individual is an eligible contract participant if the individual has aggregate amounts invested on a discretionary basis of more than $10 million or more than $5 million if such individual enters into the transaction to manage the risk associated with an asset owned or liability incurred, or reasonably likely to be owned or incurred by such individual.[7]

The Commission adopted Rule 15b12–1 (17 CFR 240.15b12–1) on a time-limited basis to permit a registered broker-dealer to engage in a retail forex business.[8] The Commission is taking no further action, and pursuant to Rule 15b12–1(d), Rule 15b12–1 will expire and no longer be effective on July 31, 2016. Upon expiration of the rule on July 31, 2016, a broker-dealer registered pursuant to Section 15(b) of the Exchange Act, including an entity that is registered as both a broker-dealer and a futures commission merchant, shall be prohibited from offering or entering into a retail forex transaction pursuant to Section 2(c)(2)(E) of the CEA.

By the Commission.

Dated: May 20, 2016.

Brent J. Fields,

Secretary.

[FR Doc. 2016–12390 Filed 5–25–16; 8:45 am]

BILLING CODE 8011–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM14–14–001; Order No. 816–A]

Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule; Order on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission is denying requests for rehearing and granting, in part, clarification of its determinations in Order No. 816, which amended its regulations that govern market-based rate authorizations for wholesale sales of electric energy, capacity, and ancillary services by public utilities pursuant to the Federal Power Act.

DATES: This rule will become effective July 25, 2016.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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Order No. 816–A

Order on Rehearing and Clarification

I. Introduction

1. On October 16, 2015, the Federal Energy Regulatory Commission (Commission) issued Order No. 816,[1] which amended its regulations that govern market-based rate authorizations for wholesale sales of electric energy, capacity, and ancillary services by public utilities pursuant to the Federal Power Act (FPA). In this order, we address requests for rehearing and clarification of Order No. 816.[2]

2. Nine requests for rehearing and clarification were filed.[3] The requests for rehearing and clarification concern

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to transactions with major swap participants, swap dealers, major security-based swap participants, security-based swap dealers, and commodity pools. *See* Exchange Act Release No. 66868 (Apr. 27, 2012), 77 FR 30596 (May 23, 2012).

[7] 7 U.S.C. 1a(18)(A)(xi).

[8] *See* Exchange Act Release No. 69964 (Jul. 11, 2013), 77 FR 42439 (Jul. 16, 2013). By its terms, Rule 15b12–1 expires on July 31, 2016. The Commission previously adopted Rule 15b12–1 as an interim final temporary rule, and extended it once on July 11, 2012. *See* Exchange Act Release Nos. 64874 (Jul. 13, 2011), 76 FR 41676 (Jul. 15, 2011) and 67405 (Jul. 11, 2012), 77 FR 41671 (Jul. 16, 2012).

[1] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, FERC Stats. & Regs. ¶ 31,374 (2015) (Final Rule).

[2] Order No. 816 became effective on January 28, 2016. On December 23, 2015, upon consideration of requests for a stay of the corporate organizational chart requirement, the Commission issued an order granting an extension of time such that market-based rate applicants and sellers would not be required to comply with the corporate organizational chart requirement prior to the issuance of an order on the merits of the requests for rehearing. *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 153 FERC ¶ 61,337 (2015).

[3] The requests for rehearing and clarification were filed by the following entities: EDF Renewable Energy, Inc. and E.ON Climate & Renewables North America LLC (IPP Developers); Edison Electric Institute (EEI); Electric Power Supply Association (EPSA); Invenergy Thermal Development LLC and Invenergy Wind Development LLC (Invenergy); National Hydropower Association (NHA); NextEra Energy, Inc. (NextEra); Southern California Edison Company (SoCal Edison); Southern Company Services, Inc. (Southern); and Transmission Access Policy Study Group (TAPS).

the following topics: Sellers with fully committed long-term generation capacity; the reporting of long-term firm purchases; the definition or duration of long-term firm transmission reservations; notices of change in status; new affiliation and behind-the-meter generation; corporate organizational charts; and waiver of Part 101 of the Commission's regulations.[4]

3. In this order, in most respects, we affirm the Commission's determinations made in Order No. 816. However, regarding some issues, we provide clarification.

4. Specifically, as discussed further below, we deny rehearing regarding the requirement to include the expiration date of the contract when a seller claims that its capacity is fully committed. To the extent that the expiration date is not known at the time a seller files for market-based rate authority, we confirm that a subsequent filing to report the contract expiration date will be treated as an informational filing rather than as an amendment to a pending application.

5. We grant clarification regarding the requirement for applicants within a regional transmission organization or independent system operator (RTO/ISO) market to report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligations. We clarify that this requirement does not apply if the generation is from a qualifying facility exempt from section 205 of the FPA. In addition, we affirm that a market-based rate seller must list all of its long-term firm power purchases in its asset appendix, Appendix B, even if it does not have market-based rate authority in its home balancing authority area.

6. We clarify that the Commission did not intend to change the definition of long-term firm transmission reservations in Order No. 816 and clarify that long-term firm transmission reservations are longer than 28 days.

7. Regarding the Commission's 100 megawatt (MW) threshold for the requirement to report new affiliations, we affirm the determinations made in Order No. 816 but clarify which markets would be a seller's relevant geographic market for purposes of the 100 MW threshold reporting requirement. We also deny a rehearing request to find that capacity in first-tier markets[5] be included for determining the 100 MW change in status threshold.

8. We affirm the Commission's determination in Order No. 816 that sellers are not required to include behind-the-meter generation in the 100 MW change in status threshold, the 500 MW Category 1 seller status threshold, or to include such generation in the asset appendices and indicative screens.

9. Additionally, we clarify that a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirements of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission, and may satisfy the requirements in Part 101 of the Commission's regulations by complying with General Instruction 16 of the Uniform System of Accounts.

10. We also provide clarification regarding other aspects of the Final Rule, including revisions to regulatory text and instructions in the asset appendix to ensure consistency with the Commission's determinations in the Final Rule.

11. Further, as discussed below, we grant an additional extension of time such that market-based rate applicants and sellers will not be required to comply with the corporate organizational chart requirement until the Commission issues an order at a later date.

