO states that "a net benefits test should ensure that the demand response program does not have negative net benefits compared to no program at all. The criterion to apply would focus on the bid-cost savings of generation and load, with the load bids adjusted for the effects of avoidance of the retail rate."[103]

(c) Standardization or Regional Variations in Compensation

43. With regard to potential regional variations for compensation mechanisms across RTO and ISO markets, many commenters, mostly those in support of the NOPR's proposed compensation level, endorse standardization.[104] Some parties, primarily industrial customers and some customer advocates, argue that, regardless of location, both demand response providers and generators provide a comparable service in terms of balancing supply and demand, as discussed above, and therefore should be comparably compensated at the LMP.[105] They argue that fair, non-discriminatory markets must adapt and eliminate barriers to entry to the use and incorporation of traditional and non-traditional resources—where non-traditional resources include actively-managed demand—in the dispatch and management of the electric system.[106] They further posit that the lack of a unified policy itself represents a regulatory barrier to demand response,[107] and that a consistent set of

[88] NECPUC May 13, 2010 Comments at 13; *see also* Sept. 13, 2010 Tr. 13:6–19 (Mr. Keene); Maryland Commission May 13, 2010 Comments at 4–5.

[89] *See, e.g.,* ACEEE Oct. 13, 2010 Comments 3–4. *See also* National Grid May 13, 2010 Comments at 4–5; NSTAR Electric Company (NSTAR) May 14, 2010 Comments at 3; Maryland Commission May 13, 2010 Comments, submitting Analysis of Load Payments and Expenditures under Different Demand Response Compensation Schemes at 10–11 (discussing PJM analysis showing that paying demand response providers LMP for all hours after compensating LSEs for lost revenues would not benefit customers in general but that positive economic benefits results when demand response providers receive LMP during at least the top 100 hours (the highest priced energy hours)).

[90] *See, e.g.,* CDWR May 13, 2010 Comments at 11; National Grid May 13, 2010 Comments at 8; ISO–NE May 13, 2010 Comments at 34; ACEEE Oct. 13, 2010 Comments 4. *But see* ISO–NE May 13, 2010 Comments at 32–33 (contending that no baseline estimation methodology that relies upon historical customer meter data can accurately and reliably estimate an individual customer's normal energy usage pattern if that customer responds frequently to price signals).

[91] NECAA May 13, 2010 Comments at 11; NYSCPB May 13, 2010 Comments at 5; National Grid May 13, 2010 Comments at 4–5.

[92] Viridity Oct. 13, 2010 Comments at 14.

[93] NAPP Oct. 13, 2010 Comments at 2.

[94] Viridity Oct. 13, 2010 Comments at 14; NAPP Oct. 13, 2010 Comments at 3; AMP Oct. 13, 2010 Comments at 4; CAISO Oct. 13, 2010 Comments at 5 and 16.

[95] EDF Oct. 13, 2010 Comments at 2; Viridity Oct. 13, 2010 Comments at 10; ELCON Oct. 13, 2010 Comments at 3.

[96] *See, e.g.,* Oct. 13, 2010 Comments of: Midwest TDUs at 4–5; NEPGA at 8, NJBPU at 2–3; NAPP at 2–3; P3; SPP at 3–4; SDG&E, SoCal Edison, and PG&E at 4–6; Viridity Energy at 2; ELCON at 2; AMP at 2; CDWR at 1, 4–5; CAISO at 4, 15; Detroit Edison at 2; Smart Grid Coalition at 2; Duke Energy at 2; EDF at 2; FTC at 1; EPSA at 4; Indicated New York TOs at 3; Midwest ISO at 9; Steel Manufacturers Ass'n at 3.

[97] P3 Oct. 13, 2010 Comments at 5.

[98] Sept. 13, 2010 Tr. 155:21–24 (Mr. Robinson); Sept. 13, 2010 Tr. 141–42 (Mr. Centolella); Dr. Hogan Sept. 13, 2010 Comments at 5; Sept. 13, 2010 Tr. 60 (Dr. Shanker); Sept. 13, 2010 Tr. 27 (Mr. Newton); SDG&E May 13, 2010 Comments at 4.

[99] Sept. 13, 2010 Tr. 19 (Mr. Ott).

[100] Midwest ISO TOs May 13, 2010 Comments at 16.

[101] NEPGA June 21, 2010 Comments at 1–2.

[102] 120 FERC ¶ 61,085 (2007).

[103] NYISO Oct. 13, 2010 Comments at 3–4.

[104] *See* May 13, 2010 Comments of: ArcelorMittal; Alcoa; ACENY; ACC; AFPA; CDWR; Mayor Bloomberg; Consert; CDRI; CPower; DR Supporters; Derstine's; Durgin; Electricity Committee; ELCON; Electrodynamics; ECS; EnerNOC; ICUB; IECA; IECPA; Irving Forest; Joint Consumers; Limington; Madison Paper; Massachusetts AG; NEMA; National Energy; National League of Cities; NJBPU; NAPP; Occidental; Okemo; Partners; Pennsylvania Department of Environment; Pennsylvania Commission; Rep. Chris Ross; Precision; PRLC; Raritan; SDEG, SoCal; PG&E; Schneider; Governor O'Malley; Steel Manufacturers Ass'n; Verso; Viridity; Virginia Committee; Wal-Mart; Waterville.

[105] *See, e.g.,* Steel Manufacturers Ass'n May 13, 2010 Comments at 12; NEMA May 13, 2010 Comments at 5.

[106] Steel Manufacturers Ass'n May 13, 2010 Comments at 12.

[107] PIO May 13, 2010 Comments at 9; DR Supporters Aug. 30, 2010 Comments at 6–7.

rules reduces the costs and complexities of demand response participation and facilitates training and transfer of personnel across regions.[108] To that end, many commenters argue that adopting a unified approach to demand response compensation at the LMP, as opposed to allowing regional variation including payment of something less than LMP, is necessary to overcome the barriers to entry of demand response providers.[109] Reciting the many benefits of demand reductions in energy use, these commenters support a compensation level that will provide a catalyst for private sector engagement in improved energy management practices. Viridity argues that the near absence of demand response participating in energy markets is powerful empirical proof that current, varying levels of compensation are inadequate—especially in markets that start with a market-based level of compensation and then reduce it by the generation portion of a customer's retail rate (LMP–G).[110]

44. Other commenters caution against standardizing the compensation level for demand response, pointing to regional differences in market structure, State regulatory environment, and resource mix.[111]

3. Commission Determination

45. The Commission acknowledges the diverging opinions of commenters regarding the appropriate level of compensation for demand response resources. As discussed above, commenters are split on this issue, with some in favor of paying the LMP for demand reductions in the day-ahead and real-time energy markets in all hours, others arguing that paying the LMP for demand reductions under any conditions will result in over-compensation or distortions in incentives to reduce consumption, and still others arguing that paying the LMP for demand reductions is only appropriate when it is reasonably certain to be cost-effective.

46. In the face of these diverging opinions, the Commission observes 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.' "[112] We also observe that, in making such judgments, the Commission is not limited to textbook economic analysis of the markets subject to our jurisdiction, but also may account for the practical realities of how those markets operate.[113]

47. As discussed further below, the Commission agrees with commenters who support payment of LMP under conditions when it is cost-effective to do so, as determined by the net benefits test described herein.[114] We have previously accepted a variety of ISO and RTO proposals for compensation for demand response resources participating in organized wholesale energy markets. We find, based on the record here that, when 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. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers.[115] As stated in the NOPR, we believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO.[116]

48. The Commission emphasizes that these findings reflect a recognition that it is appropriate to require compensation at the LMP for the service provided by demand response resources participating in the organized wholesale energy markets only when two conditions are met:

- The first condition is that the demand response resource has the capability to provide the service, *i.e.,* the demand response resource must be able to displace a generation resource in a manner that serves the RTO or ISO in balancing supply and demand.
- The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

49. With respect to the first, capability-related condition, we note that a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand.[117] Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand.

50. With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load associated with the decreased amount of load paying the bill, depending on the change in LMP relative to the size of the energy market. As stated above, this is the billing unit effect of dispatching demand response resources.[118] However, when reductions in LMP from implementing demand 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.[119] In comparison, when

[108] *See, e.g.,* Alcoa May 13, 2010 Comments at 13.

[109] NECPUC May 13, 2010 Comments at 4; NYISO May 13, 2010 Comments at 16.

[110] Viridity Energy May 13, 2010 Comments at 4.

[111] *See, e.g.,* May 13, 2010 Comments of: ConEd at 3–4; Consumers Energy at 2; California Commission at 9; CMEEC at 2–3, 14–15; Detroit Edison at 3–5; Dominion at 8; Duke Energy at 4; EPSA at 6; Hess at 4; Indicated New York TOs at 3; Maryland Commission at 5; Midwest TDUs at 2, 6; Midwest ISO TOs at 16; National Grid at 5–6; 11–12; New York Commission at 4, 11; NCPA at 3; NYISO at 2–3; ODEC at 27; PJM at 5–6; SPP at 1.

[112] *Elec. Consumers Res. Council* v. *FERC,* 407 F.3d 1232, 1236 (DC Cir. 2005) (quoting *Pub. Util. Comm'n of the State of Cal.* v. *FERC,* 254 F.3d 250, 254 (DC Cir. 2001)); *see also Town of Norwood* v. *FERC,* 962 F.2d 20, 22 (DC Cir. 1992).

[113] *See Elizabethtown Gas Co.* v. *FERC,* 10 F.3d 866, 872 (DC Cir. 1993) ("It is the FERC's established policy to consider equitable factors in designing rates, and to allow for phasing in of changes where appropriate. * * * It is hardly arbitrary or capricious so to temper the dictates of theory by reference to their consequences in practice."); *Vermont Dep't of Pub. Serv.* v. *FERC,* 817 F.2d 127, 135 (DC Cir. 1987) ("Indeed, 'the congressional grant of authority to the agency indicates that the agency's interpretation typically *will* be enhanced by technical knowledge.' " (quoting *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 811 F.2d 1563, 1570 (DC Cir. 1987))); *Columbia Gas Transmission Corp.* v. *FERC,* 750 F.2d 105, 112 (DC Cir. 1984) ("the Commission is vested with wide discretion to balance competing equities against the backdrop of the public interest").

[114] *See generally* May 13, 2010 Comments of NYSCPB; NECA; Capital Power; NECPUC; Maryland Commission; New York Commission; NSTAR; National Grid; NE Public Systems.

[115] The Commission's findings in this Final Rule do not preclude the Commission from determining that other approaches to compensation would be acceptable when these conditions are not met.

[116] NOPR at P 12.

[117] Andrew L. Ott Sept. 13, 2010 Statement at 1.

Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation. * * * These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations.

Id. at 1; *see also* CDRI May 13, 2010 Comments at 10; CDWR May 13, 2010 Comments at 5; NJPBU May 13, 2010 Comments at 2.

[118] As stated above, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load.

[119] As a simple example, assume a market of 100 MW, with a current LMP of \$50/MWh without

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. Implementation of the net benefits test described herein will allow each RTO or ISO to distinguish between these situations.

51. This billing unit effect and the net benefits test through which it is addressed herein, warrant more detailed discussion. In the organized wholesale energy markets, the economic dispatch organizes offers from lowest to highest bid in order to balance supply and demand, taking into account other parameters such as requirements for a generator to operate at a minimum level of output or minimum amount of time, reserve requirements and so forth. With dispatch of a demand response resource, the load also goes down, that is, the level of remaining load falls. However, the "supply" of resources deployed—which includes both generation and demand response—does not fall. The total costs to the system for these resources must then be allocated among the reduced quantity of remaining load.

52. In the absence of the net benefits test described herein, 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 next unit of generation is not sufficiently more expensive than 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 this 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.

53. For this reason, the billing unit effect associated with dispatch of a demand response resource in an energy market must be taken into account in the economic comparison of the energy bids of generation resources and demand response resources. Therefore, rather than requiring compensation at LMP in all hours, the Commission requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching those resources. When the above-noted conditions of capability and of cost-effectiveness are met, it follows that demand response resources that clear in the day-ahead and real-time energy markets should receive the LMP for services provided, as do generation resources. LMP represents the marginal value of an increase in supply or a reduction in consumption at each node within an ISO or RTO, *i.e.,* LMP reflects the marginal value of the last unit of resources necessary to balance supply and demand. Indeed, LMP has been the primary mechanism for compensating generation resources clearing in the organized wholesale energy markets since their formation.[120]

54. The Commission finds that demand response resources that clear in the day-ahead and real-time energy markets should receive the same market-clearing LMP as compensation in the organized wholesale energy markets when those resources meet the conditions established here as a cost-effective alternative to the next highest-bid generation resources for purposes of balancing the energy market. We discuss below the comments filed on these issues.

