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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM14-14-000; Order No. 816]

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

(Issued October 16, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule

SUMMARY:

EFFECTIVE DATE: This rule will become effective **[Insert_Date 90 days after publication in the FEDERAL REGISTER].**

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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ORDER NO. 816

FINAL RULE

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Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

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I. Introduction

1. On June 19, 2014, the Commission issued a Notice of Proposed Rulemaking (NOPR), pursuant to sections 205 and 206 of the Federal Power Act (FPA),[1] in which the Commission proposed to revise its current standards for market-based rates for sales of electric energy, capacity, and ancillary services.[2] The Commission proposed to modify and streamline certain aspects of the Commission's filing requirements to reduce the administrative burden on market-based rate sellers[3] and the Commission.

[1] 16 U.S.C. 824d, 824e.

[2] *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 (2014) (NOPR).

[3] The term "seller" as used in this Final Rule includes sellers that have already been granted market-based rate authority as well as applicants for market-based rate authority, unless otherwise noted.

2. This Final Rule represents another step in the Commission's efforts to modify, clarify and streamline certain aspects of its market-based rate program. Some aspects of this Final Rule eliminate or refine existing filing requirements, while other aspects of the Final Rule require submission of additional information from market-based rate sellers. For example, this Final Rule redefines the default relevant geographic market for an independent power producer (IPP) with generation capacity located in a generation-only balancing authority and requires sellers to report all long-term firm purchases that have an associated long-term firm transmission reservation in their indicative screens and asset appendices. The Final Rule provides clarification on issues including capacity ratings and preparation of simultaneous transmission import limit (SIL) studies. Streamlining is accomplished through, for example, elimination of the land acquisition reporting requirement, reduction in the number of notice of change in status filings due to establishment of a 100 megawatt (MW) threshold for reporting new affiliations, and clarification that sellers need not report behind-the-meter generation in the indicative screens and asset appendices. The specific components of this rule, in conjunction with other regulatory activities, are designed to ensure that the market-based rates charged by public utilities are just and reasonable.

3. Pursuant to sections 205 and 206 of the FPA, the Commission is amending its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal Regulations (CFR), which governs market-based rate authorizations for wholesale sales of electric energy, capacity, and ancillary services by public utilities.

II. Background

4. In 1988, the Commission began considering proposals for market-based pricing of wholesale power sales. The Commission acted on market-based rate proposals filed by various wholesale suppliers on a case-by-case basis. Over the years, the Commission developed a four-prong analysis to assess whether a seller should be granted market-based rate authority: (1) whether the seller and its affiliates lack, or have adequately mitigated, market power in generation; (2) whether the seller and its affiliates lack, or have adequately mitigated, market power in transmission; (3) whether the seller or its affiliates can erect other barriers to entry; and (4) whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.

5. In 2006, the Commission issued a notice of proposed rulemaking, which led to the issuance in 2007 of Order No. 697, which clarified and codified the Commission's market-based rate policy and generally retained the four prong analyses.[4] As to the first prong, the Commission adopted two indicative screens for assessing horizontal market power: the pivotal supplier screen and the wholesale market share screen (with a 20 percent threshold). Each of these uses a "snapshot in time" approach based on historical

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[4] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007) (Clarifying Order), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

data[5] and serves as a cross check on the other to determine whether sellers may have horizontal market power and should be further examined.[6] The Commission stated that passage of both indicative screens establishes a rebuttable presumption that the seller does not possess horizontal market power. Sellers that fail either indicative screen are rebuttably presumed to have market power and are given the opportunity to present evidence such as a delivered price test (DPT) analysis or historical sales and transmission data to demonstrate that, despite a screen failure, they do not have market power.[7] The Commission specified that in traditional markets (outside regional transmission organization/independent system operator (RTO/ISO) markets), the default relevant geographic market for purposes of the indicative screens is first, the balancing authority area(s) where the seller is physically located, and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority areas).[8] Generally, sellers that are located in and are members of the RTO/ISO may

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[5] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 17.

[6] *Id.* PP 62, 75.

[7] *Id.* P 13; 18 CFR 35.37(c)(3).

[8] The Commission also noted that "[w]here a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (i.e., the balancing authority area in which the generator is located)." Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of the indicative screens.[9]

6. With respect to the vertical market power analysis, in cases where a public utility or any of its affiliates owns, operates, or controls transmission facilities, the Commission requires that there be a Commission-approved Open Access Transmission Tariff (OATT) on file, or that the seller or its applicable affiliate has received waiver of the OATT requirement, before granting a seller market-based rate authorization.[10] The Commission also considers a seller's ability to erect other barriers to entry as part of the vertical market power analysis.[11] As such, the Commission requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation capacity development; and physical coal supply sources and ownership of or control over who may access transportation of coal supplies (collectively, inputs to electric power production).[12] In Order No. 697-C, the Commission revised the change in status reporting requirement in section 35.42 of the Commission's regulations to require a

[9] Where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes a default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis. *See Id.* PP 15, 231.

[10] *Id.* P 408.

[11] *Id.* P 440.

[12] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 176.

market-based rate seller to report the acquisition of control of sites for new generation capacity development on a quarterly basis instead of within 30 days of the acquisition.[13] The Commission adopted a rebuttable presumption that the ownership or control of, or affiliation with any entity that owns or controls, inputs to electric power production does not allow a seller to raise entry barriers but will allow intervenors to demonstrate otherwise.[14] Finally, as part of the vertical market power analysis, the Commission also requires a seller to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[15]

7. If a seller is granted market-based rate authority, the authorization is conditioned on: (1) compliance with affiliate restrictions governing transactions and conduct between power sales affiliates where one or more of those affiliates has captive customers;[16] (2) a requirement to file post-transaction electric quarterly reports (EQR) with the Commission containing: (a) a summary of the contractual terms and conditions in every effective service agreement for market-based power sales; and (b) transaction information for effective short-term (less than one year) and long-term (one year or longer) market-based

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[13] Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 at P 18; 18 CFR 35.42(d).

[14] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 446; 18 CFR 35.37(c).

[15] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447 (clarifying that the obligation in this regard applies to both the seller and its affiliates but is limited to the geographic market(s) in which the seller is located).

[16] 18 CFR 35.39.

power sales during the most recent calendar quarter;[17] (3) a requirement to file any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority;[18] and (4) a requirement for large sellers to file updated market power analyses every three years.[19]

8. In Order No. 697, the Commission created two categories of sellers.[20] Category 1 sellers are wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate, or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888[21]); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the

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[17] 18 CFR 35.10b.

[18] 18 CFR 35.42.

[19] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 3; 18 CFR 35.37(a)(1).

[20] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 848.

[21] *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, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 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).

seller's generation assets; and that do not raise other vertical market power issues.[22] Category 1 sellers are not required to file regularly scheduled updated market power analyses. Sellers that do not fall into Category 1 are designated as Category 2 sellers and are required to file updated market power analyses.[23] However, the Commission may require an updated market power analysis from any market-based rate seller at any time, including those sellers that fall within Category 1.[24]

9. In Order No. 697, the Commission further stated that through its ongoing oversight of market-based rate authorizations and market conditions, the Commission may take steps to address seller market power or modify rates. For example, based on its review of updated market power analyses, EQR filings, or notices of change in status, the Commission may institute a proceeding under section 206 of the FPA to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission also may, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstance to determine whether there has been a

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[22] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 849 n.1000; 18 CFR 35.36(a).

[23] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

[24] *Id.* P 853.

violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations.[25]

10. After more than six years of experience with the implementation of Order No. 697, the Commission proposed a number of changes to the market-based rate program which, taken as a whole, it believed would simplify and streamline certain aspects of the market-based rate program and reduce the burden on industry and the Commission, while continuing to ensure that the standards for market-based rate sales of electric energy, capacity and ancillary services result in sales that are just and reasonable. The Commission also proposed a number of changes to improve transparency in the market-based rate program, some of which represent increases in information collected from market-based rate sellers.

11. The Commission received 23 comments in response to the NOPR. A list of commenters is attached as Appendix F.[26]

III. **Overview of Final Rule**

12. In this Final Rule, we adopt in many respects the proposals contained in the NOPR with further modifications and clarifications and decline to adopt others. Our findings are summarized below.

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[25] *Id.* P 5.

[26] Although the Commission did not request reply comments, several commenters nonetheless submitted reply comments. The Commission will reject such reply comments.

13. First, with respect to the Commission's horizontal market power analysis, we are not, at this time, adopting the proposal to relieve market-based rate sellers in RTO/ISO markets of the obligation to submit indicative screens. However, we are confirming clarifications and adopting many of the other proposed modifications to the horizontal market power analysis. For example, we clarify 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 as part of their horizontal market power analysis. We also clarify that, when the current Commission-accepted SIL values into the relevant market are zero for all four seasons and the seller's and its affiliates' generation capacity in the relevant market is fully committed, the seller does not need to submit indicative screens. In addition, we adopt the NOPR proposal regarding reporting of long-term firm purchases.

14. We adopt the proposal to define the default relevant geographic market for an IPP located in a generation-only balancing authority area as the balancing authority area(s) of each transmission provider to which the IPP's generation-only balancing authority area is directly interconnected. We explain that an IPP should study all of its uncommitted generation capacity from the generation-only balancing authority area in the balancing authority area(s) of each transmission provider to which it is directly connected, and we provide examples and clarification of this policy.

15. We amend the indicative screen reporting format and require that the horizontal market power indicative screens and SIL Submittals 1 and 2 be filed in workable electronic spreadsheets. We find that solar photovoltaic and solar thermal facilities are

energy limited. However, we determine that, due to their unique characteristics, solar photovoltaic facilities, unlike other energy-limited facilities, must use nameplate capacity and may not use historical five-year average capacity factors.

16. We adopt the proposal to require a market-based rate seller to report in its indicative screens and asset appendix all of its long-term firm purchases of capacity and/or energy that have an associated long-term firm transmission reservation regardless of whether the market-based rate seller has control over the generation capacity supplying the purchased power. We also adopt a modified formula for converting energy to capacity, and make corresponding changes to the change in status reporting requirements.

17. We confirm most of the clarifications proposed in the NOPR regarding the SIL studies and provide some additional clarifications in response to comments.

18. With respect to the Commission's vertical market power analysis, we adopt the proposal to eliminate 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. With respect to other change in status proposals, we clarify that the 100 MW threshold does *not* include generation capacity that can be imported from first-tier markets. Similarly, we find that applicants and sellers are *not* limited to nameplate ratings when determining the 100 MW threshold. We have reconsidered the proposed clarification that market-based rate sellers must account for behind-the-meter generation in their indicative screens and asset appendices and find that behind-the-meter generation need not be accounted for

in the indicative screens and asset appendices and will not count towards the 100 MW change in status threshold or the 500 MW Category 1 seller threshold.

19. We also adopt a 100 MW change in status threshold for reporting new affiliations to align with the existing 100 MW threshold for reporting net increases in generation capacity.

20. We adopt changes to the asset appendix that sellers must submit with most market-based rate filings, and will also require that the asset appendix be submitted in an electronic format that can be searched, sorted, and otherwise accessed using electronic tools. In addition, based on comments received, we will add two additional worksheets to the asset appendix, one for end notes and another for long-term firm purchases. We provide some additional clarifications on the asset appendix as well.

21. We adopt the NOPR proposal to require a seller filing an initial application for market-based rate authority, an updated market power analysis, or a notice of change in status reporting new affiliations to include a corporate organizational chart. However, we clarify that the organizational chart need only to include the seller's affiliates as defined in section 35.36(a)(9) of the Commission's regulations rather than all upstream owners, "energy subsidiaries" and "energy affiliates."

22. We adopt the NOPR proposal and clarify 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, we clarify how 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), and confirm that hydropower

licensees that have Commission-approved cost-based rates are required to comply with the full requirements of the Uniform System of Accounts.

23. We also provide clarifications in the Final Rule with regard to simplifying assumptions, the criteria for determining seller category status, how to file a single corporate tariff, the regional reporting schedule, and the vertical affirmative statement obligation.

IV. Discussion

A. Horizontal Market Power

1. Sellers in RTOs/ISOs

a. Commission Proposal

24. Section 35.37 of the Commission's regulations requires market-based rate sellers to submit market power analyses: (1) when seeking market-based rate authority; (2) every three years for Category 2 sellers; and (3) at any other time the Commission requests a seller to submit an analysis. A market power analysis must address a seller's potential to exercise horizontal and vertical market power. If an RTO/ISO seller[27] fails

[27] RTO/ISO sellers are sellers that study an RTO, ISO, and submarkets therein as a relevant geographic market.

the indicative screens for the RTO/ISO, it can seek to obtain or retain market-based rate authority by relying on Commission-approved RTO/ISO monitoring and mitigation.[28]

25. The Commission proposed to not require sellers in RTO/ISO markets to submit indicative screens as part of their horizontal market power analyses if they rely on Commission-approved monitoring and mitigation to prevent the exercise of market power. Under the proposal, RTO/ISO sellers instead would simply state that they are relying on such mitigation to address any potential market power they might have, and describe their generation and transmission assets and provide an asset appendix with a list of generation assets and entities with market-based rate authority (generation list) and a list of transmission assets and natural gas intrastate pipelines and gas storage facilities (transmission list). Under this proposal, all RTO/ISO sellers seeking market-based rate authority in an RTO/ISO market would make an initial filing, consistent with current practice, and those sellers required to file updated market power analyses every three years (i.e., Category 2 sellers) would continue to make their scheduled filings. The Commission noted that it would retain the ability to require an updated market power analysis, including indicative screens, from any market-based rate seller at any time.

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[28] In Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111, the Commission stated that "to the extent a seller seeking to obtain or retain market-based rate authority is relying on existing Commission-approved [RTO/ISO] market monitoring and mitigation, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns."

b. Comments

26. Some commenters support the Commission's proposal to allow market-based rate sellers in RTO/ISO markets with Commission-approved monitoring and mitigation to not file indicative screens when submitting initial applications requesting market-based rate authority and updated market power analyses.[29] Some commenters request that the Commission clarify aspects of its proposal[30] or extend the proposal to additional circumstances.[31] Some commenters oppose the Commission's proposal, raising issues regarding the Commission's legal authority to eliminate the indicative screens[32] or the effectiveness of RTO/ISO monitoring and mitigation.[33] For example, Potomac Economics agrees with the general principal underlying the Commission's proposal, but states that in some cases, participants selling into RTO markets may be exempt from certain market power mitigation measures or the mitigation measures may not be fully

[29] American Electric Power Service Corporation (AEP) at 4-5; Electric Power Supply Association (EPSA) at 3-4; FirstEnergy Service Company (FirstEnergy) at 4-5; Golden Spread Electric Cooperative, Inc. (Golden Spread) at 6; NextEra Energy, Inc. (NextEra) at 2; Subsidiaries of NRG Energy, Inc. (NRG Companies) at 8-9.

[30] *See, e.g.*, E.ON Climate & Renewables North America LLC (E.ON) at 3-4; Southern California Edison Company (SoCal Edison) at 16; Julie Solomon and Matthew Arenchild (Solomon/Arenchild) at 2; Edison Electric Institute (EEI) at 6.

[31] *See, e.g.*, FirstEnergy at 10; AEP at 6; EEI at 7.

[32] American Antitrust Institute (AAI) at 3-7; American Public Power Association and National Rural Electric Cooperative Association (APPA/NRECA) at 6-21; Transmission Access Policy Study Group (TAPS) at 1-2, 5-9, 17-18.

[33] Potomac Economics at 3-4.

effective and that the Commission's proposal may allow some participants with potential market power to sell at market-based rates without this market power being fully addressed.[34] APPA/NRECA contend that the proposal is a fundamental departure from the market-based rate scheme that the courts have previously upheld.[35]

c. **Commission Determination**

27. The Commission received 15 comments on this issue from a wide variety of market participants. Indeed, this was one of the most widely commented upon aspects of the Commission's NOPR. The comments included those who fully support the Commission's proposal, those who favor only portions of it, those who seek clarification of it and those who oppose it. And among those who oppose it, there are various reasons for their opposition, which include legal, economic, and implementation issues. While the Commission considers further the issues that were raised in these comments, we are not prepared to adopt at this time the proposal in the NOPR and will continue with our current practice of requiring that sellers in RTO/ISO markets submit the indicative screens when submitting initial applications requesting market-based rate authority and updated market power analyses and relying on the Commission-approved market monitoring and mitigation. We will transfer the record on this aspect of the NOPR to

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[34] Potomac Economics at 2.

[35] APPA/NRECA at 8-10 (citing *Mont. Consumer Counsel v. FERC*, 659 F.3d 910; *California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004) (*Lockyer*); *Blumenthal v. FERC*, 552 F.3d 875,882 (D.C. Cir. 2009) (*Blumenthal*)).

Docket No. AD16-8-000 for possible consideration in the future as the Commission may deem appropriate.

28. Because we continue to value the information obtained through the indicative screens and are not prepared at this time to adopt the proposal, market-based rate sellers in RTO/ISO markets must continue to submit the indicative screens as part of their horizontal market power analysis unless the seller and its affiliates do not own or control generation capacity or all of their capacity is fully committed. We will continue to allow sellers to seek to obtain or retain market-based rate authority by relying on Commission-approved RTO/ISO monitoring and mitigation in the event that such sellers fail the indicative screens for the RTO/ISO markets.[36]

2. Sellers with Fully Committed Long-Term Generation Capacity

a. Commission Proposal

29. The Commission has found that, if generation is committed to be sold on a long-term firm basis to one or more buyers and cannot be withheld by a seller, it is appropriate for a seller to deduct such capacity when performing the indicative screens.[37] In the NOPR, the Commission clarified that where all generation owned or controlled by a seller and its affiliates in the relevant balancing authority areas or markets including first-tier balancing authority areas or markets is fully committed, sellers may satisfy the Commission's market-based rate requirements regarding horizontal market power by

[36] *See* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 11.

[37] *See id.* P 41.

explaining that their capacity is fully committed in lieu of including indicative screens in their filings. The Commission proposed to clarify that, in order to qualify as "fully committed," a seller must commit the generation capacity so that none of it is available to the seller or its affiliates for one year or longer.

30. The Commission proposed that sellers claiming that all of their relevant generation capacity[38] is fully committed would have to include 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. The Commission stated that in order to qualify as fully committed, the commitment of the generation capacity cannot be limited during that 12-month consecutive period in any way, such as limited to certain seasons, market conditions, or any other limiting factor. Furthermore, the Commission stated that a seller's generation would not qualify as fully committed if, for example, the seller has generation necessary to serve native load, provider of last resort obligations, or a contract that could allow the seller to reclaim, recall, or otherwise use the capacity and/or energy or regain control of the generation under certain circumstances (such as transmission availability clauses).

[38] "Relevant" generation capacity refers to seller and affiliated capacity in the study area, including the first tier.

31. Additionally, the Commission stated that, consistent with the existing regulations, a change in status filing will be required when a long-term firm sales agreement expires if it results in a net increase of 100 MW or more.[39]

b. <u>Comments</u>

32. Many commenters support the Commission's proposal.[40] For example, EPSA agrees with the Commission's assessment that the study of uncommitted generation in indicative screens becomes a purely mathematical task and provides no significant additional information when sellers' fully-committed long-term capacity is deducted from the indicative screens.[41] NextEra, also agreeing with the Commission's proposal, states that where all generation owned or controlled by sellers and their affiliates is fully committed to purchasers not affiliated with the seller, the ability to exercise market power is severely limited or non-existent.[42] FirstEnergy states that it supports the proposal because a seller whose generation capacity is fully committed on a long-term basis lacks

[39] The Commission noted that such a change would be a departure from the characteristics the Commission relied upon in granting market-based rate authority. *See* 18 CFR 35.42(a).

[40] EPSA at 4; Solomon/Arenchild at 2; NextEra at 3; EEI at 8; FirstEnergy at 7; NRG Companies at 10.

[41] EPSA at 5.