II. Discussion

A. Sellers With Fully Committed Long-Term Generation Capacity

1. Final Rule

12. In Order No. 816, the Commission clarified that sellers may explain that their generation capacity in the relevant geographic market (including first-tier markets) is fully committed, in lieu of submitting indicative screens, in order to satisfy the Commission's market-based rate requirements regarding horizontal market power in instances where all generation owned or controlled by a seller and its affiliates in the relevant balancing authority areas or markets (including first-tier markets) is fully committed. The Commission clarified that to qualify as fully committed, a seller must commit the capacity to a non-affiliated buyer so that none of it is available to the seller or its affiliates for one year or longer. The Commission also adopted the proposal that sellers claiming that all of their relevant capacity is fully committed must provide the following information: the amount of generation capacity that is fully committed, the names of the counterparties, the length of the long-term contract, the expiration date of the contract, and a representation that the contract is for firm sales for one year or longer.[6]

13. In response to NextEra's concern that at the time a seller files for market-based rate authority, the expiration date may be unknown, the Commission stated that if a contract expiration date is unknown at the time of the market-based rate filing, the seller must, within 30 days of the date becoming known, submit an informational filing, in the docket in which the seller was granted market-based rate authorization, to inform the Commission of the contract expiration date. In response to another commenter's remark that the expiration date is reported separately in electric quarterly report (EQR) filings, the Commission noted that many contracts reported in EQR filings do not include expiration dates and determined that it would require expiration date information in order to show that generation capacity is fully committed.[7]

2. Requests for Rehearing

14. NextEra requests rehearing of the Commission's determination concerning sellers with fully committed long-term generation capacity, stating that the Commission erred in requiring a market-based rate seller to report the expiration date of a long-term contract to the Commission within 30 days of the date being known, rather than simply in an EQR filing.[8] NextEra contends that the Commission erred by failing to set forth an explanation of the specific after-the-fact need for the contract expiration date, as the seller is also required to provide the length of the long-term contract in order to demonstrate that it has no uncommitted capacity.[9] NextEra states that if the Commission concludes that there is an actual need for this information given that after-the-fact reporting means that the expiration date can only be used in an *ex post* analysis, the Commission should clarify that it will permit sellers to provide the information to the Commission either through an EQR submission or on an after-the-fact basis.[10] NextEra states that to the extent that a seller informs the Commission of the contract expiration date within 30 days of the date becoming known, the Commission should clarify that it will treat such filings as informational filings rather

[4] 18 CFR pt. 101 (2015).

[5] We clarify that for purposes of this order, the term ''first-tier markets'' includes all first-tier areas, whether they are a balancing authority area or an RTO/ISO market.

[6] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 39.

[7] *Id.* P 44.

[8] NextEra Rehearing Request at 2.

[9] *Id.* at 12.

[10] *Id.* at 13.

than as amendments to pending applications.[11]

3. Commission Determination

15. The Commission stated in Order No. 816 that sellers claiming that capacity is fully committed must provide, among other things, the length of the long-term contract and the expiration date of the contract. The same information must be provided for long-term firm sales of affiliated generation capacity located in the relevant balancing authority areas or markets, including first-tier markets. Including this information in the record of a seller's market-based rate filing is necessary so that a seller's claims of fully committed capacity can be verified as needed.

16. In Order No. 816, the Commission addressed comments submitted by NextEra regarding contract expiration dates. In consideration of NextEra's contention that the expiration date may be unknown at the time a seller files for market-based rate authority,[12] the Commission determined that, in such instances, the seller must follow up with an informational filing to inform the Commission of the contract expiration date, within 30 days of the date becoming known.[13]

17. In its request for rehearing, NextEra questions the necessity of requiring the expiration date given that sellers are required to provide the length of the contract. We continue to believe that the expiration date is an important piece of information for sellers to provide. The expiration date provides the Commission with a specific date as to when the affected generation capacity may become uncommitted and the expiration date allows the Commission to verify the information previously provided by the seller for purposes of the Commission's *ex ante* analysis of the seller's potential market power. With regard to NextEra's argument that the Commission erred in requiring the market-based rate seller to report the expiration date of a contract to the Commission within 30 days of the date being known, rather than in an EQR filing, we note that, as the Commission stated in Order No. 816, many contracts reported in EQR filings do not include expiration dates.[14] Finally, consistent with Order No. 816, we grant NextEra's request that the Commission clarify that filings reporting contract expiration dates in support of a seller's claim that capacity is fully committed will be treated as informational filings rather than as amendments to filings.[15]

B. Reporting of Long-Term Firm Purchases

1. Final Rule

18. The Commission adopted the proposal to report in the indicative screens long-term firm purchases of capacity and/or energy that have an associated long-term firm transmission reservation. The Commission stated that requiring applicants under the market-based rate program to report all of their long-term firm purchases of energy and/or capacity, regardless of whether the applicant has operational control of the generation capacity supplying the purchased power, will improve the accuracy of the indicative screens.[16] The Commission stated that long-term firm power purchase agreements that are reported in the indicative screens also should be reported in the asset appendix, Appendix B, and created a separate sheet in Appendix B specifically for applicants to report all such long-term firm purchases.[17]

19. The Commission stated that the requirement that applicants only include long-term firm power purchase agreements in their indicative screens if they have an associated long-term transmission reservation will not apply within RTO/ISO markets if that RTO/ISO does not have long-term firm transmission reservations or their equivalent. Instead, applicants in such RTO/ISO markets will be required to report all long-term firm energy and/or capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a network resource or as a resource with capacity obligations.[18]

2. Requests for Rehearing

20. SoCal Edison and NextEra seek clarification with regard to the reporting of long-term firm purchases.

21. SoCal Edison seeks clarification that the requirement to report all long-term firm energy and/or capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligations does not apply if the generation is a qualifying facility exempt from section 205 of the FPA. SoCal Edison asserts that there is no reason why an applicant that holds a long-term contract with a qualifying facility exempt from FPA section 205 should have to report that in the appendix and screens, even if the facility has capacity obligations, when affiliate-owned exempt qualifying facilities would be excluded from the reporting requirement.[19]

22. NextEra seeks clarification related to the necessity of reporting long-term power purchases in the asset appendix, Appendix B, by entities that do not have market-based rate authorization in their balancing authority area and as a result are not required to submit indicative screens.[20] NextEra states that in Order No. 816, the Commission stated that long-term firm power purchase agreements that are reported in the indicative screens also should be reported in the asset appendix. NextEra states that based on this statement, NextEra understands that the Commission will not require the inclusion of long-term power purchase agreements if a seller does not have market-based rate authority in its balancing authority area, but instead makes only cost-based sales.[21] NextEra asks the Commission to confirm that the inclusion of such information is only required for companies that have market-based authority in the relevant geographic market.[22]

3. Commission Determination

23. We grant SoCal Edison's requested clarification. Applicants purchasing energy and/or capacity from a qualifying facility that is exempt from section 205 of the FPA under a long-term firm power purchase agreement do not need to include such purchases in their indicative screens or in their asset appendix. In Order No. 816, the Commission determined that qualifying facilities that are exempt from section 205 of the FPA do not need to be reported in the asset appendix or indicative screens.[23] Therefore, to ensure consistency in horizontal market power analyses filed by sellers we clarify that this exemption applies equally to long-term firm power purchases agreements backed by such resources.

24. We reject NextEra's requested clarification. A market-based rate seller must list all of its generation assets in its asset appendix even if it does not have market-based rate authority in its balancing authority area or, indeed, even if its generation is fully committed and it is not submitting any indicative

[11] *Id.* at 14.

[12] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 38.

[13] *Id.* P 44.

[14] *Id.*

[15] *Id.*

[16] *Id.* P 130.

[17] *Id.* P 139.

[18] *Id.* P 145.

[19] SoCal Edison Rehearing Request at 2.

[20] NextEra Rehearing Request at 2.

[21] *Id.* at 14.

[22] *Id.* at 15.

[23] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 255.

screens. We see no reason to treat long-term firm power purchase agreements differently than other generation capacity. In Order No. 816, the Commission determined that long-term firm power purchase agreements with an associated long-term firm transmission reservation (or that are capacity resources in RTO/ISO markets) must be reported in a seller's indicative screens and asset appendix. Excluding long-term firm power purchase agreements as requested by NextEra would be inconsistent with that policy. In addition, sellers without market-based rate authority in their own balancing authority area typically seek market-based rate authority elsewhere and do so by submitting indicative screens for their first-tier markets. A seller's long-term firm power purchase agreements are a resource that would need to be reflected in the screens for the seller's first-tier markets. Since these agreements are reflected in the screens to the extent that they provide potential exports from a seller's balancing authority area to first-tier markets, they should be included in the seller's asset appendix.

25. We also clarify that the generation capacity associated with a unit-specific long-term contract should be reported in the ''Notes'' portion of the asset appendix. An example of this will be posted on the Commission's Web site.

C. Clarification of the Definition or Duration of Long-Term Firm Transmission Reservations

1. Final Rule

26. In the Final Rule, the Commission provided clarification on the preparation of simultaneous transmission import limit (SIL) studies. In discussing SIL studies, the Commission declined a request to redefine the applicable duration of long-term firm transmission reservations, stating that it is currently defined as 28 days or longer.[24]

2. Requests for Rehearing

27. Southern states that Order No. 816 appears to erroneously refer to long-term firm transmission reservations as comprising reservations that are 28 days or longer. Southern maintains that this is contrary to precedent indicating that the expectation for entities performing SIL studies was that only transmission reservations with a duration longer than 28 days (*i.e.,* a duration of 29 days and greater) should be considered to be long-term firm reservations.

3. Commission Determination

28. We clarify that the Commission did not intend to change the definition of long-term firm transmission reservations in Order No. 816. We reaffirm prior Commission guidance that short-term reservations are up to one month and long-term reservations are greater than one month.[25] February is the shortest month, which means that long-term firm transmission reservations must be longer than 28 days. Thus, we clarify that long-term firm transmission reservations are longer than 28 days.

D. Notices of Change in Status

1. Final Rule

29. In the Notice of Proposed Rulemaking (NOPR), the Commission proposed to revise the change in status regulations at 18 CFR 35.42 to include a 100 MW threshold for reporting new affiliations. The Commission stated that a market-based rate seller that has a new affiliation would not be required to file a change in status for an affiliation with an entity with generation assets until its new affiliations result in a cumulative net increase of 100 MW or more of nameplate capacity in any relevant geographic market.[26] In the Final Rule, the Commission adopted the proposed changes to the change in status requirements of section 35.42 of the Commission's regulations.[27]

30. In the Final Rule, the Commission stated that the 100 MW threshold applies to each new relevant market (not previously studied) in which a seller and/or its affiliates acquire a cumulative net increase of 100 MW.[28] The Commission clarified that the phrase ''any relevant market'' refers to a market in which a seller already has generation located and acquires an additional 100 MW or accumulates 100 MW or more in a new market that the seller had not studied previously.[29] The Commission also clarified that the 100 MW threshold does not include generation capacity that can be imported from first-tier markets.[30] The Commission agreed with commenters that generation capacity in first-tier markets should not be treated the same as capacity located in the seller's relevant geographic market/study area.[31]

2. *Requests for Rehearing*

31. IPP Developers request that the Commission make the following three clarifications: (1) If an affiliate of a seller acquires or controls 100 MW of generating capacity (including long-term firm purchases), the seller must submit a notice of change in status report if that 100 MW is located in the same relevant market that was studied as the basis for the seller's grant of market-based rate authority; (2) if an affiliate of the seller acquires or controls 100 MW or more of generating capacity (including long-term firm purchases) in a market that is two tiers away or more, the seller is not required to submit a notice of change in status report; and (3) if an affiliate of the seller acquires or controls 100 MW or more of generating capacity (including long-term firm purchases) in a market that is in the first-tier, the seller is not required to submit a notice of change in status report.[32] IPP Developers state that these three clarification requests appear to be a proper application of the Commission's statements in Order No. 816. IPP Developers conclude that a seller does not have a change in status reporting obligation in regard to an affiliate's generation in first-tier and beyond areas.[33]

32. However, IPP Developers state that the following statement in paragraph 238 of Order No. 816 makes this reporting obligation unclear: ''if a seller's affiliate is granted market based rate authority, and that results in 100 MW or more of new generation *in a market,* then the seller will have to file a corresponding change in status.'' [34] IPP Developers state that ''a market'' could be any market other than the seller's studied relevant market, *i.e.,* affiliate generation in first-tier or beyond markets.[35] IPP Developers state that this statement appears to say that a seller must file a notice of change in status report regardless of the market in which an affiliate of the seller acquires or controls 100 MW or more of generating capacity.[36]

33. IPP Developers state that if the Commission is not inclined to provide the clarifications above, then IPP Developers request rehearing.[37]

34. TAPS seeks rehearing of the threshold calculation, arguing that

[24] *Id.* P 197.

[25] *Market-Based Rates for Wholesale Sales of Electric Energy Capacity and Ancillary Services by Public Utilities,* Order No. 697–B, FERC Stats. & Regs. ¶ 31,285 at P 25 (2008).

[26] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* FERC Stats. & Regs. ¶ 32,702, at P 96 (2014) (NOPR).

[27] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 251.

[28] *Id.* P 231.

[29] *Id.* P 237.

[30] *Id.* P 18.

[31] *Id.* P 229.

[32] IPP Developers Rehearing Request at 1–3.

[33] *Id.*

[34] *Id.* at 3–4 (citing Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 238 (emphasis added)).

[35] *Id.* at 4.

[36] *Id.*

[37] *Id.* at 3.

capacity in first-tier markets should be included for determining changes in the 100 MW change in status threshold.[38] TAPS states that in the NOPR, the Commission proposed to clarify that the ''relevant geographic market'' for purposes of that 100 MW trigger included generation capacity that could be imported from first-tier markets.[39] TAPS states that the Commission then reversed the NOPR proposal, stating that it would ''exclude markets and balancing authority areas that are first-tier to the seller's study area.'' [40] TAPS states that the Commission erred and should grant rehearing to revise Order No. 816 to include generation in first-tier markets for purposes of change in status reporting, whether or not it is supported by a long-term firm transmission reservation.[41] Specifically, TAPS states that the Commission should require sellers to: (1) Include first-tier capacity when there is a long-term transmission reservation associated with the capacity; and (2) include all other first-tier capacity either in its entirety or, in the alternative, on a *pro rata* basis consistent with the inclusion of such generation in market power screens.[42]

35. TAPS states that the NOPR's proposal to include first-tier generation capacity is both simple and adequate.[43] TAPS states that the Commission could allow sellers, with appropriate support, to prorate generation in markets first-tier to the study area in the same way capacity is assigned pro rata for indicative screen analyses (assuming there are no firm transmission reservations associated with the first-tier capacity, in which case it should be accorded its full megawatt value). TAPS states that this approach would be consistent with the methodology used in the indicative screens, but would require more analysis than reporting of all first-tier capacity for purposes of change in status reports.[44]

3. Commission Determination

36. We grant clarification regarding IPP Developers' three examples of the application of Order No. 816. The scenarios presented by IPP Developers are a proper application of the Final Rule, assuming that the seller is not a power marketer (*i.e.,* the seller owns generation). We also grant clarification regarding the Commission's statement in paragraph 238 of Order No. 816. In paragraph 238 of Order No. 816, the Commission stated that ''if a seller's affiliate is granted market-based rate authority, and that results in 100 MW or more of new generation *in a market,* then the seller will have to file a corresponding change in status.'' [45] We clarify that the phrase ''in a market'' means any relevant geographic market for the seller at the time of the change in status filing. Further, we note that the relevant geographic market for a particular seller depends on whether the seller is a power producer or a power marketer, whether the seller owns transmission or is interconnected to an affiliated transmission system, and whether the seller's generation is in an RTO/ISO. The relevant markets for a power marketer include any market where the power marketer's affiliates own generation. Thus, a power marketer that does not own any generation itself would need to report a change in status for a 100 MW net increase in any market where an affiliate owns generation and has been granted market-based rate authority.[46] However, for a power producer, the relevant geographic market is where the seller's generation is physically located. Thus, a power producer would not need to report a 100 MW affiliate net increase in a market where the power producer itself does not own any generation. Similarly, in traditional (non-RTO/ISO) markets, the default relevant geographic market is ''first, the balancing authority area where the seller is physically located, and second, the markets directly interconnected to the seller's balancing authority area.'' [47] However, ''[w]here a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is one relevant geographic market (*i.e.,* the balancing authority area in which the generator is located).'' [48] For a seller located in an RTO/ISO market, the seller may consider the RTO/ISO as the default relevant geographic market.[49] In each circumstance, the market-based rate seller will have to determine whether any 100 MW increase is in a market that would be a relevant geographic market for that seller.

37. We deny TAPS's request that capacity in first-tier markets be included for determining the 100 MW change in status threshold. As the Commission stated in Order No. 816, when a seller has a change in status in a particular market, it does not need to include any changes in adjoining first-tier markets in calculating the 100 MW threshold, even when a purchaser has long-term firm transmission rights to import affiliated capacity located in a first-tier market. We reiterate that, with respect to the calculation of the 100 MW threshold, 100 MW located outside of the study area is not equivalent to 100 MW inside the study area. In addition, requiring sellers to consider generation capacity in first-tier markets, and prorate generation from the first-tier markets into the study area, creates uncertainty as to when a seller would trip the 100 MW threshold and effectively would force a seller to prepare import analyses to determine how much of their additional first-tier capacity could be imported into the study area. We believe that the increased burden of preparing such studies would outweigh the potential benefit gained from receiving additional information about a seller's affiliated generation.

E. New Affiliation and Behind-the-Meter Generation

1. Final Rule

38. As stated above, the Commission adopted the NOPR proposal to establish a 100 MW threshold for reporting new affiliations in change of status filings. The Commission stated that a market-based rate seller that has a new affiliation will not be required to file a change in status for an affiliation with an entity with generation assets until its new affiliations result in a cumulative net increase of 100 MW of capacity in a relevant geographic market.[50] The

[38] TAPS Rehearing Request at 1.

[39] *Id.* at 4 (citing NOPR, FERC Stats. & Regs. ¶ 32,702 at P 96).

[40] *Id.* at 5 (citing Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 230).

[41] *Id.* at 6.

[42] *Id.* at 5.

[43] *Id.* at 6–7.

[44] *Id.* at 7.

[45] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 238 (emphasis added).

[46] A power marketer with no affiliated generation is a Category 1 seller (exempt from filing triennial updated market power analysis) in all regions and has no relevant geographic market. A power marketer that acquires generation via a long-term power purchase agreement has a relevant geographic market where the power associated with this agreement is delivered (sinks), not where it originates (unless source and sink are in the same market, which is often the case). In this scenario, the power marketer is a Category 1 or 2 seller in the relevant geographic market depending on the MWs associated with the contract(s). Category 2 sellers must submit triennial update market power analyses.

[47] *Market-Based Rates for Wholesale Sales of Electric Energy Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 (2007).

[48] *Id.* P 232 n.217.

[49] *Id.* P 235 (noting that a seller may consider the RTO/ISO as the default relevant geographic market ''unless the Commission has already found the existence of a submarket'').

[50] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 251. The Commission noted that if a seller files a notice of change in status for another reason, *e.g.,* to report the entrance into a power purchase agreement of more than 100 MW, the seller should note that it has a new affiliate with market-based rate authority and include that new affiliate and any related assets in the seller's asset appendix. *Id.* P 251 n.334.

Commission stated that the 100 MW threshold will be determined for each relevant geographic market but will not consider generation capacity additions in first-tier markets.[51]

39. The Commission did not adopt the NOPR proposal to count behind-the-meter generation in the 100 MW change in status threshold and 500 MW Category 1 seller threshold or to include such generation in the asset appendix and indicative screens.[52]

40. The Commission stated that the output of behind-the-meter generation should be reflected in the load data reported in the FERC Form No. 714, which reflects the fact that the load is lower than it otherwise would be if a portion of the load were not served by behind-the-meter generation. The Commission also stated that, since behind-the-meter generation is netted out of the load data, requiring sellers to count behind-the-meter generation as installed capacity could result in double-counting a portion of the seller's generation capacity. The Commission clarified that behind-the-meter generation that is consumed on-site by the host load and not sold into the wholesale market, or is not synchronized to the transmission grid, is not relevant to the Commission's horizontal market power analysis.[53]

2. Requests for Rehearing

41. TAPS requests rehearing and/or clarification, arguing that behind-the-meter generation that is available to make wholesale sales and that is not reflected as a reduction in load reported in Form No. 714 should be included in seller reporting obligations, including the 100 MW change in status threshold, the indicative screens, the asset appendix, and the 500 MW Category 1 seller status threshold.

42. Specifically, TAPS states that the Commission should make clear that behind-the-meter generation that is not consumed on-site by the host load and reflected in Form No. 714 load data must, consistent with the Commission's duty to assess market power, be included in seller reporting obligations and indicative screens and category seller status determinations. TAPS contends that generation that participates in the wholesale markets influences a seller's market power regardless of whether it may be termed behind-the-meter.[54] TAPS argues that even if it were otherwise permissible, the exclusion for behind-the-meter generation would be arbitrary and capricious. TAPS states that because Order No. 816 fails to limit the scope of the behind-the-meter exclusion to that included in load reported in Form No. 714 or not synchronized to the grid and provides no definition of behind-the-meter generation, sellers are left to their own devices to determine what is meant by behind-the-meter generation and then to exclude those resources for purposes of reporting under Order No. 816.[55]

43. TAPS states that the Commission should clarify that its exclusion of behind-the-meter generation was intended to be restricted by its clarification at paragraph 253 of the Final Rule—that only generation that is reflected in Form No. 714 or not synchronized would be excludable from generation from market-based rate reporting and market power screens. Alternatively, TAPS states that the Commission should grant rehearing and: (1) Adopt its NOPR proposal to include behind-the-meter generation, with El Paso's clarification—*i.e.,* that behind-the-meter generation that is not reflected as a decrease in load on Form No. 714 should be included in seller reporting obligations and all market power screens; or (2) otherwise avoid creating a behind-the-meter generation blind spot of undefined proportions in its market power monitoring and assessment regimen.[56]

3. Commission Determination

44. We deny TAPS's request for rehearing. As the Commission stated in the Final Rule, the output of behind-the-meter generation largely should be reflected in the load data reported in the FERC Form No. 714, which reflects the fact that the load is lower than it otherwise would be if a portion of the load were not served by behind-the-meter generation. Accordingly, since behind-the-meter generation is netted out of the load data, requiring sellers to count behind-the-meter generation as installed capacity could result in double-counting a portion of some sellers' generation capacity. Further, the Commission stated in the Final Rule that behind-the-meter generation not sold into the wholesale market is not relevant to the Commission's horizontal market power analysis. Regarding TAPS's concern about behind-the-meter generation that is available to make wholesale sales and is not reflected in load reported in Form No. 714, we believe, at this time, that this category of generation is relatively limited and that the burden of sellers reporting this behind-the-meter generation would outweigh the benefits of such reporting. Therefore, at this time, we will not require sellers to report this type of generation.

F. Corporate Organizational Charts

1. Final Rule

45. In the Final Rule, the Commission adopted the proposal to require a seller to include a corporate organizational chart when filing an initial application for market-based rate authority, an updated market power analysis, or, in some circumstances, a notice of change in status reporting new affiliations.[57] The Commission revised the regulatory text in section 35.37(a)(2) and in section 35.42(c) in this regard.

2. Requests for Rehearing

46. Invenergy, SoCal Edison, NextEra, EEI, and EPSA request rehearing and/or clarification with respect to the requirement to submit corporate organizational charts. Parties argue, among other things, that the requirement imposes a substantial administrative burden on filers and is at odds with the objective of streamlining the market-based rate filing process.

3. Commission Determination

47. As noted above, upon consideration of requests for a stay of the corporate organizational chart requirement, the Commission issued an order granting an extension of time such that market-based rate applicants and sellers would not be required to comply with the corporate organizational chart requirement prior to the issuance of an order on the merits of the requests for rehearing.[58] Upon consideration of the concerns raised by the parties on rehearing regarding this requirement, we grant an additional extension of time such that market-based rate applicants and sellers will not be required to comply with the corporate organizational chart requirement until the Commission issues an order at a later date addressing this requirement. The extension will allow the Commission more time to fully consider the benefits and burdens associated with the corporate organizational chart requirement.[59]

[51] *Id.* P 251.

[52] *Id.* P 252.

[53] *Id.* P 253.

[54] TAPS Rehearing Request at 11.

[55] *Id.*

[56] *Id.* at 13.

[57] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 21.

[58] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 153 FERC ¶ 61,337 (2015).

[59] The Commission continues to consider appropriate mechanisms for consolidating the Commission's data collection requirements, including this organizational chart requirement,

G. Part 101 Waivers

1. Final Rule

48. The Commission clarified that granting waiver of 18 CFR part 101 under market-based rate authority does not waive the requirements under Part I of the FPA for hydropower licensees. In addition, the Commission clarified that hydropower licensees that only make sales at market-based rates may satisfy the requirements in Part 101 of the Commission's regulations (Uniform System of Accounts) by complying with General Instruction 16 of the Uniform System of Accounts, and confirmed that hydropower licensees that have Commission-approved cost-based rates are required to comply with the full requirements of the Uniform System of Accounts.[60]

2. Requests for Rehearing

49. NHA requests clarification that a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirements of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission.[61] Alternatively, NHA requests that the Commission clarify that it will allow licensees that otherwise sell only at market-based rates to request authorization, on a case-by-case basis, to continue to rely on General Instruction 16 of the Uniform System of Accounts at the time a reactive power tariff is filed with the Commission.[62]

50. NHA argues that the Commission determined in Order No. 697 that ''little purpose would be served to require compliance with accounting regulations for entities that do not sell at cost-based rates and do not have captive customers.'' [63] NHA represents that the Commission has previously found that reactive power tariffs do not have captive customers and do not raise the same concerns as other cost-based rate tariffs.[64] Additionally NHA notes that entities with a reactive power tariff and a market-based rate tariff have been previously granted waiver of Part 101.[65]

3. Commission Determination

51. We clarify that a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirements of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission. Such a seller may satisfy the requirements in Part 101 of the Commission's regulations by complying with General Instruction 16 of the Uniform System of Accounts. We find that this clarification is consistent with previous Commission findings in Order No. 697 and *Sunbury,* as noted by NHA. We continue to find, however, that hydropower licensees that have Commission-approved cost-based rates are required to comply with the full requirements of the Uniform System of Accounts.[66] Additionally, we remind sellers that ''previously granted waivers of the accounting requirements will continue to be rescinded where a seller is found to have market power (or where the sellers accepts a presumption of market power) and the seller proposes cost-based rate mitigation or the Commission imposes cost-based rate mitigation.'' [67]

H. Capacity Ratings

1. Final Rule

52. In the Final Rule, the Commission revised the regulations at 18 CFR 35.42 relating to the change in status reporting requirements to permit sellers to use nameplate or seasonal capacity ratings for the 100 MW threshold for most generation and allow energy-limited generation to use either nameplate or a five-year average capacity factor.[68] The Commission found that solar photovoltaic and solar thermal facilities are energy limited and determined that, due to their unique characteristics, solar photovoltaic facilities, unlike other energy-limited facilities, must use nameplate capacity and may not use five-year average capacity factors.[69]

2. Request for Rehearing

53. Southern notes the Commission's determination in the Final Rule permitted sellers to use nameplate or seasonal capacity ratings for the 100 MW threshold for most generation. Southern states that the regulatory text accompanying the Final Rule includes the phrase ''or seasonal'' in 18 CFR 35.42(a)(2)(i) but not in 18 CFR 35.42(a)(1). Southern requests that the Commission add the phrase ''or seasonal'' to 18 CFR 35.42(a)(1) to align with the discussion in the Final Rule.[70]

3. Commission Determination

54. We find that it is appropriate to revise 18 CFR 35.42(a)(1) to add the phrase ''or seasonal.'' Additionally, we are revising both 18 CFR 35.42(a)(1) and (a)(2)(i) to further align the regulations with the discussion in the Final Rule. Specifically, the revised regulations will indicate that the 100 MW or more of capacity should be based on nameplate or seasonal capacity ratings and, for energy-limited resources, with the exception of solar photovoltaic facilities, the capacity ratings should be based on nameplate or five-year average capacity factors. These revised regulations will indicate that for solar photovoltaic facilities, the capacity ratings should be based on nameplate capacity.

I. Inputs to Electric Power Production

1. Final Rule

55. The Commission considers a seller's ability to erect other barriers to entry as part of the vertical market power analysis and, as such, the Commission requires a seller to provide a description of its inputs to electric power production.[71] Section 35.36(a)(4) of the Commission's regulations define inputs to electric power production to mean intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, physical coal supply sources and ownership of or control over who may access transportation of coal supplies.

56. In the Final Rule, the Commission eliminated the requirement that market-based rate sellers file quarterly land acquisition reports and provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses. Specifically, the Commission adopted the proposal to

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with the proposed rulemakings in Docket Nos. RM15–23 and RM16–3.

[60] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 22.

[61] NHA Clarification Request at 3–5.

[62] *Id.* at 5.

[63] *Id.* at 3 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 984).

[64] *Id.* at 3–4 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 483 (''concerns underlying the affiliate restrictions do not apply to sales of reactive power because those sales are typically either made to transmission providers so that the transmission provider can satisfy its obligation to provide reactive power or made by the transmission provider under its applicable [open access transmission tariff]'')).

[65] *Id.* (citing *Sunbury Generation, LLC,* 108 FERC ¶ 61,160 (2004) (*Sunbury*); *Illinois Power Generating Co.,* 148 FERC ¶ 61,238 (2014) (granting waivers of Parts 41, 101, and 141 of the Commission's regulations to entities with a cost-based rate reactive power tariff and a market-based rate tariff)).

[66] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 22.

[67] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 986.

[68] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 232.

[69] *Id.* P 15.

[70] Southern Rehearing Request at 7 n.15 (citing Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 232).

[71] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 6.

revise the regulations at 18 CFR 35.42 relating to the change in status reporting requirements regarding sites for new generation capacity development and also adopted the proposal to revise the regulations at 18 CFR 35.37 to remove the requirement that sellers provide information regarding sites for generation capacity development to demonstrate a lack of vertical market power. However, no changes to the definition of inputs to electric power production were made in the Final Rule.

2. Commission Determination

57. In light the determinations made in the Final Rule, we revise our regulations at 18 CFR 35.36(a)(4) to remove sites for generation capacity development from the definition of inputs to electric power production. However, we clarify that the affirmative statement regarding barriers to entry required in 18 CFR 35.37(e)(3) continues to cover sites for generation capacity development.

J. Transmission/Natural Gas Assets Sheet

1. Final Rule

58. In the NOPR, the Commission proposed to require any seller that has been granted waiver of the requirement to file an open access transmission tariff (OATT) for its transmission facilities to report in its Transmission/Natural Gas Assets Sheet the citation to the Commission order granting the OATT waiver for those transmission facilities.[72] The Commission did not adopt the NOPR proposal in the Final Rule, agreeing with SoCal Edison that this requirement would not provide useful information in light of Order No. 807.[73] The Commission further stated that, ''even if a seller has been granted waiver of the requirement to file an OATT, those transmission facilities should be reported in its asset appendix.'' [74]

2. Commission Determination

59. Upon further consideration, we modify the requirement to report in the asset appendix transmission facilities that have been granted an individual OATT waiver or that qualify for a blanket waiver under Order No. 807 and find that sellers are no longer required to include such facilities in their Transmission/Natural Gas Assets Sheet. We find that the burden of providing information on such facilities outweighs any benefit to reporting it. For this reason, we eliminate the requirement to report in the Transmission/Natural Gas Assets Sheet facilities that qualify for blanket waiver of the OATT requirement under Order No. 807 and those that have been granted an individual OATT waiver.

K. Long-Term Firm Power Purchases List

1. Final Rule

60. In the Final Rule, the Commission established a new, separate list in the asset appendix in which market-based rate sellers are to report their Long-Term Firm Power Purchase Agreements (PPAs).[75] The Commission agreed with commenters that the format of the Generation Assets Sheet was not well suited for reporting long-term firm purchases.

2. Commission Determination

61. Subsequent to the issuance of Order No. 816, Commission Staff received numerous calls from sellers requesting guidance with respect to completing the Long-Term Firm PPAs Sheet. Upon further consideration, we recognize that certain modifications to this sheet and its instructions are warranted to improve its clarity. To that end, we are making the following changes. First, we are eliminating the existing column B, ''Docket # where MBR authority was granted'' as this is duplicative of information required elsewhere in the asset appendix. In response to questions as to whether the ''Market/Balancing Authority Area'' column was referring to the source or sink of the transaction, we are adding a column and specifically requesting sellers to identify both the source and sink of the transaction in separate designated columns. Finally, in response to other questions raised by market-based rate filers, we are adding a column requiring sellers to indicate whether a particular long-term firm purchase agreement is backed by a specific identified generation unit or by the supplier's generation fleet (*i.e.,* a ''system'' contract). Instructions for the Long-Term Firm PPAs Sheet have been modified to reflect these changes and to make certain other clean up edits.

L. Generation Assets Sheet, Rows [B] and [H]

1. Final Rule

62. The Final Rule contained instructions for completing the asset appendix. The description of Row [B] indicated that, if applicable, sellers should include the docket number where market-based rate or qualifying facility status was originally granted, and that it can be an EL or QF docket number. The description of Row [H] listed the six market-based rate regions but mistakenly listed the Southeast region twice and failed to mention the Northwest region.

2. Commission Determination

63. We revise the instructions for Row [B] of the asset appendix to remove references to EL and QF dockets. This revision does not change the Commission's determinations in Order No. 816. Rather, this revision aligns the description and format information regarding Row [B] with the Commission's intent that Row [B] contain the docket number where market-based rate authority was granted.

64. We revise the instructions to Row [H] of the Generation Assets Sheet to delete the second reference to ''Southeast'' and replace it with ''Northwest.''

III. Information Collection Statement

65. The Office of Management and Budget (OMB) regulations implementing the Paperwork Reduction Act of 1995 [76] require that OMB approve certain information collection requirements imposed by an agency.[77] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

66. The revisions made in Order No. 816 to the information collection requirements for market-based rate sellers were approved under FERC–919 (OMB Control No. 1902–0234).[78] This order clarifies and makes minor revisions to some aspects of the existing information collection requirements for the market-based rate program. The

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[72] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 120.

[73] Order No. 816, FERC Stats. & Regs. ¶ 31,374 at P 300 (citing *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities,* Order No. 807, FERC Stats. & Regs. ¶ 31,367 (2015) (amending Commission regulations to waive the OATT requirements of section 35.28, the OASIS requirements of Part 37, and the Standards of Conduct requirements of Part 358, under certain conditions, for entities that own interconnection facilities)).

[74] *Id.* P 295 (citing Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 378 (''We clarify that the transmission facilities that we require to be included in that asset appendix are limited to those the ownership or control of which would require an entity to have an OATT on file with the Commission (even if the Commission has waived the OATT requirement for a particular seller).'')).

[75] *Id.* P 270.

[76] 44 U.S.C. 3507(d) (2012).

[77] 5 CFR 1320.11.

[78] OMB approved the information collection in Order No. 816 on December 22, 2015.

changes to the information collection include:

- Removing the need to list transmission facilities in the Transmission/Natural Gas Assets Sheet that have an OATT waiver or that qualify for the blanket OATT waiver (a slight burden decrease)
- adding a source/sink column and a column for generation unit/system contract type to the Long-Term Firm PPAs Sheet (slight burden increases)
- removing column B, ''Docket # where MBR authority was granted'' from the Long-Term Firm PPAs Sheet and removing references to ''EL'' and ''QF'' in the instructions for Row [B] of the Generation Assets Sheet (*de minimis* decreases)
- removing sites for generation capacity development from the definition of inputs to electric power production at 18 CFR 35.36(a)(4) (no change to burden).

The Commission estimates that there will be no net change to burden. This Final Rule will be submitted to OMB for review and approval of a ''No Material/Nonsubstantive Change.''

Title: Market Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities (FERC–919).

Action: Clarification and Revision of Currently Approved Collection of Information.

OMB Control No.: 1902–0234.

Respondents for This Rulemaking: Public utilities, wholesale electricity sellers, businesses, or other for profit and/or not for profit institutions.

67. 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, email: *DataClearance@ferc.gov,* phone: (202) 502–8663, fax: (202) 273–0873]. Comments concerning 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 email to OMB at *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to FERC–919 and OMB Control Number 1902–0234.

IV. Document Availability

68. 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.

69. 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.

70. User assistance is available for eLibrary and the FERC's Web site 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. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

V. Effective Date

71. These regulations are effective July 25, 2016.

List of Subjects in 18 CFR Part 35

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

By the Commission.

Issued: May 19, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

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

§ 35.36 [Amended]

■ 2. Amend § 35.36 as follows:

■ a. In paragraph (a)(4), remove the comma and add in its place a semicolon.

■ b. In paragraph (a)(4), remove the phrase ''sites for generation capacity development;''.

■ 3. Amend § 35.42 by revising paragraphs (a)(1) and (a)(2)(i) to read as follows:

§ 35.42 Change in status reporting requirement.

(a) * * *

(1) Ownership or control of generation capacity or long-term firm purchases of capacity and/or energy that results in cumulative net increases (*i.e.,* the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of capacity based on nameplate or seasonal capacity ratings, or, for solar photovoltaic facilities, nameplate capacity, or, for other energy-limited resources, nameplate or five-year average capacity factors, in any individual relevant geographic market, or of inputs to electric power production, or ownership, operation or control of transmission facilities; or

(2) * * *

(i) Owns or controls generation facilities or has long-term firm purchases of capacity and/or energy that results in cumulative net increases (*i.e.,* the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of capacity based on nameplate or seasonal capacity ratings, or, for solar photovoltaic facilities, nameplate capacity, or, for other energy-limited resources, nameplate or five-year average capacity factors, in any individual relevant geographic market;

* * * * *

■ 4. Revise appendix B to subpart H to read as follows:

Appendix B to Subpart H of Part 35—Corporate Entities and Assets Sample Appendix

BILLING CODE 6717–0–P

	Instructions for completing the Asset Appendix Sheet: Generation Assets		
Column	**Title**	**Format**	**Description**
[A]	Filing Entity and its Energy Affiliates	Free Form Text	Name of the Filing Entity and its Affiliates. Please use the exact name as in the Company Registration database if possible.
[B]	Docket # where MBR authority was granted	Text in the form: ERXX-XXX-XXX where "X" is a digit	If applicable, Docket Number where MBR was originally granted.
[C]	Generation Name (Plant or Unit Name)	Free Form Text	Unit Name or if all units in a plant are reasonably similar, a plant name. Use EIA-860 or industry standard names to the extent possible.
[D]	Owned By	Free Form Text	Name of the Entity owning the generation unit or plant. Please use the same name as in the Company Registration database if possible.
[E]	Controlled By	Free Form Text	Name of the Entity that controls the output of the generation unit or plant. Please use the same name as in the Company Registration database if possible.
[F]	Date Control Transferred	MM/YYYY or DD/MM/YY	The date the unit came under the control of the Entity listed in "[E] Controlled By." Often it is the date the generation was acquired or built.
[G]	Location: Market/Balancing Authority Area	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name.
[H]	Location: Geographic Region	Specific Text	One of the six MBR regions: Northeast, Southeast, Central, SPP, Northwest, Southwest.
[I]	In-Service Date	MM/YYYY or MM/DD/YY	The date the unit first came into service.
[J]	Capacity Rating: Nameplate (MW)	Numeric. Either an integer or fixed width numeric with one decimal	The nameplate capacity rating of the unit, usually provided by the manufacturer, in MWs.
[K]	Capacity Rating: Used in Filing (MW)	Numeric. Either an integer or fixed width numeric with one decimal	The capacity rating of the unit(s), in MWs, used in this filing.
[L]	Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative		A single capital letter (either "N", "S","U","E", or "A") to designate the rating methodology of the unit's capacity used in this filing. Describe "Alternative" Capacity Rating Method in End Notes Sheet.
[M]	End Note Number (Enter text in End Notes Sheet)	Integer	The number of the explanatory note in End Notes Sheet that refers to this entry. The numbers should be ascending integers throughout the appendix. If there are three notes in the Generation Assets Sheet, then the first end note in the next asset sheet should be four (please do not start over with a new numbering sequence).

	Instructions for completing the Asset Appendix Sheet: Long-Term Firm Power Purchase Agreements (PPA)		
Column	Title	Format	Description
[A]	Filing Entity and its Energy Affiliates	Free Form Text	Name of the Filing Entity or affiliate of the Filing Entity that is purchasing the energy or capacity.
[B]	Seller Name	Free Form Text	Name of the Filing Entity that is selling the capacity and/or energy. Please use the exact name as in the Company Registration database if possible.
[C]	Amount of PPA (MW)	Numeric. Either an integer or fixed width numeric with one decimal	Contracted amount of the PPA in MW. If the contract is for the entire output of a specific generation unit, you may de-rate the unit using the same de-rating methodology that is used for generators of the same technology elsewhere in the appendix. If this amount is de-rated please explain in the End Notes Sheet. Energy-only contracts must be converted from MWh to MW. Only report contracts one year or longer.
[D]	Location: Market/Balancing Authority Area (Source)	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name. For "System" PPAs, identify all markets and balancing authority areas from which the PPA is sourced to the extent the source location(s) is specified in the PPA.
[E]	Location: Market/Balancing Authority Area (Sink)	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name. For all PPAs, identify where the capacity and/or energy is delivered.
[F]	Location: Geographic Region (Sink)	Specific Text	Same instruction as the Generation Assets Sheet.
[G]	Start Date (mo/da/yr)	MM/DD/YY	The Start Date of the PPA
[H]	End Date (mo/da/yr)	MM/DD/YY	The End Date of the PPA
[I]	Type of PPA (Unit or System)	"Unit" or "System"	Enter the text "Unit" if the PPA is from a specific unit such as a wind generator selling its output to a utility, or from multiple units at a single plant. Please provide the name of the unit or facility supplying the PPA in the End Notes Sheet. Enter "System" if the PPA is sourced from a utility's or IPP's fleet with different units providing power at different times.
[J]	End Note Number (Enter text in End Notes Sheet)	Integer	Same instruction as the Generation Assets Sheet.

	Instructions for completing the Asset Appendix Sheet: Transmission/Natural Gas Assets		
Column	Title	Format	Description
[A]	Filing Entity and its Energy Affiliates		Same instruction as the Generation Assets Sheet.
[B]	Cite to order accepting OATT or the order approving the transfer of transmission facilities to an RTO or ISO		Commission cite to the order accepting the Filing Entity's or its Energy Affiliate's current OATT, or the order transferring control of the transmission facilities to an RTO/ISO.
[C]	Asset Name and Use	Free Form Text	Legal name of the facility and brief description of the type of facility (i.e. transmission line or gas pipeline).
[D]	Owned By		Name of the Entity owning the transmission/natural gas assets.
[E]	Controlled By		Name of the Entity that controls the transmission/natural gas assets.
[F]	Date Control Transferred		Same instruction as the Generation Assets Sheet.
[G]	Market/Balancing Authority Area		Same instruction as the Generation Assets Sheet.
[H]	Geographic Region		Same instruction as the Generation Assets Sheet.
[I]	Size (e.g., length and kV for electric, length and diameter for pipelines, and capacity for gas storage)	Free Form Text	Description of the size of the facility in the measures relevant to the specific type of facility. For example, for electric "Size" refers to the length and kV rating of the transmission line; for gas pipeline "Size" refers to the length and diameter of the pipeline; for gas storage "Size" refers to the capacity of the facility.
[J]	End Note Number (Enter text in End Notes Sheet)		Same instruction as the Generation Assets Sheet.

Instructions for completing the Asset Appendix Sheet: End Notes

Column	Title	Format	Description
[A]	End Note Number	Integer	Should match an End Note number in the Generation Assets, Long-Term Firm PPAs or Transmission/Natural Gas Assets Sheets.
[B]	Sheet (Generation Assets, Long-Term Firm PPAs or Transmission/Natural Gas Assets)	The words "Generation", "PPA", or "Transmission/Natural Gas"	Indicates in which asset sheet the End Note is located.
[C]	Explanatory Note	Free Form Text	Text providing the clarification or explanatory note.

This is an example of the required appendix listing the filing entity and all its energy affiliates and their associated assets, which must be submitted with relevant market-based rate filings.

Asset Appendix: Generation Assets

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
						Location						
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority Area	Geographic Region	In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet)

Asset Appendix: Long-Term Firm Power Purchase Agreements (PPA)

Note:

Energy-only contracts must be converted to MW

Only report contracts one year or longer

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
			Location						
Filing Entity and its Energy Affiliates	Seller Name	Amount of PPA (MW)	Market / Balancing Authority Area (Source)	Market / Balancing Authority Area (Sink)	Geographic Region (Sink)	Start Date (mo/da/yr)	End Date (mo/da/yr)	Type of PPA (Unit or System)	End Note Number (Enter text in End Notes Sheet)

Asset Appendix: Transmission/Natural Gas Assets

Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location		Size	
Filing Entity and its Energy Affiliates	Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority Area	Geographic Region	Size (e.g., length and kV for electric, length and diameter for pipelines, and capacity for gas storage)	End Note Number (Enter text in End Notes Sheet)

		Asset Appendix: End Notes
		End Notes for Entries in the Generation, Long-Term Firm PPA and Transmission/Natural Gas Assets Sheets
[A]	[B]	[C]
End Note Number	Sheet (Generation, PPA or Transmission / Natural Gas)	Explanatory Note

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DEPARTMENT OF LABOR

Office of Labor-Management Standards

29 CFR Parts 403 and 458

The Reorganization and Delegation of Authority for the Procedures Involving the Election of Officers in Federal Sector Labor Organizations; Filing Threshold for Simplified Annual Reports; and Instructions Regarding the Reports for Labor Organization Officer and Employee, Labor Organization Annual Report, Trusteeship, and Terminal Trusteeship

AGENCY: Office of Labor-Management Standards, DOL.

ACTION: Final rule; technical corrections.

SUMMARY: The Office of Labor-Management Standards (OLMS) is making a number of technical corrections to its regulations and LM form instructions. OLMS is revising the instructions for the Form LM–30, Labor Organization Officer and Employee Report. OLMS is also amending a 2003 final rule on labor organization annual reports in order to incorporate the previously updated filing threshold for smaller labor organizations with gross annual receipts totaling less than $250,000, make a technical correction to the instructions for the Form LM–2 Labor Organization Annual Report, Item 36 (Dues and Agency Fees), as well as to update the instructions for the Form LM–15, Trusteeship Report, and Form LM–16, Terminal Trusteeship Report. In addition, OLMS is amending a 2013 technical amendment implementing Secretary's Order No. 02–2012, which delegated appellate authority over certain federal sector labor organization officer election matters to the Administrative Review Board.

DATES: Effective May 26, 2016.

FOR FURTHER INFORMATION CONTACT: Andrew R. Davis, Chief of the Division of Interpretations and Standards, Office of Labor-Management Standards, U.S. Department of Labor, 200 Constitution Avenue NW., Room N–5609, Washington, DC 20210, *olms-public@dol.gov,* (202) 693–0123 (this is not a toll-free number), (800) 877–8339 (TTY/TDD).

SUPPLEMENTARY INFORMATION:

Background

The Form LM–30 final rule that is the subject of these corrections appeared in the **Federal Register** on October 26, 2011 (76 FR 66441); the final rule revised the Form LM–30, Labor Organization Officer and Employee Report, its instructions, and related provisions in the Department's regulations. The rule implemented section 202 of the Labor-Management Reporting and Disclosure Act of 1959 (LMRDA), 29 U.S.C. 432, whose purpose is to require officers and employees of labor organizations to report specified financial transactions, arrangements, and holdings to effect public disclosure of any possible conflicts of interest with their duty to the labor organization and its members. The Form LM–30 and instructions are referenced in 29 CFR part 404. See 29 CFR 404.3 (Form of Annual Report).

These corrections also amend a final rule published in the **Federal Register** on October 10, 2003 (68 FR 58374), concerning labor organization annual reports. In that rule, the Department increased the filing threshold for Form LM–2 filers from $200,000 to $250,000 in gross annual receipts. See 68 FR 58383. However, the rule did not make a corresponding amendment to the text of 29 CFR 403.4(a)(1) (Simplified annual reports for smaller labor organizations), which permits smaller labor organizations to file the simplified Form LM–3 if they do not have gross annual receipts that meet the filing threshold for the Form LM–2.

Furthermore, the 2003 rule mandated electronic filing of the Form LM–2 for labor organizations with $250,000 or more in gross receipts. See 68 FR 58407. The instructions for the Form LM–2 were properly revised to reflect this requirement, but the rule did not update the instructions for the Form LM–15, Trusteeship Report, or the instructions for the Form LM–16, Terminal Trusteeship Report, both of which still contain references to the old paper format of the Form LM–2. Pursuant to Title III of the LMRDA and the Department's regulations at 29 CFR part 408, the instructions for the Forms LM–15 and LM–16 detail a parent organization's obligation to complete the Form LM–2 on behalf of a subordinate organization that it has placed in trusteeship.

Moreover, today's corrections fix an omission in Section III of the instructions for the Form LM–16, by making clear that the treasurer of the parent union, in addition to the president (or corresponding principal officers), is required to sign the subordinate union's Form LM–2 report, pursuant to 29 U.S.C. 461(a). The Forms LM–16 and LM–16 and instructions are referenced in 29 CFR part 408. See 29 CFR 408.3 (Form of Initial Report) and 29 CFR 408.7 (Terminal Trusteeship Information Report).

Additionally, these amendments correct a technical error in the instructions for Form LM–2 Labor Organization Annual Report, Item 36 (Dues and Agency Fees), by clarifying an example concerning the reporting by a parent body and its subordinate for dues retained by the parent body from dues checkoff as payment for supplies purchased from the parent body by its subordinate. The Form LM–2 and instructions are referenced in 29 CFR part 403. See 29 CFR 403.3 (Form of Annual Financial Report—Detailed Report).

Finally, these corrections amend a final rule published in the **Federal Register** on February 5, 2013 (78 FR 8022), concerning technical amendments implementing Secretary's Order No. 02–2012 (77 FR 69378),