55. Some commenters dispute that the foregone consumption of energy by demand response resources performs the service of balancing supply and demand in the energy market as would energy supplied by generators in the day-ahead and real-time energy markets, arguing that it is inappropriate to pay electric consumers to not consume.[121] The Commission disagrees. Generation and load must be balanced by the RTOs and ISOs when clearing the day-ahead and real-time energy markets, and such balancing can be accomplished by changes in either supply or demand. The Commission finds that in the organized wholesale energy markets demand response can balance supply and demand as can generation.

56. Commenters that oppose this finding do not adequately recognize a distinctive and perhaps unique characteristic of the electric industry. The electric industry requires instantaneous balancing of supply and demand at all times to maintain reliability. It is in this context that the Commission finds that demand response can balance supply and demand as can generation when dispatched, in the organized wholesale energy markets.

57. Due to a variety of factors, demand responsiveness to price changes is relatively inelastic in the electric industry and does not play as significant a role in setting the wholesale energy market price as in other industries. The Commission has recognized that barriers remain to demand response participation in organized wholesale energy markets. For example, in Order No. 719, the Commission stated:

> [D]espite previous Commission and RTO and ISO efforts to facilitate demand response, regulatory and technological barriers to demand response participation persist, thereby limiting the benefits that would otherwise result. A market functions effectively only when both supply and demand can meaningfully participate, and barriers to demand response limit the meaningful participation of demand in electricity markets.[122]

Barriers to demand response participation at the wholesale level identified by commenters include the lack of a direct connection between wholesale and retail prices,[123] lack of dynamic retail prices (retail prices that vary with changes in marginal wholesale costs), the lack of real-time information sharing, and the lack of market incentives to invest in enabling technologies that would allow electric customers and aggregators of retail customers to see and respond to changes in marginal costs of providing electric service as those costs change. For example, Dr. Kahn states:

> 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

demand response, and an LMP of $40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be $4,000 with demand response compared to the previous $5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from $50/MWh to $42.11/MWh ($4,000/95). Therefore, the payment of LMP to demand resources is cost-effective.

[120] *See* DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 2 (footnote omitted)).

[121] *See, e.g.,* ISO–NE May 13, 2010 Comments at 3; APPA May 13, 2010 Comments at 12; Capital Power May 13, 2010 Comments at 2; EPSA May 13, 2010 Comments at 72.

[122] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 83 (citing Federal Energy Regulatory Commission Staff, A National Assessment of Demand Response Potential (June 2009), found at *http://www.ferc.gov/legal/staff-refports/06-09-demand-response.pdf;* Barriers to Demand Side Response in PJM (2009)). In compliance filings submitted by RTOs and ISOs and their market monitors pursuant to Order No. 719, as well as in responsive pleadings, parties have mentioned additional barriers, such as the inability of demand response resources to set LMP, minimum size requirements, and others.

[123] *See, e.g.,* Monitoring Analytics May 13, 2010 Comments at 4–6.

their immediate response to such increases in true marginal costs of supplying them.[124]

Furthermore, EnerNOC states:

On a more fundamental level, the inadequate compensation mechanisms in place today in wholesale energy markets fail to induce sufficient investment in demand response resource infrastructure and expertise that could lead to adequate levels of demand response procurement. Without sufficient investment in the development of demand response, demand response resources simply cannot be procured because they do not yet exist *as resources.* Such investment will not occur so long as compensation undervalues demand response resources.[125]

58. The Commission concludes that paying LMP can address the identified barriers to potential demand response providers.

59. Removing 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 all demand could respond to the marginal cost of energy. To that end, the Commission emphasizes that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers; rather, it facilitates greater competition, with the markets themselves determining the appropriate mix of resources, which may include both generation and demand response, needed by the RTO and ISO to balance supply and demand based on relative bids in the energy markets. In other words, while the level of compensation provided to each resource affects its willingness and ability to participate in the energy market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid.[126]

60. Another issue raised by a number of commenters, largely representing generators, is whether a lower payment based on LMP–G is the economically-efficient price that sends the proper price signal to a potential demand response provider. These commenters argue that, by not consuming energy, demand response providers already effectively receive "G," the retail rate that they do not need to pay. They therefore contend that demand response providers will be overcompensated unless "G" is deducted from payments made by the RTO or ISO for service in the wholesale energy market, resulting in a payment of LMP–G. These commenters suggest that payment of LMP–G will result in a price signal to demand response providers equivalent to the LMP (*i.e.,* (LMP − G) + G). Similarly, some commenters argue that paying demand response resources the LMP will lead to a wholesale electricity price that is not economically efficient.[127]

61. The Commission disagrees with commenters who contend that demand response resources should be paid LMP–G in all hours. First, as discussed above, demand response resources participating in the organized wholesale energy markets can be cost-effective, as determined by the net benefits test described herein, for balancing supply and demand and, in those circumstances, it follows that the demand response resource should also receive compensation at LMP. Second, such comments largely rely on arguments about economic efficiency, analogizing to incentives for individual generators to bid their marginal cost. These arguments fail to acknowledge the market imperfections caused by the existing barriers to demand response, also discussed above. 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." [128] Furthermore, Dr. Kahn argues that 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 cost*—both at competitively-determined levels." [129]

62. Several other considerations also support this Commission conclusion. In the absence of market power concerns, the Commission does not inquire into the costs or benefits of production for the individual resources participating as supply resources in the organized wholesale electricity markets and will not here, as requested by some commenters, single out demand response resources for adjustments to compensation. 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," [130] notwithstanding the particular costs of production of individual resources. Commenters have not justified why it would be appropriate for the Commission to continue to apply this approach to generation resources yet depart from this approach for demand response resources.

63. In addition, we agree with the New York Commission that given the differences in retail rate structures across RTO footprints and even within individual States, requiring ISOs and RTOs to incorporate such disparate retail rates into wholesale payments to wholesale demand response providers would, even though perhaps feasible, create practical difficulties for a number of parties, including State commissions and ISOs and RTOs. Moreover, incorporating such rates could result in customer uncertainty as to the prevailing wholesale rate.

64. Some arguments advocating paying LMP–G rather than LMP are based on an assumption that demand response resources need to purchase the energy in day-ahead markets or by other means and then "resell" the energy to the market in the form of demand response. However, as the Commission previously stated in *EnergyConnect,* the Commission does not view demand response as a resale of energy back into the energy market.[131] Instead, as the Commission also explained in *EnergyConnect* and in Order No. 719–A, the Commission asserts jurisdiction with respect to demand response in organized wholesale energy markets because of the effect of demand response and related RTO and ISO market rules on Commission-jurisdictional rates.[132]

65. With regard to the "buyers' cartel" argument, the Commission disagrees that market rules establishing circumstances in which particular resources can participate and receive the LMP represents cooperative price setting. RTOs and ISOs evaluate the bids

[124] DR Supporters Sept. 16, 2009 Comments filed in Docket No. EL–09–68–000 (Kahn Affidavit at 6). *See also id.* at 4 (Customers offering to reduce consumption should be induced "to behave as they would if market mechanisms alone were capable of rewarding them directly for efficient economizing.").

[125] EnerNOC May 13, 2010 Comments at 4; *see also* Alcoa May 13, 2010 Comments at 4; Viridity May 13, 2010 Comments at 5–6.

[126] Generation and demand response resources have the potential to earn other revenues through bilateral arrangements, capacity markets where they exist, and ancillary services.

[127] *See* NEPGA June 21, 2010 Comments at 1–2.

[128] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154.

[129] DR Supporters Aug. 30, 2010 Reply Comments (Kahn Affidavit at 9–10).

[130] *See New England Power Pool,* 101 FERC ¶ 61,344, at P 35 (2002).

[131] *See EnergyConnect,* 130 FERC ¶ 61,031 at P 32.

[132] *Id.; see also* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292, at P 47.

from generation and demand response resources to establish the order of dispatch which secures the most economical supplies needed, consistent with the reliability constraints imposed on the system. Imposing a cost-effectiveness condition does not convert this unit commitment process by the RTO or ISO into collusion among bidders, whether generation or demand response. Furthermore, the market rules administering such a program would be approved by this Commission and demand response resources would be subject to Commission-approved rules, just like any other participants in the organized wholesale energy markets. In addition, arguments that the subject of this proceeding is equivalent to the types of market manipulation investigated in *Amaranth* and *ETP* are groundless and without merit. In *Amaranth,* the trader was accused of engaging in a fraudulent scheme with scienter in connection with a jurisdictional transaction. Here, there is no such allegation, merely speculation that the Commission is somehow facilitating coordination of demand-side bidders in order to lower prices.

66. Some commenters argue that demand response providers and generators should both be compensated at the market clearing price only if both are subject to the same market participation rules, penalty structures, testing requirements, and market monitoring provisions. The ISOs and RTOs already consider how to ensure comparability between demand response and generation in terms of market rules.[133] The Commission agrees that as a general matter demand response providers and generators should be subject to comparable rules that reflect the characteristics of the resource, and expect ISOs and RTOs to continue their evaluation of their existing rules in light of this Final Rule and make appropriate filings with the Commission.

67. Some commenters argue that the Commission should not impose a single pricing rule due to differences in market structure, State regulatory environment, and resource mix among the ISOs and RTOs. While such differences may exist, the commenters have not shown why such differences warrant a different compensation level among the ISOs and RTOs. As discussed above, regardless of the resource mix or the State regulatory environment, demand response, which satisfies the net benefits test described herein and can balance the system, is a cost-effective alternative to generation in the organized wholesale energy markets, and payment of LMP represents the marginal value of a decrease in demand.

B. Implementation of a Net Benefits Test

1. Comments

68. In response to questions that the Commission posed in the Supplemental NOPR, some commenters advocate a net benefits trigger based on a particular price threshold.[134] The NYISO currently has a static bid threshold of $75/MWh in its day-ahead demand response program.[135]

69. However, other commenters assert that using a static threshold based on historical data misses the changes that occur within electricity markets across seasons and years, and that it is erroneous to assume that all demand response occurring above a certain threshold price (for instance, at the very highest loads or highest priced hours) will result in lower costs to wholesale customers and that demand response is not cost-effective at prices below the static threshold price.[136] They argue that a static threshold offer price cannot easily adjust with changing energy market prices which may result in inefficient dispatch of demand resources, excluding demand response participation in hours when demand response can provide beneficial savings and including demand response participation in hours when there are no beneficial savings.[137] The New York Commission supports a dynamic, rather than a static bid threshold, arguing that, while a static bid threshold helps prevent demand response providers from gaming the system by seeking compensation for reducing electricity consumption for reasons other than market prices, it can also limit participation in a demand response program because prices might not exceed the threshold on a consistent basis.[138]

70. In a similar vein, some commenters suggest utilizing a dynamic bid threshold for determining when LMP payment would apply.[139] For example, NECPUC favors use of a dynamic mechanism such as a price threshold based on a preset heat rate of marginal generation and fuel price, like that currently used in New England's Day-Ahead Load Response Program (DALRP),[140] for the ISO–NE control area.[141] National Grid suggests a trigger, determined by each ISO or RTO, using a particular price on the supply offer curve at which the additional cost of paying LMP to demand resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions.[142]

71. Still other commenters urge compensating demand response during an ISO- or RTO-defined period of critical high-cost hours in which it is cost-effective to pay LMP. These commenters argue that the effect of demand response on the market clearing price is greatest during a limited number of hours during the year.[143] Therefore, identifying the hours in which to pay LMP to demand response resources could be used as a cost-effective net benefits test with potential savings for ratepayers. According to PJM, further analysis is needed to ascertain the critical high-cost hours in which it will be cost-effective to pay full LMP for demand response.[144]

72. The Consumer Demand Response Initiative (CDRI) proposes a mechanism for determining what demand response resources are cost-effective in any

[133] *See PJM Interconnection, L.L.C.,* 129 FERC ¶ 61,081 (2009).

[134] For example, National Grid states that the threshold could be triggered by a particular price on the supply offer curve at which the additional cost of paying LMP to demand response resources is most likely to be outweighed by LMP reductions in the wholesale energy market as a result of the demand reductions produced by these resources. National Grid May 13, 2010 Comments at 6. Those in favor of a price threshold include National Grid (but allow the ISO or RTO to identify threshold based on analysis); NE Public Systems; NECPUC; ISO–NE (minimum offer price based on fixed heat rate, times a fuel price index); New York Commission (supports ISO–NE's heat rate indexed price threshold).