[42] NextEra at 3.

the ability to exercise horizontal market power by withholding such capacity from the market.[43]

33. NRG Companies also support the proposal and request that the Commission clarify that even if the seller and/or its affiliates have uncommitted capacity in one or more first-tier markets, no indicative screens will be required if all of their generation capacity in the relevant market is fully committed under long-term contracts and (1) the simultaneous import limitation for the relevant market is zero, indicating that no capacity can be imported from affiliates in first-tier markets, or (2) neither the seller nor its affiliates have firm transmission rights into the relevant market from any first-tier market in which its affiliates have uncommitted capacity.[44]

34. NextEra states that there is no need to provide screens in balancing authority areas where all generation owned or controlled by sellers and their affiliates is fully committed to purchasers not affiliated with the seller and further requests that the Commission not require screens if there is uncommitted capacity in any first-tier market when 100 percent of the seller's generation capacity in the relevant market is fully committed.[45]

35. EPSA requests clarification that the proposed term "fully committed" would also apply to circumstances where a seller retains the right to sell capacity to a second buyer, but only when the first buyer under the long-term contract waives the right to purchase.

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[43] FirstEnergy at 7.

[44] NRG Companies at 10-11.

[45] NextEra at 4.

EPSA explains that if the buyer under a long-term contract has the right to call on the full output of the seller's generation, and the seller may only offer the capacity to a second buyer when the first buyer foregoes its purchase right, then that capacity should be considered fully committed and thus, excluded from the indicative screens.[46]

36. Solomon/Arenchild state that the Commission's proposal that the exemption from the submittal of screens depends, in part, on whether the seller has uncommitted capacity in first-tier markets is inconsistent with its general approach in defining geographic markets and when screens are required. They recommend that the Commission's proposal be amended. In the NOPR, the Commission stated that "where all generation owned or controlled by a seller and its affiliates in the relevant balancing authority areas or markets *including first-tier balancing authority areas or markets* is fully committed, sellers may explain that their capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the Commission's market-based rate requirements regarding horizontal market power."[47] Solomon/Arenchild propose that the language "including first-tier balancing authority areas or markets" be excluded.[48] Alternatively, they state that the definition could be modified to only include first-tier

[46] EPSA at 5.

[47] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 43 (emphasis added).

[48] Solomon/Arenchild at 2-3.

supply that has a corresponding long-term firm transmission agreement into the relevant balancing authority area.[49]

37. With regard to the information a seller must provide, NextEra seeks clarification on the phrase “firm sales for one year or longer.” NextEra requests that the Commission clarify that the term “firm” has the same meaning as in the Commission’s EQR Data Dictionary, where it is defined as “a service or product that is not interruptible for economic reasons.”[50]

38. NextEra does not oppose the Commission’s proposal to require that sellers provide the expiration date of the contract in updated market power analyses, but NextEra states that it does not agree with requiring this information in initial market-based rate applications. NextEra states that, more often than not, at the time a seller files for market-based rate authority, the expiration date is unknown.[51] EEI does not support requiring the expiration date and notes that the expiration date is reported separately in EQR filings.[52]

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[49] *Id.* at 3.

[50] NextEra at 4-5 (citing http://www.ferc.gov/docs-filing/eqr/order770/data-dictionary.pdf).

[51] *Id.* at 5.

[52] EEI at 8.

c. Commission Determination

39. Consistent with the NOPR, the Commission clarifies here that when all of a seller's generation capacity is sold on a long-term firm basis to one or more buyers, the seller has no uncommitted capacity and in such cases will not be required to file the indicative screens. Sellers may explain that their generation capacity is fully committed in lieu of including indicative screens in their filings 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 balancing authority areas or markets, is fully committed. We clarify 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. We also adopt the proposal that for those sellers claiming that all of their relevant capacity is fully committed they must include 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. In order to qualify as fully committed, the commitment of the generation capacity cannot be limited during that 12-month consecutive period in any way, such as limited to certain seasons, market conditions, or any other limiting factor. As stated in the NOPR, a seller's generation would not qualify as fully committed if, for example, that generation is needed for the seller to meet its native load or provider of last resort obligations, or the power sales contract in question could allow the seller to reclaim, recall, or otherwise use the

generation capacity and/or energy or regain rights to the generation under certain circumstances (such as transmission availability clauses). Additionally, a change in status filing will be required when a long-term firm sales agreement expires if it results in a net increase of 100 MW or more.

40. We do not adopt the suggestions by NRG Companies, NextEra, and Solomon/Arenchild regarding capacity in first-tier markets. We will not implement NRG Companies' and NextEra's proposals that the Commission not require sellers to submit indicative screens even if they have uncommitted capacity in one or more first-tier markets as long as all of the seller's capacity in the relevant market is fully committed. A seller may fail an indicative screen in a market where it does not have any uncommitted capacity due to its imports into the study area.[53] However, when the current Commission-accepted SIL values into the relevant market are zero for all four seasons, the seller does not have to consider imports in its market-power studies. Therefore, we clarify that if the seller's capacity in the relevant market is fully committed and all the SIL values into the relevant market are zero, the seller does not need to submit the indicative screens.

41. We do not adopt the suggestion from Solomon/Arenchild to only consider first-tier supply that has long-term firm transmission rights into the relevant market. First-tier generation capacity without long-term firm transmission rights still can be imported into

[53] For example, this can occur when a seller is relatively large and the study area is relatively small and relies significantly on imports to meet its load obligations.

the relevant market as long as the SIL value is not zero; albeit on a non-firm, *pro rata* basis.[54] The SIL values used in the Commission's horizontal market power analysis are net of long-term firm transmission reservations. While a seller's *pro rata* share of the SIL value or transmission capacity that may be used to import generation capacity from the first-tier ultimately may be small, it should not be ignored.

42. We also decline to adopt EPSA's request that we clarify that a seller's generation capacity is fully committed where the seller retains the right to sell capacity to a second buyer.[55] We are concerned that permitting a more flexible definition of fully committed could create the potential for sellers to claim that their contracts meet the standard for fully committed even where it is not clear that the capacity's output is fully committed. Moreover, the contract-specific analysis could create inconsistencies in the way data is reported.

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[54] Stated another way, if the SIL value is not zero, and the seller has uncommitted generation capacity in a first-tier market, that uncommitted capacity is capable of reaching the study area and will affect the market power analysis. However, a seller's first-tier uncommitted capacity has to compete with non-affiliated first-tier uncommitted capacity to enter the study area, so the Commission allows sellers to allocate to themselves a portion of the SIL value based on the percentage of uncommitted generation capacity they and their affiliates own in the aggregated first-tier area in relation to the total amount of uncommitted generation capacity in this area. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 373-375.

[55] Here we are referring to a situation in which the seller retains rights to sell the same generation capacity to a second buyer. We are not referring to a contractual arrangement whereby capacity is fully committed but is sold to multiple buyers; e.g., 500 MW of a 1,000 MW unit is sold to buyer A, while the remaining 500 MW of the unit is sold to buyer B, with A and B having exclusive rights to their respective shares of the unit.

43. With regard to NextEra's request that the Commission clarify that "firm" has the same meaning as in the Commission's EQR Data Dictionary, we clarify here that the term "firm" means a "service or product that is not interruptible for economic reasons," as it is defined in the Commission's EQR Data Dictionary.

44. We believe that NextEra raises a valid point concerning unknown expiration dates. Therefore, we clarify here that if a contract expiration date is unknown at the time of the market-based rate filing, the seller must follow up with 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, within 30 days of the date becoming known. In response to EEI's argument that the expiration date is reported separately in EQR filings, we note many contracts reported in EQR filings do not include expiration dates. Further, there can be a time gap between when a seller receives market-based authority and when it submits its EQR. This time gap may be as large as 120 days, and would not meet the need for this information. Therefore, we will require expiration date information to show that generation capacity is fully committed.

3. Relevant Geographic Market for Certain Sellers in Generation-Only Balancing Authority Areas

a. Commission Proposal

45. In the NOPR, the Commission noted that "the horizontal market power analysis centers on and examines the balancing authority area where the seller's generation is

physically located"[56] and that the default relevant geographic market under both indicative screens "will be first, the balancing authority area where the seller is physically located [the seller's home balancing authority area] and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets)."[57] However, the Commission noted that "[w]here a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (i.e., the balancing authority area in which the generator is located)."[58] Similarly, the Commission noted that RTO/ISO sellers are required "to consider, as part of the relevant market, only the relevant [RTO/ISO] market and not first-tier markets to the [RTO/ISO]."[59]

46. The Commission noted that Order No. 697 stated that a "balancing authority area means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, and the balancing authority maintains load/resource balance within this area."[60] The Commission further noted that, given that generation-only balancing authority areas do not have any load, these balancing authority areas do

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[56] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 47 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 37).

[57] *Id.* (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232).

[58] *Id.* (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217).

[59] *Id.* (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 231 n.215).

[60] *Id.* P 51.

not appear to meet the Commission definition of a default relevant geographic market. In light of the unusual and complex circumstances that are associated with defining the relevant geographic market of an IPP located in a generation-only balancing authority area, and in light of the fact that a generation-only balancing authority area is not a market, the Commission proposed in the NOPR that the default relevant geographic market(s) for such a seller would be the balancing authority areas of each transmission provider to which its generation-only balancing authority area is directly interconnected. The Commission proposed that such IPP seller study all of its uncommitted generation capacity from the generation-only balancing authority area in the balancing authority area(s) of each transmission provider to which it is directly interconnected, since all such uncommitted capacity could potentially be sold into any of the markets that are directly interconnected to the IPP's generation-only balancing authority area, even if the IPP has not sold into that market.

47. In the NOPR, the Commission stated that "[f]or purposes of market power analyses for market-based rate authority, we propose to define an IPP as a generation resource that has power production as its primary purpose, does not have any native load obligation, is not affiliated with any transmission owner located in the first-tier markets in which the IPP is competing and does not have an affiliate with a franchised service territory. This IPP could also have an OATT waiver on file with the Commission."[61]

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[61] *Id.* P 49 n.50.

48. To illustrate the NOPR proposal, the Commission explained that if an IPP is located in a generation-only balancing authority area that is embedded within a transmission provider's balancing authority area, and that balancing authority area is the only balancing authority area that the IPP's generation-only balancing authority area is directly interconnected with, then the IPP would provide indicative screens for that transmission provider's balancing authority area.[62]

49. The Commission provided another example for an IPP located in a generation-only balancing authority area in a remote area such as the desert southwest. In that case, the IPP would have to provide indicative screens for the balancing authority area(s) of the transmission provider(s) to which its generation-only balancing authority area is directly interconnected. The IPP would assume that all of its uncommitted capacity could compete in each balancing authority area of the transmission provider(s) to which its generation-only balancing authority area is directly interconnected, since all such uncommitted capacity could potentially be sold in each market to which there is a direct interconnection, even if the IPP has not sold into that market in the past. An IPP in this situation would not need to study any first-tier markets.[63]

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[62] The Commission proposed that an IPP in this situation would not need to study the transmission provider's balancing authority first-tier markets, just as would be the case if that generator were similarly located in the transmission provider's balancing authority area.

[63] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

50. For an IPP in a generation-only balancing authority area directly interconnected to a transmission provider at an energy trading hub, the Commission proposed that the IPP would provide indicative screens that study itself in the balancing authority area of each transmission provider that is directly interconnected at the trading hub. Thus, the balancing authority areas that are directly interconnected at the hub would each be relevant geographic markets for that IPP, and the IPP would provide indicative screens that study the IPP in each of those transmission providers' balancing authority areas. The Commission proposed that the IPP would provide indicative screens that assume that all of its uncommitted capacity may compete in each of the balancing authority areas that are directly interconnected at that trading hub, since all such uncommitted capacity could potentially be sold in each market to which there is a direct interconnection, even if the IPP has not sold into that market in the past. The IPP in this situation would not need to provide indicative screens that study itself in any markets that are first-tier to the various balancing authority areas that are directly interconnected at the trading hub.

b. <u>Comments</u>

51. Solomon/Arenchild agree in principal with the Commission's proposal to define relevant geographic market(s) for sellers located in generation-only balancing area as the balancing authority areas of each transmission provider to which the generation-only balancing authority area is directly interconnected. Solomon/Arenchild suggest that the Commission confirm that the proposal also applies to quasi-generation-only balancing authority areas, such as Ohio Valley Electric Corporation and Alcoa Power Generating,

Inc.-Yadkin Division. According to Solomon/Arenchild, in these quasi-generation-only balancing authority areas, generation was built to serve load in a balancing authority area, but there is no longer any material load present in the balancing authority area.[64]

52. However, Solomon/Arenchild voice concerns with the Commission's proposal to have an IPP provide screens that study the IPP in the balancing authority area of each transmission provider that is directly interconnected at the trading hub. Citing the example in the NOPR regarding IPPs interconnected to the Hassayampa switchyard, Solomon/Arenchild state that, as proposed, the solution is overly burdensome and likely to have unintended consequences.[65] They explain that the Commission's proposal, as they understand it, would require New Harquahala Generating Company, LLC (Harquahala) and Arlington Valley, LLC (Arlington Valley) to each perform indicative screens for all Arizona Nuclear Power Project switchyard participants. They state that this would be at least six balancing authority areas and perhaps more, resulting in a "significant increase in the scope of the analysis and the burden."[66]

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[64] Solomon/Arenchild at 15.

[65] The Commission explained in the NOPR that if an IPP in a generation-only balancing authority area in the Arizona desert is directly interconnected to a transmission provider at the Palo Verde trading hub at the Palo Verde and Hassayampa switchyards, then it would provide screens that study all of its uncommitted capacity in each balancing authority area that is directly interconnected at the switchyard. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 56.

[66] Solomon/Arenchild at 15-17 (citing NOPR, FERC Stats. & Regs. ¶ 32,702 at P 56).

53. Solomon/Arenchild also argue that the proposal does not clarify many of the steps that must be considered. They state that a seller has to determine if each of the analyses require a presumption that 100 percent of the output of each of the relevant merchant generators can be "imported" into each of the six or more balancing authority areas. They further state that the SIL studies done by the transmission owners in the region would have to be aligned with the analyses and they question whether that means that each of the balancing authority areas would be required to conduct two SIL studies – one that assumes each of the potentially relevant generators reside "within" their balancing authority areas and one that does not. Solomon/Arenchild also question whether Harquahala and Arlington Valley should be singled out from their other counterparts who are also interconnected at Hassayampa, merely because they reside in a generation-only balancing authority area.[67]

54. Solomon/Arenchild state that the proposal to conduct indicative screens for multiple interconnected balancing authority areas appears to merely create multiple opportunities for the generator in a generation-only balancing authority area to fail an indicative screen. Solomon/Arenchild further state that in proposing that each generator consider multiple relevant balancing authority areas, it seems that the Commission is acknowledging the highly interconnected nature of the region (a key reason for the existence of a "hub"), while still rejecting the proposition that a "hub" itself can be a

[67] *Id.* at 17.

relevant market. Solomon/Arenchild explain that it is worth noting that in the Western Interconnection (unlike in the Eastern Interconnection), load flow models such as those underlying the SIL analyses are based not on individual balancing authority areas, but on "areas" that more closely approximate real world conditions.[68]

55. Solomon/Arenchild state that the proposal could have significant market-distortive effects. Solomon/Arenchild postulate that if a generator fails an indicative screen in the Salt River Project balancing authority area, but not in the Arizona Public Service balancing authority area, the Salt River Project balancing authority area may lose opportunities to purchase at market-based rates, and generators may lose opportunities to sell at market-based rates. Solomon/Arenchild contend that this would not occur if somewhat broader markets are considered. Solomon/Arenchild conclude that, in the absence of creating broader markets for generation-only balancing authority areas like those at Hassayampa, the Commission should not change its current practice. That is, sellers in generation-only balancing authority areas should use as the default relevant market, the directly interconnected balancing authority areas and that the scope of such definitions be evaluated on a case-by-case basis.[69]

56. Lastly, Solomon/Arenchild request that the Commission clarify that, to the extent that a seller fails the indicative screens in the balancing authority area(s) to which it is

[68] *Id.* at 17-18 (noting that Western Electricity Coordinating Council transmission models used an "Area 14," which covers the Arizona "region" as the basis for SIL studies rather than the individual balancing authority areas).

[69] *Id.* at 18.

directly interconnected, sales at the "hubs" be treated as "at the metered boundary" of a seller's mitigated balancing authority area, and hence, allow market-based rate sales at the hubs.[70]

57. Romkaew Broehm and Gerald A. Taylor (Broehm/Taylor) agree with the Commission's logic in proposing to define relevant markets as the balancing authority areas that are directly interconnected to the generation only-balancing authority area. However, Broehm/Taylor encourage the Commission to look beyond its default market rule when defining a proper relevant geographic market for a market power analysis for all sellers. Broehm/Taylor question whether a seller's home balancing authority area and its first-tier balancing authority area would be adequate for determining relevant default markets. According to Broehm/Taylor, during the 2000-2001 Western power crisis experience, suppliers with generation more than two wheels away could easily reach the California buyers and became pivotal sellers, simply by having firm transmission rights at the key interfaces.[71] Broehm/Taylor explain that if the Commission were to require sellers to report all of their transmission reservation data, a seller with reservations on a path from a first-tier to a second-tier balancing authority area would need to perform a market power analysis for the second-tier balancing authority area.[72] Broehm/Taylor state that this suggests that the Commission should

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[70] *Id.*

[71] Broehm/Taylor at 3.

[72] *Id.* at 3-5.

expand its review to consider other information, such as sellers' transmission reservation data. Broehm/Taylor therefore recommend that the Commission require all sellers to summarize their historical short-term trade patterns outside their home balancing authority area and report their firm transmission service reservations of one month or longer as part of their triennial updated market power analysis filing. Broehm/Taylor state that sellers are required to report this information to the Commission via EQRs and that this information can be used to determine whether or not the default geographic markets as defined by the Commission are adequate for purposes of market power analyses.[73]

58. EPSA generally supports the proposal, but suggests consistent treatment in the Commission's evaluation of nested balancing authority areas. It requests that the Commission clarify that it will implement the proposal in such a manner to ensure that as long as there is network deliverability from the nested balancing authority areas through the interconnected balancing authority areas and to the first-tier balancing authority areas, those first-tier balancing authority areas should be included in the indicative screens of sellers in the generation-only balancing authority areas. According to EPSA, this approach would more accurately reflect the geographic area in which the energy from the nested balancing authority area is available and with which it can

[73] *Id.* at 5-6.

compete. They also state that this approach would be consistent with the analysis for an IPP's balancing authority area that is connected to a trading hub.[74]

59. NRG Companies request that the Commission clarify that if a seller in a generation-only balancing authority area fails the indicative market power screens and surrenders or loses market-based rate authorization to sell in one or more of the markets connected to the trading hub, the seller will still be allowed to make market-based rate sales at the trading hub, as long as it retains market-based rate authorization in at least one of the balancing authority areas interconnected to the trading hub. NRG Companies state that such clarification is consistent with the Commission's holding in Order No. 697 that a seller that has lost market-based rate authorization and is making sales subject to cost-based mitigation may continue to "make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority in which the seller has market-based rate authority."[75]

60. EEI encourages the Commission to clarify that IPPs connected to a hub would need to perform the market power analyses only for the home market of each transmission provider connected to the hub, not the transmission provider's first-tier adjacent markets, and that the IPPs could conduct a single analysis, not separate ones for each provider's market. EEI also requests the Commission consider whether a similar

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[74] EPSA at 6.

[75] NRG Companies at 12-13 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 817).

approach could be used for entities that are not IPPs and for entities that have a *de minimis* amount of load in their balancing authority areas.[76]

c. Commission Determination

61. We adopt the NOPR proposal to define the default relevant geographic market(s) for an IPP located in a generation-only balancing authority area as the balancing authority areas of each transmission provider to which the IPP's generation-only balancing authority area is directly interconnected. For purposes of this provision, we define an eligible IPP as a generation resource that has power production as its primary purpose, does not have any native load obligation, is not affiliated with any transmission owner located in the target or first-tier markets in which the IPP is competing and does not have an affiliate with a franchised service territory.[77]

62. We also adopt the proposal for such an IPP to study all of its uncommitted generation capacity from the generation-only balancing authority area in the balancing authority area(s) of each transmission provider to which it is directly interconnected. We clarify that we do not consider other generation-only balancing authority areas to which an IPP may be interconnected to be balancing authority areas of transmission providers. If an IPP is located in a generation-only balancing authority area that is embedded within a transmission provider's balancing authority area, and that balancing authority area is

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[76] EEI at 9.

[77] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 49 n.50. This IPP could also have an OATT waiver on file with the Commission or qualify for a blanket waiver under 18 CFR 35.28(d).

the only balancing authority that the IPP's generation-only balancing authority area is directly interconnected with, then the IPP only needs to study that transmission provider's balancing authority area. An IPP in this situation would not need to study the transmission provider's first-tier markets. An example of this situation is NaturEner Power Watch, LLC (NaturEner), which has a generation-only balancing authority area that is located within the NorthWestern Energy balancing authority area. NaturEner would provide indicative screens that examine all of its uncommitted capacity in the NorthWestern Energy balancing authority area. NaturEner would not need to study itself in any other balancing authority areas unless its generation-only balancing authority area is directly interconnected to other balancing authority areas.

