135 FERC ¶ 61,053
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-12-000]

Electricity Market Transparency Provisions of Section 220 of the Federal Power Act

(April 21, 2011)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Commission proposes to amend its regulations pursuant to section 220 of the Federal Power Act (FPA), as enacted by section 1281 of the Energy Policy Act of 2005 (EPAct 2005), to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce. In doing so, the Commission proposes to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission.

In addition, the Commission proposes to refine the existing EQR filing requirements by directing all filers to: (1) report the transaction date and time, as well as the type of rate by which the price in the transaction or contract was set (i.e., fixed price, formula, index, regional transmission organization/independent system operator (RTO/ISO) price, or index); (2) indicate whether the transaction was reported to an index publisher; (3) identify the broker or exchange used for a transaction, if applicable; and (4) report electronic tag (e-Tag) ID data in EQRs. The Commission also proposes to:

(1) standardize the unit for reporting energy and capacity transactions; (2) omit the time zone from the contract section; and (3) eliminate the Data Universal Numbering System (DUNS) data requirement. These refinements to the existing EQR filing requirements reflect the evolving nature of electricity markets and promote greater price transparency and confidence in electricity markets.

DATES: Comments are due [60 days after 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.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Transparency Provisions of Section 220 of the Federal Power Act — Docket No. RM10-12-000

NOTICE OF PROPOSED RULEMAKING

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Electricity Market Transparency Provisions of Section 220 of the Federal Power Act — Docket No. RM10-12-000

NOTICE OF PROPOSED RULEMAKING

(April 21, 2011)

1. To facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, the Federal Energy Regulatory Commission (Commission) proposes to revise its regulations to require market participants that are excluded from the Commission's jurisdiction under section 205 of the Federal Power Act (FPA)[1] and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission.[2] In doing so, the Commission proposes to exercise

[1] 16 U.S.C. 824d. For ease of reference, this Notice of Proposed Rulemaking (NOPR) refers to market participants that are not public utilities under section 201(f) of the FPA as "non-public utilities." FPA section 201(f) provides: No provision in this Part shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto. 16 U.S.C. 824(f).

[2] These proposed requirements would not apply to a transaction for the purchase or sale of wholesale electric energy or transmission services within the Electric

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its authority under section 220 of the FPA,[3] as adopted in the Energy Policy Act of 2005 (EPAct 2005).[4] This proposal would allow the Commission and the public to gain a more complete picture of wholesale power and transmission markets in interstate commerce by providing additional information concerning price formation and market concentration in these markets. Public access to additional sales and transmission-related information in the EQR would improve market participants' ability to assess supply and demand fundamentals and to price interstate wholesale market transactions. It also would strengthen the Commission's ability to identify potential exercises of market power or manipulation and to better evaluate the competitiveness of the interstate wholesale markets.

2. In addition, the Commission proposes to make certain revisions to the existing EQR filing requirements and apply those revisions to all market participants filing EQRs. The Commission proposes to revise the EQRs currently filed by public utilities under FPA section 205(c) and that will be filed by non-public utilities under FPA section 220. These revisions include the addition of new fields for: (1) reporting the transaction date and time, as well as the type of rate; (2) indicating whether the sales transaction was reported to an index publisher; (3) identifying the broker or exchange used for a sales

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Reliability Council of Texas (ERCOT), consistent with the exclusion set forth in FPA section 220(f). 16 U.S.C. 824t(f).

[3] 16 U.S.C. 824t.

[4] EPAct 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

transaction, if applicable; and (4) reporting electronic tag (e-Tag) ID data. The Commission also proposes to eliminate the time zone from the contract section and the Data Universal Numbering System (DUNS) data requirement. Further, the Commission proposes to standardize the unit for reporting energy and capacity transactions. These refinements to the existing EQR filing requirements reflect the evolving nature of electricity markets, would increase market transparency for the Commission and the public, and would allow market participants to file the information in the most efficient manner possible.[5]

I. Background

A. Order No. 2001

3. The Commission set forth the EQR filing requirements in Order No. 2001.[6] Order No. 2001 requires public utilities to electronically file EQRs summarizing transaction information for short-term and long-term cost-based sales and market-based

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[5] The Commission also is reviewing the software currently used to file EQRs.

[6] *Revised Public Utility Filing Requirements*, Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 72 FR 56735 (Oct. 4, 2007), 120 FERC ¶ 61,270, *order on reh'g and clarification*, Order No. 2001-H, 73 FR 1876 (Jan. 10, 2008), 121 FERC ¶ 61,289 (2007), *order revising filing requirements*, Order No. 2001-I, 73 FR 65526 (Nov. 4, 2008), 125 FERC ¶ 61,103 (2008).

rate sales and the contractual terms and conditions in their agreements for all jurisdictional services.[7] The Commission established the EQR reporting requirements to help ensure the collection of information needed to perform its regulatory functions over transmission and sales,[8] while making data more useful to the public and allowing public utilities to better fulfill their responsibility under FPA section 205(c) [9] to have rates on file in a convenient form and place.[10] As noted in Order No. 2001, the EQR data is designed to "provide greater price transparency, promote competition, enhance confidence in the fairness of the markets, and provide a better means to detect and discourage discriminatory practices."[11]

4. Since issuing Order No. 2001, the Commission has provided guidance and refined the reporting requirements, as necessary, to simplify the filing requirements and to reflect changes in the Commission's rules and regulations.[12] For instance, in 2007 the

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[7] Order No. 2001, FERC Stats. & Regs. ¶ 31,127.

[8] *Id*. P 13-14.

[9] 16 U.S.C. 824d(c).

[10] Order No. 2001, FERC Stats. & Regs.¶ 31,127 at P 31.

[11] *Id.* P 31.

[12] *See, e.g., Revised Public Utility Filing Requirements for Electric Quarterly Reports*, 124 FERC ¶ 61,244 (2008) (providing guidance on the filing of information on transmission capacity reassignments in EQRs); *Notice of Electric Quarterly Reports Technical Conference*, 73 FR 2477 (Jan. 15, 2008) (announcing a technical conference to discuss changes associated with the EQR Data Dictionary).

Commission adopted an Electric Quarterly Report Data Dictionary, which provides in one document the definitions of certain terms and values used in filing EQR data.[13] Moreover, in 2007, the Commission required transmission capacity reassignment to be reported in the EQR.[14] The refinements to the existing EQR requirements that we are proposing in this NOPR build upon the Commission's prior improvements to the reporting requirements and further enhance the goals of providing greater price transparency, promoting competition, instilling confidence in the fairness of the markets, and providing a better means to detect and discourage discriminatory and manipulative practices.

B. EPAct 2005

5. In EPAct 2005, Congress added section 220 to the FPA,[15] directing the Commission to "facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce" with "due regard for the public interest, the

[13] Order No. 2001-G, 120 FERC ¶ 61,270.

[14] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 817, *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (March 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126.

[15] 16 U.S.C. 824t.

integrity of those markets, fair competition, and the protection of consumers."[16] FPA section 220 grants the Commission authority to obtain and disseminate "information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public."[17] The statute specifies that the Commission may obtain this information from "any market participant,"[18] except for entities with a *de minimis* market presence.[19] EPAct 2005 added a similar transparency provisions in the Natural Gas Act.[20]

6. In 2006, Commission staff conducted an extensive outreach effort to formulate options for implementing EPAct 2005's transparency provisions for wholesale natural gas and electricity markets. As a result, the Commission used its new transparency authority to adopt additional filing and posting requirements for the sale or transportation of physical natural gas in interstate commerce in Orders No. 704 and 720. Order No. 704

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[16] In addition, FPA section 220(b)(1-2) directs the Commission to exempt from disclosure information that is "detrimental to the operation of an effective market or [that would] jeopardize system security," and "to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of proprietary trading information." 16 U.S.C. 824t(b)(1-2).

[17] 16 U.S.C. 824t(a)(2).

[18] *Id*. 824t(a)(3)(A).

[19] *Id*. 824t(d).

[20] 15 U.S.C. 717t-2.

requires buyers and sellers of more than a *de minimis* volume of natural gas to report aggregate volumes of relevant transactions in an annual filing.[21] In Order No. 720, the Commission required major non-interstate pipelines to post daily scheduled volume and other data for certain receipt and delivery points.[22] Order No. 720 also requires interstate pipelines to post information regarding no-notice service.[23]

7. The Commission declined to extend such requirements to wholesale electricity markets because, at the time of the Natural Gas Transparency Notice of Proposed Rulemaking, the Commission was considering other reforms to its regulation of electricity markets.[24] In particular, the Commission was undertaking open access

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[21] *Transparency Provisions of Section 23 of the Natural Gas Act,* Order No. 704, 73 FR 1014 (Jan. 4, 2008), FERC Stats. & Regs. ¶ 31,260, at P 32 (2007), *order on reh'g*, Order No. 704-A, 73 FR 55726 (Sept. 26, 2008), FERC Stats. & Regs. ¶ 31,275, *order dismissing reh'g and clarification*, Order No. 704-B, 125 FERC ¶ 61,302 (2008), *order granting clarification*, Order No. 704-C, 75 FR 35632 (June 23, 2010), 131 FERC ¶ 61,246 (2010); *see also*, *Pipeline Posting Requirements under Section 23 of the Natural Gas Act*, Order No. 720, 73 FR 73494 (Dec. 2, 2008), FERC Stats. & Regs. ¶ 31,283, at P 3 (2008), *order on reh'g*, Order No. 720-A, 73 FR 73494 (Dec. 2, 2008), FERC Stats. & Regs. ¶ 31,302, *order on reh'g and clarification*, Order No. 720-B, 75 FR 44893 (July 30, 2010), FERC Stats. & Regs. ¶ 31,314 (2010).

[22] Order No. 720, FERC Stats. & Regs. ¶ 31,283 at P 1.

[23] *Id.*

[24] *See Transparency Provisions of Section 23 of the Natural Gas Act; Transparency Provisions of the Energy Policy Act*, Notice of Proposed Rulemaking, 72 FR 20791 (April 26, 2007), FERC Stats. & Regs. ¶ 32,614, at P 9-11 (2007) (Natural Gas Transparency NOPR) ("The Commission does not propose action with respect to electric markets at this time. The Commission has recently addressed and is currently addressing electric market transparency in other proceedings.").

transmission service reforms and the more general review of competition in wholesale electricity markets.[25] As a result of these efforts, the Commission issued two final rules. In Order No. 890, the Commission exercised its remedial authority "to limit further opportunities for undue discrimination, by minimizing areas of discretion, addressing ambiguities and clarifying various aspects of the *pro forma* [Open Access Transmission Tariff]."[26] Moreover, in Order No. 719, the Commission made reforms "to improve the operation [and competitiveness] of organized wholesale electric power markets" in connection with "fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable and not unduly discriminatory or preferential rates."[27] Although these final rules improved transparency in wholesale markets in a number of ways, the Commission believes the revisions proposed in this order are necessary to facilitate price transparency in wholesale electricity markets.

C. Notice of Inquiry

8. On January 21, 2010, the Commission issued a Notice of Inquiry[28] seeking comments on whether the Commission should apply the EQR filing requirements to non-

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[25] *Id*.

[26] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 40.

[27] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, 74 FR 37776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292, *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[28] *Electricity Market Transparency Provisions of Section 220 of the Federal*

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public utilities and whether the Commission should consider other refinements to the existing EQR filing requirements. In response to the Transparency NOI, the Commission received 40 comments. Of those comments, twenty-eight discuss extending the EQR filings to non-public utilities; five discuss EQR refinements; and six discuss both. We have considered these comments in drafting the proposals in this NOPR, and we invite further comments on these proposals.

II. Discussion

A. Extending the EQR Filing Requirements to Non-Public Utilities

1. Background

a. Need for Information from Non-Public Utilities

9. Currently, market participants that fall within the Commission's jurisdiction under FPA section 205(c)[29] must file EQRs summarizing contractual terms and conditions in their agreements for jurisdictional services, including market-based rate sales, cost-based sales, transmission service, and transmission capacity reassignments. In addition, EQR filers must provide detailed transactional information for power sales and transmission capacity reassignments made during the most recent calendar quarter.

Power Act, Notice of Inquiry, 75 FR 4805 (Jan. 29, 2010), FERC Stats. & Regs. ¶ 35,565 (2010) (Transparency NOI).

[29] FPA section 205(c) requires public utilities to file all rates and charges for any transmission or sale subject to the Commission's jurisdiction in a convenient form and place for public inspection. 16 U.S.C. 824d(c).

10. Transactions made by both public utility and non-public utility market participants provide critical pricing information that market participants can use to make better-informed decisions about, among other things, sales, purchases, and infrastructure investments. Access to reliable data reduces differences in available information among various market participants, results in greater market confidence, lowers transaction costs, and ultimately supports competitive markets, which helps lower electricity costs for consumers. Applying the EQR filing requirements to the non-public utilities that fall above the *de minimis* threshold will increase price transparency to the public and the Commission and aid the Commission in its oversight of wholesale power and transmission markets. As the Commission explained in implementing the transparency provisions under section 23 of the Natural Gas Act:

> The Commission's market-oriented policies for the wholesale natural gas industry require that interested persons have broad confidence that reported market prices accurately reflect the interplay of legitimate market forces. Without confidence in the fairness of price formation, the true value of transactions is very difficult to determine. Further, price transparency makes it easier for us to ensure that jurisdictional prices are "just and reasonable."[30]

11. Based on the most recent data available in the 2009 U.S. Energy Information Administration's (EIA) Form 861, non-public utilities account for significant volumes of the 3.2 billion MWh of total annual wholesale electricity sales made within the 48

[30] Order No. 704-A, 124 FERC ¶ 61,269 at P 3; *see also* Order No. 704, FERC Stats. & Regs. ¶ 31,260 at P 7.

contiguous states (excluding ERCOT).[31] In particular, about 29 percent of those wholesale sales are made by non-public utilities. Non-public utilities make a significant portion of sales in certain regional wholesale markets within the United States. The 2009 EIA Form 861 data indicates that non-public utilities account for 60 and 70 percent of wholesale sales within the Western Electric Coordinating Council (WECC) and SERC Reliability Corporation (SERC) regions, respectively. Similarly, non-public utilities make up about 80 percent of all wholesale sales that occur within the Florida Reliability Coordinating Council (FRCC). Given non-public utilities' significant presence in national and regional wholesale electricity markets, obtaining information about their sales transactions is important to unmasking how prices are formed in electricity markets. The lack of information from non-public utilities results in an incomplete picture of these markets, and hampers the ability of the public and the Commission to detect and address the potential exercise of market power and manipulation.

12. Among the refinements this NOPR proposes to the EQR filing requirements is a requirement that all market participants provide information about the index publishers, if any, to which they report their transactions and any broker or exchange they use. This information would provide greater transparency regarding electricity index prices and

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[31] *See* U.S. Energy Information Administration, *Form EIA-861, Annual Electric Power Industry Report* (April 2010), *available at* http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

how well those index prices reflect market forces, thus creating greater confidence in the electricity market. In addition, this NOPR proposes several refinements to the EQR filing requirements, including requiring all filers to report: (1) the transaction date and time; (2) the type of rate by which the price in the transaction or contract was set (i.e., fixed price, formula, index, or RTO/ISO price); and (3) e-Tag ID data. The Commission also proposes to: (1) standardize the unit for reporting energy and capacity transactions; (2) omit the time zone from the contract section; and (3) eliminate the DUNS number requirement.

13. Section 220(a)(4) of the FPA requires the Commission to "consider the degree of price transparency provided by existing price publishers and providers of trade processing services, and . . . rely on such publishers and services to the maximum extent possible." As discussed below, we have reviewed existing publications and we believe that the additional data that would be required under this NOPR is not available through existing sources and is necessary to provide a complete picture of price formation in wholesale power markets.

b. Notice of Inquiry Regarding Extending the EQR Filing Requirements

14. In the Transparency NOI, the Commission sought comments regarding whether the Commission should extend the EQR filing requirements to non-public utilities. The Commission also sought comments on what information the Commission should collect, whether the Commission should establish a threshold for reporting, and the burden on market participants that would have to adapt their existing systems to be able to provide

the information. The Commission also asked whether extending the filing requirements would impact market liquidity.

2. Commission Authority

a. Comments

15. Several commenters question whether the Commission has the authority to extend the EQR filing requirements to non-public utilities.[32] Many of these commenters emphasize that the Commission's jurisdiction under section 220 is limited to collecting information regarding wholesale electricity and transmission markets. They point to section 220(b), which states that "[t]he Commission may prescribe rules . . . [that] provide for the dissemination, on a timely basis, of information about the availability and prices of wholesale electric energy and transmission service."[33] They argue that non-public utilities constitute a small percentage of the wholesale market, and therefore information from these market participants will not enhance transparency significantly.[34] In addition, Alaska Power argues that utilities in Alaska do not engage in energy and transmission transactions in interstate commerce and, therefore, should not be required to

[32] APPA; NRECA; Southwest Transmission; EMCOS; Public Systems; East Texas Electric Cooperatives; Cities/M-S-R; TANC; MID; New York Public Power; Delaware Municipal; California DWR; Public Power Council; Allegheny; Utah Associated Municipal; NCPA; NYMPA/MEUA.

[33] 16 U.S.C. 824t(b).

[34] APPA; NRECA; EMCOS; Public Systems; East Texas Electric Cooperatives; TANC; Delaware Municipal; Utah Associated Municipal; NYMPA/MEUA.

file EQRs. Many commenters also argue that there is a lack of evidence to support imposing the EQR filing requirements on non-public utilities.[35] For instance, NRECA and TANC argue that, in the Transparency NOI, the Commission overstated the volume of sales that would be reported if the Commission extended the filing requirements to non-public utilities.[36] APPA asserts that EIA statistics on non-public utility sales cited by the Commission in the Transparency NOI reflect bundled retail sales to consumers rather than information on wholesale sales, which is relevant to the Commission's oversight of jurisdictional wholesale markets.[37] NRECA and TANC claim that the Commission should have excluded retail sales from EIA's estimate of electric utility sales that are made by entities other than public utilities.[38] TANC also asserts that the Commission should have excluded sales from utilities in ERCOT because those utilities are outside the Commission's section 220 jurisdiction. APPA asserts that the Commission's efforts would be better spent focusing on Regional Transmission Organization (RTO) and Independent System Operators (ISO) market transparency.

16. NRECA and TANC further contend that the absence of EQR information from non-public utilities has not hampered the Commission's ability to approve market-based

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[35] Southwest Transmission; East Texas Electric Cooperatives; TANC; Utah Associated Municipal.

[36] NRECA at 11; TANC at 16.

[37] APPA at 5-6.

[38] NRECA at 11.

rates. For example, TANC argues that the Commission has been conducting *ex ante* and *ex post* analyses of public utilities' market power and has been approving and evaluating mergers for decades without information from non-jurisdictional entities.

17. Cities/M-S-R state that entities under consideration in this proceeding have no statutory obligation to file their energy sales agreements with the Commission, nor are their rates subject to reasonableness determinations before the Commission. Accordingly, Cities/M-S-R argue that there is no need to use the EQR mechanism to replace other filing obligations, such as an annual filing with the EIA, for entities exempt from section 205 of the FPA.

18. Other commenters argue that the Commission has the authority under the FPA to extend the EQR filing requirements to non-public utilities. EEI asserts that section 220 provides the Commission with clear authority and responsibility to extend the EQR filing requirements. DC Energy notes that section 205 also provides the Commission with broad authority to require otherwise exempt entities to provide information related to the rates for jurisdictional services.

19. Several commenters also support the Commission's effort to increase transparency in wholesale electricity markets and assert that the additional reporting requirements will assist the Commission in carrying out its statutory obligations.[39] The City of Dover states that reporting is needed to enable the Commission to understand the impact of certain

[39] *See, e.g.*, City of Dover at 1; DC Energy at 5-6; California PUC at 2-3; PG&E at 3; Wisconsin Electric at 2; EEI at 3.

transactions. DC Energy strongly supports the Commission's efforts and argues that such reporting will help facilitate the detection of market power. In addition, California PUC states that the additional filing requirements can help state regulatory agencies: (1) oversee utility procurement; (2) establish statewide renewable portfolio standards, energy efficiency initiatives, demand response programs, and capacity market activities; and (3) further greenhouse gas policies.

b. Discussion

20. The market transparency provisions in section 220 of the FPA direct the Commission to "facilitate price transparency" in markets for the sale and transmission of electric energy in interstate commerce.[40] The transparency provisions authorize the Commission to "prescribe such rules as the Commission determines necessary and appropriate" for the dissemination of "information about the availability and prices of wholesale electric energy and transmission service."[41] These provisions expand the Commission's authority to collect such information, not only from public utilities, but "from any market participant"[42] with more than a *de minimis* market presence.[43] The

[40] 16 U.S.C. 824t(a)(1).

[41] *Id.* at 824t(a)(2).

[42] *Id.* at 824t(a)(3). This section states, in relevant part, that "[t]he Commission may obtain the information described in paragraph (2) from *any market participant*." *Id.* (emphasis added).

[43] *Id.* at 824t(d).

Commission proposes, in this NOPR, to fulfill its responsibility under section 220 of the FPA by requiring non-public utilities with more than a *de minimis* market presence in wholesale markets to comply with the EQR filing requirements outlined in the next section.

21. Currently, market participants that fall within the Commission's jurisdiction under FPA section 205 must file EQRs. Section 201(f) of the FPA exempts certain entities (i.e., Federal entities, municipalities, and certain cooperatives with Rural Electrification Act financing and that sell less than 4,000,000 MWh of electricity per year) from the Commission's section 205 jurisdiction.[44] However, the transparency provisions in FPA section 220 specifically permit the Commission to obtain price and availability information from "any market participant." The phrase "any market participant" is not defined in section 220 and is not limited to public utilities subject to the Commission's jurisdiction under section 205 of the FPA.

22. We interpret "any market participant" to include non-public utilities that fall under FPA section 201(f).[45] Such an interpretation of "any market participant" is consistent with the broad mandate in section 220 to "facilitate price transparency in the markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of

[44] *Id*. at 824(f).

[45] *See id.* at 824t(a)(3)(A).

consumers." Furthermore, in EPAct 2005, Congress amended section 201(b)(2) of the FPA[46] to provide that, "[n]otwithstanding section 201(f)," the entities described in section 201(f) shall be subject to the Commission's jurisdiction for purposes of carrying out certain provisions, including FPA section 220. Thus, reading FPA section 201(b)(2) in conjunction with section 220, EPAct 2005 granted the Commission authority to collect information concerning the availability and prices of wholesale electric energy and transmission service from entities that are not public utilities.

23. We disagree with certain commenters' assertions that information about wholesale sales made by non-public utilities will not significantly enhance price transparency because non-public utilities are a small percentage of the wholesale market. As noted above, based on 2009 EIA Form 861 data, non-public utility sales account for approximately 29 percent of wholesale sales in the 48 contiguous states (excluding ERCOT),[47] while non-public utilities account for 60 and 70 percent of wholesale sales within the WECC and SERC regions, respectively. Similarly, non-public utilities make

[46] FPA section 201(b)(2) states that: Notwithstanding section 201(f), the provisions of sections . . . 220 . . . shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this Act with respect to such provisions. *Id.* at 824(b)(2).

[47] The Commission has excluded ERCOT from its calculations consistent with FPA section 220(f), which states that section 220 does not apply to wholesale sales of electric energy or transmission services within ERCOT. *Id.* at 824t(f). However, ERCOT members would need to report wholesale power sale contract and transaction information in EQR to the extent they make interstate sales outside of ERCOT.

up about 80 percent of all wholesale sales that occur within FRCC. Given non-public utilities' significant presence in national and regional wholesale electricity markets, obtaining information about their sales transactions is essential to understanding how prices are formed in electricity markets.

24. Certain commenters dispute the accuracy of the 29 percent figure cited in the Transparency NOI[48] as the percentage of wholesale sales made by non-public utilities, arguing that the Commission incorrectly relied on EIA statistics pertaining to non-public utility bundled sales instead of wholesale sales. In particular, NRECA, APPA, and TANC argue that the Transparency NOI calculated the 29 percent figure based on EIA's figures for retail electric utility sales, labeled "Sales to Ultimate Consumers." In fact, however, the Commission arrived at the 29 percent figure in the Transparency NOI by using the 2007 EIA Form 861 wholesale sales data classified by EIA as "Sales for Resale," and not "Sales to Ultimate Consumers."[49] This 29 percent figure remains the same using the most recently available date (i.e. 2009) from EIA Form 861.[50] Thus, the

[48] Specifically, the Transparency NOI stated that EIA's Electric Power Industry Overview 2007 estimated that 29 percent of electric utility sales are made by publicly-owned electric utilities (municipals, public utility districts or public power districts, state authorities, irrigation districts, and joint municipal action agencies, consumer-owned rural electric cooperatives, and Federal electric utilities). *See* Transparency NOI, FERC Stats. & Regs. ¶ 35,565 at P 9 & n. 21 (citing Energy Information Administration, Electric Power Industry Overview 2007 (March 2009) *available at* http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html).

[49] *See* Annual Electric Power Industry Report Instructions, *available at* hptt://www.eia.doe.gov/cneaf/electricity/forms/eia861.pdf.

percentages of wholesale sales made by non-public utilities cited in the Transparency NOI and this NOPR are accurate.

25. With respect to APPA's comments that the Commission should focus on increasing market transparency in RTOs/ISOs instead of increasing market transparency by requiring non-public utilities to file EQRs, we agree that transparency in the organized markets is important. In fact, the RTOs/ISOs already make available a significant amount of information about the availability and prices for wholesale sales and transmission service within their markets. For example, in Order No. 719, the Commission further promoted transparency in RTO/ISO markets by directing RTOs/ISOs to reduce the lag time for the release of offer and bid data and requiring RTOs/ISOs to justify in compliance filings their policy regarding the aggregation of offer data and cost data, discussing how the policy avoids participant harm and the possibility of collusion, while fostering market transparency.[51] However, notwithstanding the high value the Commission places on market transparency in RTO/ISO markets, we continue to believe that increasing transparency broadly across all markets subject to the Commission's jurisdiction by requiring all market participants, including non-public

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[50] At the time that the Commission issued the Transparency NOI, EIA had not yet released the data for 2009.

[51] *See Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, 74 FR 37776 (Jul. 29, 2009), FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

utilities with more than a *de minimis* presence in those markets, to provide information through EQRs is equally important.

26. NRECA's and TANC's arguments that the Commission should not require non-public utilities to report information in the EQR because the Commission has been approving market-based rates and evaluating mergers for decades without such information miss the mark. Disseminating information through the EQR about wholesale sales made by non-public utilities would benefit the Commission, market participants and the public in several different ways in addition to improving the Commission's ability to evaluate jurisdictional sellers' market-based rate authorizations and proposed mergers and acquisitions. Information about non-public utility sales would provide a more complete view of the prices and volumes that underlie price formation in the wholesale power markets. Information on all sales, rather than sales made only by public utilities, would allow market participants to value their transactions more accurately and increase confidence that market prices reflect all relevant supply and demand forces. Such information, in combination with other information tools, would also allow the Commission to better monitor for indications of market power and manipulation at major trading hubs and on electricity indices. For example, without the inclusion of non-public utility transactions in the EQR, the Commission may incorrectly conclude that substantial market price deviations, or other indicators, at major trading hubs or on electricity indices are attributable to the exercise of market power or manipulation by a public utility, when in fact, those price deviations reflect legitimate market forces caused by significant volumes being transacted by non-public utilities.

27. In addition, as the Commission explained in the Transparency NOI, obtaining EQR information from non-public utilities would strengthen the Commission's oversight of its market-based rate program under FPA section 205 and provide a better basis for considering whether to approve merger and acquisition proposals under FPA section 203.[52] The Commission's market-based rate program is grounded in an *ex ante* analysis of whether to grant a seller market-based rate authority and an *ex post* analysis of whether a seller with market-based rate authority has obtained excessive market share since it was granted authorization to transact at market-based rates or since the last review of such rates.[53] One tool used in some cases to conduct an *ex ante* analysis of whether to grant market-based rate authority to a seller is the delivered price test (DPT). The DPT defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and then calculates each supplier's economic capacity and available economic capacity for each season/load condition.[54] Rather than relying on a

[52] *See* Transparency NOI, 130 FERC ¶ 61,039 at P 10-12.

[53] The Ninth Circuit Court of Appeals upheld the Commission's market-based rate regulatory scheme because it relies on a "system [that] consists of a finding that the applicant lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation." *State of California, ex rel. Bill Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004), *cert. denied* (S. Ct. Nos. 06-888 and 06-1100, June 18, 2007) (*Lockyer*).

[54] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 FR 39904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, *clarified*,

(continued…)

DPT analysis for analyzing a market-based rate seller's authority that is based on proxy prices and published price indices for sales by non-public utilities, obtaining more complete price and volume information for sales of electricity by non-public utilities would more accurately reflect market prices, improve the quality of the DPT results and assist the Commission in identifying whether sellers can exercise market power. The DPT also is used by the Commission to evaluate the effect on competition with respect to proposed mergers and acquisitions under FPA section 203. Therefore, obtaining more complete price and volume information would provide a better basis for considering whether to approve merger and acquisition proposals.

28. Such information from non-public utilities would also provide the Commission with important actual sales information for performing *ex post* analysis of whether a jurisdictional seller with market-based rate authority has gained an excessive market share since the original authorization to transact at market-based rates or since the Commission's last review of such rates. Information about sales by non-public utility

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124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 73 FR 79610 (Dec. 30, 2008), FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, 74 FR 30924 (June 29, 2009), FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, 75 FR 14342 (March 25, 2010), FERC Stats. & Regs. ¶ 31,305 (2010). The Commission requires the DPT if a seller fails one of the indicative screens. The indicative screens analyze the number of megawatts of capacity an applicant owns or controls, rather than analyzing actual price data. However, "sellers that do not pass the indicative screens are allowed to provide additional analysis for Commission consideration," including price data. Order No. 697, FERC Stats. & Regs ¶ 31,252 at P 62.

market participants will allow the Commission to compare prices for power sold by jurisdictional sellers with those of non-public utility sellers in the same market.

29. Cities/M-S-R argues that the EQR mechanism should not replace other filings made by non-public utilities, such as an annual filing with the EIA, because non-public utilities have no statutory obligation to file sales agreements with the Commission and their rates are not subject to the Commission's reasonableness determinations. Although non-public utilities are not subject to the same filing requirements and rate determinations under FPA sections 205 and 206 as public utilities are, we propose that reporting in the EQR is the proper mechanism for non-public utilities to make information about their wholesale sales and transmission available to the public. As we note below, existing sources of information about non-public utility wholesale sales are insufficient to facilitate price transparency. The EQR is an established public reporting process that already provides substantial transparency into public utility sales. Furthermore, by requiring non-public utilities to file information in the EQR in the format used by public utilities, we can help ensure the consistency and comparability of the information. Consistency and comparability between filers is important because wholesale markets do not distinguish between sellers that are subject to the Commission's FPA section 205 jurisdiction or the Commission's regulations and sellers that are typically exempt from such Commission's jurisdiction. Expanding the applicability of the Commission's EQR filing requirements allows the Commission and the public to equally evaluate all transactions in the market.

30. With respect to Cities/M-S-R's arguments that they do not file sales agreements or need reasonableness determinations from the Commission on their rates, so they should not be required to file EQRs, we note that our jurisdiction under FPA section 220's transparency provisions is limited to the dissemination of information that will aid in market transparency for the public and the Commission. Section 220 gives the Commission no jurisdiction related to, nor do our proposed regulations govern, the rates, terms, and conditions of service of market participants that are excluded from the Commission's FPA section 205 jurisdiction. The Commission is requiring only the posting of information important to ensuring market transparency and is not engaging in traditional regulation of rates, terms and conditions of service for non-public utilities.

31. In response to Alaska Power, we propose to exempt utilities located entirely in Alaska from the EQR filing requirements because they are electrically isolated from the contiguous United States. In addition, we propose to apply this exemption to utilities located entirely in Hawaii.

3. Proposed Filing Requirements for Non-Public Utilities

a. Existing Sources of Information

i. Comments

32. California DWR, NRECA, New York Public Power, City of Fayetteville, and SWP argue that section 220 of the FPA requires the Commission to determine that existing price publications are insufficient before establishing any new reporting requirements. Commenters also urge the Commission to consider whether new reporting requirements would be duplicative of existing sources, such as EIA reports, ISO/RTO

data, and private index publishers.[55] Public Systems claim that the Commission may not impose EQR filing requirements on market participants in New England because RTOs in New England already provide the public with extensive data regarding price and the availability of wholesale electric energy. SWP also suggests that the Commission could combine data from multiple sources, such as the California Independent System Operator (CAISO), existing EQRs, and pricing publications, to conduct *ex ante* or *ex post* market analyses.

33. According to APPA, before expanding EQR requirements to non-public utilities, the Commission should look closely at the amount and type of wholesale sales these utilities actually make and consider other sources of available information on such sales, such as EIA publications and forms, to determine whether the additional information supplied through their EQR filings would help in achieving the Transparency NOI's stated goals. NRECA and Cities/M-S-R state that cooperatives and other electric utilities annually file form EIA-861, "Annual Electric Power Industry Report," with the EIA. They explain that this form includes information such as peak load, generation, electric purchases, sales and revenues. Moreover, NRECA states that EIA provides access to the daily volumes, high and low prices, and weighted average prices from hubs around the country. In addition, NRECA states that cooperatives that receive Rural Utilities Service

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[55] *See, e.g.*, East Texas Electric Cooperatives at 2-3; New York Public Power at 3-4; NRECA at 6-8; Cities/M-S-R at 10-11; DEMEC at 3-4; Public Systems at 11-15; TANC at 10-11, 14-15; SWP at 8.

(RUS) financing are required to file RUS Form 12, which includes such information as electric purchases, sales, and revenues and is publicly available through a database purchased from Ventyx.[56] NRECA also states that the Energy Management Institute provides results of a daily survey of wholesale transactions that they conduct in all the major trading regions of the country. Furthermore, TANC and NRECA note that forward market prices are available through the New York Mercantile Exchange and the IntercontinentalExchange. Finally, Sam Rayburn Municipal believes that any additional reporting requirement would be duplicative because its power supply structure is simple and reported in detail in its formal financing, accounting and engineering documents.[57]

ii. <u>Discussion</u>

34. In carrying out Congress' directive to facilitate price transparency in wholesale sales and transmission markets, FPA section 220 requires that the Commission consider the degree of price transparency provided by existing price publishers and trade processing services, and rely on such publishers and services to the maximum extent possible.[58] As pointed out by commenters, there are already a number of sources of publicly available information about wholesale markets, including EIA and RUS forms,

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[56] Ventyx is a commercial provider that offers Velocity Suite, an application that includes data from generation and transmission cooperatives, distribution cooperatives, municipal utilities, and other market participants exempt from the Commission's FPA section 205 jurisdiction.

[57] Sam Rayburn Municipal at 2.

[58] *See* 16 U.S.C. 824t(a)(4).

RTOs/ISOs, electric index publishers, and commercial data providers that provide varying degrees of price transparency. However, the Commission believes the degree of price transparency provided by existing sources is insufficient for facilitating price transparency.

35. The two most significant publicly available forms that capture information about non-public utility power sales are the EIA Form 861 and the RUS Form 12. EIA Form 861 reports total volume (MWh) and revenue associated with a filer's wholesale power sales for an entire year.[59] However, Form EIA Form 861 does not detail individual wholesale transactions, including the counterparty, location, price, and delivery timeframe as well as other transaction details contained in EQR. Rather, EIA Form 861 filers report their aggregated annual volume of sales for resale and corresponding revenues. RUS Form 12 provides accounting details for power transaction by entities that fall under 7 U.S.C. 901 authority.[60] RUS Form 12 provides considerably more detail than EIA Form 861 through the inclusion of the energy purchaser and other contract details for individual energy sales.[61] However, RUS Form 12 provides only limited price

[59] On line 12 of Schedule 2, Part B, EIA Form 861 collects information on electricity "Sales for Resale." http://www.eia.doe.gov/cneaf/electricity/forms/eia861.pdf.

[60] RUS Form 12b SE itemizes sales of electricity while RUS Form 12b PP itemizes purchases of electricity. http://www.usda.gov/rus/dcs/electric-forms/form12-2006.pdf, http://www.usda.gov/rus/dcs/downloads/form12/1717b-3.pdf.

[61] RUS Form 12b SE data field "Statistical Classification (b)" provides detail on whether the sale is for requirements service, long-term firm service or intermediate-term firm service, among other classifications.

(continued…)

transparency because the form does not contain information on delivery location and time. Delivery location and time are critical for gaining insight into price formation.[62] Without transaction-specific delivery location and time information, Form EIA 861 and RUS Form 12 do not provide sufficient price transparency into wholesale electricity markets. Therefore, expanding EQR filing requirements to non-public utilities would provide price transparency that is not available through EIA Form 861 or RUS Form 12.

36. RTOs/ISOs post extensive information about RTO/ISO wholesale market prices and market participant bid/offer data that provide valuable transparency for spot wholesale power markets run by RTOs/ISOs. These postings contain detailed location, market and product information. However, these postings are limited to the wholesale electricity markets that are administered by RTOs and ISOs. In addition, publicly posted RTO/ISO data does not provide price transparency into the bilateral transactions entered into by market participants within the RTO/ISO balancing authority area that can impact RTO/ISO market price formation. These bilateral transactions are frequently scheduled into the RTO/ISO market.[63] The terms of bilateral transactions are often not reported to

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http://www.usda.gov/rus/dcs/downloads/form12/1717b-3.pdf.

[62] For example, one would expect power sold in a load-constrained area during on-peak hours to be priced very differently from power sold in a generation-rich area during off-peak hours.

[63] For example, NYISO estimates that approximately 50 percent of the energy scheduled in their markets was transacted bilaterally. *See* http://www.nyiso.com/public/about_nyiso/understanding_the_markets/energy_market/index.jsp.

RTO/ISO markets and not included in publicly posted price and bid/offer data. While some bilateral transactions are already reported in the EQR, expanding the EQR filing requirements to include non-public utilities would give the Commission and the public a better view into bilateral transactions. This data would also enhance the RTO/ISO market monitoring units' ability to monitor RTO/ISO markets. Thus, expanding EQR filing requirements to non-public utilities would provide valuable price transparency into bilateral wholesale electricity markets that is not currently captured in publicly posted data from RTOs/ISOs.

37. Existing daily index publications provide a degree of price transparency into spot wholesale electricity markets by capturing certain transactions. However, this price transparency is limited because these index publications do not capture longer-term transactions. Expanding EQR filing requirements to non-public utilities would provide price transparency for longer-term transactions not included in daily index publications.

38. Organized exchanges, such as the IntercontinentalExchange, also provide valuable price information, but that information is limited only to prices for particular power products at standardized locations. Finally, commercial data providers, like Ventyx, provide a valuable service by collecting and packaging existing publicly available data. However, their products are limited by the availability of existing information, and therefore do not, in themselves, increase price transparency.

39. In addition, information about non-public utility transmission service and reassigned transmission capacity sales may be available in the Open Access Same-Time Information System (OASIS). However, information on OASIS is not readily accessible

to the public. Thus, requiring information about non-public utility transmission service and reassigned transmission capacity sales to be made publicly available through the EQR will facilitate price transparency in the transmission markets and aid the public and the Commission in detecting and addressing possible market power and manipulation in these markets.

b. Scope of Proposed EQR Filing Requirements for Non-Public Utilities

i. Comments

40. BPA and Cities/M-S-R question whether the Commission needs all of the information included in the EQR and whether quarterly filings are necessary. In particular, BPA believes that the critical information that the Commission needs to measure the size of the relevant market is contained in the transaction section, Field Numbers 46-67, and that the information in the contract section would not be necessary or helpful to the Commission. In addition, APPA and Salt River note that the Commission may need to customize the EQR filing forms to reflect the types of information applicable to public power entities.[64] However, EEI states that if particular reporting requirements do not apply to a given filer, it can simply indicate “not applicable.”

41. In addition, BPA asserts that the burden would be greatly reduced if the Commission were to limit the filing requirements for BPA to wholesale power sales at

[64] Salt River at 4-5.

market-based rates. Thus, BPA supports excluding the cost-based sales to consumer-owned utilities, direct services industries, and inter-business line transmission services transactions.

42. APPA asserts that sales by joint action agencies, state agencies, and power or water districts to their own members should not be reported.[65] APPA argues that if the Commission expands EQR filing requirements to public power utilities, these agencies and districts should only be required to file EQR information on their excess power sales (i.e., sales to entities other than their member utilities or long-term distribution customers). TAPS and Public Power argue that joint-action agencies should not be required to report transactional information on long-term, wholesale sales of power to their member utilities. In addition, TAPS argues that generation and transmission (G&T) cooperatives' sales to their members should not be included. TAPS explains that although technically at wholesale, such sales are analogous to a vertically integrated utility's internal supply of its retail sales unit and subsequent retail sale, neither of which is reported through public utilities' EQRs.[66]

43. LPPC and Salt River argue that the Commission should avoid requirements for reporting on long-term power supply arrangements that are solely between non-jurisdictional entities. For instance, LPPC argues that the power sold under long-term

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[65] APPA at 5.

[66] TAPS at 2, 12.

arrangements between non-jurisdictional entities is not a factor to market participants when considering competitive purchases or sales nor is it relevant to the Commission's market manipulation oversight. Thus, such power arrangements do not factor into the market over which the Commission has oversight.[67]

44. By contrast, PG&E, Wisconsin Electric, and EEI believe that market participants that are excluded from the Commission's section 205 jurisdiction should file the same data elements that jurisdictional entities are required to file under the EQR Data Dictionary.

ii. <u>Commission Proposal</u>

45. The Commission proposes to apply the same EQR requirements to non-public utilities that it currently requires from public utilities, with some adjustments, as discussed below. In particular, the Commission proposes that non-public utilities be required to report the same information about wholesale sales, transmission service, and transmission capacity reassignments that are currently reported by public utilities. Expanding the same EQR data elements to non-public utilities will help ensure comparability and consistency with filings by public utilities, which will make it easier for market participants and the public to use the information. In addition, requiring the same sales and transmission-related information from non-public utilities will allow the

[67] LPPC at 3.

Commission to better evaluate the performance of wholesale markets as a whole and make it easier to determine that jurisdictional prices are "just and reasonable."

46. In their comments, several market participants suggest that non-public utilities should not be required to file certain sales in the EQR, such as certain cost-based sales. BPA, for instance, suggested that cost-based sales to consumer-owned utilities, inter-business line transmission services transactions and sales to direct services industries, which are developed based on cost-based rates, should not be filed.[68] Other commenters suggest that joint action agencies should not be required to report transactional information on the long-term, wholesale sales of power to their member utilities.

47. The Commission proposes that all wholesale sales, including cost-based and market-based sales, be included in EQR filings from non-public utilities with more than a *de minimis* market presence. Although several commenters argue that certain sales, such as sales by joint action agencies, state agencies, and power or water districts to their own members, should not be reported, we conclude that excluding these wholesale sales in the EQR adversely impacts price transparency in wholesale electricity markets. Specifically, these sales can impact market prices regardless of whether or not they are made by entities that fall under the Commission's FPA section 205 jurisdiction. For instance, if the agencies and districts did not supply their members, then the members would have to purchase supply from other sources in the market. Also, depending on these agency and

[68] Cities/M-S-R at 9.

district rules, the members may be able to sell excess power into the market. In either case, these sales would have an effect on the formation of prevailing market prices. Sales transactions by non-public utilities, whether cost-based or market-based, can influence wholesale electricity markets. Excluding certain segments of wholesale sales would result in an incomplete picture of wholesale price formation and would hamper the ability of the public and Commission to detect and address the potential exercise of market power and manipulation.

48. Furthermore, we agree with TAPS that a vertically integrated utility that internally supplies its retail sales unit would not need to report that supply in the EQR because there is no wholesale sale in this situation. However, in the case of a G&T cooperative selling to its member cooperatives to meet the members' load obligations, this would constitute a wholesale sale that must be reported in the EQR. Such reporting is consistent with how jurisdictional cooperatives report their sales in the EQR. Any subsequent sale by a member cooperative to its retail customers would be a retail sale that is not reported in the EQR.

49. We believe that certain data fields in the EQR may not be applicable to filings made by non-public utilities. For example, contract data Field Number 19 (FERC Tariff Reference) and transaction data Field Number 50 (FERC Tariff Reference) require filers to insert a "FERC Tariff Reference." Non-public utilities may not possess an appropriate FERC Tariff Reference (Fields 19 and 50) for certain wholesale contracts and transactions. In cases where a FERC Tariff Reference is not applicable, the Commission proposes to require that a filer state that the appropriate FERC Tariff Reference is "Not

Required," or "n/r," in their EQR filing. However, if the sale relates to a previously filed reciprocal open access transmission tariff (OATT), the Commission proposes that the appropriate reference to the reciprocal OATT be included in the EQR. In addition, non-public utilities can mark as "Not Required," or "n/r," for the "Product Type Information" captured in Field Number 30, which relates to whether the transaction is "cost-based," "capacity reassignment," "market-based," or "other," because the values for Field Number 30 are defined based on types of FERC-approved tariffs.

50. In its comments, BPA noted that the information necessary for the Commission to measure the size of a relevant market for merger analysis can be found in the transaction section (Field Numbers 46 through 67) of the EQR, but that the contract section (Field Numbers 14 through 45) does not appear to be necessary or helpful for merger analysis. The Commission agrees with BPA's assessment that the transaction section would be the relevant data fields in the EQR to use in determining the size of a wholesale energy market. However, the EQR's function is not limited to merger analysis, as discussed above.

51. Furthermore, limiting EQR data to only transactions data would significantly detract from the Commission's efforts to facilitate price transparency under FPA section 220. The contract section of the EQR provides critical price transparency information in several ways. First, the contract section provides information and valuable context on when rates were established and the terms of the rates. Without contextual information, such as when and how a rate was agreed upon, the sales price that is reported in the transaction section (Field Number 64) might appear anomalous compared to other prices

reported in the transaction section. Second, there are a number of products and agreements that are reported solely on the contract section of the EQR, such as emergency energy, interconnection agreements, membership agreements, and must run agreements.[69] These products and agreements can impact a market participant's ability to make sales and access transmission, which are aspects of price formation. Therefore, excluding them would limit the price transparency impact associated with expanding the EQR to non-public utilities.

c. Burden

i. Comments

52. EEI believes that the burden on non-public utilities would be no greater than the burden on jurisdictional entities, once systems are in place to collect and compile the information. However, several commenters state that complying with any additional reporting requirements would be a significant burden for municipals and cooperatives. Public Power Council states that the EQR requirements are burdensome and the value of the information that the Commission would collect from most Northwest public power entities does not justify the cost that would be expended by non-public utilities to produce the information. Further, Utah Associated Municipal states that filing EQRs to report

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[69] For a detailed list, please refer to Appendix B in the *Electric Quarterly Report Data Dictionary*, Version 1.1, *available at* http://www.ferc.gov/docs-filing/eqr/soft-tools/eqrdatadictionary.pdf.

those sales made every hour of every day to nearly every member utility would give the Commission no useful information relevant to its purposes.

53. Cities/M-S-R argue that it is unnecessarily burdensome for the Commission to collect transaction data for market transparency purposes on a quarterly basis and state that the Commission has created annual, not quarterly, reporting requirements under the natural gas transparency provisions. Cities/M-S-R also assert that the data required on Form 552 for natural gas transactions is less involved than EQR data fields and creates a more limited burden on responding parties. Further, Cities/M-S-R state that the scope of the EQR information is broader than necessary and the frequency is too great for the limited purpose of obtaining information to improve the Commission’s delivered price test analysis.

54. According to APPA, a number of its members estimated that they would require from two weeks to nine months for the initial setup, and one to three days to compile, verify, and file the EQR each quarter. The City of Fayetteville states that it has not done a detailed cost/time analysis, but believes that it would fall in the upper quartile of the time estimates reported in the APPA comments. Allegheny estimates that significant computer system changes and additional ongoing personnel resources may be required, the costs of which would need to be passed along to the cooperative’s customers. Salt River estimates that it would need at least six months to develop an internal EQR filing program. In addition, Salt River encourages the Commission to provide guidance through workshops or training sessions and to provide opportunities for interaction with staff while preparing initial filings, and to allow sufficient time to ensure completeness

and accuracy of the filings. Based on its own experience, DC Energy states that, while the burden will vary depending on the scope and amount of activities, there would be an upfront time investment of 2-4 person-weeks to design and implement an EQR tracking/reporting system, and an ongoing reporting burden of 2-3 person-days per quarter. It states that this estimate is based on a "self-build model" and believes there also are off-the-shelf products that will automatically generate these reports for an entity, resulting in less of a burden.

55. BPA states that the burden would be greatly reduced if the Commission were to limit the filing requirements for BPA to wholesale power sales at market-based rates (thereby excluding inter-business line transmission services transactions, and the statutorily-mandated cost-based sales to consumer-owned utilities and direct services industries[70]) and eliminate the fields associated with contract data. BPA also argues that it should not be required to report transmission services sales made by BPA's functionally separated Power Services section to its Transmission Services section because these inter-business line transactions are not discretionary, open market transactions that would aid the Commission in evaluating market power issues.

ii. <u>Discussion</u>

56. We acknowledge that enhancing price transparency by extending the EQR filing requirements to non-public utility market participants will impose a new burden on those

[70] BPA notes that direct services industries are generally a defined set of aluminum companies and large industries in the Pacific Northwest. BPA at 1.

market participants. However, we believe that, on balance, the benefit of increased price transparency stemming from the filing of such information will outweigh the burden on these market participants above the *de minimis* threshold. We assume that most non-public utilities already capture transaction-specific information for accounting and record-keeping purposes. Therefore, we believe the burden imposed will relate primarily to the required format for submitting that information. In addition, we believe that the amount of burden created by requiring non-public utilities to file EQRs will depend on how many transactions the non-public utility makes. Accordingly, entities with a relatively small number of wholesale sales will face less of a burden.

57. Cities/M-S-R contend that the data collected under the natural gas market transparency provisions is less burdensome because it is collected annually, not quarterly, and contains less detail than the EQR data. We note that the Commission has promulgated two rules under the natural gas market transparency provisions in section 23 of the NGA,[71] Order Nos. 704 and 720. Order No. 704 requires certain purchasers and sellers of natural gas to file an annual report about specified physical natural gas transactions. Order No. 720 requires major non-interstate pipelines to file certain receipt and delivery information on a daily basis. Therefore, Order No. 720 requires data to be provided more frequently than the EQR. In addition, Order No. 720 requires non-interstate pipelines to post detailed information, including the transportation service

[71] 15 U.S.C. 717t-2.

provider's name, posting data, posting time, nomination cycle, location name, additional locational information if needed to distinguish between points, location purpose description, posted capacity, scheduled volume, available capacity, and measurement unit for each receipt or delivery point that meets certain criteria.[72] Although the level of detail in the EQR may be greater than that required under Order Nos. 704 and 720, this difference reflects variations between transactions made in the natural gas and electricity markets.

58. We disagree with Cities/M-S-R's suggestion that the Commission seeks to obtain EQR information from non-public utilities solely to improve the Commission's DPT. As discussed above, the Commission proposes to require non-public utilities to file EQRs to fulfill Congress's directive in FPA section 220 to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce. The information in these EQRs will provide valuable information that serves a number of purposes. This information will provide a more complete picture of price formation in wholesale electricity markets for the Commission and the public. In addition, obtaining sales price and volume information in EQRs from non-public utilities will increase the Commission's ability to monitor utilities' power sales for indications of market power and manipulation. Also, as explained in the Transparency NOI,[73] and discussed above,

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[72] *See* 18 CFR 284.14.

[73] *See* Transparency NOI, FERC Stats. & Regs. ¶ 35,565 at P 9-12.

collecting EQR information from non-public utilities would improve the quality of the DPT results and assist the Commission in determinations concerning a seller's ability to exercise market power and provide a better basis for considering whether to approve merger/acquisition proposals under FPA section 203.

59. We believe that the EQR compliance burden on non-public utilities above the *de minimis* threshold would be greatest during the initial set-up phase, when data is mapped into the new required format. However, to the extent a filer uses the same format for each EQR, once the filer's system is mapped to the interim and final formats, the burden will be significantly reduced. The Commission invites comment from non-public utilities and public utilities on how their existing data capture processes have been or can be mapped to facilitate EQR filing in its current and proposed formats.

60. We recognize that the initial implementation and ongoing reporting associated with the proposed EQR filing requirements will result in additional costs and burden on non-public utilities. However, the Commission has tried to balance the need for data with efforts to minimize the burden on filers. To help alleviate the burden of filing EQRs, the Commission has designed a system that allows EQRs to be filed using the Internet so that all filers submit EQRs to the Commission electronically. In addition, the Commission is only requiring those non-public utilities that fall above the *de minimis* threshold test to file EQRs. We also agree with Salt River that workshops or training sessions to provide guidance may be helpful and we will make every effort to provide technical assistance prior to the implementation of the EQR filing requirements for non-public utilities.

d. ***De Minimis* Threshold**

i. **Comments**

61. Commenters propose a wide range of *de minimis* market presence thresholds for non-public utility exemptions from the EQR filing requirements, from 8 million MWh to 100 MWh of annual sales. In favor of the 8 million MWh threshold, two commenters[74] point to FPA section 206(e), which gives the Commission refund authority over certain sales made by non-jurisdictional entities except for an entity that sells less than 8 million MWh of electricity per year.[75] Cities/M-S-R also argue that a threshold of at least 8 million MWh per year is appropriate because of the growth in the electricity market, as evidenced by the reported wholesale sales, which have nearly tripled between 1997 and 2008.[76]

62. Other commenters recommend a threshold level of 4 million MWh, based on either annual wholesale sales[77] or annual total sales.[78] In support of a 4 million MWh threshold, many commenters refer to section 201(f) of the FPA, which specifically excludes from the Commission's jurisdiction electric cooperatives that sell less than 4

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[74] Cities/M-S-R at 14; Imperial at 6.

[75] 16 U.S.C. 206(e).

[76] Cities/M-S-R at 14.

[77] *See, e.g.*, APPA at 9; NRECA at 26; New York Public Power at 6; Delaware Municipal at 5; City of Fayetteville at 7; Southwest Transmission at 3; Alaska Power at 2.

[78] *See, e.g.*, City of Dover at 2; Northwest Utility at 2; TANC at 20.

million MWh of electricity per year.[79] They also cite to the definition of a small utility under the Regulatory Flexibility Act and Small Business Act, which define a utility as small if its total annual output (i.e., wholesale and/or retail) does not exceed 4 million MWh.[80] APPA states that a threshold of 4 million MWh annual wholesale sales would capture approximately 70 percent of public power utilities' wholesale sales, and 82 percent of wholesale sales made by cooperative, Federal, and public power utilities combined. APPA argues that using annual wholesale sales will eliminate the potential for double-counting some public power wholesale sales in RTO regions, such as joint action agency sales to their members. APPA also argues that the use of EIA data to determine which utilities are above the *de minimis* threshold for reporting purposes will eliminate the potential for double-counting some public power wholesale sales in RTO regions. For example, notes APPA, joint action agencies situated in RTO regions are often required to sell their wholesale power into their RTO's market at the point of generation, buy it back at their members' load nodes, and then sell the same energy to

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[79] In particular, FPA section 201(f) provides, in part, that "[n]o provision in this subchapter shall apply to, or be deemed to include . . .an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year." 16 U.S.C. 824(f).

[80] The Regulatory Flexibility Act (RFA) definition of a "small entity" refers to a definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. *See* 15 U.S.C. 632. According to the Small Business Act, a small electric utility is one that has a total electric output of less than 4 million MWh in the preceding year. 15 U.S.C. 631.

their members. Using EIA data would eliminate potential double-counting of these joint action agency sales to members as sales to an RTO as well. Additionally, the City of Fayetteville argues that, in promoting wholesale market transparency, retail sales to ultimate consumers should not be counted toward the cutoff, because such sales do not bear on whether a section 201(f) entity's wholesale market presence is *de minimis*.

63. EMCOS believes that 4 million MWh based on total annual sales is appropriate, but that both inter-affiliate sales by consumer-owned utilities and must-offer sales into Day 2 markets should be excluded to avoid over-reporting. NRECA and Allegheny argue that the Commission also should not consider sales by G&T cooperatives to their members as wholesale sales for purposes of the *de minimis* 4 million MWh sales threshold. NRECA states that when a G&T cooperative makes sales to its member cooperatives under long-term wholesale power contracts, it is essentially acting as the functional equivalent of a generation division of a vertically integrated public utility. NRECA also argues that if the Commission does not exclude sales by G&T cooperatives to their member cooperatives, then it should establish a rebuttable presumption that non-public utility cooperatives that sell less than 4 million MWh of power to third parties other than their member cooperatives are exempt from the filing requirement as having a *de minimis* impact on wholesale markets if such sales constitute less than 2 percent of wholesale sales in the region.

64. LPPC asks the Commission to exempt non-jurisdictional entities from having to report long-term sales agreements (of greater than one year) between non-jurisdictional entities. LPPC also asks the Commission to provide a mechanism for requests for waiver

sought by parties on the ground that specific transactions or categories of transactions are not of a nature that their reporting is relevant to the Commission's oversight of the wholesale marketplace. LPPC states that examples of typical long-term agreements between non-jurisdictional entities are the thirty-year sales agreements between municipal utilities and MEAG Power, which was formed by the Georgia Assembly for the purpose of generating power to be sold under long-term agreements to municipal utility participants. LPPC states that the power sold under these agreements does not factor into the market over which the Commission has oversight.

65. Some commenters further note that the Commission has used a 4 million MWh of total sales threshold in several contexts. For instance, TANC states that the Commission has used this threshold in granting waivers of standards of conduct for transmission providers under Order Nos. 888,[81] 889,[82] and 890,[83] and with respect to the requirement

[81] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 FR 64688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[82] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, 62 FR 12484 (March 14, 1997), FERC Stats & Regs. ¶ 31,049, *reh'g denied*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

[83] Order No. 890, FERC Stats. & Regs. ¶ 31,241.

that RTOs/ISOs accept demand response bids by aggregators of retail customers.[84] Furthermore, some commenters, such as LPPC, argue that a utility that sells 4 million MWh or less of energy per year is too small to affect the electricity markets, so excluding it from the EQR requirements would still provide the Commission with information on the large majority of wholesale transactions by non-jurisdictional entities.

66. By contrast, EEI and DC Energy recommend adopting relatively low thresholds. EEI states that the Commission could apply one of the following thresholds: (1) 100 MWh of sales for resale per year used by the Commission in the context of FERC Forms 1 and 1-F between major and non-major utilities; or (2) 114,000 MWh of sales per year, based on what a qualifying facility (QF) exempted from FPA section 205 (20 MW or smaller) could produce in a year.[85]

67. Sam Rayburn Municipal believes that a threshold exemption should exist where there is no retail competition or the relative size or amount of power transactions is insignificant by size or substance.

ii. <u>Discussion</u>

68. FPA section 220(c)(2)(d) specifies that the Commission shall not require entities with a *de minimis* market presence to comply with the reporting requirements of FPA section 220. At present, the Commission collects data regarding cost-based sales,

[84] TANC at 19-20 (citing *Wolverine Power Supply Coop., Inc.*, 127 FERC ¶ 61,159, at P 15 (2009); Order No. 719, FERC Stats. & Regs. ¶ 31,218).

[85] EEI at 4.

market-based rate sales, transmission service, and transmission capacity reassignments from entities subject to section 205 of the FPA. Data regarding sales, transmission service, and transmission capacity reassignments provided by non-public utilities is not readily available. Without this data, the public is unable to observe a significant number of trades and is unable to develop a more complete view of wholesale power and transmission markets. As discussed above, a more complete view of price formation in the markets will provide the public with greater price transparency to evaluate the concentration of market participants in a market and the market participant's ability to unduly influence the market, and will assist the public and the Commission in detecting and addressing the potential exercise of market power and manipulation.

69. The Commission proposes that a non-public utility would be exempt under the *de minimis* market presence threshold from filing EQRs if it makes 4 million MWh or less of annual wholesale sales (based on an average of the wholesale sales it made in the preceding three years), unless the non-public utility is a Balancing Authority[86] that makes 1 million MWh or more of annual wholesale sales (based on an average of wholesale sales it made in the preceding three years). As requested by some commenters, the Commission proposes to calculate the *de minimis* market presence threshold on the

[86] As defined in the North American Electric Reliability Corporation's (NERC) Glossary of Terms Used in Reliability Standards, a Balancing Authority is the "responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balancing within a Balancing Authority Area, and supports Interconnection frequency in real time." *See* http://www.nerc.com/files/Glossary_of_Terms_2011Mar15.pdf.

amount of annual wholesale sales made by the non-public utility rather than total (i.e. wholesale and retail) sales. The transparency provisions in FPA section 220 focus on the Commission requiring information concerning the availability and prices of "wholesale electric energy and transmission service."[87] Therefore, the Commission proposes to use only the wholesale electricity sales made by non-public utilities for purposes of calculating the *de minimis* market presence threshold.

70. To reduce the filing burden and promote clear compliance requirements, the Commission proposes that non-public utilities use the annual wholesale sales volumes they currently report to EIA to calculate whether they meet the *de minimis* threshold.[88] The Commission proposes that the threshold be calculated using the "Sales for Resale" data published in EIA Form 861.[89] "Sales for Resale" as reported in EIA Form 861 does not include retail sales, as addressed above.

71. The Commission believes that establishing a 4 million MWh annual wholesale sales threshold for non-public utilities that are not Balancing Authorities will allow the Commission and the public to access information from market participants whose transactions could have an impact on wholesale market prices and thereby increase price

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[87] *See* 16 U.S.C. 824t(a)(2).

[88] This proposal is consistent with APPA's suggestion to use EIA data when calculating the *de minimis* threshold. *See* APPA at 9-10.

[89] "Sales for Resale" figures can be found on Line 12 in "Schedule 2, Part B. Energy Sources and Disposition." *See* http://www.eia.doe.gov/cneaf/electricity/forms/eia861/eia861instr.pdf.

transparency for the markets and aid in the Commission's oversight of wholesale electricity markets,[90] while alleviating the reporting burden for smaller entities.

72. With respect to non-public utilities that are Balancing Authorities, the Commission believes requiring them to file EQRs if they make 1 million MWh or more of annual wholesale sales will provide a more complete picture of prices within the balancing authority area markets that are operated by non-public utilities and thereby assist market participants and the Commission, particularly with respect to conducting market-based rate analyses for jurisdictional market-based rate sellers. For traditional (non-RTO/ISO) markets, the Commission uses the balancing authority area as the default relevant geographic market for its market-based rate analysis.[91] For example, Order No. 697 noted that if a transmission-owning Federal power marketing agency is the home or first-tier market to a seller located outside of an RTO/ISO, then that seller must treat that Federal power marketing agency's balancing authority area as a relevant geographic market and file a market power analysis on it just as it would any other relevant market.[92] Obtaining sales information from non-public utility Balancing Authorities that operate

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[90] It is important to note that electricity markets can be comprised of markets that are regional, local, and even nodal. For example, exerting market power does not necessarily involve a large volume of physical sales. In fact, small volumes of power sales can influence market pricing, particularly when transmission limitations and other dynamics exist.

[91] *See* Order No. 697, FERC Stats. & Regs ¶ 31,252 at P 232.

[92] *See id.*

that balancing authority area would greatly assist the Commission in determining whether to grant a seller market-based rate authority (*ex ante* analysis) and allow a more effective after-the-fact examination of market-based rate authorizations (*ex post* analysis). The Ninth Circuit Court of Appeals upheld the Commission's market-based rate program based on the dual requirement of an *ex ante* finding of the absence of market power and post-approval reporting requirements through the EQR. Specifically, the Ninth Circuit held that "FERC's system consists of a finding that the applicant lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation."[93]

73. APPA expresses concern about double counting of wholesale sales by joint action agencies situated in RTO/ISO markets. APPA notes that joint action agencies in RTO/ISO regions are often required to sell their wholesale power into the RTO/ISO market at the point of generation, buy it back at their members' load nodes and then sell the same energy to their members. APPA suggests that using EIA data would eliminate double counting of these joint action agency-to-member transactions as sales to an RTO/ISO. As noted above, the Commission proposes that non-public utilities use EIA data to determine whether they meet the *de minimis* threshold. However, the Commission is concerned with capturing all wholesale power sales as they occur (no

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[93] *Lockyer*, 383 F.3d 1013.

matter how many times the power changes hands). Therefore, in the example provided by APPA, the Commission agrees that EIA data should be used by the joint action agency to determine whether it meets the *de minimis* threshold for filing EQRs. However, if the joint action agency, or other non-public utility, determines that it falls above the *de minimis* threshold based on the EIA data, then the Commission would expect the joint action agency or other non-public utility to report all wholesale sales in a manner that is consistent with existing EQR reporting standards.

74. Some commenters argue that the Commission should not consider sales such as inter-affiliate sales by consumer-owned utilities or sales by G&T cooperatives to their members for purposes of the *de minimis* threshold. For ease of reference, we shall refer to the transactions raised by NRECA, and others as "inter-familial transactions". We disagree with commenters' assertions that wholesale inter-familial transactions should not be considered sales for purposes of the *de minimis* annual wholesale sales threshold. Rather, the Commission believes that any sale of wholesale electricity should count towards the threshold, regardless of the type of transaction from which the sale originated (e.g., G&T cooperative sales to its members captured under long-term wholesale power agreements). Moreover, reporting of wholesale inter-familial transactions will assist the Commission and the public in monitoring price formation and understanding electricity prices, quantities, and market trends, particularly in bilateral markets.

75. We further note that the Commission will not propose the rebuttable presumption suggested by NRECA that non-public utility cooperatives that sell less than 4 million MWh of power to third parties other than their member cooperatives are exempt from the

EQR filing requirements as having a *de minimis* impact on wholesale markets if such sales constitute less than 2 percent of wholesale sales in the region. We also do not propose a mechanism for requesting waiver of the EQR reporting requirements on the basis that the nature of specific transactions or categories of transactions are not relevant to the Commission's oversight of wholesale markets. Under the proposed *de minimis* threshold, a non-public utility that makes 4 million MWh or less of annual wholesale sales would be exempt from filing EQRs unless the non-public utility is a Balancing Authority making 1 million MWh or more of annual wholesale sales. Because entities with a *de minimis* market presence are thereby exempted from the EQR filing requirement, the Commission does not believe it is necessary to establish a rebuttable presumption or waiver procedures. In addition, as explained above, we believe that it is necessary to capture a G&T cooperative's sales to its members for transparency purposes, and therefore will not propose the rebuttable presumption approach as suggested by NRECA.

76. Sam Rayburn Municipal believes that a threshold exemption should exist where there is no retail competition or the relative size or amount of power transactions is insignificant by size or substance under this effort. We agree with Sam Rayburn Municipal's comments about a threshold exemption, but we disagree with its comment on an exemption where retail competition does not exist. In states where retail competition is not present there are still wholesale transactions that are of interest to the Commission and public. These transactions are part of wholesale electricity price formation even in regions where retail competition does not exist. Additionally, it is the

Commission's duty to ensure market transparency and obtain reporting from a sufficient number of market participants to accurately understand the physical electricity market as a whole.

77. EMCOS believes that must-offer sales into a "Day-2" RTO/ISO market should be excluded because they involve output committed under contracts.[94] In particular, EMCOS commented that must-offer sales into "Day-2" central security-constrained dispatch/central unit commitment markets should be excluded from the calculation of the *de minimis* threshold, because such sales reflect only the application of a tariff requirement for bidding both load and the output of resources already contractually committed to serving that load in order to facilitate bid-based pricing, and do not provide useful information about the exchange of commercial consideration leading to price formation. The Commission believes that resources committed under contract do impact price formation and should be included in the *de minimis* threshold calculation. Must-offer provisions often do not dictate the price at which a unit may offer its supply into the market. Even if a must-offer unit is a price taker through self-scheduling, the unit is impacting price formation through its supply into RTO/ISO markets.

[94] EMCOS at 12.

B. Refinements to the Existing EQR Requirements

1. Background

78. In addition to seeking comments on whether the Commission should extend the EQR reporting requirements to non-public utilities, the Commission also sought comments regarding certain refinements to the EQR reporting requirements. Specifically, the Commission sought guidance on whether to: (1) require the reporting of the trade date, type of rate, and resales of financial transmission rights in secondary markets; (2) use a standard unit for reporting energy and capacity transactions; and (3) omit the time zone from the contract section.

79. As discussed above, the Commission has determined that it should consider whether substantial reforms to the EQR reporting requirements are needed. After considering comments received in response to the Transparency NOI, the Commission is proposing in this NOPR to make the following refinements to the EQR: (1) reporting of the transaction date; (2) reporting of the type of rate by which the price was set (i.e., fixed price, formula, index, or RTO/ISO price); (3) standardizing the unit for reporting energy and capacity transactions (i.e., \$/MWh, \$/MW-month); and (4) omitting the time zone from the contract section. The Commission is also proposing not to require the reporting of resales of financial transmission rights in secondary markets.

80. In addition, the Commission proposes other refinements that were not included in the Transparency NOI. In particular, the Commission proposes to require EQR filers to: (1) report the time that the transaction took place; (2) identify the broker or exchange used for a sales transaction, if applicable; (3) indicate whether the transaction was

reported to an index publisher; and (4) report certain e-Tag data. The Commission also proposes to eliminate the DUNS number requirement.

2. General Refinements

81. In combination with the broader effort to improve the Commission's access to information about the availability and prices of wholesale sales of electricity, the Transparency NOI considered other refinements to the existing EQR filing requirements. As discussed above, these refinements included: (1) reporting the trade date (i.e., the date on which a transaction price is set) and the type of rate (i.e., fixed price, a formula, an index, or an RTO/ISO price); (2) reporting resales of financial transmission rights in secondary markets; (3) standardizing the unit for reporting energy and capacity transactions (i.e., $/MWh and $/MW-month); and (4) omitting the time zone from the contract section of the EQR. The proposals described above are detailed in Appendix B.

a. Trade Date & Time and Type of Rate

i. Comments

82. DC Energy agrees that the EQR reporting requirement should include the contract date, and states that master agreements or evergreen contracts do not preclude an entity from specifying when the agreement to transact was executed.[95] California PUC also supports the addition of requirements to report the trading date information and to specify

[95] DC Energy at 10.

whether the reported rate is a fixed price, a formula, or an index. It states that prices without trading dates are less informative because prices change over time.[96]

83. EEI, EPSA, and Duke Energy argue that the burden of collecting the trade date and type of rate from all filers likely will require system changes and thus outweighs the value of such information.[97] In addition, EPSA suggests that there are several problems with adding the trade date, such as it being subject to multiple interpretations and creating major software problems in the Commission's EQR program.[98]

84. EPSA's other major concern with this reporting requirement is timing. Any reporting requirement would have to be prospective only, as "trade date" is not currently a reporting requirement. Thus, there may be major software problems created with the Commission's EQR program. EPSA states that, if implemented by the Commission without grandfathering preexisting transactions, there would be no way for reporting entities to differentiate new deals from old, and the old deals will not have a reported trade date. Thus, any analysis done with this newly reported data would have a field precluded from historical data. Any adjustments made to prior quarters' data presumably would need to include this information, which may be impossible to gather for preexisting transactions. EPSA is concerned that the Commission's EQR software would

[96] California PUC at 3-4.

[97] EEI at 6-7; EPSA at 2-3; Duke Energy supports the comments filed by EEI at 2.

[98] EPSA at 4.

generate error messages for leaving the field blank. The Transparency NOI provides no discussion of these problems and EPSA states that the Commission should seriously consider these concerns before requiring that transaction dates be reported.

85. In addition, EPSA states there is an overlap issue. If a deal is concluded in one quarter but goes to delivery in another quarter (or quarters), will it have to be reported in the quarter the transaction was concluded as well as the quarter(s) of delivery? What about any intervening quarters – will the entity have to report deals in some form of abeyance between conclusion and delivery?

86. Also, EPSA states that some of its member companies have reported that they do not track how the price was set and therefore could not currently comply with a requirement to report the type of rate. Thus, if this proposal is adopted, market participants would need to make major system changes to be able to capture and report this data. If the Commission proceeds down this route, EPSA contends that the Commission should allow a significant period of time for implementation before this aspect of a rule change became mandatory so that reporting parties could hire the necessary contractors, and have time to reconfigure data capture and reporting systems to collect this new data.

87. However, if the Commission decides to require filers to include the trade date and type of rate, then EEI and EPSA propose several revisions. EEI suggests that the Commission clarify that “trade date” includes only the date and not the time of day when

a transaction price was set and only include it in the transactions section, not the contract section.[99] Also, EEI proposes that "the date the price was agreed to" should refer to the date the trade was finally executed.[100] According to EPSA, its members have reported that through custom and usage in the trading industry, the term "Trade Date" has developed the broadly understood meaning of "the date upon which the parties agree upon the terms of, and enter, a transaction." EPSA argues that the Commission should give the term "Trade Date" the same meaning it generally has in the industry.[101] In addition, EEI suggests that if the Commission decides to include the type of rate, then the options should be modified to "fixed," "formula without index," and "formula with index." EEI also requests that the Commission clearly define these rate types and give examples to ensure that industry applies the terms consistently.[102]

88. FirstEnergy asserts that the EQR Contract Data already captures the trade date via the Contract Execution Date in Field 21, which provides for the date the contract was signed. According to FirstEnergy, typically the rate for the transaction will be agreed upon on this date. FirstEnergy also states that the Commencement Date is reported in the Contract Terms in Field 22, which provides for the date that the terms in the contract are

[99] EEI at 6-7.

[100] *Id.* at 6.

[101] EPSA at 4.

[102] EEI at 7.

effective. Further, FirstEnergy explains that Fields 43 and 44 provide the first and last dates for the sale of the product at the specified rate. In addition, FirstEnergy states that the Commission's proposed field to describe the type of rate for each transaction is already reported under field 37, Rate Description. According to FirstEnergy, this field currently requires that the filing company either cite the FERC accession number for the relevant FERC tariff or provide the entire rate algorithm.[103] Similarly, EPSA argues that the "type of rate" information is already captured in the "contract" field and that creating a new field would be a significant burden.[104]

ii. <u>Discussion</u>

89. The current Commission EQR reporting requirements include, among other things, the Contract Execution Date (Field Number 21), the Contract Commencement Date (Field Number 22), Rate Description (Field Number 37), Begin Date (Field Number 43), and End Date (Field Number 44).[105] These contract fields were not intended to capture trade-specific details related to each specific transaction, but rather to capture contractual terms and conditions under which two entities transact for all jurisdictional services.

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[103] FirstEnergy at 2-3.

[104] EPSA at 5.

[105] These fields are outlined in more detail in the *Electronic Quarterly Report Data Dictionary*, Version 1.1, *available at* http://www.ferc.gov/docs-filing/eqr/soft-tools/eqrdatadictionary.pdf.

90. We agree with the points made by DC Energy and the California PUC. Master agreements and evergreen contracts do not preclude an entity from specifying when an agreement to transact was executed. Prices without trading dates are less informative because prices change over time.

91. Presently, the trade date and type of rate by which the price was set are not provided or collected publicly. The trade date is essential to assessing the significance of prices in relation to market conditions in effect at that time.[106] Many of the prices reported in the EQR are the result of confirmation made under master agreements. Because the prices are not set in the contracts themselves, the Commission is unable to determine from EQR data when the price was set. Additionally, the Commission is unable to conclude whether the price was based on a fixed price, a formula, an index, or an RTO/ISO price.

92. Therefore, to improve market transparency, the Commission proposes to require market participants to report the date on which parties to a reported transaction agreed upon a price (trade date) and, additionally, require the type of rate by which the price was set (i.e., fixed price, formula, index, or RTO/ISO price) in its respective EQR filings. The date and type of rate are to accompany each specific sales transaction and be reported in the EQR transaction section only in the quarter the sale occurs.

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[106] Currently, the EQR collects only the start and end date of physical transactions. Trades entered into months before the transaction dates are reported in the same manner as trades entered into minutes before the transaction occurs, making it difficult to differentiate between trades made under different circumstances.

93. We propose to clarify the term “trade date” as “the date upon which the parties agree upon the price of a transaction.” As discussed below, we also propose tracking the time of the transaction. Further, EEI suggests that the Commission clarify how to specify the type of rate and provide examples to ensure that industry applies the terms consistently. As a result, the options for the type of rate that the Commission is proposing will be “fixed,” “formula,” “index,” and “RTO/ISO price.” A “fixed” rate will be defined as a fixed charge per unit of consumption. An example is an agreement for the sale of 30 MWh during every on-peak hour during 2012 for an agreed upon rate in advance of delivery. A “formula” rate will be defined as a calculation of a rate based upon a formula that does not contain an index component. An example is a cost-of-service rate. An “index” rate will be defined as a calculation of a rate based upon an index or a formula that contains an index component. An example is an options agreement where power is sold at a published index price (or at a percentage of that published index price). An “RTO/ISO price” will be defined as a rate that is based on an RTO/ISO published price or a formula that contains an RTO/ISO price component. An example is a generator’s sale to into a RTO/ISO day-ahead market.

94. This proposal would impose additional reporting requirements on any market participant that is required to file an EQR with the Commission. The Commission will ensure its EQR software can accommodate such requirements before the first EQR filings containing the trade date and type of rate must be submitted. Reporting of the trade date and type of rate would occur prospectively from the time the requirements are implemented. Accordingly, market participants would not have to re-file prior EQR

filings with the proposed time and date information and would not have to adjust a prior quarter's information on already executed transactions. However, if the Final Rule requires EQR filers to report the trade date and type of rate of their transactions, we would expect market participants to include the trade date and type of rate for transactions taking place from the date of the Final Rule's implementation. Any re-filings and adjustments to EQR filings made prior to the date of effectiveness of such a rule would follow the EQR filing requirements imposed at the time of the original filing.

95. Although not raised in the Transparency NOI, the Commission now proposes to require market participants to also report the time of trade. We propose to clarify the term "time of trade" as "the time upon which the parties agree upon the price of a transaction." The Commission recognizes that not only the date, but also the time of trade, is essential in identifying some forms of market manipulation that may be designed to target daily index price creation for the purpose of benefiting financial swap settlements. Without knowing what time a trade occurred, customers and the Commission would have difficulty identifying these out-of-market, or anti-competitive, transactions from those that followed the ebbs and flows of the daily market. This is due to the fact that competitive market pricing is often fluid to reflect changes in supply and demand fundamentals. For example, market pricing for next-day power on the morning before delivery may be entirely different than pricing that afternoon as outage, forecast and other information continually changes. It is possible for market participants to attempt to "direct" physical market pricing throughout the day in an effort to impact settlement pricing for other positions. This behavior may involve trading large volumes

at the beginning of the trading day in order to "direct" pricing in subsequent hours or other strategies that concentrate trading in a narrow time window.

b. Resales of Financial Transmission Rights in Secondary Markets

96. In the Transparency NOI, staff sought comments as to whether the Commission should collect information about the resale of financial transmission rights in secondary markets through reporting to the EQR. Specifically, the Transparency NOI asked whether market participants perceive that collecting this information would enhance market transparency and, if so, to designate what current EQR filing requirements should be imposed on resales of financial transmission rights in secondary markets. In addition, comments were sought to identify other filing requirements that may be applicable to the resale of financial transmission rights in secondary markets that are not current EQR filing requirements and explain whether and, if so, how collection of the information would improve market transparency.

i. Comments

97. California PUC and SDG&E support reporting sales of financial transmission rights to increase transparency of financial transmission right trading by both transmission and non-transmission owners and to reveal whether sales in the secondary market result in market concentration or increased liquidity. SDG&E also supports requiring transaction-specific information for financial transmission right secondary transactions as is required for all other transactions. APPA, Duke Energy, EEI and Morgan Stanley question the need for information concerning resale of financial transmission rights and assert that the burden of collecting financial transmission right

resale information may outweigh the minimal value of such information. EPSA believes that the Commission should not collect financial transmission right data as part of this transparency effort because it would be unnecessary, duplicative and not provide any useful information.[107] APPA and EPSA state that secondary financial transmission right markets are relatively illiquid and Morgan Stanley states that the Commission has recognized that financial transmission right markets are thinly traded at this time.[108] FirstEnergy argues that this filing requirement would be duplicative because RTO market monitors may have the responsibility for reviewing the secondary bilateral financial transmission right markets.[109] DC Energy also believes that reporting requirements for secondary market financial transmission right sales should be the province of the ISOs/RTOs.[110] APPA also sees the task of assuring transparency of financial transmission right transactions as a responsibility of the RTOs.[111] Morgan Stanley similarly recommends that the Commission monitor secondary market financial transmission right transactions by requesting each RTO to provide quarterly or annual

[107] EPSA at 5-6.

[108] Morgan Stanley at 2.

[109] FirstEnergy at 3-4.

[110] DC Energy at 10-11.

[111] APPA at 13.

data on such transactions arising in their markets.[112] In addition, PJM observes that, as a threshold question, the Commission should first determine whether it has any jurisdiction over this type of transaction before deciding whether to compel participant reporting.[113] PJM also states that its bulletin board on the PJM eFTR system may provide a means to access secondary market financial transmission right transaction information, making increased participant reporting unnecessary.[114]

ii. Discussion

98. We agree with certain commenters that RTOs/ISOs collect and publish some financial transmission right data and that RTOs/ISOs are the proper entities for reporting information about financial transmission rights. We believe that requiring financial transmission right data to be reported by market participants in the EQR, in addition to the information already provided by RTOs/ISOs, would not significantly improve price transparency in these markets. Therefore, we do not propose to require entities to report information about financial transmission rights in the EQR at this time.

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[112] Morgan Stanley at 2-3.

[113] PJM at 4-5.

[114] *Id.* at 2-4.

c. Standardizing the Unit for Reporting Energy and Capacity Transactions

i. Comments

99. California PUC, DC Energy, and PG&E support standardizing EQR data on capacity and energy across all filers to help the Commission and other market participants compare prices.[115] PG&E further states that $/MWh is an appropriate unit for energy transactions and $/MW is an appropriate unit for capacity transactions because these units are commonly used in organized electricity markets, including the markets operated by CAISO.[116]

100. EEI states that having common units for reporting energy and capacity transactions (i.e., $/MWh and $ per MW-month) would simplify interpretation of the data, but that the Commission should clarify that this change requires the conversion only of KWh to MWh and KW to MW (i.e., utilities can still report transactions in MW/Month, MW/Day, KVA, MVAR, etc.). In addition, EEI notes that if the Commission makes this change, then it will likely have to increase the number of digits allowed in the Rate field – particularly if the units being reported are MWhs.[117]

101. EPSA does not advocate standardizing units for reporting transactions. EPSA states that capacity may be sold on a $/MW-Day, $/MW-Week, $/KW-Day, $/KW-

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[115] California PUC at 4; DC Energy at 11; and PG&E at 3.

[116] PG&E at 3.

[117] EEI at 8.

Week, $/KW-Month, or $/KW-Year basis, and argues that the parties should report those trades in accordance with the way the products were measured, priced and sold under each transaction. According to EPSA, this will reduce the possibility of errors in translating one unit to another.[118]

ii. <u>Discussion</u>

102. We propose to insert an additional field to the EQR transaction section to standardize the units for reporting energy and capacity within the EQR. We agree with several commenters that the usefulness of the additional field will simplify interpretation of the data and aid the Commission and other market participants in comparing prices. The additional field will provide a consistent rate for comparison purposes and allow the Commission to develop internal checks in the EQR software on the accuracy of a filing.

103. Today, the EQR filing requirements include, among other things, the Transaction Rate Units (Field Number 65). This field requires a market participant to report the measure for the appropriate price of the product sold.[119] To avoid possible confusion, we clarify that the additional field we are proposing to add would not remove or replace any current EQR filing requirement. It would simply add a new field to capture a common unit for reporting energy and capacity transactions.

[118] EPSA at 6.

[119] Valid values include: $/KVA, $/KW, $/KW-DAY, $/KW-MO, $/KW-WK, $/KW-YR, $/KWH, $/MVAR-YR, $/MW, $/MW-DAY, $/MW-MO, $/MW-WK, $/MW-YR, $/MWH, $/RKVA, CENTS, CENTS/KVR, CENTS/KWH, and FLAT RATE. Rate units should match product names.

104. To ensure that similar sales can be easily compared, the Commission is proposing to standardize the units in which energy and capacity sales may be filed in the EQR. Therefore, energy transactions will be required to be reported as $/MWh and capacity transactions will be required to be reported as $/MW-month. Each filing entity will be required to make the conversion for any measurement that is not in this denomination. Several commenters suggested that requiring transactions to be reported using a standardized unit would introduce conversion errors into EQR. Converting the quantity and price for energy and capacity sales to $/MWh and $/MW-month generally requires routine, commonly-used calculations. Commission staff is available to assist filers with any filing-related questions, including conversion questions. Additionally, the Commission will ensure the appropriate number of digits in the EQR software to accommodate the conversion.

d. Omitting the Time Zone from the Contract Section of the EQR

i. Comments

105. DC Energy and EPSA support eliminating from the contract section of the EQR the requirement to report the time zone, so long as the Commission maintains the requirement to report the time zone in the transaction report.[120] EEI states that the time

[120] DC Energy at 11; EPSA at 6-7.

zone information in the contract section of the EQR is simply unnecessary and that deleting this requirement would help to reduce burden.[121]

ii. <u>Discussion</u>

106. We propose eliminating the Contract Time Zone (Field Number 45) as currently required in EQR filings. We agree with EEI that time zone information in the contract section of the EQR is unnecessary and that eliminating it would reduce the burden of filing the EQR. However, we clarify that, although we propose to eliminate time zone information from the contract section, we will continue to require EQR filers to report the time zone where the transaction took place in the transaction section (Field Number 55).

3. <u>Additional EQR Enhancements</u>

107. In the almost nine years since the Commission established EQRs under Order No. 2001, large financial markets have emerged and become increasingly intertwined with physical wholesale power markets. Further, the diversity and complexity of derivatives instruments that are linked to physical power prices have grown exponentially. EQR reporting requirements have not kept pace with these market evolutions. The refinements proposed in this NOPR are intended to allow the Commission and market participants to use the EQR to identify behavior in physical power markets that may be designed to influence a market participant's financial positions linked to physical market pricing fundamentals.

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[121] EEI at 8.

108. The Commission recognizes that there is an incentive to manipulate bilateral wholesale spot markets for the purpose of influencing financial swap settlements. Although leveraged financial positions can provide legitimate hedging capabilities, they can also create incentives for companies to alter physical market prices. Incentives to manipulate can be especially strong outside of RTO/ISO markets, where bilateral transactions are used to determine swap settlement values.

109. For these reasons, the Commission proposes to require several new data fields in the EQR that will enable market participants and the Commission to identify physical wholesale transactions that could contribute to pricing designed to influence financial swap settlements. These additional enhancements were not raised for comment in the Transparency NOI, but rather are being proposed in this NOPR as the Commission continues to weigh appropriate measures to help facilitate greater price transparency and help ensure that a market participant does not manipulate wholesale electricity markets for the purpose of benefiting its financial positions. Thus, the Commission proposes to require EQR filers to report in the transaction section of the EQR the following information: (1) the index publisher(s) to which the transaction was reported; (2) the exchange on which the transaction was consummated or the brokerage firm that arranged the transaction; and (3) the time the transaction occurred.

a. Identify Transactions Reported to Index Publishers

110. The Commission proposes to require all market participants to report in the transaction section of EQR the index price publisher to which they have reported their

sales transactions. The Commission has recognized the importance of price indices in energy markets, noting in its *Policy Statement on Natural Gas and Electric Price Indices*:

> Price indices are widely used in bilateral natural gas and electric commodity markets to track spot and forward prices. They are often referenced in contracts as a price term; they are related to futures markets and used when futures contracts go to delivery; . . . and state commissions use indices as benchmarks in reviewing the prudence of gas or electricity purchases. Since index dependencies permeate the energy industry, the indices must be robust and accurate and have the confidence of market participants for such markets to function property and efficiently. [122]

111. The Commission believes that requiring in the EQR the names of index price publishers to which wholesale power sale transactions are reported would allow the Commission, market participants and other interested parties greater transparency to see how market forces are affecting those index prices and the market concentration of the companies' sales used to calculate the index prices.

112. In addition to market participants' significant use of index prices with respect to tracking electric spot and forward prices, the use of index prices has expanded to form settlement prices for financial products. Because bilateral physical spot markets are used to settle financial swaps, there is an incentive to manipulate the physical markets to benefit larger financial positions. For example, linked financial-swap contracts at several hubs traded at volumes many times larger than bilateral spot trading at that particular hub. The multiple of financial-swaps at such hubs in relation to physical transactions

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[122] *See Price Discovery in Natural Gas and Electric Markets*, Policy Statement on Natural Gas and Electric Price Indices, 104 FERC ¶ 61,121, at P 6, *clarified*, 105 FERC ¶ 61,282 (2003).

indicates that opportunities to profit from physical market manipulation strategies involving financial positions already exist. For instance, a market participant with fixed price financial-swap contracts could manipulate the physical index price by transacting power at a loss for transactions that contribute to the index price. However, the market participant could still profit from such activity because any loss from selling power that contributes to the index price could be more than offset by financial-swap gains resulting from moving the index price. Thus, greater transparency could further our understanding of how index prices are formed. This, in turn, could lead to more robust indices, enhance public confidence in their accuracy and reliability, and improve the Commission's ability to monitor prices for exercises of market power and manipulation.

113. Section 35.41(c) of the Commission's regulations[123] requires market-based rate power sellers to submit a notification to the Commission if they report transactions to electric or natural gas price index publishers. However, this regulation does not require market-based rate sellers to specify the price index publishers to which they report their transactions and it applies only to one subset of market participants whose transactions are used to form index prices, i.e., jurisdictional power sellers with market-based rate authorization from the Commission. Obtaining information from all market participants about which transactions are reported to which index publishers will strengthen the

[123] 18 CFR 35.41(c). *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, *see* Order Amending Market-Based Rate Tariffs and Authorizations, 105 FERC ¶ 61,218, at P 116-119 (2003).

Commission's and interested observers' ability to determine whether these index prices reflect market forces and provide market participants with greater confidence in the accuracy of index prices. Therefore, we propose to require each EQR filer to report in the transactions section the particular electric or natural gas index publisher to which they report transactions, if applicable. To eliminate redundancy between the EQR filings and the notification required under 18 CFR 35.41(c) from market-based rate sellers, we propose to amend that provision to no longer require notifications from these sellers to the Commission stating whether they are reporting transactions to electricity or natural gas index publishers, or updates of such notifications.

b. Identify the Exchange/Broker used to Consummate a Transaction

114. Exchanges and brokers routinely publish index prices composed of wholesale transactions that were consummated on their exchange or through their brokerage services. Such index prices are used to track electric spot and forward prices and, increasingly, to form settlement prices for financial products. We believe that requiring information regarding whether exchanges or brokers were used to consummate a transaction will promote visibility into index prices and bolster the Commission's market monitoring efforts.

c. Collection of e-Tag ID Data

115. To schedule physical interchange transactions,[124] market participants submit e-Tags to transmission system operators. Generally, e-Tags track energy transfers, including where the power is sourced and delivered; the responsible parties in the receipt, delivery and movement of the power; the timing; and the volumes and specific details regarding which transmission paths are used. An e-Tag is reported to NERC or WECC, but is not presently reported to the Commission.

116. The Commission proposes to require EQR filers to submit e-Tag IDs for each transaction reported in the EQR in the event an e-Tag is used to schedule the transaction. The e-Tag ID is a subset of information associated with a full e-Tag and consists of four components: (1) Source Balancing Authority Entity Code;[125] (2) Purchasing-Selling Entity Code;[126] (3) e-Tag Code or Unique Transaction Identifier;[127] and (4) Sink

[124] An interchange transaction involves a transfer of energy from a seller to a buyer that crosses one or more balancing authority area boundaries.

[125] The Source Balancing Authority is defined as the host Balancing Authority in which the generation is located.

[126] The Purchasing-Selling Entity is the entity creating and submitting the e-Tag request to the authority service, which authorizes implementation of interchange schedules between balancing authority areas. The Purchasing-Selling Entity also is the entity that purchases or sells, and takes title to, energy, capacity and interconnected operations services.

[127] The e-Tag Code is a unique seven-character transaction identifier for each bilateral energy transaction scheduled on the transmission network. It is assigned by the e-Tag system when transmission service to accommodate the transaction is reserved.

Balancing Authority Entity Code.[128] Requiring e-Tag IDs as part of EQR filings would address a major gap in EQR information as it is currently reported: the source location of wholesale sales transactions. E-Tag IDs would assist market participants and the Commission in identifying chains of transactions and transaction paths. Using the information currently reported in the EQR, it is difficult to identify linked re-sales or chains of transactions between filers. EQRs currently require reporting of the Point of Receipt Balancing Authority (Field Number 39) for power sales contracts if that information is specified in the contract. In practice, however, many EQRs do not contain information related to the Point of Receipt Balancing Authority because many contracts do not specify source information.

117. Accessing e-Tag IDs through the EQR would facilitate price transparency by enabling all market participants to "follow" transactions across markets. In other words, market participants would be able to identify that an energy trade from Company A to Company B and an energy trade reported by Company B to Company C are, in fact, a re-sale of power from Company A to Company C because both sales would reflect the same e-Tag ID. Also, the markups observed for these "arbitrage" transactions are a valuable indicator of competitiveness in the wholesale market. Specifically, one would expect the arbitrage value between differently-priced markets to be closely associated with the cost to secure transmission between those markets. Persistent price differences between

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[128] The Sink Balancing Authority is defined as the host Balancing Authority in which load is located.

markets that are not consistent with transmission costs could indicate that the ability to arbitrage market price differences is not fully competitive.

118. In addition, the Source Balancing Authority information contained in the e-Tag ID would provide additional detail on the contract path used to schedule a transaction. In analyzing EQR filings, the Commission has found that source information related to a power sale is a vital component in analyzing transactions for anti-competitive behavior. Specifically, without some general knowledge of where power is being generated, it would be difficult to determine whether an interchange transaction is competitively arbitraging price separations between markets or behaving anti-competitively. Furthermore, the e-Tag IDs will allow the Commission and market participants to better monitor interchange transactions and detect potential abuses.

119. In a NOPR in Docket No. RM11-12-000 (e-Tag NOPR), to be issued concurrently with this NOPR, the Commission proposes to require the Commission-certified Electric Reliability Organization, i.e., NERC, to provide Commission staff with non-public access to complete e-Tag data. This data will, among other things, help the Commission to monitor wholesale markets and prevent market manipulation. In the e-Tag NOPR, the Commission explains that accessing e-Tag data through NERC, rather than requiring individual market participants to provide such data to the Commission, would avoid burdening market participants with submitting the complete e-Tags with both NERC and the Commission. In addition, it would avoid burdening the Commission with developing and maintaining a new system to capture such data from market participants. In this NOPR, the Commission is proposing to require individual market participants to file, if

applicable, a sub-set of e-Tag information, specifically e-Tag IDs, as part of the EQR because market participants are able to match their e-Tag IDs with the transactions they are required to report in the EQR. As explained above, access to this information in the EQR will allow the public and the Commission to "follow" transactions across markets.

d. Eliminating the DUNS Number Requirement

i. Comments

120. Under existing requirements, filers must identify all customers and sellers reported in the EQRs using DUNS numbers, a numeric identifier assigned by Dun & Bradstreet, Inc. The Commission required DUNS numbers in order to distinguish among similarly named, but different, service providers.[129] Although the Transparency NOI did not seek comment on whether to continue requiring DUNS numbers in EQRs, several commenters urged the Commission to eliminate this requirement. EEI argues that DUNS numbers have proven not to be a unique way to identify entities and have become a waste of time, resources, and money. In addition, EEI and Wisconsin Electric state that some market participants have multiple DUNS numbers, while others have only one or none at all.[130] Wisconsin Electric notes that DUNS numbers listed in the EQR are often incorrect, and that not all market participants subscribe to the proprietary cross-referencing service.[131]

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[129] *See* Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 90.

[130] Wisconsin Electric at 2.

[131] *Id*.

EPSA asserts that its members view DUNS numbers as more of an administrative burden than a help and that an error message occurs even though the Commission has instructed a party to input zero when a counterparty does not have a DUNS number. As an alternative to DUNS numbers, Wisconsin Electric proposes that the Commission adopt a more widely used identification system, such as federal tax IDs. EEI proposes using a company's legal name or a new ID developed through the FERC eTariff program. EPSA does not advocate a specific identification method but did recognize that a uniform nomenclature should be adopted.

ii. <u>Proposal</u>

121. The Commission proposes to eliminate the DUNS number requirement from EQR filings. Customer/counterparty identification through unique identifier numbers is a significant component of EQRs, particularly when identifying sales to individual companies. In the EQR, the customer company names are reflected in Field Numbers 16 and 48 as unrestricted, or free-form, text fields. As a result, the customer company names inserted in Field Numbers 16 and 48 are not always uniformly reported by different sellers. To help ensure more precise identification of counterparties, however, EQRs use DUNS numbers in Field Numbers 17 and 49. However, DUNS numbers have proven to be an imprecise identification system. As noted by commenters, EQR filers can have multiple DUNS numbers, only one DUNS number, or no DUNS number at all.

122. In considering alternatives to the use of DUNS numbers, the Commission finds that none of the suggested approaches would provide a viable replacement to the current approach and requiring a different numbering system would create legacy issues.

Therefore, the Commission will not replace the DUNS number requirement with another approach at this time, but rather will continue to rely on the insertion of customer company names in the free-form fields, Field Numbers 16 and 48.

III. <u>Information Collection Statement</u>

123. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[132] 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 an agency 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. The Paperwork Reduction Act (PRA)[133] requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability.[134]

124. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will

[132] 5 CFR 1320.8.

[133] 44 U.S.C. 3501-3520.

[134] OMB's regulations at 5 CFR 1320.3(c)(4)(i) require that "Any recordkeeping, reporting, or disclosure requirement contained in a rule of general applicability is deemed to involve ten or more persons."

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.

125. The Commission's estimate of the additional average annual Public Reporting Burden and cost[135] related to the proposed rule in Docket RM10-12-000 follow.

	No. of respondents per year	No. of responses per respondent per year	Implementing Burden		Recurring Operating Burden		Average Annual Burden (implementation cost averaged over the 3 yrs.)	
			Burden hrs. per respondent	Cost per respondent	Burden hrs. per response	Cost per response	Burden Hours	Cost
Public Utility Filers								
Current filers	831	4	160	$15,659	8	$783	70,912	$6,940,157
Non-Public Utilities								
Non-BA, with >4 mill. MWH wholesale sales/yr.	53	4	400	$39,148	24	$2,349	12,155	$1,189,577
BA, with >4 mill. MWH wholesale and retail sales/yr.	3	4	400	$39,148	24	$2,349	688	$67,335
BA, small with >=1mill. MWH wholesale and retail sales/yr. & <=4 million MWh	5	4	400	$39,148	24	$2,349	1,147	$112,224
Sub-Total for Non-Public Utilities	61						13,989	$1,369,136
GRAND TOTAL, AVERAGE ANNUAL ESTIMATES	**892**	**4**					**84,901**	**$8,309,293**

126. In calculating the number of current respondents filing EQRs, the Commission looked at the number of agents responsible for submitting the filings of the EQR, which came to 1,291 filers. Out of those 1,291 filers, only 831 reported transactions during

[135] For purposes of calculating the annual averages, the implementation burden and cost have been averaged, spread over the 3-year period, and added to the recurring burden and cost.

2009. Therefore, the Commission proposes to use 831 as the number of respondents.[136] Although the Commission estimates the total number of current respondents to be 831, this figure overstates the number of corporate families filing the EQR because some of the filings were made separately by affiliates from the same company. For instance, of the 831 filer names, 28 began with FPL, 24 began with NRG, 12 began with Wheelabrator, and 11 began with Dynegy. This trend was common among other filers.

127. For non-public utility filers, the Commission separately estimated the burden for non-balancing authorities with more than 4 million MWh of annual wholesale sales; balancing authorities with more than 4 million MWh of annual wholesale and retail sales; and balancing authorities with 1 million MWh or more of annual wholesale and retail sales. In the RFA Certification section below, the Commission uses the SBA definition of a small utility to determine how many small entities will be impacted by the proposed rule. The SBA defines a utility as small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total

[136] There were 1,435 unique respondents to the EQR reporting for 1,638 unique sellers during the third quarter of 2010. Neither the number of respondents nor the number of unique sellers accurately reflects the number of entities and affiliated entities that respond to the EQR. For instance, respondents will often report sales for unique sellers, either individual generation units or affiliated entities, separately in the EQR. Similarly, affiliate relationships exist for unique respondents. These respondents may share EQR filing software and techniques or may even be filed by the same staff.

electric output for the preceding twelve months did not exceed four million MWh.[137] We also used the SBA definition to determine the burden on respondents in the table above.

128. The Commission recognizes that there will be an increased burden involved in the initial implementation associated with filing EQRs. This burden includes the set-up software on a utility's computers, the initial entry of the contract data, and the mapping of the transaction data from the utility's internal computer systems into the format required by the Commission. For non-public utility filers, we estimate a burden of 400 hours per year for the initial implementation phase. For current EQR filers, we estimate that the additional data requirements will involve a burden of 160 hours. This burden is lower than that for non-public utility filers because of current filers' familiarity with EQR reporting.

129. For the recurring effort involved in filing the EQR each subsequent quarter, we anticipate that the burden will be minimal, particularly as filing transaction data will be automated for companies that have mapped their systems to the required format. Thus, we estimate a recurring burden of 24 hours per response (rather than per year) for all non-public filers if the requirements of this rulemaking are to be implemented. We have estimated that current filers spend about 16 hours to meet the existing recurring requirements of filing EQRs. With the additional data proposed to be required, we estimate that current filers' recurring burden will increase by 8 hours.

[137] 13 CFR 121.101.

Information Collection Costs: The Commission seeks comments on the costs and burden to comply with these requirements.

Total average annual costs = $8,309,293 ($6,940,157 for public utilities plus $1,369,136 for non-public utilities). The Commission estimates that the hours to complete the EQR reporting requirements will be divided among an entity's accounting, legal and support staff. We estimate an average hourly cost of $97.87 (including a senior accountant at $50.22/hr., a financial analyst at $67.00/hr., legal services at $250/hr., and support staff at $24.25/hr.).[138]

Title: FERC-516, Electric Rate Schedules and Tariff Filings (which includes the Electric Quarterly Report [EQR])[139]

Action: Proposed Revisions to the EQR

OMB Control No: 1902-0096

Respondents: Public and non-public utilities

Frequency of Responses: Initial implementation and quarterly filings

Necessity of the Information: The Commission is proposing to enact requirements that would facilitate price transparency in wholesale markets for the sale and transmission of

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[138] Hourly average wage is an average and was calculated using Bureau of Labor Statistics (BLS), Occupational Employment Statistics data for May, 2009 (at http://www.bls.gov/oes/) for the accounting, financial, and support staffs. The average hourly figure for legal support is a composite from BLS and other resources, taking into account the hourly cost for both in-house and contractor organizations.

[139] For administrative purposes, the Commission will consider whether to separate the EQR requirements from the remaining reporting requirements under FERC-516. If that is done, FERC would then request a separate OMB Control No. for EQR.

electric energy in interstate commerce by requiring certain non-public utilities to file the EQR. This proposal would allow the Commission and the public to gain a more complete picture of wholesale power and transmission markets in interstate commerce by providing additional information concerning price formation and market concentration in these markets. Public access to additional sales and transmission-related information in the EQR would improve market participants' ability to assess supply and demand fundamentals and to price interstate wholesale market transactions. It also would strengthen the Commission's ability to identify potential exercises of market power or manipulation and to better evaluate the competitiveness of the interstate wholesale markets. In addition, the Commission proposes to make certain revisions to the existing EQR filing requirements and apply those revisions to all market participants filing EQRs. These refinements to the existing EQR filing requirements reflect the evolving nature of electricity markets, would increase market transparency for the Commission and the public, and would allow market participants to file the information in the most efficient manner possible.

Internal review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

130. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873]. Comments on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at oira_submission@omb.eop.gov. Please reference OMB Control No. 1902-0096, FERC-516 and the docket number of this proposed rulemaking in your submission.

IV. Environmental Analysis

131. 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.[140] The actions taken here fall within categorical exclusions in the Commission's regulations for information gathering, analysis, and dissemination.[141] Therefore, an environmental assessment is unnecessary and has not been prepared in this rulemaking.

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[140] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 486 FR 1750 (Jan. 22, 1988), FERC Stats. & Regs. ¶ 30,783 (1987).

[141] 18 CFR 380.4(a)(5).

V. Regulatory Flexibility Act Certification

132. The RFA[142] 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 proposed rule and that minimize any significant economic impact on a substantial number of small entities. The SBA's Office of Size Standards develops the numerical definition of a small business.[143] 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 MWh.[144]

133. As discussed in Order No. 2000,[145] in making this determination, the Commission is required to examine only the direct compliance costs that a rulemaking imposes upon small businesses. It is not required to consider indirect economic consequences, nor is it

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[142] 5 U.S.C. 601-612.

[143] 13 CFR 121.101.

[144] 13 CFR 121.201, Sector 22, Utilities & n.1.

[145] *See Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089, at 31,237 & n.754 (1999), *order on reh'g,* Order No. 2000-A, 65 FR 12,088 (Mar. 8, 2000), 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. D.C. 205 (D.C. Cir. 2001) (citing *Mid-Tex Elec. Coop.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985) (Commission need only consider small entities "that would be directly regulated"); *Colorado State Banking Bd.* v. *RTC,* 926 F.2d 931 (10th Cir. 1991) (Regulatory Flexibility Act not implicated where regulation simply added an option for affected entities and did not impose any costs)).

required to consider costs that an entity incurs voluntarily.

134. Based on EIA Form 861, there are 372 non-public utilities that made wholesale sales in 2009.[146] As discussed above, the Commission is proposing to exempt from the EQR filing requirements non-public utilities with a *de minimis* market presence. The Commission estimates that 311 of the 372 non-public utilities will be exempt from this rulemaking because they make four million MWh or less of annual wholesale sales and are not Balancing Authorities. Of the 372, 309 are considered small entities because they make four million MWh or less of annual wholesale and retail sales. In balancing the need for information with the burden on small utilities, the Commission is proposing to base the *de minimis* threshold on wholesale sales and thus will exempt a majority of small non-public utilities from this proposed rulemaking. In fact, the Commission believes that the proposed rule, if finalized, would apply to only five non-public utilities (Balancing Authorities) that are considered small entities. The Commission believes that the direct, economic impact on these five small non-public utilities may be significant in terms of initial start-up costs (estimated to be $39,148), but that the recurring costs ($2,349 per quarterly filing, or $9,396 per year) will likely be small. However, the Commission does not consider five non-public utilities to be a substantial number of small entities. Using this *de minimis* threshold, the proposed rule will apply to approximately 16 percent of the

[146] We excluded non-public utilities that are located in Alaska, Hawaii, and Texas.

372 non-public utilities with wholesale sales, while capturing approximately 85 percent of the total volume of non-jurisdictional sales.

135. This rulemaking also proposes changes to the existing filing requirements and thus current EQR filers also will be impacted. Based on analysis of EIA Form 861, there are 186 public utilities and, of these, 51 make four million MWh or less of annual wholesale and retail sales. When considering annual wholesale and retail sales from these 51 entities together with sales by their affiliates, only 28 combined entities had annual wholesale and retail sales of or below four million MWh. The Commission does not consider this to be a substantial number of small entities. Furthermore, we note that public utilities may request, on an individual basis, waiver from the EQR reporting requirements.[147] In addition, the Commission expects that the direct, economic cost to comply will be less significant. While public utilities will need to modify their systems to capture and report the additional data, they already have the system in place. The estimated additional costs from the proposed rule are: (1) for implementation of the changes, $15,659, and (2) for each quarterly report, $783 (or $3,132 annually). Thus, the Commission certifies that this proposed rule will not have a significant impact on a substantial number of small entities.

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[147] The Commission has granted requests for waiver of the EQR filing requirements. *See Bridger Valley Elect. Assoc., Inc.*, 101 FERC ¶ 61,146 (2002). Entities with a waiver will continue to have a waiver and will not need to file a new request for waiver.

VI. Comment Procedures

136. 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 60 days from publication in the *Federal Register*. Comments must refer to Docket No. RM10-12-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

138. 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.

139. 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.

VII. Document Availability

140. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

141. 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.

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 email 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.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 18 C.F.R 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. § 35.10b is revised to read as follows:

§ 35.10b Electric Quarterly Reports.

Each public utility as well as each non-public utility with more than a de minimis market presence shall file an updated Electric Quarterly Report with the Commission covering all services it provides pursuant to this part, for each of the four calendar quarters of each year, in accordance with the following schedule: for the period from January 1 through March 31, file by April 30; for the period from April 1 through June 30, file by July 31; for the period July 1 through September 30, file by October 31; and for the period October 1 through December 31, file by January 31. Electric Quarterly Reports must be prepared in conformance with the Commission's software and guidance posted and available for downloading from the FERC Web site (http://www.ferc.gov).

(a) For purposes of this section, the term "non-public utility" means any market participant exempted from the Commission's jurisdiction by virtue of the Federal Power Act, 16 U.S.C. 824f.

The term does not include an entity that engages in purchases or sales of wholesale electric energy or transmission services within the Electric Reliability Council of Texas or any entity that engages solely in sales of wholesale electric energy or transmission services in the states of Alaska or Hawaii.

(b) For purposes of this section, the term "de minimis market presence" means any non-public utility that makes 4,000,000 megawatt hours or less of annual wholesale sales, based on the average annual sales for resale over the preceding three years as published by the Energy Information Administration's Form 861 unless the non-public utility is a Balancing Authority that makes 1,000,000 megawatt hours or more of annual wholesale sales, as published by the Energy Information Administration's Form 861.

3. In § 35.41, paragraph (c) is revised to read as follows:

§ 35.41 <u>Market behavior rules.</u>

* * * * *

(c) <u>Price reporting</u>. To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the <u>Policy Statement on Natural Gas and Electric Price Indices</u>, issued by the Commission in Docket No. PL03-3-000, and any clarifications thereto. Seller must notify the Commission as part of its Electric Quarterly Report filing requirement in § 35.10b of this chapter whether it reports its transactions to publishers of electricity and natural gas indices. In addition, Seller must adhere to any other standards and requirements for price reporting as the Commission may order.

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Appendix A: List of Commenters

<u>**Short Name or Acronym**</u>	<u>**Commenter**</u>
Alaska Power	Alaska Power Association
Allegheny	Allegheny Electric Cooperative
APPA	American Public Power Association
BPA	Bonneville Power Administration
California DWR	California Department of Water Resources State Water Project
California PUC	Public Utilities Commission of the State of California
Cities/M-S-R	City of Redding, California, City of Santa Clara, California, and M-S-R Public Power Agency
City of Dover	City of Dover, Delaware
City of Fayetteville	Public Works Commission of the City of Fayetteville, North Carolina
Consolidated Edison Energy, Inc. and Consolidated Edison Solutions, Inc.	Consolidated Edison Energy, Inc. and Consolidated Edison Solutions, Inc.
Delaware Municipal	Delaware Municipal Electric Corporation, Inc.
DC Energy	DC Energy, LLC
Duke Energy	Duke Energy Corporation
EEI	Edison Electric Institute
EPSA	Electric Power Supply Association
East Texas Cooperatives	East Texas Electric Cooperatives
ELCON	Electricity Consumers Resource Council

EMCOS	Eastern Massachusetts Consumer-Owned Systems
FirstEnergy	FirstEnergy Service Company
Imperial	Imperial Irrigation District
LPPC	Large Public Power Council
MID	Modesto Irrigation District
Morgan Stanley	Morgan Stanley Capital Group, Inc.
New York Public Power	New York Association of Public Power
Northwest Utility	Northwest Requirements Utility
NRECA	National Rural Electric Cooperative Association
NYMPA/MEUA	Northern California Power Agency; New York Municipal Power Agency and Municipal Electric Utilities Association of New York
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
Public Power Council	Public Power Council
Public Systems	Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative, Inc.
Salt River	Salt River Project
Sam Rayburn Municipal	Sam Rayburn Municipal Power Agency
SDG&E	San Diego Gas & Electric Company
Southwest Transmission	Southwest Transmission Dependent Utility Group

TANC	Transmission Agency of Northern California
TAPS	Transmission Access Policy Study Group
Utah Associated Municipal	Utah Associated Municipal Power Systems
Wisconsin Electric	Wisconsin Electric Power Company

Appendix B: Proposed Refinements to the Existing EQR

Fields Proposed to be Removed

Field #	Field	Required	Value	Definition
17	Customer DUNS Number	Yes	Nine digit number	The unique nine digit number assigned by Dun and Bradstreet to the company identified in Field Number 16.
45	Time Zone	Yes		The time zone in which the sales will be made under the contract.
49	Customer DUNS Number	Yes	Nine digit number	The unique nine digit number assigned by Dun and Bradstreet to the counterpart to the contract.

Fields Proposed to be Created

Section	Field	Required	Value	Definition
Transaction	Transaction Datetime	Yes	YYYYMMDDHHMM	The date and time when the price of this transaction was agreed upon.
Transaction	Standardized Transaction Price	Yes, for Energy and Capacity sales only	Number with up to 8 decimals.	Actual price charged for the product per unit. The price cannot be averaged or otherwise aggregated. For energy transactions, this price must be reported in $/MWh. For capacity transactions, this price must be reported in $/MW-Month.
Transaction	Type of Rate	Yes	----	See definitions for each product type below.
			Fixed	A rate determined by a fixed charge per unit of consumption.
			Formula	A rate determined using a formula that does not contain an index component.
			Index	A rate determined using an index or using a formula that contains an index component.
			RTO/ISO Price	A rate determined using a RTO/ISO published price or using a formula that contains a RTO/ISO published price.
Transaction	Broker/Exchange Name	If a the transaction was conducted with the assistance of a broker or exchange	Unrestricted Text (60 Characters)	The name of the broker or exchange that was used to conduct the transaction

Transaction	Reported to Index Publisher	If the transaction was reported to an Index Publisher	Unrestricted Text (60 Characters)	The name of the index publisher(s) that the transaction terms were reported to.
Transaction	e-Tag ID	If the transaction was scheduled using an e-Tag	Unrestricted Text (30 Characters)	The e-Tag ID used to schedule the energy transaction. The e-Tag ID reported, must be identical in format to the e-Tag ID used to schedule the transaction.