[135] NYISO implements a day-ahead demand response program by which resources bid into the market at a minimum of $75/MWh and can get paid the LMP. *See* section 4.2.2.9 ("Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions") of NYISO's Market Services Tariff.

[136] Sept. 13, 2010 Tr. 52–53 (Mr. Peterson); Massachusetts AG Oct. 13, 2010 Comments at 23.

[137] Massachusetts AG Oct. 13, 2010 Comments (attachment, Demand Response Potential in ISO New England's Day-Ahead Energy Market, Synapse Energy Economics, Inc. Oct. 11, 2010 at 9). *See generally,* NECPUC May 13, 2010 Comments at 18.

[138] *Id.*

[139] National Grid May 13, 2010 Comments at 6; New York Commission May 13, 2010 Comments at 10; Viridity May 13, 2010 Comments at 24. *See generally* NECPUC, New York Commission; ISO–NE; NSTAR; ACEEE; and NYSCPB Oct. 13, 2010 Comments.

[140] The DALRP establishes a minimum offer price by approximating the variable cost component, in the form of a fuel cost, of a hypothetical peaking unit sufficiently high enough in the supply stack to ensure net benefits. On a monthly basis, this minimum offer price is reset to reflect the product of an appropriate fuel price index and a proxy heat rate. *See* NECPUC Oct. 13, 2010 Comments at 15.

[141] NECPUC Oct. 13, 2010 Comments at 14–16; NECPUC May 13, 2010 Comments at 17.

[142] *Id.* at 5–6.

[143] Maryland Commission May 13, 2010 Comments at 4–5; *see generally* NSTAR, ACEEE and NYSCPB Oct. 13, 2010 Comments.

[144] Maryland Commission May 13, 2010 Comments at 4 n.9.

hour.[145] This dispatch algorithm tests whether the money necessary to compensate demand response is less than the cost savings due to the decreased market-clearing price resulting from implementing demand response. In a sense, it is a dynamic cost/benefit analysis built into the dispatch algorithm. This cost/benefit analysis accounts for the billing unit effect. The billing unit effect occurs when demand response resources are dispatched to balance the system; the associated reduction in load results in fewer MWh of realized load (demand) paying for the sum of generator and demand response resource MWh, so load pays an effective rate which is greater than the LMP set to procure resources. Some commenters assert that if the Commission finds that a net benefits test is needed, it should require organized wholesale energy market operators to implement a proposal similar to that submitted by CDRI.[146]

73. Under the proposal submitted by CDRI, the demand response bids are part of the supply stack to which a security-constrained economic dispatch process is applied. All demand response bids that result in a lower price to customers, including consideration of the reduced number of billing units, are selected while those bids that raise the price, as compared to selecting the next generation bid in the supply stack, are not. This dispatch algorithm, as proposed, would be used by the ISO or RTO to determine a revised LMP that would be charged to load. The revised LMP creates a surplus (or over-collection) of revenue for the ISO or RTO that is then distributed to the LSEs through a settlement algorithm with the goal of holding LSEs harmless.[147]

74. During the September 2010 Technical Conference, Dr. Ethier of ISO–NE stated that a dynamic net benefits test done on an hourly basis that examines the effect of the demand response resource on LMPs, similar to that proposed by CDRI, would become very complicated to implement and require essentially an iterative process.[148] Dr. Ethier states that the ISO would have to run the dispatch model to formulate a base LMP with no demand response and then re-run it with demand response in the market; however those two iterations alone do not "cover the whole waterfront" in terms of the possible iterations required. According to Dr. Ethier, the ISO could dispatch too much demand response the first time, or if the ISO first rejected dispatching demand response, it may need to go back and dispatch smaller amounts of demand response to determine what would happen to the LMPs. Dr. Ethier stated that it is unclear where the ISO would stop the iteration of testing the impact on LMPs of dispatching demand response.[149] Andy Ott of PJM also stated during the technical conference that implementing a net benefits test would entail an iterative process that would be costly and difficult, if the RTO could even do it.[150]

75. Other commenters do not support the use of a net benefits test, but state that if one is adopted it should be based on general principles that RTOs and ISOs must apply to their systems in determining when LMP payments will apply.[151] A few commenters articulated specific criteria to be used in a net benefits test.[152] AEP believes that the objective of an incentive payment for demand response resources on the basis of broad market benefits can be achieved through a review of the costs and benefits of individual providers. Constellation states that any net benefits test should be based on the difference between the value consumers receive from energy and the cost of energy production.[153]

76. ISO–NE argues that a net benefits test should be based on economic efficiency, the sum of producer and consumer surplus, which suggests that demand response incentives ought to be provided to encourage demand reductions when the cost of energy production exceeds the value of consumption, and to encourage usage when the cost of energy production is less than the value of consumption. ISO–NE further states that a net benefits test that focuses solely on consumer savings ignores the value lost by consumers when energy consumption levels are reduced in response to incentive payments. ISO–NE posits that any variant of a LMP payment should be limited to a very small number of high-priced hours to minimize the economic distortions and avoid significant administrative complexities.[154]

77. A few commenters state that policies affecting energy prices will also impact capacity prices because generation owners with fixed costs must raise capacity price offers to remain financially viable at lower energy prices.[155] ISO–NE and Pepco argue, therefore, that the Commission should adopt a net benefits test that considers the impact of demand response compensation on both energy and capacity markets.[156] According to ISO–NE, when considering capacity market impacts under full-LMP compensation, long-term increases in capacity prices in response to suppressed LMPs offset consumer savings and leaves consumers worse off over time.[157] Robert Weishaar of the DR Supporters argues that properly compensating demand response should flatten the load profile and decrease the forecast of load projections, which would reduce capacity clearing prices.[158] Donald Sipe of CDRI adds that to the extent that scarcity revenues are not sufficient, capacity markets are designed to ensure that a generator's capital costs are recovered; in a forward market that looks ahead as load adjusts, one can see whether a resource is performing or not. For purposes of long-run reliability, he argues, as long as compensation is in the amount that is necessary to induce new investment and reflects market value, the argument that demand response in the bid stack will push out generators is only true if generators are higher priced than the consumer resources that are brought by demand response.[159]

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[145] The approach submitted by CDRI was developed for implementation in the ISO–NE day-ahead energy market. The discussion here is generalized to be applicable to any energy market that uses security-constrained economic dispatch to select the least-cost resources and establish a market-clearing price.

[146] PIO July 27, 2010 Comments at 6; Massachusetts AG Oct. 13, 2010 Comments at 11; Viridity Oct. 13, 2010 Comments at 2. *See* CDRI May 13, 2010 Comments for a full description of the algorithms.

[147] CDRI May 13, 2010 Comments Attachment B at 18. CDRI states that the dispatch and settlement algorithms "could be employed to evaluate dispatch and assure customer benefits, without being employed to perform allocations and settlements." CDRI Oct. 13, 2010 Comments at 4.

[148] Sept. 13, 2010 Tr. 80–81 (Dr. Ethier).

[149] *Id.*

[150] Sept. 13, 2010 Tr. 82:16–21 (Mr. Ott).

[151] *See generally* AEP, Midwest ISO, Occidental, NYISO, Constellation Oct. 13, 2010 Comments.

[152] *See, e.g.,* Midwest ISO October 13, 2010 Comments at 9–14 and Table 1 (setting forth comprehensive list of benefits and costs of demand response by type of market participants); Occidental October 13, 2010 Comments at 4–5 (any net benefits test must take into consideration offsetting variables, such as higher LMPs in the subsequent periods where demand rebound increases market price, and capacity market price effects); AEP October 13, 2010 Comments at 3–4 (AEP does not recommend the use of a societal benefits component (*i.e.,* health, environment, or employment efforts)).

[153] Constellation October 13, 2010 Comments at 3–4.

[154] ISO–NE Oct. 13, 2010 Comments at 4–5 and 21.

[155] *See, e.g.,* Sept. 13, 2010 Tr. 94:13–22 (Dr. Shanker); Sept. 13, 2010 Tr. 98:4–24 (Mr. Peterson); Sept. 13, 2010 Tr. 99:2–7 (Mr. Sunderhauf); ISO–NE Oct. 13, 2010 Comments at 5.

[156] Sept. 13, 2010 Tr. 99:1–24 (Mr. Sunderhauf); ISO–NE Oct. 13, 2010 Comments at 5.

[157] ISO–NE Oct. 13, 2010 Comments at 6.

[158] Sept. 13, 2010 Tr. 103–104 (Mr. Weishaar).

[159] Sept. 13, 2010 Tr. 106:16–24 (Mr. Sipe).

2. Commission Determination

78. For the reasons discussed previously, the Commission is requiring each RTO and ISO to implement the net benefits test described herein to determine whether a demand response resource is cost-effective. More specifically, the Commission is adopting two distinct requirements with respect to the net benefits test. While we find that the integration of the billing unit effect into the RTO/ISO dispatch processes has the potential to more precisely identify when demand response resources are cost-effective, we also recognize and understand the position of several of the RTOs and ISOs that modification of their dispatch algorithms may be difficult in the near term. Given these technical difficulties, we will require to RTOs and ISO to perform (1) the net benefits test described below to determine on a monthly basis under which conditions it is cost-effective to pay full LMP to demand resources; [160] and (2) a study of the feasibility of developing a mechanism for determining the cost-effective dispatch of demand resources.

79. First we direct each RTO and ISO to undertake an analysis on a monthly basis, based on historical data and the RTO's or ISO's previous year's supply curve, to identify a price threshold to estimate where customer net benefits, as defined herein, would occur. The RTO or ISO should determine the threshold price corresponding to the point along the supply stack for each month beyond 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, and update the calculation monthly. The ISOs and RTOs are to determine monthly threshold prices based on historical data. The threshold prices would be updated monthly as new data becomes available and posted on the RTO Web site. For example, the RTO should conduct an analysis of supply curves for January through December 2010 to be used as a starting point to establish threshold prices for 2011. Those numbers would be updated monthly during 2011 for significant changes in resource availability and fuel prices, with the process repeated monthly to reflect that month's data from the previous year.[161] The supply curve analysis should be updated monthly, by the 15th day of the preceeding month in advance of the effective date, to allow demand response providers as well as other market participants to plan, while still reflecting current supply conditions.[162]

80. Based on historical evidence and analysis submitted in this proceeding, the threshold point along the supply stack for each month will fall in the area where the supply curve becomes inelastic, rather than the extreme steep portion at the peak or in the flat portion of the supply curve.[163] In other words, LMP will be paid to demand response resources during periods when the nature of the supply curve is such that small decreases in generation being called to serve load will result in price decreases sufficient to offset the billing unit effect. The Massachusetts AG noted that the actual supply stack has locally flat and steep sections at all bid prices. We recognize that the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective. We accept this result given the apparent computational difficulty of adopting a dynamic approach that incorporates the billing unit effect in the dispatch algorithms at this time.[164]

81. We direct each RTO and ISO to file its analysis as supporting documentation to the accompanying tariff revisions with the Commission on or before July 22, 2011, along with proposed tariff revisions necessary to comply with this Final Rule. The filing should include the data, analytical methods and the actual supply curves used to determine the monthly threshold prices for the last 12 months to show how the RTO or ISO would calculate the curves.[165] The Commission-approved net benefits test methodology must be posted on the RTO or ISO's Web site, with supporting documentation. The RTO or ISO must also post the price threshold levels that would have been in effect in the previous 12 months. In addition, when the net benefits test becomes effective, the supply curve analysis for the historic month that corresponds to the effective month should be updated for current fuel prices, unit availabilities, and any other significant changes to historic supply curve and posted on the RTO Web site (for example, the supply curve analysis for the March price threshold would be posted in mid-February). Finally, the supply curve analyses for all months should be updated and posted on the RTO Web site if a significant change to the composition or slope of the historic monthly curves occurs, such as extended outages or retirements not previously reflected.

82. Some commenters argue that that there would be no need for a net benefits test if demand response resources were paid LMP–G, while others argue that use of a net benefits test otherwise undermines our decision to compensate demand response resources at the LMP. As stated above, the Commission finds that when a demand response resource participating in an organized wholesale energy market is capable of balancing supply and demand in the energy market and is cost-effective, as determined by the net benefits test described herein, that demand response resource should receive the same compensation, the LMP, as a generation resource when dispatched. We see no reason to reduce that compensation simply to avoid the use of the net benefits test that will ensure benefits to load.