63. Similarly, if the IPP is located in a generation-only balancing authority area and is not embedded within a single transmission provider's balancing authority area, the IPP would need to provide indicative screens for the balancing authority area(s) of the transmission provider(s) to which its generation-only balancing authority area is directly interconnected. For example, if it were the case that the generation-only balancing authority areas of the Gila River Power Company LLC and Sundevil generation plants are each directly interconnected with the balancing authority area operated by Arizona Public Service Co. (APS), then each of those IPPs would study themselves in the APS balancing authority area, and each would treat all other competing generators from generation-only balancing authority areas directly interconnected with the APS balancing authority area as being in the APS balancing authority area. The IPPs in generation-only balancing authority areas would also study themselves in the same manner in any other

balancing authority areas to which their generation-only balancing authority area is directly interconnected.[78] An IPP in this situation would not need to study any of the transmission providers' first-tier markets, just as would be the case if it were a generator located within the transmission provider's home balancing authority area.[79]

64. Finally, we adopt the proposal to require an IPP in a generation-only balancing authority area that is directly interconnected to a transmission provider at a trading hub to provide indicative screens that study itself in the balancing authority area of each transmission provider that is directly interconnected at the trading hub[80] and to assume that all of its uncommitted capacity may compete in each of those balancing authority areas.[81] If the uncommitted capacity of an IPP studying a balancing area authority directly interconnected to a trading hub exceeds the transmission provider's SIL, then the

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[78] However, the transmission provider, in all cases, would consider the IPP generation capacity as first-tier generation when conducting its SIL studies and indicative screens.

[79] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

[80] As noted in the NOPR, when we state that the transmission providers' balancing authority areas are directly interconnected at the hub we are assuming that all such balancing authority areas are directly interconnected with each other. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 56 n.58.

[81] For example, if an IPP in a generation-only balancing authority area in the desert southwest is directly interconnected to a transmission provider at the Palo Verde trading hub at the Palo Verde and Hassayampa switchyards, then the IPP would provide screens that study all of its uncommitted capacity in each balancing authority area that is directly interconnected at the trading hub. An IPP in this situation would not need to study any markets that are first-tier to the various balancing authority areas that are directly interconnected at the trading hub.

capacity assumed available to compete in that balancing authority area will be equal to the SIL.

65. We appreciate the concerns of Solomon/Arenchild that this requirement is overly burdensome, but think the proposal achieves an appropriate balance. Historically, these sellers frequently failed the indicative screens for their home markets since they often own or control the majority of installed capacity, but have no associated load from which to reduce their market shares. The Commission's approach in this Final Rule likely will obviate the need to submit a DPT to rebut the presumption of market power that results from failure of the indicative screens, which typically is more burdensome and expensive than preparing indicative screens for multiple markets. In addition, the obligation to submit screens for all balancing authority areas directly interconnected to a trading hub would apply to a limited number of market-based rate sellers and these sellers could rely on previously-accepted studies to complete their indicative screen analyses. We believe that this approach helps sellers by providing explicit guidance on the definition of the default market for their specific situation.

66. In response to Solomon/Arenchild's concern that a transmission provider would need to conduct two SIL studies, we clarify that SIL studies should consider the IPP's generation capacity as first-tier generation to each balancing authority area studied. There would be no need to conduct a second SIL study that assumes that the IPP is located within a transmission provider's balancing authority area. However, if an IPP has a long-term firm transmission reservation into a particular transmission provider's balancing authority area for all or a portion of its output, then the SIL study would have

to reflect the fact that the IPP's generation capacity associated with the transmission reservation would be a firm import to that specific transmission provider. However, multiple SIL studies would not need to be performed; in this case, the IPP's generation capacity associated with the transmission reservation would be modeled as a firm import to the relevant transmission provider's balancing authority area.

67. With regard to requests that the Commission clarify that, to the extent a seller fails the indicative screen in the balancing authority area(s) it is directly interconnected to, sales at hubs are treated as "at the metered boundary"[82] of a seller's mitigated balancing authority area, and hence, market-based rate sales at hubs are allowed, we clarify as follows. An IPP would be allowed to make market-based rate sales at a trading hub if it loses market-based rate authority in one of the markets connected to the trading hub, so long as the hub is not located within the market in which the IPP is prohibited from selling.[83]

68. We find Broehm/Taylor's request that the Commission require all market-based rate sellers to report their historical sales and transmission reservation data and to use such data to define the relevant geographic market, including markets beyond the first-

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[82] Mitigated sellers are allowed to make market-based rate sales for export at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller has market-based rate authority. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 819-821.

[83] Resale of any sort by an affiliate of the mitigated seller into the seller's mitigated balancing authority area(s) (i.e., by looping power through adjacent markets) are violations of a Commission-approved tariff that may also, depending on the facts, violate the Commission's market manipulation regulations. *See id.* P 831.

tier, to be outside the scope of this rulemaking. This aspect of the NOPR proposal is limited to the relevant geographic market for IPPs in generation-only balancing authority areas.

69. We interpret EPSA's reference to nested balancing authority areas to mean generation-only balancing authority areas that are embedded within a transmission provider's balancing authority area. With regard to EPSA's request to require IPPs in generation-only balancing authority areas to provide indicative screens for first-tier balancing authority areas when there is network deliverability from the embedded balancing authority area through the interconnected balancing authority area to the first-tier balancing authority areas, we reiterate that an IPP in this situation would not need to study the transmission provider's first-tier markets, even if there is available transmission capacity. As noted above, if an IPP is located in a generation-only balancing authority area that is embedded within a transmission provider's balancing authority area, and that balancing authority area is the only balancing authority that the IPP's generation-only balancing authority area is directly interconnected with, then the IPP only needs to study that transmission provider's balancing authority area.

70. We clarify, in response to the request from Solomon/Arenchild, that the Commission's proposal also is meant to apply to quasi-generation-only balancing authority areas such as Ohio Valley Electric Corporation, Alcoa Power Generating, Inc.-Yadkin Division and Electric Energy Inc. We interpret EEI's request for the Commission to consider applying the proposal to entities that are not IPPs and entities

that have a *de minimis* amount of load in their balancing authority areas to also be referring to quasi-generation-only balancing authority areas.

71. In response to EEI's request, we clarify that an IPP in a generation-only balancing authority area that is directly interconnected to a hub would need to perform the market power analyses only for the home market of each transmission provider connected to the hub, not the transmission provider's first-tier adjacent markets. However, we decline to grant EEI's request to allow IPPs to provide a single analysis for all balancing authority areas interconnected to the trading hub and Solomon/Arenchild's similar request for broader markets to be considered. Preparing a single analysis for all balancing authority areas interconnected to a trading hub would require that these areas be combined into a single, consolidated market. We believe that such a request is beyond the scope of this proceeding.[84]

4. Reporting Format for the Indicative Screens and SIL Submittals 1 and 2

a. Commission Proposal

72. When submitting indicative screens as part of a horizontal market power analysis, sellers are required to use the standard screen formats adopted by the Commission in

[84] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 268 ("[a]ny proposal to use an alternative geographic market (i.e., a market other than the default geographic market) must include a demonstration regarding whether there are frequently binding transmission constraints . . . that prevent competing supply from reaching customers within the proposed alternative geographic market.").

Order Nos. 697 and 697-A, which are provided in Appendix A to Subpart H of Part 35.[85] Although sellers currently submit their indicative screens using the standard formats, they perform their own mathematical calculations. In the NOPR, the Commission noted that in *Puget Sound Energy, Inc.*[86] the Commission adopted standardized formats for reporting SIL study results, which includes Submittal 1, a spreadsheet that calculates the SIL values to be used in the indicative screens. However, the Commission noted in the NOPR that the current standard screen formats for indicative screens does not have a row for SIL values even though the Uncommitted Capacity Import values are constrained by the SIL values from row 10 of Submittal 1 used to report SIL study results.

73. Thus, the Commission proposed to amend the indicative screen reporting formats in Appendix A of Subpart H of Part 35. The Commission proposed that Appendix A include new rows for SIL Values, Long-Term Firm Purchases (from outside the study area), and Remote Capacity (from outside the study area) in both the pivotal supplier and market share screen reporting formats. The Commission stated that including a row in the indicative screens for SIL Values will help reinforce the relationship between affiliated and non-affiliated generation capacity imports and the SIL value. The Commission also proposed to modify the descriptive text of the rows in the indicative

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[85] The Commission noted in the NOPR that the market share screen was inadvertently deleted from Appendix A to Subpart H of Part 35 at the time that the Commission made a correction to the pivotal supplier screen in Order No. 697-A. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 42 n.39.

[86] 135 FERC ¶ 61,254 (2011) (*Puget*).

screens for Installed Capacity, Long-Term Firm Purchases, Long-Term Firm Sales, and Uncommitted Capacity Imports.[87] The Commission stated that the new rows and their descriptions will clarify whether the resources are either inside or outside the study area for Installed Capacity and Long-Term Firm Purchases. Furthermore, the description for Uncommitted Capacity Imports will now be consistent across both indicative screens. The Commission provided an example of the proposed new indicative screens reporting formats in Appendix A of the NOPR.

74. The Commission proposed to revise the regulations at 18 CFR 35.37(c)(4) to require sellers to file the indicative screens in a workable electronic spreadsheet format.[88] The Commission also proposed to post on the Commission's website a pre-programmed spreadsheet as an example that sellers may use to submit their indicative screens.[89]

75. Next, the Commission proposed to add a paragraph to the end of section 35.37(c), making it paragraph (5), to codify the Commission's requirement that sellers submitting

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[87] The Commission proposed to change the phrase "Imported Power" in Rows D and H of the pivotal supplier screen to "Uncommitted Capacity Imports." The Commission also proposed to make the same change to Row E of the Market Share Screen. Thus, under this proposal, all four rows in the indicative screens will have the same text for this field, which represents affiliate and non-affiliate uncommitted capacity able to be imported from the first tier.

[88] "Workable electronic spreadsheet" refers to a machine readable file with intact, working formulas as opposed to a scanned document such as an Adobe PDF file.

[89] The Commission explained in the NOPR that if a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission website.

SIL studies adhere to the direction and required format for Submittals 1 and 2 found on the Commission's website[90] and submit their information, as instructed, in workable electronic spreadsheets.

b. Comments

76. APPA/NRECA and Golden Spread state that they support requiring sellers to file the indicative screens in a workable, electronic spreadsheet format.[91] EEI states that to the extent that the Commission's proposal simply reflects the Commission's current requirements for conducting the indicative screens and *Puget* submittal analyses, the changes are appropriate and reasonable.[92]

77. EEI requests that the Commission specify that it simply wants market-based rate sellers to file the information electronically using standard formats such as Adobe, Excel, or Word. EEI adds that if the Commission has something more complex in mind, it should explain the need for a more complex approach and should work with the regulated community in developing the new formats that will be posted on the FERC website, and in preparing other such guidance, information, and requirements related to the market-

[90] The sample spreadsheets for Submittals 1 and 2 are found at the Commission's website at http://www.ferc.gov/industries/electric/gen-info/mbr/authorization.asp under "Quick Links."

[91] APPA/NRECA at 4; Golden Spread at 7.

[92] EEI at 9.

based rate program, to ensure that all are reasonable, clear, accurate, easy to use, and most cost-effective.[93]

78. Solomon/Arenchild state that the proposal to require sellers to provide a summary spreadsheet of the SIL components used to calculate the SIL values in the electronic spreadsheet format provided on the Commission's website is potentially helpful but seek clarification as to whether only Line 10 of Submittal 1 is required to be filed publicly.[94]

79. El Paso commends the proposal to add new rows to clearly identify Long-Term Firm Purchases and Remote Capacity from outside the study area. It states that these reporting modifications will not only provide clarity and transparency for the Commission's review, but will also correctly recognize traditional entities, like El Paso, which have invested in remote generation capacity to serve their native load customers.[95] El Paso states that the Commission should extend its proposal further and apply it to the study of first-tier balancing authority areas. El Paso states that the Commission's proposed modifications to the standard screen formats in Appendix A do not consider when a seller with remote generation performs the analysis for the balancing authority areas market where its remote generation is located. El Paso recommends that the Commission extend its proposal to modify the horizontal screen formats to add the following rows to the screen formats in Appendix A: (i) "Seller Native Load outside the

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[93] *Id.* at 9-10.

[94] Solomon/Arenchild at 11-12.

[95] El Paso at 2-3.

study area" as a separate line in row K of the Market Share Analysis and (ii) "Amount of Seller Load outside the study area attributable to Seller Capacity inside the study area, if any" as a separate line in row N of the Pivotal Supplier Analysis.[96]

c. Commission Determination

80. We adopt the NOPR proposal to amend the indicative screen reporting formats in Appendix A of Subpart H of Part 35 to include new rows for SIL Values, Long-Term Firm Purchases (from outside the study area), and Remote Capacity (from outside the study area) in both the pivotal supplier and market share screen reporting formats. We also adopt the NOPR proposal to revise the regulations at 18 CFR 35.37, as proposed in the NOPR, to require sellers to file the indicative screens in a workable electronic spreadsheet format and to codify the requirement that sellers submitting SIL studies adhere to the direction and required formats for SIL Submittals 1 and 2 found on the Commission's website and submit their information in workable electronic spreadsheets. The adopted indicative screen reporting formats for Appendix A to Subpart H is provided in Appendix A of this Final Rule.

81. In response to EEI's request that the Commission specify that it simply wants market-based rate sellers to file the information electronically using standard formats such as Adobe, Excel, or Word, we clarify that Excel or another spreadsheet format will be acceptable but an Adobe PDF file will not be acceptable. As the Commission stated in the NOPR, a "workable electronic spreadsheet" refers to a machine readable file with

[96] *Id.* at 3-4.

intact, working formulas as opposed to a scanned document such as an Adobe PDF file. If a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission website.[97]

82. In response to Solomon/Arenchild's request that the Commission clarify whether only row 10 of Submittal 1 is required to be filed publicly, we clarify that the Commission expects that all of Submittal 1, not just row 10, will be filed publicly. Submittal 1 provides summary numeric data showing how the SIL values were calculated for a given relevant geographic market and some of this data already is publicly available. While we discourage submitting any portion of Submittal 1 as privileged, to the extent a filer intends to request privileged treatment for any portion of Submittal 1 or any other portion of its filing, such filing must comply with 18 CFR 388.112, including the justification for privileged treatment, i.e., why the information is exempt from disclosure under the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. 552 (2012).

83. We believe there is no need to expand the indicative screens as proposed by El Paso because the scenario El Paso describes can be addressed within the screens, as

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[97] It must have one worksheet for each of the indicative screens and each screen must have the same exact rows, columns, and descriptive text as the sample worksheets. Cells requiring negative values must be pre-programmed to only allow negative values. Likewise, cells with calculated values must contain a working formula that calculates the value for that cell. The file must be submitted in one of the spreadsheet file formats accepted by the Commission for electronic filing. The list of acceptable file formats can be found at the Commission's website: http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp.

amended by this Final Rule. However, we clarify that a seller with remote generation serving the seller's home balancing authority area (rather than serving the balancing authority area where the generation is physically located) should account for that generation capacity in row C "Long-Term Firm Sales (in and outside the study area)" if that generation is used to serve load in the seller's home study area by virtue of dynamic scheduling and/or long-term firm transmission reservations. If the seller's remote generation is not committed to serving load in the seller's home balancing authority area, then that generation should be studied as uncommitted generation in the first-tier balancing authority area where it is located.

5. Competing Imports

a. Commission Proposal

84. In the NOPR, the Commission noted that it permits sellers to make simplifying assumptions, where appropriate, and to submit streamlined horizontal market power analyses. The Commission noted that Order No. 697 provided that "'a seller, where appropriate, can make simplifying assumptions, such as performing the indicative screens assuming no import capacity or treating the host balancing authority area utility as the only other competitor.'"[98] In the NOPR, the Commission clarified that the phrase "assuming no import capacity" means that a seller may assume "no *competing* import capacity" from the first-tier area (i.e., directly interconnected balancing authority areas

[98] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 66 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 321).

or markets).[99] The Commission further clarified that the seller must still include any uncommitted capacity that it and its affiliates can import into the study area.

b. <u>Comments</u>

85. EEI, APPA/NRECA, and Golden Spread support the Commission's proposed clarifications regarding sellers performing simplified indicative screens assuming no competing import capacity.[100]

c. <u>Commission Determination</u>

86. We confirm the Commission's clarification in the NOPR regarding competing import capacity. Specifically, "assuming no import capacity" means that a seller may assume "no *competing* import capacity" from the first-tier markets (i.e., adjacent balancing authority areas or markets). This clarification is consistent with the April 14, 2004 Order[101] and other Commission orders.[102] The seller must still include any uncommitted capacity that it and its affiliates can import into the study area.

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[99] *Id.* P 67 (emphasis in original).

[100] EEI at 10; APPA/NRECA at 4; Golden Spread at 7.

[101] *AEP Power Marketing, Inc. et al.*, 107 FERC ¶ 61,018, at P 38 (April 14 Order), *order on reh'g*, 108 FERC ¶ 61,026 (2004) ("Where appropriate, the screens allow the applicant to submit streamlined applications or to forego the generation market power analysis entirely and, in the alternative, go directly to mitigation. For example, if an applicant would pass the screens without considering *competing* supplies from adjacent control areas, the applicant need not include such imports in its studies." (emphasis added)).

[102] *See, e.g.*, *Acadia Power Partners, LLC et al.*, 107 FERC ¶ 61,168, at P 12 (2004) ("We remind applicants that they may provide streamlined applications, where appropriate, to show that they pass both screens. For example, if an applicant would pass

(continued…)

6. Capacity Ratings

a. Commission Proposal

87. In the NOPR, the Commission noted that it allows sellers submitting indicative screens to rate their generation facilities using either nameplate or seasonal capacity ratings. The Commission stated that Order No. 697 allows sellers with energy-limited resources, such as hydroelectric and wind generation facilities, to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor, including a sensitivity test using the lowest and highest capacity factors for the previous five years. The Commission noted that since the issuance of Order No. 697, the Commission has recognized that sellers with newly-built energy-limited generation facilities may not have five years of historical data and has allowed the use of the five most recent years of regional average capacity factors from the Energy Information Administration (EIA) to determine capacity factors for those resources.

88. In the NOPR, the Commission proposed to identify solar technologies as energy-limited generation resources and to allow such sellers to use either nameplate capacity or five-year historical average capacity ratings to determine the capacity rating for their solar technology generation resources. The Commission stated that similar to other energy-limited generation resources, sellers using the five-year average capacity factor must include sensitivity tests using the lowest and highest capacity factors for the

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both screens without considering *competing* supplies imported from adjacent control areas, the applicant need not include such imports." (emphasis added) (footnote omitted)).

previous five years. The Commission proposed that sellers with energy-limited generation facilities (including solar technologies) that do not have five years of historical data may use nameplate capacity, or the EIA-derived, regional capacity factor for the previous five years appropriate to their specific technology as defined in the EIA publication *Annual Energy Outlook*,[103] but may not use seasonal ratings.[104] For sellers using EIA-derived estimates, the Commission proposed to require that sellers submit their calculation of the regional capacity factor as well as copies of the appropriate tables of regional generation capacity ratings from EIA's *Annual Energy Outlook* in their filing.

89. In addition, the Commission sought industry input in identifying additional technologies that are energy-limited generation resources, and what capacity factors should be used to rate them. The Commission acknowledged that solar photovoltaic facilities will effectively function with zero capacity during nighttime hours or during heavy overcast conditions, as the sun does not provide much, if any, solar energy from

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[103] *See* EIA, Annual Energy Outlook (May 2014), *available at* http://www.eia.gov/forecasts/aeo/source_renewable.cfm.
In Table 58 through Table 58.9 "Renewable Energy Generation by Fuel – (by Area)," EIA provides data for the total generating capacity, and actual (or estimated) electricity generated by renewable type for 22 "electricity market module regions" covering the lower 48 states. After converting the inputs into matching units, sellers can divide actual (or estimated) electricity generated by installed capacity to find the capacity factor.

[104] The Commission stated that sellers should use either nameplate, a five-year average of historical data, or EIA-derived five-year average regional capacity factors instead of seasonal capacity factors for energy-limited resources. The Commission noted that a five-year average wind capacity factor derived from EIA regional data was an appropriate proxy for wind generators that do not have five years of historical data.

solar photovoltaic facilities during such conditions. Thus, the Commission sought comment on whether these operating characteristics warrant establishing a different method of setting capacity factors for solar generation as compared to other generation technologies.

90. Also in the NOPR, the Commission proposed to clarify that, within each filing, a seller must use the same capacity rating methodology for similar generation assets. The Commission stated that if a seller chooses in a particular filing to use seasonal ratings for one of its thermal units, it must use seasonal ratings for all of its thermal units in that filing. Likewise, if the seller chooses to use an alternative rating methodology, such as the five-year average for any energy-limited generation resource, it must use the five-year average for all energy-limited generation resources in that filing for which five years of historical data is available; otherwise it must use the EIA-derived capacity factors for those resources for which the seller does not have five years of data. The Commission stated that the seller must specify in the filing's transmittal letter or accompanying testimony, and in the generation asset appendix, which rating methodologies it is using. The seller must use the specified rating methodologies consistently throughout its entire filing, including in its transmittal letter, asset appendix, and indicative screens. The Commission noted that this proposal does not preclude the seller from using a different capacity rating methodology for each type of generation facility (thermal or energy limited) in subsequent filings (e.g., in its initial filing a seller may use nameplate ratings for its thermal units, then in its next filing choose to use seasonal ratings for its thermal units).

b. Comments

i. Identify Solar as Energy Limited

91. Many commenters support the Commission's proposal to identify solar technologies as energy-limited generation resources.[105]

ii. Use of Capacity Factors

92. E.ON agrees with the Commission's proposal to allow a seller that owns or controls solar technology generating resources to use either nameplate capacity or five-year historical average capacity ratings to determine capacity rating, and to use EIA-derived, regional capacity factor estimates if the seller does not have five-year historical capacity data. EEI asks the Commission to consider allowing a given seller, with or without five years of historical data, to use an alternative to the EIA regional capacity ratings if the seller can demonstrate that the alternative is more accurate as to one or more of the specific solar-generation facilities at issue in the filing, while allowing use of actual or historical data for other facilities in the same market.

93. Many commenters sought clarification on the Commission's proposals regarding use of capacity factors for energy-limited resources. E.ON seeks clarification that if the seller relies on EIA-derived capacity factors for a solar resource, it is not precluded from using actual historical five-year data to establish capacity factors for its other energy-limited resources.[106] SoCal Edison requests clarification as to the calculation of the five-

[105] *See, e.g.,* E.ON at 4; NextEra at 6; EEI at 11; SunEdison, Inc. (SunEdison) at 1.

[106] E.ON at 5.

year average capacity factor for a given triennial; specifically, what periods do the five years cover, and what is the average, is it by unit or technology.[107] SoCal Edison also asks if the EIA-derived capacity factor is used, whether it is to apply to nameplate capacity or seasonal ratings.[108] EEI requests that the Commission clarify that companies can use the average of the data available in the EIA data tables, up to a maximum of a five-year average.[109] SoCal Edison strongly supports allowing a seller to use nameplate capacity ratings anytime a seller is required to file only an asset appendix.

94. Broehm/Taylor state that the Commission should require use of the average historical capacity factor of existing energy limited resources with the same technologies within the same region instead of the EIA-derived, regional capacity factor estimates proposed by the Commission. Broehm/Taylor state that the EIA-derived, regional capacity factor estimates are an annual average value that does not reflect seasonality, thereby creating a disconnect with the Commission's indicative screens, which are required to be performed on a seasonal basis. Broehm/Taylor further state that generation patterns for certain energy limited resources such as solar and wind may vary by months and seasons in certain locations.[110]

[107] SoCal Edison at 15-16.

[108] *Id.* at 16.

[109] EEI at 12 (noting that some of the EIA tables only cover 2011 forward, so five years of EIA data might not be available).

[110] Broehm/Taylor at 6.

95. Further, Broehm/Taylor state that they "seek Commission clarification on whether the availability factors[111] are required to be applied only to nameplate capacity ratings of energy limited resources." Broehm/Taylor ask whether the Commission's statement "that sellers without five years of historical data cannot use seasonal ratings imply that the availability factors should not be applied to seasonal ratings." Broehm/Taylor state that, if this is the case, it is appropriate to apply the same availability calculation to both new and existing units of energy limited resources. Broehm/Taylor caution that sellers need to be consistent in using capacity ratings for calculating historical capacity factors and if the capacity ratings are nameplate in the historical capacity factor calculation, these capacity factors should be applied to nameplate capacity ratings.[112]

iii. Identifying Other Energy-Limited Resources

96. In response to the Commission's request for industry input in identifying additional technologies that are energy-limited generation resources, SoCal Edison identifies the following: hydro, wind, solar, biomass, and geothermal resources. It further states that it believes this list can and should be expanded as appropriate.[113]

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[111] Broehm/Taylor use the term "availability factors" several times. The Commission has never used availability factors as a basis for de-rating generation capacity.

[112] Broehm/Taylor at 7.

[113] SoCal Edison at 15.

iv. Require Same Rating Methodology for All Resources of the Same Technology

97. NextEra states that it does not support requiring the same rating methodology for all resources of the same technology. To better reflect a seller's market power, NextEra urges the Commission to provide sellers the option in submitting indicative screens to reflect, if known, the historical capability for resources of the same technology and, if unknown, to submit EIA regional data for those specific resources.[114] EEI echoes these concerns stating that sellers should be able to use five-year historical data for particular energy-limited generation resources where the sellers have the information, even as they may need to use a regional capacity factor for other such facilities for which they do not have the information.[115]

v. Limiting Capacity Standard to Peak Hours for Solar

98. FirstEnergy states that the Commission properly recognized in the NOPR that solar photovoltaic facilities will effectively function with zero capacity during nighttime hours or during heavy overcast conditions.[116] FirstEnergy states that in the event that the Commission permits capacity ratings of solar technologies to be based on historical generation output rather than on nameplate ratings, such capacity ratings should be

[114] NextEra at 7.

[115] EEI at 11.

[116] FirstEnergy at 7.

based on the output of such generating facilities during peak day-light hours only.[117] Idaho Power believes that using peak hours for determining solar capacity factors would be appropriate and would provide better data.[118] Broehm/Taylor state that the Commission did not provide the definition of peak hours and suggests that the Commission give reasonable flexibility to sellers with regard to the number of peak hours when calculating availability factors for energy limited technologies as long as sellers justify their approach.[119]

99. However, SoCal Edison contends that the screens are not designed for a particular hour or the peak hour for many types of generation, all hours should be considered when calculating the capacity rating.[120] EPSA states that using peak hours will not provide a better measure of capacity for solar technology generation resources, and consistent with other intermittent energy resources, such as wind, a historical average capacity rating during peak hours would more accurately represent output of the facility incorporating the variability of output given environmental and weather events that affect solar generation resources output.[121] E.ON states that it is unclear that the use of peak hours is appropriate. It states that these energy-limited resources can provide energy in

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[117] *Id.* at 8.

[118] Idaho Power at 3.

[119] Broehm/Taylor at 7-8.

[120] SoCal Edison at 15.

[121] EPSA at 6-7.

daylight hours and not necessarily only in peak-defined hours. E.ON asks that if the Commission ultimately adopts some limiting capacity standard, whether that is peak hours or otherwise, that the Commission clarify that the solar photovoltaic resource would not be precluded from selling energy products at market-based rates in any off-peak hours.[122] EEI states that the Commission should allow a seller to use an alternative to EIA regional capacity ratings if they can demonstrate that the alternative is more accurate as to one or more of the specific solar facilities at issue in the filing. EEI states that the Commission should give sellers the option to base solar capacity factors on peak hours rather than all hours, but should not require them to do so.[123] NextEra states that as the horizontal market power indicative screens are intended to study peak hours, it believes that it may be more consistent to require the nameplate capacity rating, which for solar technologies largely correlate to peak load times, rather than the five-year average capacity factor or EIA regional data.[124]

c. Commission Determination

100. We adopt the NOPR proposals with certain modifications and clarifications. Specifically, we will allow sellers with energy-limited generation facilities to use capacity factors to de-rate those facilities in their market power analysis, with certain clarifications discussed below. We will also identify solar thermal technologies as

[122] E.ON at 5.

[123] EEI at 11.

[124] NextEra at 6.

energy-limited technologies, but require the use of nameplate capacity ratings for solar photovoltaic units.

i. Identify Solar as Energy Limited

101. We accept the NOPR proposal to identify solar photovoltaic and solar thermal facilities as energy-limited generation resources. However, as discussed below we will continue to require a seller to use nameplate ratings for its solar photovoltaic facilities. We will allow a seller to treat solar thermal facilities in the same manner as other energy-limited resources. If a seller chooses to use a rating based on a five-year average capacity factor for solar thermal facilities in their filings, they must follow all of the requirements discussed in this Final Rule regarding the use of capacity factors. Further, a seller must use the same rating methodology for non-affiliated solar thermal facilities, as it does for its own solar thermal facilities.

102. For solar photovoltaic facilities we adopt NextEra's proposal and require the use of nameplate capacity in the asset appendices and market power studies. As noted above, there was no consensus among commenters as to whether to de-rate solar photovoltaic facilities based on either an annual capacity factor or an on-peak capacity factor. Given the generation profile of solar photovoltaic facilities (i.e., output is highest during peak hours), we believe that use of nameplate ratings is reasonable for the purposes of the horizontal market power analysis. In addition, the Commission's experience to date is that sellers typically use nameplate ratings for solar photovoltaic facilities in their market power analyses and asset appendices, so this requirement is consistent with current industry practice. Although we are requiring the use of nameplate capacity for solar

photovoltaic resources, we clarify that adopting the use of a limiting capacity factor, such as peak hours, for any generation resource, would not preclude that resource from selling energy products at market-based rates in off-peak hours.[125]

ii. Use of Capacity Factors

103. We will continue to allow a seller with energy-limited generation facilities other than solar photovoltaic to use capacity factors to de-rate those facilities in its market power analysis. For purposes of this discussion we are excluding solar photovoltaic from using capacity factors; as discussed above, solar photovoltaic will be rated on nameplate rating. We clarify that for energy-limited facilities, a seller may use either the nameplate capacity or a rating based on a five-year average capacity factor. When a seller chooses to use a certain rating methodology for an energy-limited resource, it must consistently use that rating methodology for that specific type of energy-limited resource in its market-power studies (i.e., its energy-limited facilities, and non-affiliated energy-limited facilities).[126] A seller must specify in the filing's transmittal letter or accompanying testimony, and in the applicable asset appendices, which rating methodology it is using for each technology. To the extent that a seller chooses to use a capacity factor, it must use a unit-specific, historical five-year average for any unit for which it can obtain five or

[125] E.ON at 5.

[126] This is a change from the NOPR proposal to require that if a seller uses an alternative rating methodology for any energy-limited resource, it must use an alternative rating for all energy-limited resources.

more years of operating history, and use the EIA-derived regional capacity factor for any unit for which it is unable to obtain five years of operating history.[127]

104. A seller must use the same capacity rating method for non-affiliated energy-limited facilities that it uses to rate the capacity of its own energy-limited facilities when they are preparing their market-power analyses. Thus, a seller that uses nameplate ratings for its own energy-limited facilities should use nameplate ratings for all other energy-limited facilities included in their horizontal market power studies. Likewise, a seller that de-rate its own energy-limited facilities using five-year average capacity factors should de-rate non-affiliated energy-limited facilities using EIA regional average capacity factors in its screens and DPTs. Consistent with Order No. 697, we will continue to require a seller that de-rates its energy-limited facilities to include sensitivity tests using the lowest capacity factor in the previous five years, and the highest capacity factor in the previous five years.[128]

105. In the NOPR the Commission stated that a seller would be allowed to use different capacity rating methodologies in subsequent filings. However, we find here that a seller must use the same rating methodology in subsequent filings until the next updated triennial market power analysis. Thus, a seller would not be allowed to change its rating

[127] Sellers must use five years of historical data even if that means using data from multiple EIA reports. We recognize that this may necessitate sellers including years after the study period. However, this information is still historical and therefore consistent with the requirements of Order No. 697, FERC Stats. & Regs. ¶ 31,252, at PP 298-301.

[128] *Id.* P 344.

methodologies until its next updated triennial market power analysis (e.g., if a seller uses nameplate ratings for nuclear plants in its triennial, it must use nameplate for nuclear in all filings, until its subsequent triennial). If a seller is a Category 1 seller (i.e., not required to file an updated triennial market power analysis), it would be allowed to change rating methodologies when its region's transmission owners' updated triennial market power analyses are due. We reject SoCal Edison's request to allow a seller to switch rating methods just because it is filing an asset appendix. A seller must use the same rating methodology for each specific technology in all filings. We do not see this as more burdensome, because the capacity rating for most facilities will not change between filings. In fact, we believe this may be less burdensome because companies will not have different versions of their asset appendix.

106. We adopt the NOPR proposal to require that a seller submit its calculations of the regional capacity factor as well as copies of the appropriate tables of regional generation capacity ratings from EIA's *Annual Energy Outlook* in its filing. We also clarify that when using the EIA tables to calculate a regional average for energy-limited facilities, a seller should calculate capacity factors using the most recent five calendar years of data available in the tables. Further, the capacity factors should be applied per unit, to each generation facility and applied to the facilities' nameplate ratings. Although we intend the use of EIA regional capacity factors as a simple and objective means for a seller to de-rate energy-limited facilities, we will allow a seller to propose alternative methods of de-rating such facilities in response to EEI and Broehm/Taylor's comments. A seller proposing alternative methodologies must provide the data and calculations used to

derive the capacity factors to the Commission in public, non-privileged files. Further, the seller must also provide the EIA regional average capacity factor as a comparison and explain why it believes its methodology provides a more accurate capacity rating than the EIA regional average. We will decide on a case-by-case basis whether to accept any such proposed alternative methodology.

iii. Identifying Other Energy-limited Resources

107. In the NOPR, the Commission sought industry input in identifying additional technologies that are energy-limited generation resources, and what capacity factors should be used to rate them. As discussed above, we adopt the proposal to identify solar thermal technologies as energy limited. However, given that the Commission only received one comment identifying additional technologies (other than solar) and the Commission did not receive any comments regarding what capacity factors should be used to rate additional technologies, we will not specifically identify any additional technologies as energy limited at this time.

7. Reporting of Long-Term Firm Purchases

a. Commission Proposal

108. In Order No. 697, the Commission stated that a seller's uncommitted capacity, as calculated in the indicative screens, is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and long-term firm capacity purchases, minus operating reserves, native load commitments, and long-term

firm sales.[129] The Commission also stated that generation capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility. Therefore, market-based rate sellers have been required to report long-term firm purchases in row B of the indicative screens (Long-Term Firm Purchases) only if the purchase granted them control of the capacity. Similarly, for purposes of reporting a change in status, sellers have been required to report long-term firm capacity purchases when assessing their cumulative generation capacity only if such purchases confer control of such capacity to them.[130] In the NOPR, the Commission noted that this requirement applies to long-term firm energy purchases to the extent that the long-term firm energy purchase would allow the purchaser to control generation capacity.[131]

109. In the NOPR, the Commission noted that the limited reporting of long-term firm purchases may create errors or misleading results in the indicative screens submitted by some sellers including incorrectly-sized markets and negative market shares for franchised public utilities and inconsistencies between the SIL values reported in the screens and the SIL values calculated for the relevant market or balancing authority area. The Commission noted instances where neither the seller nor the purchaser under a long-

[129] *Id.* P 38.

[130] *See* Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at PP 99-101.

[131] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 73 (citing Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at PP 99-101).

term firm power sale is attributed with the generation capacity that is used to make the sale because the seller deducted the capacity committed under the long-term firm power sale from its uncommitted capacity while the purchaser followed existing Commission policy and, because it did not "control" this capacity, did not include it as part of its uncommitted capacity.

110. The Commission proposed in the NOPR to modify the policy with respect to the reporting of long-term firm purchases in the indicative screens. Specifically, the Commission proposed to require applicants[132] under the market-based rate program to report all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices, where the purchaser has an associated long-term firm transmission reservation, regardless of whether the seller has operational control over the generation capacity supplying the purchased power.[133] The Commission proposed that if the long-term firm purchase involves the sale of energy and does not identify an

[132] Although we generally use the term "sellers" elsewhere in the Final Rule when referring to market-based rate sellers and applicants, in this section, we refer to such sellers as "applicants" to avoid confusion when discussing market-based rate sellers who are purchasers under long-term firm power purchase agreements.

[133] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 79. In *Vantage Wind, LLC*, 139 FERC ¶ 61,063 (2012) (*Vantage Wind*), the Commission directed the purchasers to report all long-term firm purchases if the purchase had long-term firm transmission rights associated with those resources. In the NOPR, the Commission assumed for purposes of the proposal that all long-term firm purchases necessarily have long-term firm transmission rights associated with them. If that is not the case, the Commission stated that applicants or intervenors are free to raise fact-specific circumstances that they believe may support a different attribution of capacity. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 79 n.97.

associated capacity amount, the purchaser must convert the amount of energy to which it is entitled into an amount of generation capacity for purposes of its indicative screens and asset appendices, i.e., include the amount of the capacity as long-term firm purchases in rows B (Long-Term Firm Purchases (from inside the study area)) or B1 (Long-Term Firm Purchases (from outside the study area)) of the proposed revised indicative screens and include it in its asset appendix. The Commission proposed that a seller under that firm power purchase agreement must continue this approach the next time it submits a market-based rate triennial or change in status filing with the Commission, i.e., convert the energy into capacity and include the amount of capacity as a long-term firm sale in row C (Long-Term Firm Sales).[134] The Commission proposed that, when making these

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[134] In the NOPR, the Commission stated that many power purchase agreements for firm energy specify an associated capacity commitment from the seller. In cases where capacity commitments are not specified in the power purchase agreement, we propose that applicants use the following formula to convert energy to capacity (on a one-year basis): [energy (MWh) / 8,760] / capacity factor = capacity (MW).

> Where energy (MWh) is the total amount of energy purchased under the power purchase agreement over the calendar year; 8,760 is the total hours of a calendar year (use 8,784 in a leap year); capacity factor is actual capacity factor achieved by the unit(s) supplying the energy during the calendar year and is a measure of a generating unit's actual output over a specified period of time compared to its potential or maximum output over that same period. For example, if 700,000 MWh is the amount of firm energy purchased under a power purchase agreement during a calendar year, and the capacity factor of the generator supplying the energy is 0.8 or 80 percent, then the 700,000 MWh of energy would be converted into approximate 100 MW of capacity. That is: (700,000 MWh / 8,760) / 0.8 = 100 MW.

NOPR, FERC Stats. & Regs. ¶ 32,702 at P 79 n.98.

filings, both the purchaser and the seller must show how they made the energy-to-capacity conversion. Although the Commission proposed this attribution of capacity as a general policy, the Commission noted that applicants or intervenors may raise fact-specific circumstances that they believe may support a different attribution of capacity.

111. The Commission stated that the intent of the proposed reform is to have an applicant report all long-term firm purchases that it makes where the selling entity has a legal obligation to provide the purchaser with an energy supply that cannot be interrupted for economic reasons or at the seller's discretion. If the purchaser has contractual rights to receive the output of a long-term firm energy purchase, the Commission proposed that the amount of the capacity supplying that purchase must be reported in the purchaser's screens.

112. In the NOPR, the Commission stated that the proposal to require applicants to report all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices is supported based on several considerations. First, it will size the market correctly and therefore improve the accuracy of the indicative screens, especially for franchised public utilities, whose indicative screens are used by the non-transmission owning sellers to prepare their own indicative screens. Currently, applicants often do not report some or all of their long-term firm purchases because they do not control these resources. Including all long-term firm purchases in the indicative screens will properly size the market and eliminate the unrealistic results (e.g., negative market shares) caused by the under-reporting of generation noted above.

113. Second, the Commission stated that this proposed change will establish consistent treatment of long-term firm sales and long-term firm purchases in the indicative screens. The Commission noted that applicants typically deduct long-term firm sales without making a determination as to whether those sales confer operational control to the purchaser. The Commission explained that, in Order No. 697, it did not require that sellers make such a determination before deducting the capacity supporting long-term firm sales: "Uncommitted capacity is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales."[135] In Order No. 697, the Commission stated that "[s]ellers may deduct generation associated with their long-term firm requirements sales, unless the Commission disallows such deductions based on extraordinary circumstances."[136]

114. In the NOPR, the Commission explained that it is only on the "buy" side of long-term firm purchases that the Commission has considered the issue of control in reporting capacity in the screens.[137] The Commission stated that the result is that some generation capacity sold under long-term power purchase agreements "disappears" from the market because neither the seller nor the purchaser includes the capacity as part of its uncommitted capacity (i.e., the seller subtracts the amount sold under the long-term

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[135] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 38 (footnotes omitted).

[136] *Id.* P 38 n.18.

[137] Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at PP 99, 100.

power purchase agreement from its capacity for purposes of its screens, but sometimes the purchaser does not add the corresponding amount to its capacity for purposes of its screens). The Commission stated that it is inevitable that some generation capacity will be excluded from the indicative screens, with resulting errors in market shares and overall market size, when differing standards are applied to long-term firm purchases and long-term firm sales with respect to the allocation of such capacity. The Commission stated that the NOPR proposal will make those standards consistent, reducing such errors.

115. Third, requiring the reporting of all long-term firm power purchases also will ensure consistent treatment of owned or installed capacity and long-term firm purchases in the indicative screens. The Commission stated that the horizontal market power analysis implicitly assumes that applicants control all of their owned or installed capacity listed in their indicative screens but this is not necessarily the case.[138] For example, in situations where an applicant is a minority owner of a jointly-owned generating unit, it is quite possible that the applicant will not have operational control (i.e., commitment and dispatch authority) over the unit.[139] However, applicants typically include all of their

[138] As the Commission explained in the NOPR, in Order No. 697, the Commission noted that its historical approach has been that the owner of a facility is presumed to have control of the facility unless such control has been transferred to another party by virtue of a contractual agreement. The Commission stated in Order No. 697 that it would continue its practice of assigning control to the owner absent a contractual agreement transferring such control. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 183.

[139] Another example is when a generator confers operational control to a third party through a long-term tolling agreement. *See, e.g.*, *Shell Energy North America (US), L.P.*, 135 FERC ¶ 61,090, at P 3 (2011).

owned or controlled generation capacity in the indicative screens regardless of whether they actually control the commitment and dispatch of this capacity. Accordingly, the Commission proposed that an applicant with long-term firm purchases treat such contracted-for capacity in a similar manner to an applicant that owns capacity; that is, such purchases should be included in the applicant's portfolio of generation for the indicative screens.

116. Further, the Commission stated in the NOPR that for those applicants incorrectly reporting long-term firm power purchases in the wrong row of the indicative screens,[140] uniform reporting of these purchases will also help to ensure consistency between the SIL values reported in the screens and the Commission's accepted SIL values for the relevant market or balancing authority area. In the NOPR, the Commission stated that improperly classifying long-term firm purchases (or imports of remotely-owned installed capacity) as Imported Power in the existing screens (row D of the pivotal supplier screen and row E of the market share screen) may lead to an overstatement of the market's SIL values.[141] The

[140] The NOPR stated that "[a]s the Commission noted in *Vantage Wind*, improperly classifying long-term firm purchases (or imports of remotely-owned installed capacity) as Imported Power in the existing screens . . . may lead to an overstatement of the market's SIL values." NOPR, FERC Stats. & Regs. ¶ 32,702 at P 85 (citing *Vantage Wind*, 139 FERC ¶ 61,063).

[141] The Commission noted *Vantage Wind*, 139 FERC ¶ 61,063 at P 16 ("In its updated market power analysis, Puget accounted for both its remote generation from its Colstrip plant located in Montana and its firm power purchase agreements from Bonneville Power Administration as Imported Power (Line D of the market share screen and the pivotal supplier screen) rather than as Installed Capacity (Line A of the market share screen and the pivotal supplier screen) or a Long-term Firm Purchase (Line B of the

(continued…)

Commission explained in the NOPR that this is because the sum of the values in the existing pivotal supplier screen for Seller and Affiliate Imported Power shown in row D and Non-Affiliate Imported Power shown in row H should be less than or equal to the Commission-accepted SIL values. All Commission-accepted SIL values account for (i.e., subtract) long-term transmission reservations into the study area, so that they reflect the transmission capability available to competing sellers after accounting for the capability that the local utility has reserved for its own use to import power from remote resources. Thus, the Commission explained that classifying long-term firm purchases as Imported Power effectively "double counts" import capability in the screens because it adds back the import capability associated with long-term firm purchases and assumes that this capability is available to potential competitors. The Commission stated that this problem does not arise if long-term firm purchases (and imports of remotely-owned installed capacity) are properly classified in the indicative screens as Long-Term Firm Purchases (rows B1 and F1 in the proposed screen format for the pivotal screen) and Remote Capacity (rows A1 and E1 in the proposed screen format for the pivotal screen), respectively. The Commission stated that this proposal is intended to help clarify how to

market share screen and the pivotal supplier screen), respectively. Consequently, the total SIL shown in Puget's screens exceeded the net SIL value for the Puget balancing authority area as accepted by the Commission in [*Puget*, 135 FERC ¶ 61,254]. When Vantage Wind applied the Commission-approved SIL values to its analysis without making any other adjustments to Puget's screens, Vantage Wind appeared to fail the screens because Puget's capacity was underreported.").

classify imports of firm power and remotely-owned capacity. The Commission also proposed these changes to the screen format for the market-share screen.

b. Comments

117. Commenters mostly disagree with the proposal, either supporting the Commission's existing "control test" or expressing concerns that the Commission's proposal does not actually make the reporting more accurate.[142] SoCal Edison states that the Commission's identified flaws in the control test and the current reporting of long-term purchases are not well supported and do not merit abandonment of the control test.[143] In particular, SoCal Edison disputes the "disappearing capacity" concern raised in the NOPR, asserting that generation capacity associated with long-term firm sales is reflected in some manner in the screens.[144] SoCal Edison also contends that the Commission's assertion that a long-term firm purchase is just like ownership with regard to the ability to get energy to the market is demonstrably false in some cases.[145]

118. E.ON and FirstEnergy agree with the Commission's proposal.[146] FirstEnergy states that "attribution of all such capacity to the purchaser, as proposed by the FERC,

[142] EPSA at 10; APPA/NRECA at 21-24; SoCal Edison at 3-11; Solomon/Arenchild at 8-10; Avista at 2-4; NextEra at 8; TAPS at 2.

[143] SoCal Edison at 3.

[144] *Id.* at 5.

[145] *Id.* at 11.

[146] E.ON at 6; FirstEnergy at 8.

will recognize appropriately the rights of the purchaser in the purchased resource and will help to improve the consistency of market power studies."[147] E.ON requests clarification that sellers of long-term capacity in RTO markets would not be required to submit indicative screens solely because the purchaser was required to do so.[148]

119. EEI urges the Commission to engage in further dialogue, noting that some EEI members have concerns, and some agree with at least some elements of the proposal. EEI states that some members were concerned that they would lose flexibility to reflect actual ownership and control of assets in indicative screens and asset appendices, and whether they would need to report the long-term contracts in the asset appendix.[149]

120. Avista/Puget state that the Commission's proposed solution goes too far and that the Commission instead should retain its current treatment of purchased capacity and/or energy based on the concept of operational control established in Order No. 697, with certain modifications to ensure that the capacity does not disappear from reports of the market.[150] To prevent generation capacity from disappearing in the indicative screens, Avista/Puget propose that the Commission modify its current policy with regard to the seller's treatment of sold energy such that it is the mirror image of the purchaser's treatment. Under Avista/Puget's proposal, generating capacity associated with a long-

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[147] FirstEnergy at 8-9.

[148] E.ON at 7.

[149] EEI at 12.

[150] Avista Corp. and Puget Sound Energy, Inc. (Avista/Puget) at 2.

term sale would be assigned to the seller, for purposes of conducting the indicative screen computations, if the contract does not convey control of the capacity to the purchaser.[151]

121. TAPS expresses concerns that the proposed change may well result in inaccurate reporting and mask the market power of large sellers where they retain control over the resource(s).[152] APPA/NRECA concede that this may fix some administrative problems, but worry that the resulting indicative screens will not accurately reflect actual market shares or pivotal supplier conditions.[153]

122. Indicated Utilities state that if the Commission adopts this rule, it should exempt from this requirement the capacity and/or energy associated with power purchase agreements from inherently intermittent qualifying small power production facilities entered into under 18 CFR Part 292, Subpart C, namely solar and wind qualifying facilities.[154] Indicated Utilities state that power purchase agreements with intermittent resource qualifying facilities are often fundamentally different from other power purchase agreements and thus warrant different treatment from that proposed in the NOPR.[155] For that reason Indicated Utilities urge the Commission to retain for such

[151] *Id.* at 4.

[152] TAPS at 2.

[153] APPA/NRECA at 21-24.

[154] Indicated Utilities at 2.

[155] *Id.* at 5.

power purchase agreements its existing policy of attributing capacity and/or energy to the entity that "controls" the qualifying facilities, as that term has been used in Order No. 697.[156]

123. EPSA questions the utility of this proposal and seeks clarification of how this requirement would differ from the reporting required in EQRs. EPSA states that it appears that the information required to be reported by this proposal would duplicate the information provided by sellers contained in the EQRs, which are required to be filed under current Commission regulations. EPSA suggests that if the Commission is seeking this information, then the Commission should not adopt the proposed revision but just refer to the EQR data.[157]

124. EPSA requests clarification that in evaluating long-term contracts for the indicative screens, sellers are still permitted to make conservative assumptions in their initial application and triennial updated market power analyses.[158]

125. Indicated Utilities state that the Commission should clarify that this proposed change – whether for intermittent qualifying small power production facilities power purchase agreements or other power purchase agreements – applies only to the indicative screens and asset appendices, and does not apply to any DPT analyses submitted to rebut a presumption of market power brought about by failure of one or

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[156] IWU at 7.

[157] EPSA at 9-10.

[158] *Id.* at 10.

both of the screens. Indicated Utilities contend that it would be consistent with the Commission's post-Order No. 697 approach for the proposed policy to apply only to the indicative screens while maintaining the current "control-based" approach to DPT analyses. Indicated Utilities state that the indicative screens are designed to be screens, while the DPT, on the other hand, is more granular and a more accurate means of assessing horizontal market power.[159]

126. SoCal Edison states that it does not generally object to the Commission collecting data on all long-term firm purchases through the asset appendix, but SoCal Edison asks the Commission to clarify that inclusion of a long-term firm purchase in an asset appendix does not constitute a concession that a purchase should appear in a market power screen analysis. SoCal Edison states that a seller should be permitted to rebut the presumption that any particular long-term firm purchase should be counted if the applicant is seeking to exclude the long-term firm purchase from a market power analysis. SoCal Edison further submits that if the applicant has no obligation to submit such screens, it need not rebut the presumption, but reserves the right to do so if ever requested to submit a screen analysis.[160]

127. Several commenters request clarification of various aspects of the proposal. SoCal Edison requests that the Commission explain how the buyer is to obtain the capacity factor information, which may not exist, in order to convert energy-only

[159] Indicated Utilities at 8-9.

[160] SoCal Edison at 12.

transactions.[161] Solomon/Arenchild state that converting an energy-only contract to MW-equivalents rather than the full amount of capacity may create confusion. Solomon/Arenchild ask whether the determining characteristic is whether a capacity payment is part of the long-term contract.[162] NextEra expresses concerns with the formula proposed for converting long-term energy purchases to a capacity value.[163] NextEra suggests that rather than requiring the actual energy supplied during a calendar year in the capacity calculation, a purchaser/seller should be allowed to rely on EIA regional data for energy-limited resources. NextEra states that otherwise there could be a significant overstatement of the capacity value submitted in triennial market power updates or notices of change in status.[164] APPA/NRECA state that the proposed conversation mechanism in footnote 98 of the NOPR calculates capacity as an average annual number, whereas the peak capacity purchased during a shorter interval in the study period would be the most relevant number.

128. SoCal Edison states that although the NOPR proposes reporting of long-term firm purchases where the purchase has an associated long-term firm transmission reservation, the concept of a long-term firm transmission reservation does not exist within the California Independent System Operator Corporation (CAISO) market. Therefore,

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[161] *Id.* at 17.

[162] Solomon/Arenchild at 10-11.

[163] NextEra at 9.

[164] *Id.* at 10.

SoCal Edison states that the Commission should clarify for CAISO and any other region that has eliminated long-term firm reservations, how this standard should be applied.[165]

129. Solomon/Arenchild ask for clarification on the treatment of jointly-owned facilities. They state that although the NOPR proposal abandons the need to determine the party that controls capacity under long-term contracts, the need for letter of concurrence seems to remain. They state that because the letter of concurrence previously was tied to the issue of the degree to which each party controls a facility, and control is no longer a factor, it is difficult to understand when letters of concurrence are appropriate.[166]

c. Commission Determination

130. We adopt the proposal to report long-term firm purchases in the indicative screens, with modification and clarifications as discussed below. We believe 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.

131. Some commenters contend that the proposed change will not make the screens more accurate because it may understate the market power of entities selling long-term

[165] SoCal Edison at 13.

[166] Solomon/Arenchild at 11.

firm capacity and/or energy.[167] However, this argument overlooks the fact that sellers in most cases already are deducting capacity sold pursuant to long-term firm contracts. The differing standards applied to purchasers and sellers with respect to control are the basis for the "disappearing capacity" problem described in the NOPR. Furthermore, as explained below, the Commission believes that it is more appropriate to attribute such capacity to the purchaser rather than the seller.

132. We are not persuaded by SoCal Edison's arguments disputing the existence of a "disappearing capacity" problem under the current policy. For example, SoCal Edison claims that even if an applicant does not attribute a long-term firm energy and/or capacity purchase to itself, the associated capacity will show up in the screens as non-affiliate capacity.[168] This is potentially true only if the purchased capacity is located in the same balancing authority area or market as the purchaser because the non-affiliated capacity included in the indicative screens only includes capacity located in the study area.[169] Many of the long-term purchases reported in certain regions cross balancing authority areas, i.e., the purchase is made from a resource external to the purchaser's home market.

[167] APPA/NRECA at 24; TAPS at 2.

[168] SoCal Edison at 5.

[169] The indicative screens include rows for long-term firm sales and purchases made by non-affiliated sellers. However, the existence of these rows does not support SoCal Edison's argument because a long-term firm purchase made by SoCal Edison from a seller external to SoCal Edison's market (CAISO) would not show up as a long-term firm purchase made by a non-affiliated seller in CAISO. Thus, the capacity associated with the long-term firm purchase that SoCal Edison did not report would not show up in its indicative screens for the CAISO market.

Therefore, capacity associated with long-term purchases often is not included in the indicative screens. Moreover, not reporting a long-term firm purchase from an external generation resource would make the screens inconsistent with the SILs, which account for long-term transmission reservations. Long-term firm purchases usually have an associated long-term firm transmission reservation. SoCal Edison's arguments also ignore the problems that can arise when an applicant's long-term firm purchases are recorded in an incorrect line of the indicative screens, which the Commission noted in *Vantage Wind*[170] and explained in the NOPR.

133. Avista/Puget proposes to fix the "disappearing capacity" problem by allowing sellers of long-term firm energy and/or capacity to only deduct such capacity in their indicative screens if they relinquish operational control over the capacity.[171] While this proposal would solve the "disappearing capacity" problem, we find that it is more appropriate to attribute capacity from a long-term firm power purchase agreement accompanied by a long-term firm transmission reservation to a purchaser/load serving entity, rather than to the seller, because the purchaser can use that contract to meet its capacity requirements. The seller cannot withhold the power from the purchaser even though the seller has operational control over the generating unit(s) supplying the power. Power purchase agreements may give the purchaser significant economic control over the power; e.g., the purchaser can bid the energy into centralized spot markets (if present).

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[170] *Vantage Wind*, 139 FERC ¶ 61,063 at P 16.

[171] Avista at 4.

134. Moreover, applying the control test to the seller would largely negate the Commission's policy with respect to fully committed generation capacity, as described elsewhere in this Final Rule. Under this policy, in order to satisfy the Commission's market-based rate requirements regarding horizontal market power, sellers may explain that their generation capacity is fully committed in lieu of including indicative screens. Today, new generating units, many of which are wind and solar units, often represent that they are fully committed under long-term power purchase agreements and deduct all of their capacity in the indicative screens or do not provide screens at all. Under Avista/Puget's proposal to assign the control test to the seller of long-term firm capacity, such sellers would only be able to deduct their capacity if they demonstrated that the purchaser had operational control of the generating unit. These sellers either would have to demonstrate that they no longer have control of their generation capacity or, if that was not the case, submit indicative screens. What currently are routine filings requesting market-based rate authority for new fully committed generators could in some cases become complicated.

135. We reject Indicated Utilities' proposal to exempt applicants from reporting long-term firm purchases backed by intermittent or energy-limited qualifying facility resources.[172] We believe that there is no reason to ignore such long-term firm purchases in the indicative screens and that Indicated Utilities' position confuses the operational

[172] IWU at 7.

characteristics of such resources with operational control. The fact that a solar or wind unit will not produce energy at certain times is equally true whether an applicant owns a solar or wind unit or purchases energy from a solar or wind unit through a long-term firm power purchase agreement. We clarify, however, that consistent with our direction elsewhere in this Final Rule, long-term firm purchases backed by energy-limited resources may be de-rated based on a five-year average capacity factor based either on the unit's operating history or the EIA regional average. Providing this capacity rating option to applicants will yield consistent treatment of such resources in the indicative screens, whether owned or purchased.[173] This capacity rating option also addresses NextEra's concern regarding the potential overstatement of capacity associated with long-term firm power purchase agreements in the indicative screens.

136. Regarding SoCal Edison's argument concerning the distinctions between owning and purchasing generation, we reiterate that, for the purpose of horizontal market power analyses, long-term firm power purchase agreements convey rights to generation capacity that are similar (though not identical) to ownership because they provide the purchaser with a resource that the purchaser can rely on to serve its load. The common definition of a "firm" purchase is a service or product that is not interruptible for economic reasons.[174] This was the Commission's primary reason for concluding in the NOPR that a long-term firm purchase was comparable to ownership. Such purchases provide a resource that a

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[173] *See supra* Section IV.A.6.

[174] The EQR Data Dictionary uses this definition as well.

load-serving entity can count towards its capacity requirement. The variable nature of energy-limited resources is the primary reason given by SoCal Edison for disputing the NOPR's contention that long-term firm energy agreements provide the purchaser with energy that only can be interrupted for limited and specified reasons.[175] However, as discussed above, the variable nature of certain energy-limited generators is a separate issue, and we will allow applicants to de-rate long-term firm power purchase agreements backed by energy-limited resources according to a five-year average capacity factor as discussed below. This will permit equivalent treatment of energy-limited resources in the indicative screens whether owned or purchased under long-term firm power purchase agreements.

137. With regard to EPSA's contention that reporting of long-term firm power purchase agreements in the indicative screens is duplicative of reporting such transactions in EQRs, the indicative screens and EQRs perform separate functions. The former is an *ex ante* analysis of a seller's potential market power while the latter enables an *ex post* analysis of its sales. Information on long-term firm purchases and sales is required to complete the indicative screens. The need to provide this information is not "waived" because it also is reported after-the-fact in EQRs or other forms. Therefore, we affirm the need for applicants to report long-term firm purchases in the indicative screens.

[175] SoCal Edison at 11.

138. With respect to questions raised regarding the treatment of long-term firm purchases in DPT analyses, we clarify that applicants must attribute long-term firm power purchase agreements to the purchaser when the power purchase agreement has an associated long-term transmission reservation. An applicant that includes long-term firm power purchase agreements in its screens should include the same power purchase agreements in any DPT analyses filed to rebut the presumption of market power resulting from a screen failure. The fact that DPTs are more detailed, granular market power analyses does not negate the need to attribute long-term firm purchases to purchasers. We recognize that this may lead to inconsistencies in the treatment of long-term purchases between DPT analyses submitted in section 203 filings and those submitted in section 205 filings, but there already are several differences between DPT analyses filed in section 203 and 205 proceedings (e.g., the section 203 analysis is a forward-looking analysis whereas the section 205 analysis is historical).

139. We confirm that long-term firm power purchase agreements that are reported in the indicative screens also should be reported in the asset appendix, Appendix B, as proposed in the NOPR. However, we agree with commenters that the existing Appendix B is not designed to report long-term firm purchases, particularly those that are not backed by specific generating units. Therefore, the Commission is creating a separate sheet in Appendix B specifically for applicants to report all long-term firm purchases

included in their indicative screens. This new sheet to the asset appendix is described in the discussion of the asset appendix below.[176]

140. With respect to the process for converting long-term firm energy-only contracts to MW equivalents, we provide clarification and have decided to modify the approach set forth in the NOPR. First, with respect to a question raised by Solomon/Arenchild, we clarify that such conversions are needed only if a capacity amount (MW) is not specified in the contract. Long-term firm power purchase agreements that have a capacity amount specified need not be converted, regardless of whether the contract includes a separate capacity payment.

141. Upon consideration of the comments, we will modify the energy-to-capacity conversion formula proposed in the NOPR. We find there is some merit to SoCal Edison's argument that firm energy contracts cannot necessarily be linked to specific generating units (although the energy comes from a set of generating units that ultimately can be identified). Thus, we are adopting an alternative conversion approach that is responsive to these concerns; this approach is conceptually similar to the approach proposed in the NOPR but uses a different factor – load rather than generation – to convert energy into a capacity value.[177]

[176] *See infra* Section IV.D.

[177] Although we are adopting an alternative approach in the Final Rule, the alternative approach is a logical outgrowth of the approach proposed in the NOPR. *See Aeronautical Radio, Inc. v. FCC*, 928 F.2d 428, 445-446 (D.C. Cir. 1991) (citing *United Steelworkers of America v. Marshall*, 647 F.2d 1189, 1221 (D.C.Cir.1980), *cert. denied*,
(continued…)

142. In place of the conversion formula set forth in the NOPR, applicants should use their actual load factor[178] in the relevant study period to convert a long-term firm energy-only contract to a MW equivalent. To determine the MW equivalent, applicants should first determine the average MW purchased under the long-term firm energy contracts over the study period.[179] Applicants should then divide the average MW purchased by their load factor to obtain the capacity value for the contract.

143. Long-term firm energy contracts serve the purchaser's load for a term of at least one year, so the purchaser's load factor is a reasonable basis to establish the capacity value of a long-term firm energy contract. This approach also avoids the need to calculate a capacity factor and link the purchase back to a generating unit or set of generating units. Applicants have ready access to their load data so performing this conversion should not be problematic or burdensome.

144. Applicants would continue to have the option of proposing a different method of attributing capacity based on the specific terms and conditions of their power purchase

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453 U.S. 913, 101 (1981)) (holding that the notice requirement of section 553 of the Administrative Procedure Act is fulfilled "so long as the content of the agency's final rule is a 'logical outgrowth' of its rulemaking proposal.").

[178] Load factor is the average load divided by the peak load in a specified time period. For example, if during a calendar year a franchised public utility has a peak load of 2,000 MW and total sales to native load customers of 10,000,000 MWh, its load factor is [(10,000,000/8760)/2000] = 0.57 or 57 percent.

[179] Average MW equals total MWh purchased during the study period divided by the total hours in the study period.

agreement. Any alternative attribution method would have to be fully supported and justified.

145. We provide several clarifications to the reporting of long-term firm power purchase agreements. First, we clarify that an applicant should report a long-term firm purchase of capacity and/or energy that has an associated long-term firm transmission reservation for either point-to-point or network transmission service. In addition, we clarify that this requirement applies regardless of whether the long-term firm transmission reservation is held by the purchaser or seller of the capacity/energy. In response to SoCal Edison's query, we clarify 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 an RTO/ISO market 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 a designated as a network resource or as a resource with capacity obligations. We further clarify that letters of concurrence will not be required to establish which party to a long-term firm power purchase agreement has control of the underlying generation resource(s).[180]

[180] However, sellers may need to submit a letter of concurrence to support claims that they do not own or control the entire capacity of a generation facility. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187.

8. Clarification of Commission Language in Performing SIL Studies

146. The SIL study is used in both the indicative screens and the DPT analysis as the basis for establishing the amount of power that can be imported into the relevant geographic market.[181] In the NOPR, the Commission summarized previous Commission SIL guidance to transmission operators provided in the April 14 Order, *Puget*, and Order No. 697. The Commission noted that the April 14 Order requires that power flow benchmark cases reasonably simulate the historical conditions that were present[182] and requires that sellers consider "all internal/external contingency facilities and all monitored/limiting facilities that were used historically to approximate area-area transmission availability" and utilize scaling methods according to the same methods used historically for non-affiliate resources.[183]

147. In the NOPR, the Commission noted that *Puget* clarified that sellers must "[p]rovide copies of all Operating Guide descriptions that were applied in the scaling section," as well as any operating guides used to ignore limiting elements in the SIL

[181] *Id.* P 19.

[182] Historical conditions include "facility/line deratings used to maintain capacity benefit margins (CBM) and transmission reliability (TRM/CBM), actual unit dispatch used to fulfill network and firm reservation obligation, the actual peak demand, generator operating limits opposed on all resources in real time, other limits/constraints imposed by the TP [Transmission Provider] during the season peaks." April 14 Order, 107 FERC ¶ 61,018 at app. E.

[183] NOPR, FERC Stats. & Regs. ¶ 32,702 at PP 147, 151 (citing April 14 Order, 107 FERC ¶ 61,018 at app. E).

study results.[184] The Commission also stated that applicants must exclude study area non-affiliated load from study area native load, and should not include first-tier generation serving study area non-affiliated load in net area interchange. In addition, the Commission specified that applicants must document all instances where the SIL study differs from historical practices.[185]

148. In the NOPR, the Commission also noted the Commission's finding in Order No. 697 that SIL studies performed by sellers "should not deviate from" and "must reasonable[ly] reflect" the seller's Open Access Same-Time Information System (OASIS) operating practices and "techniques used must have [been] historically available to customers."[186] The Commission further stated that "by OASIS practices, we mean sellers shall use the same OASIS methods and studies used historically by sellers (in determining simultaneous operational limits on all transmission lines and monitored facilities) to estimate import limits from aggregated first-tier control areas into the study area."[187] Furthermore, the Commission stated that Order No. 697 requires that power

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[184] *Id.* P 150 (citing *Puget*, 135 FERC ¶ 61,254 at app. B, Reporting Requirements for Submittals 8, 9).

[185] *Id.* (citing *Puget*, 135 FERC ¶ 61,254 at app. B, Reporting Requirements for Submittals 10 and 11).

[186] *Id.* P 146 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 (internal citations omitted)).

[187] *Id.* P 146 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 n.361).

flow cases "represent the transmission provider's tariff provisions and firm/network reservations held by seller/affiliate resources during the most recent seasonal peaks."[188]

149. The Commission noted that Order No. 697 allows the use of simultaneous total transfer capability (simultaneous TTC) values in performing SIL studies "provided that these TTCs are the values that are used in operating the transmission system and posting availability on OASIS."[189] The Commission requires sellers to provide evidence that simultaneous TTC values account for simultaneity, internal and first-tier external transmission limitations, and transmission reliability margins.[190]

150. In the NOPR, the Commission proposed to clarify several issues about how to perform SIL studies and the associated Submittals 1 and 2 found on the Commission's website.[191] In particular, the Commission proposed to clarify issues relating to what is included in OASIS practices, how to deal with conflicts between OASIS practices and

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[188] *Id.* P 152 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354); *see also Puget*, 135 FERC ¶ 61,254 at P 15 ("Long-term firm transmission reservations for applicant/affiliate generation resources that serve study area load reduce the amount of study are transmission capability available to potential competitors.").

[189] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 155 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 364).

[190] *Id.*; *see also* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 142 (clarifying that "the use of simultaneous TTC values in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin.").

[191] The sample spreadsheets for Submittals 1 and 2 are found at the Commission's website at http://www.ferc.gov/industries/electric/gen-info/mbr/authorization.asp under "Quick Links."

the Commission directions provided in Appendix B of *Puget*, and the correct load value to use in the SIL study.

151. The Commission stated that the purpose of the SIL study is to calculate the total simultaneous import capability available to first-tier uncommitted generation resources, while also considering system limitations and existing resource commitments (i.e., long-term firm transmission reservations).[192] Therefore, the methodology a transmission provider uses to calculate simultaneous TTC values[193] must be consistent with the methodology it uses for calculating and posting available transfer capability (ATC)[194] and for evaluating firm transmission service requests, consistent with Commission policy and precedent.[195] The Commission stated that import capability available to a transmission provider during real-time operations should not be included in the transmission provider's SIL value if such transmission import capability is not available to non-affiliated uncommitted generation resources requesting long-term firm transmission service.[196]

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[192] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 158.

[193] *See* row 4 of proposed Submittal 1 (Total Simultaneous Transfer Capability).

[194] In the NOPR, FERC Stats. & Regs. ¶ 32,702 at P 25, ATC was inadvertently defined as "available transmission capability"; it should have been "available transfer capability." *See* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 57.

[195] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 158.

[196] *Id.*

a. OASIS Practices

i. Commission Proposal

152. In the NOPR, the Commission proposed to clarify that the term "OASIS practices" refers specifically to the seasonal benchmark power flow case modeling assumptions, study solution criteria,[197] and operating practices historically used by the first-tier and study area transmission providers[198] to calculate and post ATC and to evaluate requests for firm transmission service.[199]

153. The Commission also proposed to clarify that in performing a SIL study, the transmission provider must utilize its OASIS practices consistent with the administration of its tariff. The seasonal benchmark power flow cases submitted with a SIL study should represent historical operating practices only to the extent that such practices are available to customers requesting firm transmission service. For example, if the transmission provider does not allow the use of an operating guide when evaluating firm

[197] Study solution criteria may include but are not limited to distribution factor thresholds, transformer tap adjustments, reactive power limits, transmission equipment ratings, and model solution settings. *Id.* P 159 n.169.

[198] We reiterate that, while entities may not be familiar with all of the OASIS practices of transmission providers in first-tier balancing authority areas, they should at least be familiar with major constraints, path limits, and delivery problems in neighboring transmission systems. *Id.* P 159 n.170 (citing Order No. 697, FERC Stats. & Regs ¶ 31,252 at P 354 n.361).

[199] The interruptible nature of non-firm transmission service makes using these practices an inappropriate means of calculating the study area's SIL value. *Id.* P 161 n.171.

transmission service requests, the transmission provider should not use the operating guide when calculating SIL values.[200]

ii. Commission Determination

154. There were no comments on the above proposals. Therefore, we adopt the proposals as set forth in the NOPR to clarify that the term "OASIS practices" refers specifically to the seasonal benchmark power flow case modeling assumptions, study solution criteria, and operating practices historically used by the first-tier and study area transmission providers to calculate and post ATC and to evaluate requests for firm transmission service, and to clarify that in performing a SIL study, the transmission provider must utilize its OASIS practices consistent with the administration of its tariff. We believe these clarifications will improve consistency between the methodology a transmission provider uses to calculate SIL values and the methodology it uses for calculating and posting ATC and for evaluating transmission service requests.

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[200] By "operating guide" we generally refer to the North American Electric Reliability Corp. (NERC)-defined term "Operating Procedure," which is defined as "a document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s)." *See* NERC, Glossary of Terms Used in NERC Reliability Standards 53 (2014), http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. In the SIL study context, this may include switching procedures, special protection systems, load throw-over schemes, temporary transmission line rating changes, and other actions that are not typically represented in the seasonal benchmark power flow models. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 161 n.172.

b. SIL Studies and OASIS Practices

i. Conflicts Between OASIS Practices and *Puget*

(a) Commission Proposal

155. In the NOPR, the Commission proposed several clarifications for instances when the methodology a transmission provider uses to calculate SIL values is inconsistent with the methodology the transmission provider uses for calculating and posting ATC and for evaluating transmission service requests. The Commission proposed to clarify that where there is a conflict between OASIS practices and the Commission directions provided in Appendix B of *Puget*, sellers should follow OASIS practices except as noted in the NOPR. The Commission reminded sellers that, in instances where actual OASIS practices differ from the SIL direction provided in *Puget*, sellers should use actual OASIS practices and provide documentation specifically identifying such practices.[201] The Commission also proposed to clarify that, to the extent that a seller's SIL study departs from actual OASIS practices,[202] such departures are only permitted where use of actual OASIS practices is incompatible with an analysis of import capability from an aggregated first-tier area.[203] The Commission invited comments identifying potential

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[201] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 162 n.173 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 356).

[202] *See Puget*, 135 FERC ¶ 61,254 at app. B.

[203] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 162.

areas where actual OASIS practices may be incompatible with the performance of SIL studies.

156. The Commission also reminded sellers that the calculated SIL value should account for any limits defined in the tariff, such as stability or voltage.[204] For example, if a seller utilizes a direct current analysis when performing a SIL study, but an alternating current analysis when evaluating transmission service requests, the seller must validate the total aggregate transfer level value, consistent with the transmission provider's OASIS practices, if modeled using an alternating current load flow model.[205]

157. The Commission also reiterated that sellers may use a load shift methodology to perform a SIL study if they use a load shift methodology in their OASIS practices, "provided they submit adequate support and justification for the scaling factor used in their load shift methodology and how the resulting SIL number compares had the company used a generation shift methodology."[206]

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[204] *Id.* P 163 n.175 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 346).

[205] *Id.* P 163 n.176 (citing *Pinnacle West Capital Corporation*, 117 FERC ¶ 61,316, at P 11 n.19 (2006) ("The resulting loading and voltages for the limiting cases, if derived from DC (direct current) load flow analysis would have been verified by AC (alternating current) load flow analysis and demonstrated to be within the applicable system operating limits as dictated by thermal, voltage or stability considerations to ensure system reliability. The Commission requires that such comparisons be included in the applicant's working papers that are submitted to the Commission.").

[206] *Id.* P 164 n.177 (quoting Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 145).

158. Regarding accounting for long-term firm transmission reservations for generation resources that serve study area load, the Commission proposed to clarify that sellers must reduce the simultaneous TTC value[207] by subtracting all long-term firm import transmission reservations, including reservations held by non-affiliated sellers.[208] The Commission noted that it has already provided guidance with respect to accounting for long-term firm transmission reservations into the study area from affiliated generation resources located outside the study area.[209] The Commission stated that proposed revised Appendix A Standard Screen Format accounts for all long-term firm import transmission reservations into the study area.[210] The Commission also proposed revisions to Submittal 2 to account for these non-affiliate long-term firm transmission reservations to ensure that the determination of the SIL value is consistent with the method used to allocate this value to uncommitted generation capacity in the aggregated first-tier area for the indicative screens.[211]

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[207] The revised Standard Screen Format (e.g., rows B1 and M1 in the market share screen (Long-Term Firm Purchases (from outside the study area))) must reflect the long-term firm reservations from Submittal 1, Table 1, row 5 of *Puget*. *Puget*, 135 FERC ¶ 61,254 at app. B.

[208] *See* NOPR, FERC Stats. & Regs. ¶ 32,702 at P 165 n.179 (citing revised app. E, Submittal 1, row 5).

[209] *Id.* P 165 n.180 (citing *Puget*, 135 FERC ¶ 61,254 at P 15).

[210] *Id.* P 165 & n.182 (citing to revised app. A, Standard Screen Format, specifically rows A1, B1, E1 and F1 in the market share screen and rows A1, B1, L1, and M1 in the pivotal supplier screen).

[211] *Id.* P 165.

(b) Comments

159. Solomon/Arenchild agree with the Commission's proposal to continue the requirement that SIL studies follow OASIS practices. Southeast Transmission Owners, however, state they are concerned that the Commission's proposal to require sellers to "subtract all long-term firm import transmission reservations, including reservations held by non-affiliated sellers, from the simultaneous TTC value" could yield a misleading conclusion regarding market activity within a given area. According to Southeast Transmission Owners, the possession by a non-affiliate of a long-term transmission reservation across a seller's interface that sinks in the seller's home balancing authority area is an indicator of an open market, representing a decision by a competitor and the ability of that competitor to compete for load in the particular balancing authority area. Southeast Transmission Owners assert that, while the components of the screen inclusive of the SIL may yield a mathematically accurate result, the tabular depiction of the availability of transmission capacity for use by non-affiliates, as proposed in the NOPR, becomes complicated and misleading and results in the market appearing more constrained than it really is. Southeast Transmission Owners urge the Commission to forego adoption of this proposal and not require deduction of long-term reservations held by non-affiliates of the seller. Instead, Southeast Transmission Owners ask that the Commission adopt an approach that appropriately reflects marketplace activity and the availability of transmission capacity to non-affiliates. However, if the Commission proceeds with this proposal, then Southeast Transmission Owners urge that the Commission recognize the ability of sellers, when

performing a SIL study and the associated screens, to rebut the results through companion sensitivities and other data that show how the utilization of import capability by non-affiliates is indicative of a competitive marketplace.[212]

(c) Commission Determination

160. We clarify that, where there is a conflict between the transmission provider's tariff or OASIS practices and the Commission directions specified in *Puget* for performing SIL studies, sellers, except as noted below, should follow OASIS practices and provide documentation specifically identifying such practices.[213]

161. We adopt the proposal that, to the extent that a seller's SIL study departs from actual OASIS practices, such departures are only permitted where use of actual OASIS practices is incompatible with an analysis of import capability from an aggregated first-tier area. The calculated SIL value should account for any limits defined in the tariff, such as stability and voltage.[214] Sellers may use a load shift methodology to perform a SIL study if they use a load shift methodology in their OASIS practices, provided they submit adequate support and justification for the scaling factor used in their load shift

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[212] Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., Louisville Gas and Electric Co., Kentucky Utilities Co., South Carolina Electric and Gas Co., and Southern Companies Services, Inc., acting as agent for Alabama Power Co., Georgia Power Co., Gulf Power Co., and Mississippi Power Co. (Southern Companies) (collectively, Southeast Transmission Owners) at 3.

[213] *See* Order No. 697, FERC States. & Regs. ¶ 31,252 at P 356.

[214] *Id.* P 346.

methodology and show how the resulting SIL values compare to those that would be obtained if the seller used a generation shift methodology.[215]

162. We also adopt the proposal to direct sellers to subtract all long-term firm import transmission reservations (including those held by non-affiliated sellers) from the simultaneous TTC and historical peak load values. Finally, we adopt the proposed revisions to Submittal 2 to account for these non-affiliate long-term firm transmission reservations. We note that the adopted Submittals 1 and 2 spreadsheet has an additional row in Submittal 2 for each non-affiliated long-term firm transmission reservation to more clearly illustrate that each transaction should be reported separately. There is also an additional row in the adopted spreadsheet in Submittal 2 for each power purchase agreement for the same reason.[216]

163. In response to Southeast Transmission Owners, we find that reducing the simultaneous TTC value and historical peak load value by long-term firm transmission reservations held by both affiliates and non-affiliates properly accounts for all import capability used to serve affiliated and non-affiliated load in the study area. This provides an accurate measure of the study area's load and import capability that is not

[215] Order No. 697-A, FERC States. & Regs. ¶ 31,268 at P 145.

[216] Though the spreadsheet published in the NOPR did not contain these additional rows, the original instructions for Submittal 2 published in Appendix B of *Puget* and the proposed spreadsheet posted on the Commission's website each had the instruction to insert "as many rows as necessary" to report each power purchase agreement. Finally, the descriptive text in rows 2 and 6 of Submittal 2 has been changed to "Power Purchase Agreement" instead of "Purchased Power Agreement" to be consistent with this nomenclature as used elsewhere in this Final Rule.

available to uncommitted generation capacity in the first-tier area. We note that such reservations are properly accounted for in the indicative screens and that treating all long-term firm transmission reservations in a consistent manner should reduce confusion rather than increase it. With respect to Southeast Transmission Owners' request that the Commission recognize the ability of sellers to rebut SIL study results through companion sensitivities, we note that sellers "[m]ay submit additional sensitivity studies, including a more thorough import study as part of the DPT. We reaffirm, however, that any such sensitivity studies must be filed in addition to, and not in lieu of, a SIL study."[217]

ii. <u>Wheel-Through Transactions</u>

(a) <u>Commission Proposal</u>

164. The Commission proposed to clarify that sellers must account for wheel-through transactions where such transactions are used to serve a non-affiliated load that is embedded within a study area. Specifically, the Commission proposed that the seller reduce the simultaneous TTC value by subtracting the value of all wheel-through transactions. The Commission observed that while wheel-through transactions are not used to serve study area load, they reduce the amount of transmission capability available to first-tier generators competing to serve study area load. Thus, the Commission proposed that these transactions be accounted for as long-term firm import

[217] Order No. 697-A, FERC States. & Regs. ¶ 31,268 at P 146.

transmission reservations and reported in Submittal 2 and proposed corresponding changes to Submittal 2.

(b) <u>Comments</u>

165. Solomon/Arenchild state they do not understand the rationale and intent of the proposal to include wheel-through transactions as a deduction to the amount of transmission capability available to first-tier generators to serve study area load. According to Solomon/Arenchild, wheel-through reservations generally do not reduce overall import capability because the import schedule nets out against the subsequent export schedule and that such reservations are not used to serve load in the balancing authority area. Southeast Transmission Owners voice similar concerns about the Commission's proposal regarding wheel through transactions.[218] According to Southeast Transmission Owners, this proposal results in an inequitable reduction of a seller's SIL that is not indicative of actual marketplace activity. Further, Southeast Transmission Owners state that, in their experience, transmission operators use the term wheel through transaction to describe transactions that are imported into, and then exported out of, their particular areas of operation, thereby not serving load in that study area. Southeast Transmission Owners are unclear what transactions the NOPR would purport to capture by this new requirement and whether a wheel through transaction under the NOPR must in fact be supported by a long-term firm reservation.

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[218] Southeast Transmission Owners at 4 (citing NOPR, FERC Stats. & Regs. ¶ 32,702 at P 166).

166. Southeast Transmission Owners are concerned that the proposal may cause confusion among sellers, result in the capture of transactions that are beyond the intended scope, and contribute to less reliable SIL values. Given these concerns over the Commission's proposal, Southeast Transmission Owners request that the Commission (1) clarify or elaborate what it means by wheel through transactions sinking in the seller's area, and (2) limit this new requirement to this category of transactions that are supported by long-term firm reservations held by the seller and its affiliates.

(c) Commission Determination

167. We agree with commenters' interpretation of the term wheel-through to mean long-term firm transmission reservations that enter and exit a study area, but do not serve load in that study area. While a wheel-through transaction is still considered to be reserved capability on transmission lines similar to other long-term firm transmission reservations, a traditional wheel-through does not serve a study area's Historical Peak Load and, as such, should not be recognized as a long-term firm transmission reservation for the purposes of the SIL study. Accordingly, we clarify that the NOPR should have instead used the terminology "wheel-into," which refers to a long-term firm transmission reservation that enters a study area and serves non-affiliated load embedded in that study area. Thus, we make this distinction to clarify these terms in the Final Rule, and to adopt the NOPR proposal to apply to wheel-into transactions rather than to wheel-through transactions.

168. Further, we clarify that wheel-into or other similarly related import transactions supported by first-tier, long-term firm transmission reservations used to serve non-

affiliated load embedded within the study area are to be accounted for in a consistent manner, and the seller should reduce the simultaneous TTC value and historical peak load value by subtracting the value of all these transactions.[219]

169. Additionally, while import and export transactions may net out for the purpose of calculating net area interchange, the Commission does not net out such long-term firm transmission reservations that are used to serve non-affiliated load embedded within the study area. Finally, we refine our proposed language in row 3 and row 7 in Submittal 2 to remove any potential confusion with the use of the term "wheel-through" to read, "Transaction to serve non-affiliated, load embedded in the study area using external generation."

iii. Preferred Approach for Treating Controllable Tie Lines

(a) Proposal

170. The Commission proposed to clarify that, where a first-tier market or balancing authority area is directly interconnected to the study area only by controllable tie lines[220] and is not interconnected to any other first-tier market or balancing authority area,

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[219] In Submittal 1, Long-Term Firm Transmission Reservations (row 5) are deducted from Total Simultaneous Transfer Capability (row 4) to yield the Calculated SIL Value (row 6). The Calculated SIL Value is compared to Adjusted Historical Peak Load (row 8) and Uncommitted First-Tier Generation (row 9) to determine the SIL Study Value (row 10), which is limited by those two values.

[220] Controllable tie lines include direct current (DC) transmission facilities and alternating current (AC) transmission facilities with the ability to control the magnitude and direction of power flows through equipment such as converters, phase shifting transformers, variable frequency transformers, etc.

sellers should follow their OASIS practices regarding calculation and posting of ATC for such areas. If sellers' OASIS practices are incompatible with the SIL study (e.g., ATC is based on tie line rating), sellers may use an alternative process to account for import capability for such tie lines.[221] The Commission also proposed to clarify that, in such circumstances, it will be presumed reasonable to model a controllable tie line as a single equivalent first-tier generator connected to the study area by a radial line. The Commission stated that sellers should document any instances where modeling of controllable tie lines deviates from OASIS practices, and explain such deviations, including: how tie line flow is accounted for in the net area interchange calculations; how tie line flow is scaled or otherwise controlled when calculating simultaneous incremental transfer capability; and how long-term firm transmission reservations are accounted for over controllable tie lines.[222]

(b) <u>Comments</u>

171. Solomon/Arenchild seek clarification of the preferred approach for treating controllable tie lines. According to Solomon/Arenchild, there are two reasonable options for treating such lines with regard to the Commission's proposal that SIL studies

[221] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 167.

[222] *Id.*

for markets "directly connected to the study area [first-tier] only by controllable tie lines" should follow OASIS practices regarding calculation and posting of ATC.[223] Using a market that has an high-voltage direct current (HVDC) tie of 200 MW as an example, Solomon/Arenchild state that one option for treating such lines is that the SIL study could include a 200 MW generator inside the balancing authority area being analyzed, assigning any share of the generation to the holder of long-term reservations on the HVDC tie, if any. Another option is that the SIL study could treat the HVDC tie as a 200 MW generator outside of the balancing authority area being analyzed but include it as part of the aggregated generation in the first-tier area.

(c) <u>Commission Determination</u>

172. We clarify that, for purposes of performing market power studies for market-based rate authorization, where a first-tier market or balancing authority area is directly interconnected to the study area only by controllable tie lines and is not interconnected to any other first-tier market or balancing authority area, sellers should follow their OASIS practices for calculation and posting of ATC for such areas.[224] However, if a seller's OASIS practices are incompatible with the SIL study (e.g., ATC is based on tie line

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[223] Solomon/Arenchild at 12 (quoting NOPR, FERC Stats. & Regs. ¶ 32,702 at P 167).

[224] Controllable tie lines are transmission facilities with associated equipment enabling control of the magnitude and direction of power flows over the facility. One example of a controllable tie line is the Cross Sound Cable, which connects the New England and New York markets.

rating), the seller may use an alternative process to account for import capability for such tie lines.

173. In such circumstances where a seller's OASIS practices are incompatible with the SIL study, sellers shall not model a controllable tie line as a radial line connected to an equivalent study area generator, as proposed by Solomon/Arenchild, as this leads to potential SIL study errors when scaling generation. However, for purposes of calculating the SIL value and consistent with the NOPR proposal, where a first-tier market or balancing authority area is directly interconnected to the study area only by controllable tie lines, each controllable tie line shall be modeled as a radial line connecting the study area to a first-tier area generator located in the first-tier area, and may be scaled as first-tier area generation. For the purposes of allocating SIL values to aggregate uncommitted first-tier generation capacity, sellers must consider actual uncommitted generation capacity in each first-tier area, rather than the capability of the controllable tie line.

iv. Treatment of Controllable Merchant Lines

(a) Commission Proposal

174. The Commission stated that in the NOPR that, to the extent that the study area is directly interconnected to first-tier areas by controllable merchant transmission lines (e.g., Linden VFT), sellers should properly account for capacity rights on such lines. If sellers hold long-term capacity rights on such lines, these rights should be accounted for as long-term firm transmission reservations. If sellers lack sufficient knowledge regarding the existence and attributes of capacity rights on controllable merchant lines,

sellers shall assume the full capacity of such lines is held by sellers with long-term firm transmission reservations.[225]

(b) Comments

175. Solomon/Arenchild note their confusion as to controllable merchant lines and the Commission's statement that, "[i]f sellers lack sufficient knowledge regarding the existence and attributes of capacity rights on controllable merchant lines, they shall assume the full capacity of such lines is held by sellers with long-term firm transmission reservations."[226] Solomon/Arenchild ask why these long-term firm transmission rights should be treated any differently than any other transmission reservations. Additionally, they ask whether the reference to "sellers" with long-term firm transmission rights really is a reference to transmission right holders as opposed to the "sellers" filing the screens. Further, Solomon/Arenchild seek clarification that the Commission's intent is to reflect the full amount of the controllable merchant line capacity in determining the total size of the market.[227]

(c) Commission Determination

176. We clarify in response to the question asked by Solomon/Arenchild that the reference to "sellers" was intended to be a generic reference to transmission right holders and not to apply to the seller submitting the study.

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[225] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 168.

[226] Solomon/Arenchild at 12; NOPR, FERC Stats. & Regs. ¶ 32,702 at P 168.

[227] Solomon/Arenchild at 12-13.

177. SIL values are net of long-term firm transmission reservation. We find that capacity rights on controllable merchant lines are comparable to long-term firm transmission reservations and should be deducted from the Total Simultaneous Transfer Capability value and Historical Peak Load value. Capacity rights on controllable merchant lines represent import capability that is only available to a specific transmission customer pursuant to the Commission's policies for merchant transmission, and is therefore not generally available to any uncommitted generator in the first-tier area. In the past, some sellers have treated controllable merchant transmission lines as if such lines were available to import generation into the study area. Such treatment is inconsistent with the merchant transmission model. However, sellers should be able to determine whether merchant transmission lines are subscribed given the requirement that merchant transmission developers disclose the results of their capacity allocation process.[228] However, where the seller is unaware of the terms and conditions for third-party capacity rights on controllable merchant lines, the seller must make a conservative assumption and subtract from the Total Simultaneous Transfer Capability and Historical Peak Load values the full capacity of the controllable merchant line as a long-term firm transmission reservation. We find this to be a reasonable assumption as the capacity on

[228] *See Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects Priority Rights to New Participant-Funded Transmission*, 142 FERC ¶ 61,038 (2013).

controllable merchant lines typically is fully subscribed.[229] This approach ensures that such capacity rights on controllable merchant transmission lines are treated in a comparable manner to long-term firm transmission reservations.

v. Inclusion of All Load Data

(a) Commission Proposal

178. In the NOPR, the Commission proposed to require sellers to include all load associated with balancing authority area(s) within the study area. The Commission stated that the SIL study is "intended to provide a reasonable simulation of historical conditions" and is not "a theoretical maximum import capability or best import case scenario."[230] The Commission noted that the SIL study "is a study to determine how much competitive supply from remote resources can serve load in the study area."[231] In the NOPR, the Commission noted the clarification in *Puget* that sellers should not report study area non-affiliated load as study area native load, and should adjust modeled net area interchange by the same amount.[232] The Commission stated that the exclusion of all study area non-affiliated load may result in SIL values that are inconsistent with the intent of the indicative screens. Furthermore, in the event the SIL value is limited by

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[229] This assumes that the capacity of the merchant tie line is included in the net area interchange value as well, such that the net impact on the SIL value is zero.

[230] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 169 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354).

[231] *Id.* (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 361).

[232] *Id.* (citing *Puget*, 135 FERC ¶ 61,254 at app. B).

study area load, restricting study area load to affiliated load fails to account for import capability that may be used to serve wholesale load customers. The Commission stated that sellers should only adjust the reported value for modeled net area interchange to account for first-tier generation serving load associated with a first-tier balancing authority area that is modeled as part of the study area.[233] To ensure Submittal 1 is consistent with these requirements, the Commission proposed to revise row 8 to read "Adjusted Historical Peak Load" (instead of "Study area adjusted native load").

(b) Comments

179. Solomon/Arenchild and Southeast Transmission Owners agree with the Commission's proposal that sellers include in SIL studies all load associated with balancing authority area(s) within the study area, with sellers' specific load obligations accounted for in the indicative screen analysis. However, Idaho Power contends that the Commission's proposal prevents an accurate accounting for a fraction of non-affiliate load that is served by non-affiliate generation when both are located in the study area. Further, Idaho Power argues that the proposal to include both affiliate and all non-affiliate load in the definition of Historical Peak Load means that any remaining amount of non-affiliate load not served by non-affiliate generation in the study area would be included in long-term firm transmission reservations, which would reduce the

[233] *Id.* (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 169 n.186 ("If the load is modeled as part of another area, i.e., as a non-area load attached to an area bus, and the net area interchange calculation includes both tie lines and non-area loads attached to area buses, net area interchange associated with service to such load should be approximately zero, and no adjustment will be necessary.")).

simultaneous TTC value by this fraction of non-affiliate load. According to Idaho Power, this would lead to the fraction of the non-affiliate load served by internal non-affiliate generation incorrectly appearing as affiliate load.[234]

(c) Commission Determination

180. We adopt the proposal to require sellers to include in the SIL studies all load associated with balancing authority area(s) within the study area. With regard to Idaho Power's argument regarding consideration of study area non-affiliate load served by non-affiliate generation, we first note that study area non-affiliate load not served by study area non-affiliate generation would only appear as a long-term firm transmission reservation when served by first-tier generation capacity. Furthermore, as the Commission noted in the NOPR, Adjusted Historical Peak Load includes both affiliate and non-affiliate native load, as well as wholesale load. This ensures the SIL value, when limited by Adjusted Historical Peak Load, remains consistent with the load values in the indicative screens and also does not provide biased SIL values when they are limited by load. This clarification is not intended to re-categorize study area non-affiliated load as study area affiliate load, but rather clarify that they together are available to be served by competitors in the first-tier market and from available non-affiliate generators within the study area. However, we agree with Idaho Power that non-affiliate load served by internal non-affiliate generation with a firm commitment should not be represented as being available to be served by competitors. Therefore, we

[234] Idaho Power at 4-5.

clarify that when a non-affiliate generator has a firm commitment to serve a non-affiliate load and both are located within the study area, then this non-affiliate generator should not be scaled and the value of this non-affiliate load should not be included in the study area Historical Peak Load as reported on row 7 of Submittal 1.

vi. <u>Sources of Load Data</u>

(a) <u>Commission Proposal</u>

181. The Commission stated in the NOPR that it is also looking for consistent, reported load values for all sellers to use in preparing SIL studies, noting that *Puget* requires that sellers use FERC Form No. 714 load values or explain the source of the data used.[235] The Commission noted that some sellers have stated that the load values in their models differ from FERC Form No. 714 data and have sought to rely on data from sources other than FERC Form No. 714. The Commission sought industry comment on what sources other than FERC Form No. 714 may be appropriate sources to rely on in determining historical peak load.

(b) <u>Comments</u>

182. Idaho Power believes that, with the other adjustments in the NOPR, use of FERC Form No. 714 data, which includes the balancing authority area load, is appropriate. However, Solomon/Arenchild state that, in their experience, the load included in seasonal benchmark power flow models often does not precisely match loads reported in

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[235] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 170 (citing *Puget*, 135 FERC ¶ 61,254 at app. B, Submittal 1, n.iv).

FERC Form No. 714 and typically used in the indicative screens. Solomon/Arenchild recommend that the Commission allow sellers to use the load data underlying the transmission models for purposes of row 7 of Submittal 1.

183. Southeast Transmission Owners believe that, regardless of its source, the load data must incorporate all data in the market under study. Southeast Transmission Owners use Southern Companies as an example to demonstrate that FERC Form No. 714 may not always reflect aggregated balancing authority area information necessary to determine the historical peak load for the SIL study because the FERC Form No. 714 data reflects load data of the Southern Companies and not the load of all other load-serving entities operating inside the Southern Companies balancing authority area. Therefore, Southeast Transmission Owners argue that, in order to perform a SIL study consistent with the Commission's existing requirements, entities like Southern Companies use archived load data from their energy management systems in order to provide the requisite balancing authority area information needed for the study. Southeast Transmission Owners assert that, while there may be other FERC Form No. 714 alternatives, archived energy management systems data serves as a reliable, cost-effective means for satisfying the Commission's requirements and ensuring that the appropriate inputs to the SIL have been obtained in order to yield accurate results.

(c) Commission Determination

184. We do not find it necessary for the load used in the seasonal benchmark case model to exactly match FERC Form No. 714 data. However, the Historical Peak Load reported in row 7 of Submittal 1 should be consistent with the load used in the seasonal

benchmark case model. We clarify that entities are permitted to deviate from reported FERC Form No. 714 load values where such values fail to account for all load within the study area, but sellers must explain and document their reasons for using an alternative data source and any adjustments made to the data. In addition, we find it acceptable for sellers to use energy management systems data to represent Historical Peak Load values, so long as sellers attest that such data is unmodified and accurate, and includes all study area affiliate and non-affiliate load.

vii. Submittals 1 and 2

(a) Commission Proposal

185. The Commission clarified in the NOPR that the values provided in Submittal 1 should generally be supported by the submitted seasonal benchmark power flow models.[236] In particular, the Commission explained that row 1 (Simultaneous Incremental Transfer Capability), row 2 (Modeled Net Area Interchange), and row 4 (Total Simultaneous Transfer Capability) should agree with the corresponding values from the seasonal benchmark power flow models. Any differences should be explained by the seller. The Commission proposed to update Submittal 1, as reflected in Appendix E to the NOPR, to provide additional clarity on the expected values for certain rows.[237] As addressed above in the discussion of wheel-through transactions, the Commission also

[236] *Id.* P 171.

[237] *See* Revised app. E, Submittal 1.

proposed revisions to Submittal 2. Revised versions of Submittals 1 and 2 were posted on the Commission's website.

(b) Commission Determination

186. We adopt the proposal to clarify that the values provided in Submittal 1 should generally be supported by the submitted benchmark power flow models. Any differences should be explained by the seller. We will also adopt the proposal to update Submittal 1, as reflected in Appendix E of the NOPR, to provide additional clarity on the expected values for certain rows. We will post the revised versions of Submittals 1 and 2 on the Commission's website and direct sellers to begin using the revised versions no later than the effective date of this Final Rule.

c. Simultaneous TTC Method

i. Commission Proposal

187. The Commission proposed in the NOPR to define the following standard guidance for data submittals and representations that sellers using the simultaneous TTC method must provide to the Commission. First, the Commission stated that sellers must provide historical data of actual, hourly, real-time TTC values used for operating the transmission system and posting transmission capacity availability on OASIS. Sellers should identify the date and hour from which simultaneous TTC values were calculated. Sellers may use the maximum sum of TTC values for any day and time during each season, so long as they also demonstrate that these TTC values are simultaneously feasible. Sellers may demonstrate that TTC values are simultaneously feasible by performing a power flow study that verifies that the declared simultaneous TTC value is

simultaneously feasible while accounting for all internal and external transmission limitations identified in Appendix E of the NOPR and *Puget*.[238] Sellers may also provide expert testimony explaining how the specific criteria and procedures used to calculate posted TTC values result in TTC values that are simultaneously feasible.

188. The Commission reiterated that, in the event there are limited interconnections between first-tier markets, the Commission will review evidence that potential loop flow between first-tier areas is properly accounted for in the underlying SIL values on a case-by-case basis.[239] However, the Commission clarified that simply attesting that first-tier markets or balancing authority areas are not directly interconnected is not sufficient evidence that TTC values posted on OASIS are simultaneous, as this does not preclude internal transmission limitations from limiting the simultaneous TTC below the sum of individual path TTC values.

ii. <u>Commission Determination</u>

189. There were no comments addressing this proposal. Thus, we adopt the standard guidance for data submittals and representations that sellers using the simultaneous TTC method must provide to the Commission.

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[238] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 172.

[239] *Id.* P 173 (citing *Atlantic Renewables Projects II*, 135 FERC ¶ 61,227, at P 9 (2011)).

d. Other Issues

i. Comments

190. Solomon/Arenchild seek several clarifications relating to the determination of the SIL and its application in the indicative screens versus a DPT analysis. First, they state that the SIL value for the indicative screens is calculated for four seasonal peaks (Winter, Spring, Summer, and Fall), whereas the DPT analysis typically evaluates a "Shoulder" season that combines Spring and Fall. Solomon/Arenchild seek that the Commission clarify that the DPT analysis of a "Shoulder" season should use the average of the Spring and Fall values, unless it can be demonstrated that facts exist to support use of either Spring or Fall values alone for the Shoulder season.

191. Second, Solomon/Arenchild state that, in their experience, the SIL values used in the DPT and those reported in the SIL submittals may legitimately differ as a direct result of underlying differences between the DPT and the indicative screens related to the treatment of long-term transmission reservations. Solomon/Arenchild ask that the Commission clarify that it is appropriate when calculating the SIL values used in the DPT analysis not to deduct any associated long-term transmission for a remote generating facility during a period when such generation is not fully available or not economic (or, alternatively, to increase the SIL to reflect additional import capacity).

192. Finally, Solomon/Arenchild seek clarification of the definition of "long-term firm transmission contracts." According to Solomon/Arenchild, the Commission's current regulations define transmission contracts with a term of 28 days or more as "long-term" and direct that such contracts be reflected in the SIL analysis. However,

Solomon/Arenchild assert that such contracts may be excluded in the indicative screen analysis and/or the DPT because they do not meet the definition of "long-term" as being one year or longer, as used for analyzing energy markets. While they recognize that both the SILs and the indicative screens are intended to depict an accurate historical representation of markets, Solomon/Arenchild contend that including only transmission reservations with durations of one year or longer provides a more robust analysis. Accordingly, Solomon/Arenchild suggest that the Commission clarify that only long-term contracts, including seasonal contracts, that are one year or longer be included in both the SIL study and the indicative screen and/or DPT analyses.[240]

193. EEI states it is concerned with the volume of clarifications in the Commission's proposal regarding SIL studies. EEI encourages the Commission to engage in further dialogue with the regulated community about the proposed changes, to ensure that the changes are reasonable, clear, accurate, and easy to implement. Additionally, EEI expresses concern that some of its members are already being required to make changes in their SIL analyses.[241]

194. Southeast Transmission Owners support EEI's request for the Commission to further caucus with industry regarding SIL studies. Given the complexities underlying the market-based rate program and the fact that industry's most recent round of triennial updated market power analysis filings will continue until June 2016, Southeast

[240] Solomon/Arenchild at 14-15.

[241] EEI at 21.

Transmission Owners state that the Commission does not need to rush action with regard to these proposals.[242] Further, Southeast Transmission Owners are concerned that the Commission's proposals may cause confusion among sellers, rather than the intended goal of streamlining the market-based rate program, and may result in less reliable SIL values.

195. SoCal Edison recommends that the Commission require each RTO/ISO, and the CAISO in particular, to perform a SIL study for common use.

ii. <u>Commission Determination</u>

196. We find Solomon/Arenchild's request for clarification regarding which Spring and Fall SIL values to use for the DPT analysis to be beyond the scope of this rulemaking proceeding. We also find their request for clarification regarding calculation of the SIL values used in the DPT analysis to be beyond the scope of this rulemaking proceeding.

197. Additionally, we decline Solomon/Arenchild's request to redefine the applicable duration of long-term firm transmission reservations, currently defined as 28 days or longer, for purposes of the SIL study as this would inflate the amount of import capability available on a long-term basis. Solomon/Arenchild have not demonstrated why the Commission should change the definition for purposes of the SIL study. Indeed, the power flow cases utilized for SIL studies are a reflection of seasonal peaks such that a "monthly" designation for such reservations appropriately captures this designation.

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[242] Southeast Transmission Owners at 6-7 (citing NOPR, FERC Stats. & Regs. ¶ 32,702 at app. C).

198. With regard to concerns about the volume and complexity of changes, we remind commenters that the proposed rule is primarily a clarification of existing policy and that the need for this clarification was based in part on a lack of specificity resulting in confusion with the SIL study process. To the extent sellers remain confused about any aspect of the Commission's instructions regarding SIL studies, Commission staff will continue to be available to discuss these issues prior to an applicant submitting its filing.

199. In response to SoCal Edison's request for the Commission to require each RTO/ISO to perform a SIL study for common use, the RTOs/ISOs do not have market-based rate tariffs on file; thus, we will not require SIL studies from RTOs/ISOs.

B. Vertical Market Power—Land Acquisition Reporting

1. Commission Proposal

200. In the NOPR, the Commission noted that all market-based rate sellers currently are required to provide, as part of their vertical market power analysis, a description of their ownership or control of, or affiliation with an entity that owns or controls, sites for generation capacity development[243] and to file notices of change in status on a quarterly basis when they acquire sites for new generation capacity development.[244] The Commission noted that in the more than six years since issuance of Order No. 697, not a single protest had been filed in response to disclosures regarding sites for new generation capacity development and it proposed to eliminate the requirement that

[243] 18 CFR 35.37(e)(2).

[244] 18 CFR 35.42(d).

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 (land acquisition reporting requirements) because the burden of such reporting outweighs the benefits.[245] The Commission noted that, if there is a concern that a particular seller's sites for generation capacity development may be creating a barrier to entry, the Commission can request additional information from the seller at any time.[246]

201. Thus, the Commission proposed to revise the regulations at 18 CFR 35.42 relating to change in status reporting requirements to remove paragraph (d). This proposed revision would remove the requirement that sellers report the acquisition of control of a site or sites for new generation capacity development for which site control has been demonstrated. Likewise, the Commission proposed to revise the regulations at 18 CFR 35.42 to remove paragraph (e), which pertains to the definition of site control for purposes of paragraph (d). In addition, the Commission proposed to revise 18 CFR 35.42 at paragraph (b) to remove the reference to the reporting of acquisition of control

[245] For example, the Commission received, from the second quarter in 2012 to the fourth quarter in 2013, approximately 90 filings from 1,380 filers. This is a reporting burden on sellers and an inefficient use of Commission resources for information that has yet to produce an actionable item or elicit a single comment in almost five years.

[246] *See* Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 at P 23 ("[I]f there is a concern that a particular seller may be acquiring land for the purpose of preventing new generation capacity from being developed on that land, the Commission can request additional information from the seller at any time.").

of a site or sites for new generation capacity development. The Commission also proposed to revise the market power analysis regulations at 18 CFR 35.37 to remove paragraph (e)(2), which requires sellers to provide information regarding sites for generation capacity development to demonstrate a lack of vertical market power.

2. <u>Comments</u>

202. Several commenters support the Commission's proposal to eliminate the land acquisition reporting requirements.[247] These commenters contend that the reporting obligation is unnecessary and unduly burdensome, with little benefit, particularly given that in the last six years intervenors have not challenged whether sites for new generation capacity development created a barrier to entry.[248]

203. EPSA and NRG Companies note that the purpose of the initial applications, triennial updates, and notices of change in status, is to identify for the Commission material facts and changes relevant to a seller's qualification for market-based rate authority. EPSA and NRG Companies state that requirements that sellers file quarterly land acquisition reports fail to further the purpose of the triennial updates and notices of change in status filings.[249] NRG Companies add that there is no reason to think that these reports would ever provide information that would call into question the validity of "the

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[247] *See, e.g.*, AEP at 5-7; E.ON at 7-8; EEI at 13; EPSA at 7; FirstEnergy at 9; NRG Companies at 7-8; NextEra at 10.

[248] *See* E.ON at 7-8; EEI at 13; FirstEnergy at 9; NextEra at 10.

[249] EPSA at 7; NRG Companies at 7-8.

rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls . . . sites for generation capacity development . . . ."[250] As such, EPSA states that the Commission's proposal furthers the Commission's stated goal of reducing the regulatory burdens on market-based rate sellers.[251]

204. NextEra asserts that, in addition to being burdensome, the reports have limited value because the land acquisition reporting requirements do not allow the netting of generation in the interconnection queue when a market-based rate seller withdraws a proposed project from the interconnection queue or places a new project in-service. According to NextEra, as a result, the information on file with the Commission does not accurately reflect actual site control in the interconnection process and the quarterly reports provide little useful information to the Commission or the public.[252]

205. On the other hand, other commenters oppose removing the land acquisition reporting requirements.[253] They argue that the fact that in the last six years intervenors have not challenged whether sites for new generation capacity development created a barrier to entry is not a reason for the Commission to ignore the issue in the future. AAI

[250] NRG Companies at 7-8 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 446).

[251] EPSA at 7.

[252] NextEra at 10.

[253] AAI at 10-12; APPA/NRECA at 26-27; TAPS at 2.

argues that, due to the relative scarcity of land suitable for renewable energy development, incumbents can erect barriers to entry through strategic generation site acquisitions, i.e., accumulate renewable energy sites with the aim of preventing rivals from developing them. Further, AAI states that the composition of generation in the United States may be on the cusp of radical restructuring, pointing to state enacted Renewable Portfolio Standards and the United States Environmental Protection Agency's rulemaking to reduce greenhouse gas emissions from new and existing power plants.[254] According to AAI, for the intended change in the generation fleet to occur, barriers to entry, including access to generation sites, must be minimized. AAI states that the Commission should continue to collect data on the acquisition of generation sites and recommends using a comprehensive database, as opposed to relying on complaints of affected parties, to monitor this issue in a systematic fashion. Lastly, AAI states that, given the anticipated high growth in renewable energy, revising land acquisition and generation capacity development reporting rules would be premature.

206. Similarly, APPA/NRECA states that a number of economic, technological, and regulatory factors are inducing the retirement of substantial coal generation and the construction of substantial new gas-fired and renewable generation in the coming years.

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[254] AAI at 11-12 (citing U.S. Energy Info. Admin., Most States Have Renewable Portfolio Standards, Feb. 3, 2012, *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=4850; Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014) (to be codified at 40 CFR pt. 60)).

APPA/NRECA asserts that where this new generation will be located will be an important issue because most of the new generation will be location-constrained renewable resources. Further, APPA/NRECA asserts that, because of constraints on gas pipeline capacity, the location of gas-fired generation sites relative to existing and proposed gas pipelines is also critical. Lastly, APPA/NRECA asserts that the retirement of coal generation can change the economic and reliability factors that will determine where new generation may be located. APPA/NRECA warns that, because the location of new generation build-out may have important economic consequences, the Commission should not ignore the barriers to entry created by the acquisition of new generation sites.[255] TAPS supports APPA/NRECA's comments with respect to land acquisition reporting. TAPS opposes the proposed elimination of the land acquisition reporting requirement given the current dramatic changes in generation resource mixes, and in particular, the potential importance of access to gas pipeline facilities.[256]

3. Commission Determination

207. We adopt the NOPR proposal to eliminate the land acquisition reporting requirements.

208. We continue to find that the current land acquisition reporting is of limited value in assessing barriers to entry. The existing land acquisition reports include: (1) the number of sites acquired; (2) the relevant geographic market in which the sites are

[255] APPA/NRECA at 26-27.

[256] TAPS at 2.

located; and (3) the maximum potential number of megawatts that are reasonably commercially feasible on the sites reported.[257] Thus, the reports identify relevant geographic market/balancing authority areas, but such reports do not indicate specific locations or whether the sites are adjacent to the existing transmission grid or natural gas pipelines. Moreover, the reports do not include any metrics or analyses to indicate whether the seller's land acquisitions provide it with control over a sufficient amount of sites to create a potential barrier to entry within a geographic market.

209. As noted above, the land acquisition reporting requirements are burdensome for sellers and yield little, if any, offsetting benefit. Out of 58 filings of land acquisition reports from the fourth quarter in 2013 to the first quarter in 2015, none has been contested or has provided sellers and the Commission with useful information regarding barriers to entry.[258] No one has used the information in a land acquisition report in a comment or protest challenging the market-based rate authority of any seller.

210. In response to the concerns raised by AAI and APPA/NRECA, we clarify that intervenors are free to challenge an applicant's claims that it has not erected barriers to entry. We also reiterate that the Commission retains the right to request additional information on such potential barriers to entry from the seller at any time if it has reason to believe that a seller's acquisition of land has created a barrier to entry or otherwise

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[257] 18 CFR § 35.42(d).

[258] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 89 n.109.

been used to exercise vertical market power.[259] Furthermore, the Commission will continue to require market-based rate sellers to affirmatively state that they and their affiliates have not and will not raise any barriers to entry in the relevant market, including of land acquisitions, as part of the Commission's vertical market power analysis required in initial applications, triennials, and notices of change in status that affect the vertical market power analysis.

211. Finally, AAI suggests that the Commission utilize a comprehensive database to monitor the acquisition of generation sites in a systematic fashion. However, the Commission did not propose any refinements to the information collected in land acquisition reports but rather the elimination of the requirement. The comprehensive database recommended by AAI would be a major undertaking with uncertain benefits, for the reasons stated above, and is beyond the scope of this rulemaking. For these reasons, we reject this request.

212. We adopt the NOPR proposal to revise the regulations at 18 CFR 35.42 relating to the change in status reporting requirements to remove paragraph (d), the requirement that sellers report the acquisition of control of a site or sites for new generation capacity development for which site control has been demonstrated. We will also remove paragraph (e), which pertains to the definition of site control for purposes of paragraph

[259] *See* Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 at P 23 ("[I]f there is a concern that a particular seller may be acquiring land for the purpose of preventing new generation capacity from being developed on that land, the Commission can request additional information from the seller at any time.").

(d), and revise paragraph (b) to remove the reference to the reporting of acquisition of control of a site or sites for new generation capacity development. Further, we adopt the NOPR proposal to revise the market power analysis regulations at 18 CFR 35.37 to remove paragraph (e)(2), which requires sellers to provide information regarding sites for generation capacity development to demonstrate a lack of vertical market power.

C. Notices of Change in Status

1. Geographic Focus

a. Commission Proposal

213. In Order No. 697-A, the Commission clarified that sellers must report a change in status when they acquire 100 MW or more in the "geographic market that was the subject of the horizontal market power analysis on which the Commission relied in granting the seller market-based rate authority."[260] In the NOPR, the Commission proposed to clarify that the 100 MW reporting threshold in section 35.42(a)(1) is not limited only to markets previously studied. The Commission proposed that, if a seller acquires generation that would cause a cumulative net increase of 100 MW or more in any relevant geographic market (including generation in both the relevant geographic market itself and any first-tier/interconnected market with the potential to import into that market) since the seller's most recent triennial updated market power analysis or change in status filing, the seller must make a change in status filing. This would include cumulative increases of 100 MW or more in a new market that has not

[260] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 512.

previously been studied because, once the seller has generation in that market, it is a relevant geographic market for that seller. The Commission clarified that a net increase measures the difference between increases and decreases in affiliated generation.

214. In Order No. 697-A, the Commission also provided the following example, "if a seller has a net increase of 50 MW in the geographic market on which the Commission relied in granting the seller market-based rate authority and 50 MW increase in a different geographic market that is in the same region . . . , the 100 MW or more threshold would not be met because the increase in generation capacity is less than [100] MW in each generation market and, accordingly, a change in status filing would not be required."[261] In the NOPR, the Commission clarified that this example described a situation where the geographic market on which the Commission relied in granting market-based rate authority was not first-tier to the geographic market in which the seller acquired an additional 50 MW. Thus, the Commission proposed to clarify that the 100 MW threshold applies to the cumulative capacity added in any relevant geographic market, including what can be imported from first-tier markets, but does not cover situations where a seller acquires less than 100 MW in one market and less than 100 MW in another market, as long as those two markets are not first-tier to each other.

215. The Commission further proposed to require that the 100 MW threshold requirement for change in status filings be calculated based on a generator's nameplate

[261] *Id.*

capacity rating because it is a single value, it exists for all types of generators, it is generally a more conservative value than a seasonal or five-year average rating would be, and it allows for uniform measurements across different types of generators.

216. The Commission proposed to revise the regulatory text in section 35.42(a)(1) of the Commission's regulations to provide greater clarity and direction on this topic.

b. **Comments**

217. Several commenters object to the Commission's proposal to consider cumulative net increases of 100 MW or more of nameplate capacity in any relevant geographic market as well as any first-tier/interconnected market with the potential to import into that market when determining whether to report a change in status.[262] Solomon/Arenchild and NextEra argue that the proposed change significantly broadens the market definition captured in the metric of what constitutes a net 100 MW change in generation capacity.[263] Solomon/Arenchild and NextEra contend that the current proposal implies that a megawatt outside of the market is equivalent to a megawatt inside of the market, which is not the case.[264] Solomon/Arenchild and NextEra further

[262] *See, e.g.*, Solomon/Arenchild at 4; NextEra at 11; E.ON at 10; EEI at 14. *But see* APPA/NRECA (supporting the Commission's proposal); Golden Spread at 7 (supporting the eleven Commission proposals that APPA/NRECA supports, which are listed on pages 4-5 of the APPA/NRECA joint comments).

[263] Solomon/Arenchild at 4; NextEra at 11.

[264] Solomon/Arenchild at 4; NextEra at 11 (stating that the proposal appears to assume that 100 MW (or even one megawatt) added to a first-tier market should be treated no differently than 100 MW added in the relevant geographic market).

argue that the Commission's proposal reinstates the "hub and spoke" methodology, which attributed all capacity controlled by the seller and its affiliates in the relevant and first-tier markets to the seller, and was properly disposed of by the Commission because megawatts added in first-tier markets cannot necessarily be imported, unless there is a firm transmission reservation, which is a distinction the proposal fails to address.[265] Solomon/Arenchild propose corresponding revisions to the Commission's proposed regulatory text.[266]

218. EEI contends that the Commission should not attribute changes in generation in one market to another market, even if the markets are first-tier to one another.[267] EEI explains that the 100 MW threshold should be measured for each market separately, without adding changes in first-tier markets, for two reasons.[268] First, the focus of the Commission's market power analyses has always been on the default balancing authority area or other market in which market-based rate authorization is sought, informed by transmission capability to import generation into that market, but not by generation ownership in adjacent markets.[269] EEI argues that there seems to be little reason to expand the change in status reporting requirement to mix changes in

[265] Solomon/Arenchild at 4; NextEra at 11.

[266] Solomon/Arenchild at 5.

[267] EEI at 14.

[268] *Id.*

[269] *Id.*

generation ownership in the relevant geographic market and the adjacent first-tier markets, which would be the subject of a separate study if market-based rate authorization is sought in those markets.[270] Second, EEI is concerned that the expansion of the change in status reporting requirement for generation ownership to account for generation in the first-tier markets would create confusion.[271] EEI states that this would complicate the tracking of generation and the application of the 100 MW threshold in the various markets and will not produce commensurate benefits.[272] EEI therefore proposes that each market should be treated independently for the purpose of change in status reporting.[273] EPSA adds that any increase in megawatts in a first-tier market would already be reflected in the analysis of that particular first-tier market and argues that amending the current regulations to require sellers to account for such increases separately would be redundant and serve to substantially increase the burden on such sellers.[274]

219. E.ON notes that the Commission proposes to require a seller to notify the Commission when it becomes affiliated with "100 MW or more in *any* relevant

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[270] *Id.*

[271] *Id.*

[272] *Id.*

[273] *Id.* at 15. EPSA also argues that the proposal would complicate the tracking of generation and similarly recommends that the Commission to treat each market separately. EPSA at 8.

[274] EPSA at 9.

geographic market"[275] and requests the Commission clarify that the "any relevant market" language is limited to the applicable geographic region and applicable first-tier markets.[276] E.ON further notes that the Commission states in the NOPR that this notification requirement would extend to "cumulative increases of 100 MW or more in a new market that has not previously been studied because, once the seller has generation in that market, it is a relevant geographic market for that seller"[277] and states that it struggles to understand the benefit of this extended notification requirement and the Commission's definition of a new "relevant" market.[278]

220. Several commenters oppose the Commission's proposal to use nameplate capacity to calculate the 100 MW change in status threshold.[279] Solomon/Arenchild argue that the proposal creates a disconnect between the asset appendix capacity ratings and indicative screens capacity ratings because most indicative screens are based on seasonal (summer/winter), not nameplate, ratings, and many sellers report summer

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[275] E.ON at 10 (citing NOPR, FERC Stats. & Regs. ¶ 32,702 at P 96) (emphasis added by E.ON).

[276] *Id.* at 10. E.ON uses the following example: If a seller owns or controls a generation facility in PJM and obtained market-based rate authorization, the fact that a new affiliate may own or control 100 MW or more of new generation in the CAISO market has no relevance to whether the seller in PJM lacks horizontal market power.

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

[278] *Id.*

[279] *See, e.g.*, Solomon/Arenchild at 3; EEI at 15; EPSA at 8-9; E.ON at 13; Idaho Power at 3-4.

ratings only in their asset appendix.[280] Solomon/Arenchild therefore propose that the Commission allow sellers to use either nameplate or seasonal ratings and, if applicable, five-year averages, for determining the 100 MW threshold for the notice of change in status.[281] Solomon/Arenchild and EEI argue that the Commission should allow energy-limited resources, in particular, to report five-year averages.[282]

221. