complaints of retaliation. Upon receiving a complaint, the Ombudsman shall investigate the basis of the alleged retaliation. Upon completion of the investigation, the Ombudsman shall report the findings to the Director with recommendations, including a recommendation to take disciplinary action against any FHFA employee found to have retaliated.

§ 1213.7 Confidentiality.

The Ombudsman shall ensure that safeguards exist to preserve confidentiality. If a party requests that information and materials remain confidential, the Ombudsman shall not disclose the information and materials, without approval of the party, except to appropriate reviewing or investigating officials, or as required by law. However, the resolution of certain complaints (such as complaints of retaliation against a regulated entity or the Office of Finance) may not be possible if the identity of the party remains confidential. In such cases, the Ombudsman shall discuss with the party the circumstances limiting confidentiality.

Dated: August 1, 2010.

Edward J. DeMarco,

Acting Director, Federal Housing Finance Agency.

[FR Doc. 2010–19424 Filed 8–5–10; 8:45 am]

BILLING CODE 8070–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–17–000]

Demand Response Compensation in Organized Wholesale Energy Markets

AGENCY: Federal Energy Regulatory Commission.

ACTION: Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference.

SUMMARY: The Federal Energy Regulatory Commission is issuing a Supplemental Notice of Proposed Rulemaking (NOPR) and Notice of Technical Conference to provide additional opportunity for comment on issues related to the March 18, 2010 NOPR, 75 FR 15362 (March 29, 2010), regarding the appropriate compensation to be paid to demand response resources in organized wholesale electric markets administered by Independent System Operators or Regional Transmission Organizations. The Commission proposed an approach for compensating demand response resources in order to improve the competitiveness of organized wholesale energy markets and thus ensure just and reasonable wholesale rates. The Supplemental NOPR seeks comment on whether the Commission should adopt requirements related to two issues addressed in comments: If the Commission were to adopt a net benefits test for determining when to compensate demand response providers, 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 invites all interested persons to submit comments in response to the issues discussed herein.

DATES: A technical conference will be held at the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, no later than 45 days following the publication of this document in the **Federal Register**. The exact date of the conference will be provided in a subsequent Commission publication in the **Federal Register**.

Comments on the NOPR will be due 30 days following the technical conference announced herein. The Commission will announce the comment close date in a subsequent publication in the **Federal Register**.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

Agency Web Site: http://ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, *see* the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

David Hunger (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8148, *david.hunger@ferc.gov.*

Helen Dyson (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8856, *helen.dyson@ferc.gov.*

SUPPLEMENTARY INFORMATION:

Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference

Table of Contents

Issued August 2, 2010.

1. In a Notice of Proposed Rulemaking (NOPR) issued in this proceeding on March 18, 2010 (March NOPR),[1] the Commission proposed to require Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)[2] with tariff provisions allowing demand response[3] resources[4] to participate in wholesale energy markets by reducing consumption of electricity from expected levels in response to price signals, to pay those demand response resources, in all hours, the market price of energy (also referred to as the "locational marginal price" or "LMP") for such reductions. In light of matters elucidated in responsive comments to the March NOPR, the Commission seeks additional comments on whether the Commission should adopt requirements related to two issues: (1) If the Commission were to adopt a net benefits test for determining when to compensate demand response providers, what, if any, requirements should apply to the methods for

[1] Demand Response Compensation in Organized Wholesale Energy Markets, Notice of Proposed Rulemaking, 75 FR 15362 (March 29, 2010), 130 FERC ¶ 61,213 (March 18, 2010).

[2] The following RTOs and ISOs have organized wholesale electricity markets: PJM Interconnection, L.L.C. (PJM); New York Independent System Operator, Inc. (NYISO); Midwest Independent Transmission System Operator, Inc. (Midwest ISO); ISO New England, Inc. (ISO–NE); California Independent System Operator Corp. (CAISO); and Southwest Power Pool, Inc. (SPP).

[3] 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).

[4] Demand response resource means a resource capable of providing demand response. 18 CFR 35.28(b)(5) (2010).

determining net benefits; and (2) what, if any, requirements should apply to how the costs of demand response are allocated. The Commission also directs staff to hold a technical conference on these issues no later than 45 days following publication of this notice in the **Federal Register**. The exact date of the technical conference will be provided in a subsequent notice.

I. Background

2. In the March NOPR, the Commission proposed to add section 35.18(g)(1)(v) to its regulations to establish a specific compensation approach for demand response resources participating in organized wholesale energy markets, i.e., the day-ahead and real-time markets administered by ISOs and RTOs. Under the proposed section, each Commission-approved ISO and RTO that has a tariff provision providing for participation of demand response resources in its organized wholesale energy market would pay demand response resources, in all hours, the market price for energy, i.e., the LMP,[5] for demand reductions made in response to price signals.[6]

3. Numerous comments were filed in response to the NOPR, many of which support the proposed demand response compensation level.[7] However, other comments support payment of LMP only when the benefits of demand response compensation outweigh the costs of paying demand response resources, as determined by some type of net benefits test.[8] Still other comments argue that, in order to determine the justness and reasonableness of the proposed compensation level, the corresponding cost allocation must be considered.[9] More specifically, these comments raise concerns regarding how the costs associated with direct 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.[10] Comments regarding net benefits and cost allocation issues are discussed below.

II. Net Benefits

A. The March NOPR

4. In the March NOPR, the Commission proposed to require ISOs and RTOs to pay LMP to demand response providers in all hours, but the Commission also sought comment on, among other things, whether payment of LMP should indeed apply in all hours and, if not, the criteria that should be used for establishing the hours when LMP should apply.[11]

B. Comments

5. As noted above, numerous commenters, primarily industrial consumers and some consumer advocates, agree with the Commission's proposal to pay LMP to demand response providers in all hours.[12] They argue that, regardless of the hour or season, all consumers share in the benefits demand response resources provide, including lowering the clearing price.[13] They also argue that, regardless of the hour or season, both demand response providers and generators provide a comparable service in terms of balancing supply and demand and therefore should be paid on a comparable basis, i.e., LMP.[14]

6. At the same time, a diverse group of commenters 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.[15] 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 hours.[16] Some commenters suggest that paying LMP in all hours might make more difficult, and less accurate, the establishment of baselines for measuring whether a demand response provider has, in fact, responded.[17]

7. Many commenters who oppose paying LMP in all hours for demand response suggest approaches, or net benefits tests, for determining when LMP should apply. These commenters state that the purpose 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

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

[6] The proposed provision applies only to demand response acting as a resource in organized wholesale energy markets. The provision will not apply to demand response under programs that ISOs and RTOs administer for reliability or emergency conditions, such as, for instance, Midwest ISO's Emergency Demand Response; NYISO's Emergency Demand Response Program; PJM's Emergency Load Response; and ISO–NE's Real-Time 30–Minute Demand Response Program, Real-Time and 2–Hour Demand Response Program, and Real-Time Profiled Response Program. The provision also will 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. P 31,281 (2008) (Order No. 719).

[7] *See* Comments of Illinois Citizens Utility Board at 2; Comments of Industrial Energy Consumers of America at 3; Comments of National Energy Marketers Association at 3–4; Comments of National League of Cities; Comments of New Jersey Board of Public Utilities at 2; Comments of North America Power Partners at 4; Comments of Pennsylvania Department of Environmental Protection at 5; Comments of Price Responsive Load Coalition at 2; Comments of Schneider Electric USA at 2; Comments of Wal-Mart Stores, Inc. at 4; Comments of Virginia Committee for Fair Utility Rates at 7.

[8] *See generally,* Comments of New York State Consumer Protection Board; New England Consumer Advocates; Capital Power; Electric Power Supply Association (EPSA); Exelon Corporation (Exelon); PJM Power Providers Group; New England Conference of Public Utility Commissioners (NECPUC); Maryland Public Service Commission (Maryland Commission); New York State Public Service Commission (New York Commission); NSTAR Electric Company; National Grid USA (National Grid); PPL Parties; New England Public Systems; Viridity Energy, Inc.; and Charles Cicchetti.

[9] Comments of ISO–NE at 39–40. *See also,* Comments of American Electric Power Service Corp. at 6–10; Comments of CAISO at 6; Comments of Consolidated Edison Company at 2; Comments of Hess Corporation at 3; Comments of the Illinois Commerce Commission at 12; Comments of PJM at 8; Comments of Potomac Economics at 3; Comments of Massachusetts Attorney General and Maine Public Advocate at 11; Comments of Midwest ISO Transmission Owners at 5–6; Comments of Midwest TDUs at 13; Comments of Edison Electric Institute at 5; Comments of NECPUC at 12, 22; Comments of New England Consumer Advocates at 11; Comments of RRI Energy, Inc. at 6; Comments of San Diego Gas & Electric Co. at 3–4.

[10] 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.,* Comments of ISO–NE at 5–6; Comments of NECPUC at 22; Comments of PJM at 12–14; Comments of PJM Power Providers Group at 37–38.

[11] March NOPR, 130 FERC ¶ 61,213 at P 20.

[12] *See* Comments of Steel Manufacturers Association at 12; Comments of Consumer Demand Response Initiative at 12; Comments of Joint Consumer Advocates at 11–12.

[13] Comments of Alliance for Clean Energy New York at 2–3; Comments of American Chemistry Council at 3; Comments of American Forest & Paper Association at 3; Comments of Crane & Co. at 2–3; Comments of Industrial Energy Consumers of America at 2; Comments of Industrial Energy Consumers of Pennsylvania at 3; Comments of Madison Paper Industries at 2–3.

[14] Comments of Steel Manufacturers Association at 12.

[15] Comments of Capital Power Corporation at 5; Comments of PJM Power Providers Group at 5.

[16] Comments of NECPUC at 13.

[17] Comments of ISO–NE at 32–33; Comments of California Department of Water Resources at 11; Comments of National Grid USA at 8.

up to that point.[18] To achieve that end, some comments advocate a net benefits trigger based on a particular price or period of hours.[19] While some proposals would utilize a static bid threshold, such as $75/MWh,[20] other proposals would utilize a dynamic bid threshold, which could be based upon fuel prices and heat rates of marginal generation.[21] 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 the full LMP.[22] In addition to advancing net benefits tests, some commenters suggest implementation of an ISO- or RTO-developed mechanism to determine whether a net customer benefit would occur in advance of dispatch.[23] Some commenters, however, state 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.[24]

C. Discussion

8. Due to matters raised in responsive comments to the March NOPR, the Commission seeks further information regarding the net benefits issue. Accordingly, the Commission seeks additional comments and directs staff to hold a technical conference regarding various net benefits tests.[25] Specifically, the Commission seeks comment on the following issues, as well as any other issues:

(1) Some commenters address the need for a net benefits test. Address why the Commission should adopt a net benefits test for determining demand response compensation, and what the objectives of any such test would be.

(2) How to define benefits, including whether the benefits associated with demand response should account only for lower market-clearing prices in the day-ahead and real-time markets or should also include consideration of operational benefits *(e.g.,* lower reserve requirements), societal benefits or another measure.

(3) In addition to the payments received from the wholesale market, what are the costs demand response providers and load serving entities incur and should these be included for purposes of a net benefits test.

(4) How to identify the beneficiaries of demand response, and how the allocation of costs related to demand response compensation affect the beneficiaries, if at all.

(5) Whether any net benefits methodology adopted should be the same for all ISOs and RTOs or whether the individual circumstances or configuration of each ISO and RTO would support a different net benefits methodology.

(6) Proposed methodologies for implementing a net benefits test. Comments also should consider whether a net benefits threshold should be established up front based on static measures, such as a specific price or number of peak hours, or established on a dynamic basis, such as a price threshold based on a pre-set heat rate and daily updated fuel price; and similarly, whether the net benefits should be an explicit test run by the ISO or RTO either after bids have been received or each hour prior to accepting demand response bids. Comments should also describe the advantages and limitations of any proposed net benefits methodologies.

III. Cost Allocation

A. Comments

9. Comments concerning cost allocation essentially ask how the proposed demand response compensation level will be funded.[26] These commenters argue that, if not structured correctly, demand response compensation methodologies can increase, rather than decrease costs to end-users.[27] Some commenters further contend that requiring payment of LMP for demand response will require ISOs and RTOs to reopen cost allocation issues that have previously been settled based on varying ISO- and RTO-specific demand response compensation levels.[28] Additional commenters assert that demand response compensation and a method for allocating the associated costs are so inextricably entwined that the two issues must be simultaneously addressed as part of an integrated demand response regime.[29]

10. Another group of commenters endorse the position that demand response compensation and cost allocation are necessarily related, but they contend that resolution of cost allocation issues can await the final rule on demand response compensation. These commenters maintain that any cost allocation approach will depend on the outcome of the final demand response compensation rule[30] and, in any case, should first be addressed through stakeholder discussions at the regional level.

11. Several commenters advocate a specific approach or discuss the pros and cons of alternative approaches for allocating the costs associated with demand response compensation. Potential approaches raised in comments include:

(1) Allocating the costs across the entire relevant ISO or RTO market, based upon the rationale that there are system-wide benefits to demand response, including reducing the market price for energy.[31] Conversely, some commenters argue that, while this approach might increase the amount of demand response provided to the market, it might also result in some market participants paying costs associated with demand response for which they do not receive equivalent benefit.[32]

(2) Allocating the costs to only the load-serving entity of record, i.e., the load-serving entity that would have served the load providing the demand response. According to commenters, this option assumes that the deemed full benefit of demand response is only received by the load-serving entity of record and that demand response does

[18] Comments of New England Consumer Advocates at 11; Comments of NYSCPB at 5; Comments of National Grid at 4–5.

[19] 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. Comments of National Grid at 6.

[20] Comments of the New York Commission at 10. According to the New York Commission, 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, but can also limit participation in a demand response program because prices might not exceed the threshold on a consistent basis.

[21] Comments of National Grid at 6; Comments of the New York Commission at 10; Comments of Viridity at 24.

[22] Comments of the Maryland Commission at 4–5.

[23] Comments of NYSCPB at 5.

[24] Midwest ISO Transmission Owners at 16.

[25] As noted above, the exact date of the technical conference will be provided in a subsequent notice and will be no later than 45 days following publication of this notice in the **Federal Register**.

[26] ISO–NE Comments at 5, 40; Comments of PJM at 8; Comments of Potomac Economics at 3.

[27] Comments of Massachusetts Attorney General and Maine Public Advocate at 11 (arguing that spreading the costs of demand response over a smaller amount of load is cost-effective only so long as the remaining load pays a lower price than it would have paid if the demand response had not participated).

[28] Comments of Midwest TDUs at 13.

[29] *Id.;* Comments of ISO–NE at 4–5; Comments of Edison Electric Institute (EEI) at 5; Comments of Charles Cicchetti at 26–27; Comments of CAISO at 6.

[30] Comments of New England Consumer Advocates at 11.

[31] *See* Comments of NECPUC at 22.

[32] Comments of Midwest ISO Transmission Owners at 5.

not impact other load-serving entities across the ISO or RTO.[33]

(3) Uplifting the costs locally to all load-serving entities within the zone impacted by the demand response reduction, based on a load ratio share. Commenters assert that this approach theoretically allocates the cost of demand response compensation to only those load-serving entities that benefitted from the demand response provided.[34]

(4) Recovering the costs through a surcharge added to the LMP for customers purchasing from the relevant energy market in the hour when the demand response resource is committed or dispatched. The rationale for this approach is that it allocates the costs of demand response resource procurement on the basis of cost-causation, *i.e.,* demand response resource costs are allocated directly to those energy market consumers who benefitted from the demand response resource provided. To implement this proposal, an adjustment to the market price paid by customers would be calculated.[35]

(5) Utilizing a hybrid approach, in a manner intended to minimize cost impacts on final customers.[36] Hybrid approaches include splitting the costs between load-serving entities and transmission owners,[37] and allocating part of the costs to the demand response provider's load-serving entity and part to all of the load-serving entities in the zone where the load reduction occurred, based on a load ratio share.[38]

B. Discussion

12. From the comments received, issues concerning cost allocation may be integrally related to the proposal relating to demand response compensation, and we believe such issues should be explored further. In addition, the diversity of comments relating to cost allocation leave open the question of whether a singular cost allocation approach should be determined by the Commission for all ISOs and RTOs or whether differing cost allocation approaches should be developed regionally and reviewed by the Commission on an ISO- and RTO-specific basis. Accordingly, the Commission seeks additional comments on whether the Commission should consider a generic approach to allocating the costs of demand response compensation required by the final rule in this proceeding, and if so, what approach the Commission should adopt. Such issues also will be explored at the staff technical conference. Specifically, the Commission seeks comment on the following issues, as well as any other issues:

(1) Whether standardizing demand response compensation among ISOs and RTOs requires simultaneous standardization of a method for allocating the costs associated with such compensation. In addition, whether standardizing demand response compensation among ISOs and RTOs requires consideration of corresponding settlements and other impacts associated with the compensation mechanism.

(2) If the Commission standardizes an approach for allocating the costs associated with requiring payment for demand response, what type of approach is appropriate. Comments should address the specific approaches delineated above, and may address other broad principles the Commission could use to determine the cost allocation method.

(3) How the use of a net benefits test would affect the need for and methodologies for determining cost allocation.

IV. Technical Conference

13. The exact date of the Commission staff technical conference directed herein will be provided in a subsequent notice and will be no later than 45 days following publication of this notice in the **Federal Register**. The conference will be held in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. All interested persons are invited to participate in the conference.

14. Those interested in speaking at the conference should notify the Commission by August 10, 2010 by completing an online form describing the topics that they will address: *http://www.ferc.gov/whats-new/registration/demand-RM10-17-000-speaker-form.asp.* Due to time constraints, we may not be able to accommodate all individuals interested in speaking, so multiple persons sharing the same position are encouraged to have one representative speak on their behalf. A detailed agenda, including panel speakers, will be published at a later date.

15. The technical conference will be transcribed. Transcripts of the conference will be immediately available for a fee from Ace-Federal Reporters, Inc. ((202) 347–3700 or 1–800–336–6646). The transcript will be available for free on the Commission's eLibrary system and on the Calendar of Events approximately one week after the conference.

16. A free webcast of the technical conference directed herein will be available. Anyone with Internet access interested in viewing this conference can do so by navigating to *http://www.ferc.gov's* Calendar of Events and locating the appropriate event in the Calendar. The events will contain a link to the applicable webcast option. The Capitol Connection provides technical support for the webcasts and offers the option of listening to the conferences via phone-bridge for a fee. If you have any questions, visit *http://www.CapitolConnection.org* or call (703) 993–3100.

17. There is an "eSubscription" link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call 202 502–8659.

18. Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an e-mail to *accessibility@ferc.gov* or call toll free (866) 208–3372 (voice) or (202) 208–1659 (TTY), or send a FAX to (202) 208–2106 with the required accommodations.

V. Comment Procedures

19. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 30 days following the technical conference announced above. Comments must refer to Docket No. RM10–17–000, and must include the commenter's name, the organization the commenter represents, if applicable, and the commenter's address.

20. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's

---

[33] Comments of PJM at 15.

[34] Comments of PJM at 14; Comments of NECPUC at 22; Comments of Midwest ISO Transmission Owners at 6.

[35] Comments of NECPUC at 22, 23.

[36] Comments of ISO–NE at 40.

[37] ISO–NE suggests charging the difference between LMP and the generation (or "G") portion of the retail rate (*i.e.,* LMP–G) to the load-serving entity that is providing the energy, and charging the remainder (*i.e.,* "G") to network load, which would be billed to transmission owners. Comments of ISO–NE at 5.

[38] As described by PJM, the "[load-serving entity] of record will receive a direct allocation of direct payments made for the demand response MWh reduction multiplied by the difference between the appropriate wholesale market price and the retail rate, and the cost associated with the MWh reduction multiplied by the retail rate allocated to all [load-serving entities] in the zone where the load reduction occurred based on a load ratio share." Comments of PJM at 10.

Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

21. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

22. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VI. Document Availability

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

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

25. User assistance is available for eLibrary and the FERC's website 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.*

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Moeller is concurring, in part and dissenting, in part with a separate statement attached.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

MOELLER, Commissioner, *concurring, in part and dissenting, in part:*

While I support the decision to supplement the record and convene a technical conference, for the reasons set forth in my concurring and dissenting statement on the NOPR that initiated this proceeding on March 18, I continue to concur and dissent, in part.

Philip D. Moeller,
Commissioner.

[FR Doc. 2010–19376 Filed 8–5–10; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

21 CFR Part 1308

[Docket No. DEA–247C]

Schedules of Controlled Substances; Placement of 2,5-Dimethoxy-4-(n)-propylthiophenethylamine and N-Benzylpiperazine Into Schedule I of the Controlled Substances Act; Correction

AGENCY: Drug Enforcement Administration (DEA), Department of Justice.

ACTION: Notice of proposed rulemaking: correction.

SUMMARY: The Drug Enforcement Administration (DEA) is correcting a notice of proposed rulemaking that appeared in the **Federal Register** of September 8, 2003. The proposed rule pertained to the scheduling of N-Benzylpiperazine (BZP), and contained an error regarding the potency of BZP relative to amphetamine. Although DEA used the correct figures in arriving at its scheduling determination, the agency is publishing this correction to provide an official statement of the actual figures. This correction does not address the scheduling of 2,5-dimethoxy-4-(n)-propylthiophenethylamine (2C–T–7) which was also placed into schedule I as a result of the above cited rulemaking.

DATES: This correction is effective August 6, 2010 without further action.

FOR FURTHER INFORMATION CONTACT: Christine A. Sannerud, PhD, Chief, Drug and Chemical Evaluation Section, Office of Diversion Control, Drug Enforcement Administration, 8701 Morrissette Drive, Springfield, VA 22152, Telephone (202) 307–7183.

SUPPLEMENTARY INFORMATION:

Background

DEA is correcting an inadvertent error that occurred in a Notice of Proposed Rulemaking that scheduled the substance n-Benzylpiperazine (BZP) as a schedule I controlled substance. The Notice of Proposed Rulemaking, published on September 8, 2003 (68 FR 52872), proposed the control of BZP in schedule I of the Controlled Substances Act (CSA). The Final Rule, published on March 18, 2004 (69 FR 12794), finalized the placement of BZP in schedule I of the CSA.

Each of these rules contained a misstatement in the "Supplementary Information" section, with regard to the potency differences between BZP and amphetamine. In each rule, it was erroneously stated that BZP is 10 to 20 times more potent than amphetamine. In actuality, the converse is true (*i.e.,* BZP is 10 to 20 times less potent than amphetamine.) Therefore this Rulemaking corrects this misstatement in the Notice of Proposed Rulemaking. Under separate rulemaking, DEA is publishing a correction to the Final Rule, published March 18, 2004 (68 FR 12794).

DEA emphasizes that these errors were made solely in the rules as published in the **Federal Register**. Both DEA and the U.S. Department of Health and Human Services (HHS) considered the correct BZP potencies during their scheduling deliberations. The correct potencies were included in both the HHS scientific and medical evaluation document, and in DEA's scheduling document, which were used to make the determination for control. The public docket for BZP contains both of these review documents. In addition, DEA has already published on the agency's Web site the correct figures regarding relative potency.

The determination of control of BZP was made after consideration of all the available data and all eight factors and the criteria for schedule I as specified in 21 U.S.C. 811 and 812. The amphetamine-like property of BZP was determined following the collective review and consideration of all the available evidence including drug discrimination and self-administration and other information. These studies were briefly mentioned in the rules controlling BZP as a schedule I controlled substance and were discussed in detail in the scientific and medical evaluation and scheduling documents prepared by both HHS and DEA.

Although the potency difference between BZP and amphetamine was discussed in the rules proposing and