83. Nearly every participant in the net benefits panel at the September 13, 2010 Technical Conference agreed that it would be counterproductive to defer to the RTO or ISO stakeholder process to determine when demand response provides net benefits without explicit guidance from the Commission.[166] We

[160] There will be inherent differences in the supply curves determined by each RTO and ISO under the net benefits test required herein due to decisions the RTOs and ISOs must make based on supply data for their regions, the mathematical methods each RTO and ISO chooses to use for smoothing the supply curves, the certainty of changes in supply due to outages in each region, local generation heat rates, and the choice of relevant fuel price indices.

[161] The ISOs and RTOs are to select a representative supply curve for the study month, smooth the supply curve using numerical methods, and find the price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity (billing units). Beyond that point, a reduction in quantity everywhere along an upward sloping supply curve would be cost-effective.

[162] Thus, the test is to determine where: (Delta LMP × MWh consumed) > (LMP new × DR); where LMP new is the market clearing price after demand response (DR) is dispatched and Delta LMP is the price before DR is dispatched minus the market clearing price after DR is dispatched.

[163] Supply elasticity is defined as the percentage change in quantity supplied divided by the percentage change in price. When the elasticity is less than or equal to one, supply is considered inelastic. So, for example, in the inelastic portion of the supply curve, a reduction in quantity supplied by one percent will result in more than a one percent decrease in price. Using the terms related to demand response compensation, the billing unit effect (percentage change in quantity supplied) will be more than offset by lower LMP (percentage change in price), thus resulting in lower prices for wholesale load.

[164] *See supra* note 114.

[165] *See supra* P 6.

[166] "[G]etting this decision resolved is an impediment to all the other stuff we want to do with price response to demand, and DR generally in our market * * * so until we get through this, we're not going to make much progress * * * the

Continued

believe that this result, and the guidance provided in this Final Rule will provide for timely improvements to RTO and ISO market pricing for demand response resources participating in organized wholesale energy markets.

84. In addition to requiring each RTO and ISO to construct the net benefits test described herein, the Commission also imposes a second requirement for each RTO and ISO to undertake a study, examining the requirements for and impacts of implementing a dynamic approach to determine when paying demand response resources LMP results in net benefits to customers. We believe that integration of the billing unit effect into RTO and ISO dispatch algorithms holds promise for more accurately integrating demand resources on a dynamic basis into the dispatch of the RTOs and ISOs. In theory, this could help ensure that the cost-effective level of demand response resources is dispatched or scheduled into the organized wholesale energy markets. Given the potential of software enhancements to determine the amount of cost-effective demand response resources purchased in the day-ahead and real-time energy markets, we believe that it would be useful for the Commission to know more about the feasibility of and requirements for implementing improvements to the existing dispatch algorithms. Therefore, we will require each RTO and ISO to undertake a study, either individually or collectively, examining the requirements for, costs of, and impacts of implementing a dynamic net benefits approach to the dispatch of demand resources that takes into account the billing unit effect in the economic dispatch in both the day-ahead and real-time energy markets, and to file the results of their study with the Commission on or before September 21, 2012.

85. ISO–NE and Pepco suggest that the net benefits test also consider the impact of demand response compensation on both energy and capacity markets. However, this Final Rule is focused only on organized wholesale energy markets, not capacity markets.[167] Given the differences in capacity markets among the ISOs and RTOs, the record in this proceeding provides neither a reasonable basis for including capacity market effects in net benefits calculations in the energy markets, nor have ISO–NE and Pepco provided a methodology for taking such effects into account. Indeed, in some cases, the capacity markets already reflect energy and ancillary service revenue in determining capacity prices.

C. Measurement and Verification

1. NOPR Proposal

86. In the NOPR, the Commission explained that demand response curtailment is a reduction in actual load as compared to the demand response provider's expected level of electricity consumption.[168] The NOPR did not address measurement and verification of demand response.

87. Each RTO and ISO with a demand response program has procedures for the measurement and verification of demand response. These procedures include techniques to establish a customer baseline for each demand response participant. This customer baseline then becomes the basis for measuring the quantity of demand response delivered to the wholesale market. Customer baselines are often based on historic load information, such as an average of five of the last ten comparable days' hourly load profile. Techniques vary among RTOs and ISOs and most have several techniques that may be allowed, depending on the demand response provider's characteristics.[169]

2. Comments

88. Commenters assert that the integrity of a demand response program is heavily dependent on measurement and verification.[170] Some commenters raise the issue that paying LMP in all hours presents a significant challenge to the accurate measurement and verification of demand response.[171] ISO–NE argues that when a market participant schedules demand reductions for many consecutive days, baselines may become stale—no longer reflecting a customer's "normal" electricity usage.[172] ISO–NE goes on to argue that "it is necessary to limit the number of hours or days that a demand resource could clear in the energy market so that the customer's 'normal' load can be estimated" to avoid the potential for manipulation.[173] In the context of the Commission's proposal to pay demand response the LMP in all hours, ISO–NE goes on to advocate requiring demand response to establish baselines by purchasing energy in the day-ahead market as a way to overcome its concerns with statistical baseline methods.[174] ISO–NE IMM makes similar arguments and recommendations.[175] Westar also appears to support this approach.[176]

89. Similarly, CPower notes that with some baseline methods, paying LMP in all hours could reward demand responders for any shift in demand from the baseline, not just shifting load from high LMP hours to low LMP hours, or could simply shift load from day-to-day in different hours to affect the calculation of actual curtailment, which it labels "checkerboarding." However, CPower believes that the capability of consumption management to shed or shift load for many hours is well into the future, and perhaps not a current concern. CPower also believes that baseline standards along with market monitoring will develop to meet these concerns.[177]

90. ISO–NE IMM asserts that "[if] the Commission adopts any proposal that permits the use of an administrative baseline it should explicitly state that any demand reductions offered into Commission-jurisdictional markets that are not genuine, even if they are the result of 'normal' activity * * * may be violations of the Commission's anti-

implication of that is if you send something back that leaves a lot of room for debate, it's going to be a while on all those other things." Testimony of Robert Ethier, Vice President, Market Design, ISO–NE, Sept. 13, 2010 Tr. at 136.

[167] Additionally, the arguments presented for focusing on the effect of demand response compensation in wholesale energy markets on capacity markets were not convincing—that decreases in energy market revenues by generators will be recouped in the form of increased capacity prices. First, they fail to consider how the increased participation by demand resources could actually increase potential suppliers in the capacity markets by reducing barriers to demand resources, which would tend to drive capacity prices down. Second, they did not examine the way in which capacity markets already may take into account energy revenues.

[168] *Demand Response Compensation in Organized Wholesale Energy Markets,* FERC Stats. & Regs. ¶ 32,656, at P 1 (2010).

[169] *See, e.g.,* ISO/RTO Council, North American Wholesale Electricity Demand Response 2010 Comparison, under the tab for "Performance Evaluation Methods" (*http://www.isorto.org/atf/cf/%7B5b4e85c6-7eac-40a0-8dc3-003829518ebd%7D/IRC%20DR%20M&V%20STANDARDS%20IMPLEMENTATION%20COMPARISON%20(20100524).XLS*).

[170] Illinois CUB May 14, 2010 Comments at 16–17; Joint Consumers May 13, 2010 Comments at 12; P3 May 12, 2010 Comments at 38; Westar May 13, 2010 Comments at 3.

[171] *See, e.g.,* ISO–NE May 13, 2010 Comments at 32.

[172] *Id.*

[173] ISO–NE May 13, 2010 Comments at 34. ISO–NE identifies several practices that, in its view, might be deployed by a demand responder to receive payment when it has not, in fact, responded to price. ISO–NE states that observations of such behavior in the Fall of 2007 led it to limit the hours demand response offers could clear the market. Citing *ISO New England Inc.,* Docket No. ER08–538–000 (February 5, 2008 filing). ISO–NE May 13, 2010 Comments at 32–34.

[174] *Id.*

[175] ISO–NE IMM May 13, 2010 Comments at 9–13 and Attachment A.

[176] Westar May 13, 2010 Comments at 3.

[177] CPower May 13, 2010 Comments at 4–5.

manipulation rules and subject to penalties thereunder." [178]

91. Noting the ongoing efforts by the industry and the North American Energy Standards Board (NAESB) on measurement and verification, EnerNOC takes the view that resolution of customer baseline issues should not delay the issuance of this Final Rule.[179]

92. Finally, some commenters assert that measurement and verification methods should not be standardized, but left to the RTOs and ISOs to reflect the unique features of their individual energy, ancillary services, and capacity markets.[180]

3. Commission Determination

93. The Commission agrees with commenters who assert that measurement and verification are critical to the integrity and success of demand response programs. Without a determination of a demand response provider's expected use of power, the ISOs and RTOs cannot determine whether that provider has in fact reduced its energy usage when paid to do so. Towards that end, all the RTOs and ISOs already have measurement and verification protocols for their demand response programs.[181] In addition, we have adopted Phase I standards for measurement and verification published by the North American Energy Standards Board,[182] and have recognized the potential benefits of the continuing NAESB effort to craft Phase II standards with more substantive and consistent wholesale standards for measurement and verification.[183]

94. A number of commenters maintain that compensating demand response resources at the LMP during all hours could make determining baselines for demand response providers exceedingly difficult. However, the impact of our adopting the net benefits test described herein is that the LMP will not be paid to demand response resources in all hours. Accordingly, implementation of this Final Rule would not appear to prevent the determination of appropriate baselines. Nonetheless, we direct ISOs and RTOs to review their current 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. Specifically, we direct each RTO and ISO to include as part of the compliance filing required herein, 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 as necessary to ensure the performance of each demand response resource. If necessary, each RTO and ISO should propose any changes needed to ensure that measurement and verification of demand response will adequately capture the performance (or non-performance) of each participating demand response market participant to be consistent with the requirements of this Final Rule.

95. Finally, we agree with ISO–NE IMM that demand reductions that are not genuine may be violations of the Commission's anti-manipulation rules.[184] Allegations of such behavior will continue to be investigated, and when appropriate, sanctions will be brought to bear.

D. Cost Allocation

1. NOPR Proposal

96. In response to the NOPR and September 13, 2010 Technical Conference, many commenters argue that, in order to determine the justness and reasonableness of the proposed compensation level, the corresponding cost allocation must be considered.[185] More specifically, these commenters raise concerns regarding how the costs associated with payment of LMP for demand response will be allocated, or assigned, within an ISO or RTO. Several commenters assert that the issues of cost allocation and net benefits are inherently linked, so that the Commission must address both issues together.[186]

2. Comments

97. Comments reveal five specific methods for cost allocation: (1) Assignment of costs to the load serving entity (LSE) associated with the demand response provider, (2) assignment of costs broadly to all purchasing customers, (3) bifurcated assignment of costs with some directly assigned to a LSE and others assigned broadly, (4) directly assign the cost for demand response compensation to the retail customers that bid the demand response into the wholesale market, and (5) the settlement method proposed by CDRI, which incorporates the cost of demand response into the dispatch algorithm. Some commenters argue not for a specific method, but for each regional entity to select and employ a method of its own,[187] and a few other commenters assert that the Commission need not address cost allocation in this proceeding.[188]

98. Some commenters argue that costs should be assigned to the LSE associated with the demand response provider because it is this entity that receives the full benefit of demand response.[189] Others argue that costs should be assigned broadly to all purchasing customers because of the concept of cost causation.[190] Cost causation dictates that the costs of demand response should be allocated directly to those entities that benefit from the demand response service provided.[191] Another method presented involves a bifurcated assignment of costs, with some directly assigned to a

[178] ISO–NE IMM May 13, 2010 Comments at 14 (footnotes omitted) (ISO–NE MMU also notes that "[i]n assessing whether demand reductions are genuine, allowance should be made for non-performance analogous to a generator's forced outage.").

[179] EnerNOC, Inc. May 13, 2010 Comments at 4.

[180] ECS May 13, 2010 Comments at 3; Indicated New York TOs May 13, 2010 Comments at 2–3; Midwest ISO May 13, 2010 Comments at 17, 21; National Grid May 13, 2010 Comments at 11–12; NSTAR May 14, 2010 Comments at 9; PPL May 13, 2010 Comments at 4.

[181] *See, e.g., PJM Interconnection, L.L.C.,* 123 FERC ¶ 61,257 (2008).

[182] *Standards for Business Practices and Communication Protocols for Public Utilities,* Final Rule, 131 FERC ¶ 61,022 (2010).

[183] *Id.,* at P 32–34.

[184] 18 CFR 1.c (2010).

[185] ISO–NE May 13, 2010 Comments at at 39–40; *see also* May 13, 2010 Comments of: AEP at 6–10; CAISO at 6; ConEd at 2; Hess at 3; ICC at 12; PJM at 8; Potomac Economics at 3; Massachusetts AG at 11; Midwest ISO TOs at 5–6; Midwest TDUs at 13; EEI at 5; NECPUC at 12, 22; NECA at 11; RRI at 6; SDG&G at 3–4.

[186] As further addressed below, several commenters assert that the costs of demand response compensation should be borne by only those market participants determined to have benefitted from the subject load reduction, as determined by some type of net benefits test. *See, e.g.,* May 13, 2010 Comments of: ISO–NE at 5–6; NECPUC at 22; PJM at 12–14; P3 at 37–38.

[187] EPSA May 12, 2010 Comments at 67; Midwest TDUs May 13, 2010 Comments at 1; ODEC May 14, 2010 Comments at 5; Potomac Economics May 14, 2010 Comments at 9–10; RRI May 13, 2010 Comments at 4; SoCal Edison May 13, 2010 Comments at 4 (advocating that the local regulatory authority is the proper entity to regulate cost allocation); Viridity May 13, 2010 Comments at 24; EnerNOC Sept. 13, 2010 Comments at 1; Midwest TDUs Sept. 13, 2010 Comments at 2.

[188] Massachusetts AG May 13, 2010 Comments at 9–10.

[189] PJM May 13, 2010 Comments at 15; Midwest ISO May 13, 2010 Comments at 6; CAISO May 13, 2010 Comments at 6; Detroit Edison May 13, 2010 Comments at 3–4; EEI May 13, 2010 Comments at 5; NUSCO May 13, 2010 Comments at 2; National Grid Sept. 13, 2010 Comments at 2–3; Midwest ISO Oct. 13, 2010 Comments at 4.

[190] NECPUC May 13, 2010 Comments at 22; DC OPC May 13, 2010 Comments at 4; PCA Sept. 10, 2010 Comments at 4; Steel Manufactures Ass'n Sept. 13, 2010 Comments at 5; Ohio Commission Sept. 13, 2010 Comments at 4; Wal-Mart Sept. 14, 2010 Comments at 3.

[191] PJM May 13, 2010 Comments at 9; NECPUC May 13, 2010 Comments at 22; PCA Sept. 10, 2010 Comments at 4.

LSE and others assigned broadly.[192] The fourth method suggested is to directly assign the costs of demand response to the retail customer that bid the demand response into the wholesale market.[193] Lastly, the settlement algorithm proposed by CDRI adjusts upward the day-ahead price paid by the customers that participate in the day-ahead energy market to account for these costs.[194]

3. Commission Determination

99. When a demand response provider curtails, the RTO experiences a reduction in load with a corresponding reduction in billing units through which the RTO derives revenue. When the two conditions discussed above 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 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, a method is needed to ensure that RTOs and ISOs recover the costs of obtaining demand response.

100. 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. 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. Allocating 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 will reasonably allocate the costs of demand response to those who benefit from the lower prices produced by dispatching demand response.[195]

101. We reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response. Bifurcated assignment of costs to the LSE and to others appears to represent an arbitrary division of cost responsibility without regard to the degree to which each receives benefits.

102. We therefore find just and reasonable the requirement 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 reduces the market price for energy at the time when the demand response resource is committed or dispatched. Accordingly, each RTO and ISO is required to make a compliance filing on or before July 22, 2011 that either demonstrates that its current cost allocation methodology appropriately allocates costs to those that benefit from the demand reduction or proposes revised tariff provisions that conform to this requirement.

E. Commission Jurisdiction

1. Comments

103. Some commenters, including several State commissions and LSEs, express concern about whether and how standardizing demand response compensation in the wholesale market will affect treatment of demand response at the retail level. They assert that the issue of demand response compensation is fundamentally intertwined with retail rates, ratepayer issues, and State jurisdictional concerns.[196] Some commenters note general concerns about the need for Federal and State level coordination. They assert that many States have taken significant steps to install advanced meters and implement programs to encourage efficient use of energy and that the success of State-level efforts should be a factor in deciding whether and how to implement demand response programs in the wholesale market.[197] According to these commenters, a Commission-mandated compensation level could have the unintended consequence of retarding the expansion of price-responsive demand at the retail level.[198]

104. Other commenters flatly question the Commission's jurisdiction to set the compensation for demand response in wholesale energy markets. They argue that it is within the purview of retail regulatory authorities to take into account local policies and concerns, and the types of demand response being offered, when determining the appropriate compensation level.[199] Indeed, the California Commission seeks clarification that this Commission does not seek to regulate retail customer rates or seeks LSE oversight authority traditionally exercised by States. The California Commission asserts that this Commission's actions concerning CAISO's Proxy Demand Resource tariff filing [200] illustrates that demand response settlement mechanisms are within the authority of the California Commission.[201]

[192] PJM May 13, 2010 Comments at 12; ISO–NE May 13, 2010 Comments at 5.

[193] DC OPC May 13, 2010 Comments at 4. It concedes that this could be a complex undertaking and would result in billing a retail customer for energy that did not consume. *Id.*

[194] CDRI, Integration of Demand Response Into Day Ahead Markets (Attachment B), May 13, 2010 Comments at 16.

[195] This approach is consistent with long-standing judicially-endorsed cost allocation principles. *See, e.g., Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1368, 1370–71 (DC Cir. 2004); *see also Illinois Commerce Comm'n* v. *FERC,* 576 F.3d 470, 476 (7th Cir. 2009).

[196] *See, e.g.,* CAISO May 13, 2010 Comments at 12; PJM May 13, 2010 Comments at 8 (appropriate and efficient demand response compensation may require coordination between the Commission, retail regulatory authorities, competitive retail suppliers, and other RTOs).

[197] *See* ISO–NE IMM May 13, 2010 Comments at 6.

[198] Illinois Commission May 13, 2010 Comments at 8; PJM May 13, 2010 Comments at 23; EEI May 13, 2010 Comments at 4; Capital Power May 13, 2010 Comments at 5; ODEC May 13, 2010 Comments at 60; Steel Producers May 13, 2010 Comments at 2.

[199] *See* Illinois Commission May 13, 2010 Comments at 13; CAISO May 13, 2010 Comments at 12–13; PJM IMM May 13, 2010 Comments at 5 ("The assertion that demand side participants should be paid full LMP, regardless of their retail tariff rate, because the current approach of paying LMP minus G represents an intervention into retail rate design, cannot be correct. The entire demand side program exists only because of the disconnect between wholesale and retail rates. The assertion that the program design should not account for the details of retail rate design leads to the conclusion that there should be no demand side program at all."); NECPUC May 13, 2010 Comments at 25 ("As energy market customers benefit most from both a well-functioning wholesale market and robust participation in retail programs, a balance between these two segments is essential. Compensation that increases demand response resource participation in the wholesale market should not be so generous, from the perspective of the customer, that it makes participation in retail programs pale in comparison."); SDG&E, SoCal Edison, and PG&E May 13, 2010 Comments at 4 ("[M]andating that ISOs take on settlement responsibility or precluding any retail settlement between retail customers, LSEs or DRPs would intrude on retail jurisdictional authority and contravenes the premise of separation outlined in Order 719."); Consumers Energy May 13, 2010 Comments at 3; Detroit Edison May 13, 2010 Comments at 4.

[200] *See California Independent System Operator Corp.,* 132 FERC ¶ 61,045 (2010).

[201] California Commission May 13, 2010 Comments at 9–10. 1. *See* also SDG&E, SCE, PG&E May 13, 2010 Comments at 2 ("[T]he Commission should clarify that its order does not preclude LRAs from administering retail revenue settlements between retail customers, Load Serving Entities

105. Other commenters foresee retail regulatory authorities effectively taking an end-run around any Commission-mandated compensation level by adjusting retail rate design or prohibiting jurisdictional end-use customers from participating in wholesale market opportunities available to demand response resources.[202] The Illinois Commission argues:

> [W]hen load serving entities are vertically integrated with generation regulated under state authority * * * any non-zero payment to a demand response resource reduces the revenues to generators under the state regulatory authority. The result is a leakage of money to an entity outside of the state's regulatory authority. Therefore, retail rates to all customers may need to be increased in order to recover the costs to generators that would have otherwise been recovered through the purchase of electricity, but instead went to the payment of a demand response resource. Therefore, compensating demand response resources may increase the likelihood that state commissions will prohibit the participation of demand response resources in the jurisdictions.[203]

106. Similarly, PJM states that the prohibition devised by retail regulatory authorities with jurisdiction over smaller distributors that deliver 4 million MWh or fewer per annum may entail the revocation of previously provided permission to participate in some or all of the wholesale market opportunities for demand resources.[204]

107. Some commenters further posit that, even where retail regulatory authorities do not prohibit or limit demand response participation, they may make adjustments to the retail rate, which affect the ultimate compensation that the retail customer will be paid for its demand reductions.[205] For example, the OMS asserts,

> If the Commission were to adopt the proposed rule, state commissions and LSEs could correct this distorted price signal by revising retail tariffs for customers that do business with [aggregators of retail customers] in order to charge the retail rate to participating customers for energy which was not consumed or metered as a result of load reductions.[206]

108. Another set of commenters, especially generators, assert that due to the disconnect between wholesale and retail issues related to demand response, Commission-mandated payments for demand response will fail to address true barriers to demand response, which exist, they assert, at the retail level. These commenters argue that the Commission's actions in this proceeding ignore the fact that the primary barrier to demand response is the disconnect between retail and wholesale prices and, according to these commenters, the remedy resides at the retail—not wholesale—level where there is a lack of dynamic pricing.[207] For example, some commenters recognize that the lack of retail real-time pricing is a barrier to demand response participation but further assert that whatever changes the Commission makes to wholesale demand response (where there is real-time pricing) will not address that fundamental problem.[208]

109. On the other hand, some commenters, such as commercial customers, wholly reject challenges to the Commission's authority to set the compensation level for demand response occurring in organized wholesale energy markets.[209] They assert that the FPA gives the Commission broad authority to correct market flaws, including compensation for demand response.[210]

110. Some commenters further argue that any disconnect between wholesale and retail issues relevant to demand response should not negate the Commission's efforts in this proceeding. They argue that dynamic retail pricing, retail shopping opportunities and the potential for retail energy efficiency measures are no substitute for adequate wholesale demand response compensation and the deployment of demand response measures akin to a generator.[211]

111. Moreover, some commenters assert that, while the Commission has authority to establish the compensation level for demand response in the wholesale market, the Commission cannot require subtraction of retail rate components from the LMP rate, reasoning that retail rates reflect a myriad of local concerns beyond the Commission's jurisdiction. These commenters assert that LMP reflects the wholesale value of the demand response service provided and that proponents of the LMP–G formulation (subtracting a portion of the retail rate) seek to draw the Commission into a review of retail rate matters beyond its purview.[212] Additionally, these commenters point to the difficulty of isolating the generation component of the retail rate from other components, such as transmission, distribution, and overhead. They argue that different retail rate contracts reflect different costs of generation, depending on local circumstances existing at the time the contract was executed, and that retail rate structures reflect a wide range of competing considerations, such as cost causation, the impact of rate design on employment, and the state of the local economy, all of which are appropriately left to State commissions. These commenters posit that, instead of tailoring the wholesale rate, *i.e.,* LMP, to retail rate conditions, it is better to get the wholesale rate right in the first instance and then allow retail rate structures adjust as needed to wholesale market conditions.[213] According to Dr. Kahn, accounting for the retail rate in this Final Rule would "ignore the proper scope of the Commission's regulatory responsibilities, the fact that the great majority of retail rate designs are economically inefficient and that it is retail rates that should not be permitted

(LSEs) and Demand Response Providers (DRPs) associated with DR participation in wholesale markets.").

[202] *See* PJM May 13, 2010 Comments at 24; PJM May 13, 2010 Comments at 18 (It is reasonable to assume that each retail regulatory authority in PJM will re-examine the impact of load reduction based on wholesale compensation equal to the LMP, including cost allocation, on the LSEs subject to its jurisdiction, and potentially re-align retail market rules affecting economic load response participation.); Delaware Commission and NECPUC May 13, 2010 Comment at 25; OMS May 13, 2010 Comments at 7 (State commissions and LSEs have significant concerns that the potential costs for non-participating customers may exceed the benefits that ARCs can provide to their States and to participating customers, so State commissions will have a significant disincentive to support the participation of ARCs in RTO energy markets and in their States if LMP compensation is adopted).

[203] Illinois Commission May 13, 2010 Comments at 15.

[204] PJM May 13, 2010 Comments at 20–21.

[205] CAISO May 13, 2010 Comments at 4.

[206] OMS May 13, 2010 Comments at 3. *See also* EEI May 13, 2010 Comments at 4.

[207] Calpine May 13, 2010 Comments at 3.

[208] *See* EPSA May 13, 2010 Comments at 7 ("The NOPR incorrectly attempts to resolve retail market barriers to DR participation (*i.e.,* lack of dynamic pricing) through a wholesale pricing fix."); RRI Energy May 13, 2010 Comments at 5 ("The NOPR is essentially trying to use an inefficient wholesale solution to remedy a retail problem. The NOPR does not attempt to address (nor should it attempt to address) the various retail rate structures that demand response providers in various regions of the country face."); The Brattle Group May 13, 2010 Comments at 8 ("[T]he appropriate avoidable retail generation rate is best done through agreements between the LSE and the curtailment service provider under the oversight of the relevant retail regulating authority. This approach . . . avoids requiring the RTO to sort through potentially complicated retail rate structures."); Steel Manufacturers Ass'n May 13, 2010 Comments at 9 ("[T]here is no rational basis for the Commission, or RTOs, to adopting varying demand response participation or compensation rules based on the retail pricing method of otherwise qualified participating loads.").

[209] DR Supporters Aug. 30, 2010 Reply Comments at 4.

[210] *Id.*

[211] Wal-Mart May 13, 2010 Comments at 11.

[212] Viridity June 18, 2010 Comments at 13.

[213] Viridity June 18, 2010 Comments at 14.

to undermine efficient wholesale rates rather than the reverse." [214]

2. Commission Determination

112. We begin by rejecting challenges to the Commission's authority to set the compensation level for demand response in organized wholesale energy markets. Section 205 of the FPA tasks the Commission with ensuring that all rates and charges for or "in connection with" the transmission or sale for resale of electric energy in interstate commerce, and all rules and regulations "affecting or pertaining to" such rates or charges are just and reasonable.[215] The Commission has previously explained that it has jurisdiction over demand response in organized wholesale energy markets, because it directly affects wholesale rates.[216]

113. For this reason, the Commission has jurisdiction to regulate the market rules under which an ISO or RTO accepts a demand response bid into a wholesale market.[217] Furthermore, as discussed above, the Commission's actions in this proceeding are consistent with Congressional policy requiring Federal level facilitation of demand response, because this Final Rule is designed to remove barriers to demand response participation in the organized wholesale energy markets.

114. Nevertheless, we recognize that jurisdiction over demand response is a complex matter that lies at the confluence of State and Federal jurisdiction. By issuing this Final Rule, the Commission is not requiring actions that would violate State laws or regulations. The Commission also is not regulating retail rates or usurping or impeding State regulatory efforts concerning demand response.

115. We acknowledge that many barriers to demand response participation exist and that our ability to address such barriers is limited to the confines of our statutory authority. At the same time, the FPA requires the Commission to ensure that the rates charged for energy in wholesale energy markets are just, reasonable, and not unduly discriminatory or preferential. The Commission has the authority, indeed the responsibility, to assure that wholesale rates are just and reasonable. Therefore, we disagree with commenters who would have the Commission refrain from acting on demand response compensation in the organized wholesale energy markets because of the potential actions that State retail regulatory authorities may or may not take. As we note above, this Final Rule is not intended to usurp State authority or impede States from taking any actions within their authority. Rather, the Commission is taking action here to fulfill its statutory mandate to ensure just, reasonable, and not unduly discriminatory or preferential wholesale rates.

V. Information Collection Statement

116. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[218] Therefore, the Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[219]

117. OMB's regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

118. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in the final rule follow.

FERC–516 data collection	Number of respondents (a)	Number of responses per respondent per year (b)	Hours per response (c)	Total annual hours (d) [a*b*c]
Compliance filing, including tariff provisions and analysis (one-time filing, due 7/22/2011).	6 (RTOs and ISOs).	1 (one-time filing).	300	1,800 (one-time filing).
Study on dynamic net benefits approach (one-time filing, due 9/21/2012)	6 (RTOs and ISOs).	1 (one-time filing).	2,000	12,000 (one-time filing).
Monthly update to price threshold and Web posting (due monthly, starting after the compliance filing due 7/22/2011).	6 (RTOs and ISOs).	12	50	3,600.

In Year 1, the following requirements are imposed [220]: (1) Compliance filing due on or before July 22, 2011, and (2) monthly updates (for months 5–12, and starting after the compliance filing). The total corresponding burden hours are estimated to be: 1,800 hrs. + (8 filings * 6 respondents * 50 hrs./filing), for a total of 4,200 hours. The corresponding total cost is estimated to be: 4,200 hours * $220/hour, for a total of $924,000.

In Year 2, (a) the monthly update to the price threshold, and (b) the study on dynamic net benefits approach (due on or before September 21, 2012) are imposed. The corresponding total burden is estimated to be 3,600 + 12,000 hours, for a total of 15,600 hours. The corresponding total cost estimate is: 15,600 hours * $220/hour, for a total of $3,432,000.

In Year 3, the monthly update to the price threshold is imposed. The corresponding total burden and cost are

[214] DR Supporters Aug. 30, 2010 Comments (Kahn Affidavit at 4).

[215] 16 U.S.C. 824d (2006).

[216] Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 at P 47.

[217] Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 at P 52.

[218] 5 CFR 1320.11(b) (2010).

[219] 44 U.S.C. 3507(d) (2006).

[220] The one-time study is due on or before September 21, 2012. For the purpose of the burden and cost estimates, we are including all of the burden and cost related to the study in Year 2, although filers may perform part of the work in Year 1.

estimated to be 3,600 hours and $792,000 (3,600 hours * $220/hour).

Title: FERC–516, "Electric Rate Schedules and Tariff Filings".

Action: Proposed Collections.

OMB Control No: 1902–0096.

Respondents: Business or other for profit, and/or not for profit institutions.

Frequency of Responses: One-time filings for (a) the compliance filing, due on or before July 22, 2011, and (b) the study on dynamic net benefits approach, due on or before September 21, 2012. In addition, monthly updates to the price threshold and Web posting will be required starting after the compliance filing.

Necessity of the Information: The information from FERC–516 enables the Commission to exercise its statutory obligation under sections 205 and 206 of the FPA. FPA section 205 specifies that all rates and charges, and related contracts and service conditions for wholesale sales and transmission of energy in interstate commerce be filed with the Commission and must be "just and reasonable." In addition, FPA section 206 requires the Commission, upon complaint or its own motion, to modify existing rates or services that are found to be unjust, unreasonable, unduly discriminatory or preferential.

119. In Order No. 719, the Commission emphasized the importance of demand response as a vehicle for improving the competitiveness of organized wholesale electricity markets and ensuring supplies of energy at just, reasonable and not unduly discriminatory or preferential rates. This Final Rule addresses the need for organized wholesale energy markets to provide compensation to demand response resources on a comparable basis to supply-side resources when demand response resources are comparable to supply-side resources, so that both supply and demand can meaningfully participate. This final rule establishes a specific compensation approach for demand response resources participating in organized wholesale energy markets, administered by RTOs and ISOs. Each Commission-approved RTO and ISO that has a tariff provision providing for participation of demand response resources in its organized wholesale energy market must: (a) Pay demand response resources the market price (full LMP) for energy (when found to be cost-effective as determined by the net benefits test described herein), (b) submit a one-time compliance filing, (c) perform monthly updates to the Price Threshold, and (d) submit a one-time Study on Dynamic Net Benefits Approach.

120. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [*Attention:* Ellen Brown, Information Clearance Officer, Office of the Executive Director, *e-mail: DataClearance@ferc.gov, phone:* (202) 502–8663, fax: (202) 273–0873]. Comments on the requirements of the final rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [*Attention:* Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by e-mail to: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include Docket Number RM10–17 and OMB Control Number 1902–0096.

VI. Environmental Analysis

121. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[221] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[222]

VII. Regulatory Flexibility Act

122. The Regulatory Flexibility Act of 1980 (RFA) [223] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a rule and that minimize 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.[224] The SBA has established a size standard for electric 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 megawatt hours.[225] ISOs and RTOs, not small entities, are impacted directly by this rule.

123. California Independent System Operator Corp. (CAISO) is a non-profit organization with over 54,000 megawatts of capacity and over 25,000 circuit miles of power lines.

124. New York Independent System Operator, Inc. (NYISO) is a non-profit organization that oversees wholesale electricity markets, dispatches over 500 generators, and manages a nearly 11,000-mile network of high-voltage lines.

125. PJM Interconnection, L.L.C. (PJM) is comprised of more than 600 members including power generators, transmission owners, electricity distributors, power marketers, and large industrial customers, serving 13 States and the District of Columbia.

126. Southwest Power Pool, Inc. (SPP) is comprised of 61 members serving over 6.2 million households in nine States and has almost 50,000 miles of transmission lines.

127. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 145,000 megawatts of installed generation. Midwest ISO has over 57,000 miles of transmission lines and serves 13 States and one Canadian province.

128. ISO New England, Inc. (ISO–NE) is a regional transmission organization serving six States in New England. The system is comprised of more than 8,000 miles of high-voltage transmission lines and over 350 generators.

129. The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VIII. Document Availability

130. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal

[221] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[222] 18 CFR 380.4(a)(15) (2010).

[223] 5 U.S.C. 601–612 (2006).

[224] 13 CFR 121.101 (2010).

[225] 13 CFR 121.201, Sector 22, Utilities.

business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

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

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

IX. Effective Date and Congressional Notification

133. This Final Rule will become effective on April 25, 2011. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

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

Kimberly D. Bose,

Secretary.

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

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

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

■ 2. Amend § 35.28 by adding a new paragraph (g)(1)(v) to read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(1) * * *

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) Pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

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

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

Appendix 1—List of Commenters

Alcan Primary Products Corp. (Alcan)
Alcoa Inc. (Alcoa)
Alliance for Clean Energy New York, Inc. (ACENY)
Alliance to Save Energy (Alliance)
American Chemistry Council (ACC)
American Clean Skies Foundation
American Council for an Energy-Efficient Economy (ACEEE)
American Electric Power Service Corporation (AEP)
American Forest & Paper Association (AFPA)
American Municipal Power, Inc. (AMP)
American Public Power Association (APPA)
American Wind Energy Association (AWEA)
ArcelorMittal USA Inc. (ArcelorMittal)
Battelle Pacific Northwest Laboratories (Battelle)
Boston College Law School Administrative Law Class (BC Law)
California Department of Water Resources State Water Project (CDWR)
California Independent System Operator Corporation (CAISO)
California Public Utilities Commission (California Commission)
Calpine Corp. (Calpine)
Capital Power Corporation (Capital Power)
Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities)
Citizens for Pennsylvania's Future (PennFuture)
Coalition of Midwest Transmission Customers (CMTC)
Connecticut Municipal Electric Energy Cooperative (CMEEC)
Consert Inc. (Consert)
Conservation Law Foundation (CLF)
Consolidated Edison Solutions, Inc. (ConEd)
Constellation Energy Commodities Group, Inc. (Constellation)
Consumer Demand Response Initiative (CDRI)
Consumer Power Advocates (CPA)
Consumers Energy Company (Consumers Energy)
CPG Advisors, Inc. (CPG)
CPower, Inc. (CPower)
Crane & Co., Inc. (Crane)
Delaware Public Service Commission (Delaware Commission)
Demand Response and Smart Grid Coalition (Smart Grid Coalition)
Demand Response Supporters (DR Supporters)
Derstine's Inc. (Derstine's)
Detroit Edison Company (Detroit Edison)
Direct Energy Services, LLC (Direct Energy)
Dominion Resources Services, Inc. (Dominion)
Dr. Alfred E. Kahn (Dr. Kahn)
Dr. Charles J. Cicchetti (Dr. Cicchetti)
Dr. Roy J. Shanker (Dr. Shanker)
Dr. William W. Hogan (Dr. Hogan)
Duke Energy Corporation (Duke Energy)
Durgin and Crowell Lumber Co., Inc. (Durgin)
Edison Electric Institute (EEI)
Edison Mission Energy (Edison Mission)
Electric Power Supply Association (EPSA)
Electricity Committee
Electricity Consumers Resource Council (ELCON)
Electrodynamics, Inc. (Electrodynamics)
Energy Curtailment Specialists, Inc. (ECS)
EnergyConnect (EnergyConnect)
Energy Future Coalition (EFC)
EnerNOC, Inc. (EnerNOC)
Environmental Defense Fund (EDF)
Exelon Corporation (Exelon)
Federal Trade Commission (FTC)
FirstEnergy Service Company (FirstEnergy)
GDF SUEZ Energy North America, Inc. (GDF)
Hess Corporation (Hess)
Illinois Citizens Utility Board (Illinois CUB)
Illinois Commerce Commission (ICC)
Independent Power Producers of New York, Inc. (IPPNY)
Indicated New York Transmission Owners (Indicated New York TOs)
Industrial Energy Consumers of America (IECA)
Industrial Energy Consumers of Pennsylvania (IECPA)
Intergrys Energy Services, Inc. (Intergrys)
International Power America, Inc. (IPA)
Irving Forest Products, Inc. (Irving Forest)
ISO New England Inc. (ISO–NE)
ISO–NE Internal Market Monitor (ISO–NE IMM)
Jiminy Peak Mountain Resort, LLC
Joint Consumer Advocates (Joint Consumers)
Limington Lumber (Limington)
Madison Paper Industries (Madison Paper)
Maryland Governor Martin O'Malley (Governor O'Malley)
Maryland Public Service Commission (Maryland Commission)
Massachusetts Attorney General (Massachusetts AG)
Midwest Independent Transmission System Operator, Inc. (Midwest ISO)
Midwest ISO Transmission Owners (Midwest ISO TOs)
Midwest TDUs
Mirant Corporation (Mirant)
Monitoring Analytics, LLC (PJM IMM)
National Electrical Manufactures Association (NEMA)
National Energy Marketers Association (NEM)
National Grid USA (National Grid)

National League of Cities (NLC)
Natural Gas Supply Association (NGSA)
New England Conference of Public Utilities Commissioners (NECPUC)
New England Consumer Advocates (NECA)
New England Power Generators Association Inc. (NEPGA)
New England Power Pool Participants Committee (NEPOOL)
New England Public Systems (NE Public Systems)
New Jersey Board of Public Utilities (NJBPU)
New York Independent System Operator, Inc. (NYISO)
New York Mayor Michael R. Bloomberg (Mayor Bloomberg)
New York State Consumer Protection Board (NYSCPB)
New York State Public Service Commission (New York Commission)
North America Power Partners LLC (NAPP)
Northeast Utilities Services Company (NUSCO)
Northern California Power Agency (NCPA)
NSTAR Electric Company (NSTAR)
Occidental Chemical Corp. (Occidental)
Office of the People's Counsel for the District of Columbia (DC OPC)
Okemo Mountain Resort (Okemo)
Old Dominion Electric Cooperative (ODEC)
Organization of Midwest ISO States (OMS)
Partners HealthCare (Partners)
Pennsylvania Department of Environmental Protection (PA Department of Environment)
Pennsylvania Office of Consumer Advocate (PCA)
Pennsylvania Public Utility Commission (Pennsylvania Commission)
Pennsylvania State Representative Chris Ross (Rep. Ross)
Pepco Holdings, Inc. (PHI)
PJM Interconnection, L.L.C. (PJM)
PJM Power Providers Group (P3)
Potomac Economics, Ltd. (Potomac Economics)
PPL Parties (PPL)
Praxair, Inc. (Praxair)
Precision Lumber, Inc. (Precision)
Price Responsive Load Coalition (PRLC)
PSEG Companies (PSEG)
Public Interest Organizations (PIO)
Public Utilities Commission of Ohio (Ohio Commission)
Raritan Valley Community College (Raritan)
Robert J. Borlick (Mr. Borlick)
RRI Energy, Inc. (RRI)
San Diego Gas & Electric Company (SDG&E)
Schneider Electric USA, Inc. (Schneider)
Southern California Edison Company (SoCal Edison)
Southwest Power Pool, Inc. (SPP)
Steel Manufacturers Association (Steel Manufacturers Ass'n)
Steel Producers (SP)
Tendrill Networks, Inc. (Tendrill)
The Brattle Group
The E Cubed Company, L.L.C. (E3)
University of California, San Diego (UCSD)
Utility Economic Engineers (UEE)
Verso Paper Corp. (Verso)
Virginia Committee for Fair Utility Rates (Virginia Committee)
Viridity Energy, Inc. (Viridity)
Wal-Mart Stores, Inc. (Wal-Mart)
Waterville Valley Ski Resort Inc. (Waterville)
Westar Energy, Inc. (Westar)
Wisconsin Industrial Energy Group (WIEG)

Appendix 2—Dissenting Statement

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets

Docket No. RM10–17–000
(Issued March 15, 2011)

MOELLER, Commissioner, *dissenting:*

While the merits of various methods for compensating demand response were discussed at length in the course of this rulemaking, nowhere did I review any comment or hear any testimony that questioned the benefit of having demand response resources participate in the organized wholesale energy markets. On this point, there is no debate. The fact is that demand response plays a very important role in these markets by providing significant economic, reliability, and other market-related benefits.

However, in a misguided attempt to encourage greater demand response participation in the organized energy markets, today's Rule imposes a standardized and preferential compensation scheme that conflicts both with the Commission's efforts to promote competitive markets and with its statutory mandate to ensure supplies of electric energy at just, reasonable, and not unduly discriminatory or preferential rates.[1] For these reasons, I cannot support this Rule.

Standardizing Demand Response Compensation

As an initial matter, RTOs and ISOs currently offer different types of demand response products that vary from region to region and in terms of capability and services offered in the day-ahead and real-time energy markets. Moreover, the RTOs and ISOs to date have been working with their market participants in a stakeholder process to design demand response compensation rules that are tailored to suit the needs of their individual energy markets. However, this will all change once the Rule takes effect and this existing framework is replaced with the requirement that every organized wholesale energy market pay demand resources the market price for energy (LMP) when its demand reductions are, in theory, found to be cost-effective.

As I recognized in my initial statement in this proceeding, organized markets such as the PJM Interconnection have already demonstrated the ability to develop demand response compensation rules. Accordingly, I would have preferred to allow these markets to continue to develop their own rules. Different demand response products will have different values that reflect their varying capabilities and to require a standard payment fails to reflect these meaningful differences.[2]

However, without ever determining that the existing region-by-region approach to compensation is unjust and unreasonable, the Rule implies that the current approach is no longer adequate to ensure that rates remain just and reasonable. In turn, the Rule finds that "greater uniformity in compensating demand response resources" is required and as justification for its action, references the existence of various barriers that limit the participation of demand response in the energy markets.[3] The majority ultimately concludes that these barriers can be removed by better equipping demand response providers with the financial resources to invest in enabling technologies.[4] This is to say that the majority believes that paying demand resources more money will help overcome these barriers and encourage more participation. The Rule, however, never clearly explains how the existence of barriers, in turn, justifies a payment of full LMP to demand resources.

The Rule (like the NOPR) does not sufficiently discuss the need for standardizing compensation across the organized markets or elaborate on how standardization will remove genuine barriers that prevent meaningful participation by demand resources in the energy markets.[5] While the Energy Policy Act of 2005 states that the policy of the U.S. Government is to remove unnecessary barriers to demand response, the statute never authorized the Commission to stimulate increased demand response participation by requiring its compensation to include incentives or preferential treatment.[6] Although, the majority is quick to claim "that removing barriers to demand response participation is not the same as giving preferential treatment to demand response providers * * *", this is exactly what is occurring in this Rule.[7] As discussed below, the majority's determination is troubling as the Rule both affords preferential treatment to demand response resources and unduly discriminates against them in other respects.

*Demand Response Resources are Comparable * * * Sometimes*

At the outset, the concept of "comparability" is at the core of this rulemaking, i.e., whether demand response resources are capable of providing a service comparable to generation resources and if so, whether these resources should receive comparable compensation for a comparable

[1] 16 U.S.C. § 824d (2006).

[2] California Commission May 13, 2010 Comments at 6, "[P]romulgating a uniform national rule at this time may inadvertently impede the implementation of optimal demand response compensation for an individual ISO or RTO which address the needs of that particular region." The California Commission "is concerned that mandatory 'one size fits all' pricing may stifle national and regional efforts to collect valuable data and experience regarding the effects of different demand response program designs on consumer participation and conflict with Congressional objectives."

[3] Rule at P 17, 57–59.

[4] Rule at P 57–59.

[5] Significant barriers do exist which prevent demand response from reaching its full potential. Specifically, 24 barriers were identified in our *National Assessment of Demand Response Potential,* FERC Staff Report, (June 2009) at 65–67.

[6] *See* Energy Policy Act of 2005, Pub. L. No. 109–58, § 1252(f), 119 Stat. 594, 965 (2005).

[7] Rule at P 59.

service. On this point, I believe they should.[8] This is not to say that a megawatt produced is the same as a megawatt not consumed; they are not perfect equivalents. The characteristics of a megawatt and a "negawatt" are different, both in terms of physics and in economic impact.

Assuming, however, that a demand resource can provide a balancing service that is identical to that of a generation resource, it would make sense that a demand resource providing a comparable service would receive comparable compensation. But this may not occur under the Rule. The majority explains that if a demand resource is capable of providing a service comparable to a generation resource, it will only be eligible to receive comparable compensation, by definition, if it can also be determined that the resource will result in a price-lowering effect to the market by passing a net benefits test.[9]

In no other circumstance is a resource required to show that its participation will depress the market price in order to receive comparable compensation for a comparable service.[10] Such a definition unduly discriminates against demand resources and as such, this requirement is unjust, unreasonable, and unduly discriminatory.

Overcompensating Demand Resources and the Net Benefits Test

At first glance, the Rule's requirement that RTOs and ISOs pay demand response resources the LMP only when it is deemed cost-effective appears to make sense. There is near-universal agreement that the LMP reflects the value of the marginal unit, and as such, it sends the proper price signal to keep supply and demand in relative balance. Accordingly, the Rule explains that if the demand resource is capable of providing a comparable service and is also cost-effective (*i.e.*, using a net benefits test to ensure that the overall benefit of the reduced LMP that results from dispatching demand recourses exceeds the cost of dispatching those resources), then this resource should be paid the same as a generation resource. However, the decision to pay demand resources the full LMP under such circumstances actually results in overcompensation that is economically inefficient, preferential to demand resources, and unduly discriminatory towards other market resources.

An example may help to illustrate a major flaw with this Rule. Assume that both a generation resource and a demand resource bid into the energy market and both bids are accepted and paid the LMP ($100). Then consider the fact that the demand resource will save an amount that it would have otherwise paid by not purchasing generation at the retail rate ("G"), which is $25. While the Rule requires that RTOs and ISOs pay the demand resource the LMP (which is the identical amount the generation resource receives), the Rule effectively ignores the fact that the demand resource will actually receive a total compensation of LMP+G ($125) as a result of its decision not to consume.[11] Meanwhile, the generation resource will only receive the LMP ($100) payment as a result of its decision to produce. While the Rule's intent is to ensure that a demand resource receives "the same compensation, the LMP, as a generation resource", this is not the actual result.[12] In this example, what will happen is that the Rule will require that the demand response resource be overcompensated by $25.[13]

The Rule effectively finds 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. Professor William W. Hogan refers to this outcome as a "double-payment" because demand resources would "receive" both the cost savings from not consuming electricity at a particular price, plus an LMP payment for not consuming that same increment of electricity.[14] Not only is this result not comparable (by valuing a negawatt more than a megawatt) and economically inefficient (by distorting the price signal), but this preferential compensation will harm the efficiency of the competitive wholesale energy markets.

The use of a net benefits test further reduces competitive efficiency and only complicates the issue. As the Rule explains, the net benefits test involves the determination of a threshold price point that is plotted along a historical supply curve in an attempt to accurately calculate whether the cost of procuring additional demand response is outweighed by the value it brings to the market in the form of a lower LMP.[15] However, this test, which attempts to justify the LMP payment by promising a "win-win" outcome, is nothing more than a fig leaf that provides little protection against the long-term potential for unintended market damage. As recognized by ISO–NE, generation is not dispatched and paid for only when such generation reduces LMP, instead generation is dispatched and paid for only when it is cost-effective.[16] Likewise, logic would require that demand resources be treated similar to generation resources and be similarly cost-effective.

During a technical conference convened to discuss the specific question on the necessity of a net benefits test, the Commission heard testimony from a panel of experts. A clear majority of the witnesses (representing a spectrum of interests that included demand response advocates, economists, generators, and the RTOs and ISOs) argued against the use of a complicated and admittedly imprecise[17] net benefits test.[18] Chief among their concerns was that a net benefits test is unnecessary since the market clearing function in a wholesale market, by definition, serves to guarantee that the resource that clears the market is the lowest-cost resource.[19] Other experts commented that the net benefits test would be complicated, costly to implement, and of little value.[20] Notably, Dr. Alfred E. Kahn, the majority's oft-quoted expert in defense of the full LMP payment, did not opine on the merit of subjecting the LMP payment to a net benefits test.

Further, as explained by Dr. Roy J. Shanker, if the Commission adopted the payment of LMP minus the retail rate ("G"), then there is no need for a net benefits test since the customer is paid the difference between the LMP and what they would have paid under their retail rate, which is their net benefit.[21] He testified that the "Net Benefits

[8] As explained below, I believe that comparable compensation is represented by the value realized by the demand resource for providing a comparable service, regardless of whether the source of that value is a payment from the market or a savings by the resource.

[9] Rule at P 47–50.

[10] Testimony of Audrey Zibelman, President and CEO of Viridity Energy, Inc., Sept. 13, 2010 Tr. at 119, "[T]he fact that we're debating this [net benefits test] is somewhat absurd. We have not required any other resource to demonstrate a benefit in order to enter this market."

[11] The proper economic measure of value realized by the demand resource is one where the RTO or ISO makes a reduction from the LMP to account for the retail rate, but then recognizes that the savings associated with the avoided retail generation cost should be added back into the equation, *i.e.*, (LMP–G)+G.

[12] Rule at P 82. If it were the result, the generation resource would be paid the LMP, $100, and the demand resource would be paid $75 and realize an additional $25 in retail rate savings. Accordingly, both resources realize equivalent compensation valued at $100.

[13] Ohio Commission May 13, 2010 Comments at 6, "[T]he Commission's proposal that RTOs pay demand response resources the full LMP takes the incentives for wholesale demand response resources a step too far. It would provide an incentive to the supplier of a demand response resource that exceeds the payments available to an equivalent supply resource. The Commission should instead focus on removing the existing barriers in the wholesale markets * * *."

[14] *See* Attachment to Answer of EPSA, Providing Incentives for Efficient Demand Response, Dr. William W. Hogan, October 29, 2009 (Docket No. EL09–68).

[15] Testimony of Robert Weishaar, Jr., Attorney for Demand Response Supporters, Sept. 13, 2010 Tr. at 46–47, "Administratively constructing an LMP-based break point for compensating Demand Response participation would ignore many other qualitative and quantitative benefits of Demand Response. Focusing only on the LMP impacts of Demand Response is problematic."

[16] ISO–NE May 13, 2010 Comments at 3–4.

[17] Rule at P 80. Recognizing that "the threshold price approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective."

[18] Testimony of Donald Sipe, Attorney for Consumer Demand Response Initiative, Sept. 13, 2010 Tr. at 43, "[T]here is probably not a need for a Net Benefits Test. But if one is adopted, it should not be an artificial threshold that can be wrong both ways. It should not be a mechanism that treats DR differently than generation."

[19] Viridity Energy, Inc., Oct. 13, 2010 Comments at 10. *See also* ELCON Oct. 13, 2010 Comments at 3; and Environmental Defense Fund Comments at 2.

[20] Testimony of Andy Ott, Sr. Vice President, PJM Interconnection, Sept. 13, 2010 Tr. at 19, "[Y]ou have to use caution to actually take a benefits test and apply that to compensation, because you may have unintended consequences."

[21] Testimony of Roy J. Shanker, Ph.D, PJM Power Providers Group, Sept. 13, 2010 Tr. at 60, "If the Commission adopts the appropriate non-discriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customer that face a fixed retail rate, then there is no need for a Net Benefits test."

criteria is troubling in and of itself, as it explicitly incorporates consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purpose." [22]

I similarly agree that this test is unnecessary and will only distort price signals by attracting more demand response than is economically efficient.[23] The use of a net benefits test also is troubling in that the Commission's decision can be viewed as somehow equating the concept of a just and reasonable rate with a lower price.[24] However, I recognize that to defend its compensation scheme, the majority needed some proposal that could arguably demonstrate that the cost of paying full LMP to demand resources would be outweighed by the "benefit" of a lower market price.[25] The net benefits test serves this unenviable role.

Relationship to State Retail Regulation

The Rule recognizes that the demand resource will retain the retail rate ("G") as part of the provider's total compensation, but declines to account for this savings citing "practical difficulties" for State commissions, RTOs and ISOs.[26] While the authority over retail rates is properly within the jurisdiction of the State commissions, under the LMP–G equation, the RTO/ISO merely subtracts the retail rate; it does not interfere with the retail rate in any way.[27] Although the Rule refers to the New York Commission's position that subtracting the retail rate would be an "administrative burden" or create "undue confusion" [28], other State commissions disagree and contend that the retail rate can be deducted without any concern about impacting the States' retail jurisdiction.[29]

Moreover, the Rule does not conclude that LMP–G would interfere with the retail jurisdiction of the States, but goes as far as to acknowledge the subtraction of G is "perhaps feasible." [30] The fact is that this calculation is quite feasible. Markets such as the PJM Interconnection currently subtract the retail rate portion from the LMP payment and there is no evidence that accounting for the retail rate by making the necessary reduction is either burdensome or interferes with the retail jurisdiction of State commissions.[31]

The Unintended Consequences of Paying Too Much

Today's determination, unencumbered by "textbook economic analysis of the markets subject to our jurisdiction" will undoubtedly have effects, both in the short-term and the long-term.[32] The intended consequence of providing additional compensation to demand resources is that demand response participation will increase in the energy markets. In turn, this additional demand response participation will have the effect of lowering the market price. However, it is at this point where the unintended effects will begin to appear.

With a reduced LMP, the price signal sent to customers will be that the cost of power is cheaper so they may decide to use more power even though the real cost of producing that power is now higher. Such a result turns the concept of scarcity pricing on its head and results in an economically inefficient outcome. Conversely, customers who are demand response providers now stand to receive more than the market price as an incentive to curtail their consumption and will begin to make inefficient decisions about using power.[33] Such inefficiencies will result in customers experiencing a short-term benefit by way of a lower LMP, but will also impose long-term costs on the energy markets.[34]

The long-term costs of allowing demand resources to receive preferential compensation will manifest themselves in various ways. As noted in my initial statement in this proceeding, the lack of dynamic prices at the retail level is the primary barrier to demand response participation. This Rule does not remedy this barrier and customers who pay fixed retail rates will not benefit from lower wholesale market prices. Meanwhile, at the wholesale level, the corrosive effect of overcompensating demand resources over time will come at the expense of other resources, particularly generation resources that will have less to invest in maintaining existing facilities and financing new facilities.[35]

The Commission's recent progress in promoting competitive wholesale energy markets has the potential to be undone as a result of this well-meaning, but misguided Rule. I believe in the proven value of market solutions and therefore agree with the majority's statement that "while the level of compensation provided to each resource affects its willingness and ability to participate in the market, ultimately the markets themselves will determine the level of generation and demand response resources needed for purposes of balancing the electricity grid." [36] That's precisely how markets should work. Price signals will attract resources and new investment when prices are high, and perhaps not so much

[22] *Id.,* Tr. at 61.

[23] EPSA May 13, 2010 Comments at 23. *See also* May 13, 2010 Comments of APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6–8.

[24] Courts have stated that to be "just and reasonable," rates must fall within a "zone of reasonableness" where they are neither "less than compensatory" to producers nor "excessive" to consumers. *Farmers Union Central Exchange v. FERC,* 734 F.2d 1486 (D.C. Cir. 1984), cert denied, 469 U.S. 1034 (1984). *See also* EPSA May 13, 2010 Comments at 19; and ISO–NE at 26–28.

[25] Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 141, "The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase cost to customers."

[26] Rule at P 63. The RTOs and ISOs uniformly state that compensation which ignores the retail rate will yield uneconomic outcomes and overcompensate the demand resource. Moreover, none of the RTOs or ISOs claimed it would be difficult to subtract the retail rate from the LMP payment. *See* May 13, 2010 Comments of CAISO at 5–6; ISO–NE at 17–26; Midwest ISO at 6–11; NYISO at 12–16; and PJM at 5–16.

[27] Testimony of Joel Newton, New England Power Generators Ass'n, Sept. 13, 2010 Tr. at 75; "The Commission is getting into a real close area with retail ratemaking as we go through this entire process. For the Commission then to say 'ignore the LSE payment' which is the realm of State commissions, it's almost as you're just hoping that the State commissions will go out and fix it. The State commissions can do that * * * [b]ut the proper thing to do now is to get the price right at the outset." *See also* Testimony of Ohio Commissioner Paul Centolella, Sept. 13, 2010 Tr. at 197; "[FERC is] putting the State in the position where if we were to try to get back to an efficient level of incentives, we would be having to in effect issue a charge for energy that was not consumed. We would be doing what would be perceived as a take-back by that customer. And that would put us in a very difficult position."

[28] Rule at P 28. Significantly, the New York Commission "acknowledges the overstated price signal inherent in an LMP-based formula for DR compensation * * *." "Although we understand that *an LMP demand response compensation formula may result in uneconomic demand response decisions in the markets (i.e., a price signal that exceeds marginal cost),* it also creates an incentive to participate in DR programs * * *." New York Commission May 13, 2010 Comments at 5–6 (emphasis added).

[29] Illinois Commission May 13, 2010 Comments at 13, "[I]f tariffs are well designed, controversy over the jurisdictional issue can be avoided. Requiring an ex ante approval of the retail rate to be subtracted from the LMP at the time demand response resources are utilized * * * accomplishes this design." *See also* Indiana Commission September 16, 2009 Comments at 3 (Docket No. EL09–68), "LMP–G is an accepted indicator of cost-effectiveness. Therefore, to provide incentive compensation at a level that is above the LMP raises the specter of unjust and unreasonable rates."

[30] Rule at P 63.

[31] *See* Sections 3.3A.4 and 3.3A.5 (Market Settlements in the Real-Time and Day-Ahead Energy Markets) of the Appendix to Attachment K of the PJM Tariff.

[32] Rule at P 46.

[33] Federal Trade Commission May 13, 2010 Comments at 6, "If customers have to pay the retail price for power they use but pay nothing for power they resell, then they will have incentives to resell power in situations in which it would be more beneficial for society for them to consume it." *See also* EPSA May 13, 2010 Comments at 23; APPA at 13; FTC at 9; Midwest TDUs at 14; Mirant at 2; New York Commission at 5; PJM at 6; PSEG at 5; and Potomac Economics at 6–8.

[34] PJM's Independent Market Monitor (a/k/a Monitoring Analytics, LLC) Oct. 16, 2009 Comments at 7–8 (Docket No. EL09–68), "Demand side resources are not generation. In a well functioning market, demand-side resources avoid paying the market price of energy when they choose not to consume. This allows customers to make efficient decisions about using power. It also follows that a customer receiving more than the market price as an incentive to curtail will make inefficient decisions about using power, and that this inefficiency imposes a cost rather than providing a benefit to society."

[35] NYISO May 13, 2010 Comments at 15, "[P]aying demand response an LMP-based payment because it is thought that demand response participation will reduce LMPs for all customers is not a sufficient rationale for justifying an 'additional payment' for a favored technology. Demand response is not the only resource able to provide such benefits. However, [other] technologies may be kept out of the market by demand response that would be uneconomic at LMP–G but participates when subsidized at LMP."

[36] Rule at P 59.

when prices are low.[37] If the playing field is level, resources can compete to the best of their abilities and efficient, cost-effective market outcomes will result.

[37] PJM Interconnection's experience with paying LMP–G for demand response in its energy market provides an example of how market fundamentals properly influence demand resource participation. PJM's Independent Market Monitor recently reported that "[p]articipation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels, and improved measurement and verification, but *have showed strong growth through the summer period as price levels and load levels have increased. Citing* Monitoring Analytics, LLC, *2010 State of the Market Report for PJM* at 30 (March 10, 2011) (emphasis added).

As noted earlier, I would have preferred that we allow the regional markets to continue to develop their own compensation proposals. However, I also recognize that returning to a pre-NOPR era would be difficult now that the Commission has signaled a new policy of standardized compensation. Accordingly, if I were to now support any standardization of demand response compensation, it would be the LMP–G approach, which in my opinion, is the only economically efficient outcome for the markets.

Ultimately, the Rule, by requiring demand resources to artificially suppress the market price in order to receive incomparable compensation, will negatively impact the long-term competitiveness of the organized wholesale energy markets.[38] As such, lacking sufficient rationale, I cannot support this Rule 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

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[38] Federal Power Act § 205(a), 16 U.S.C. § 824d (2006), "[A]ll rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful."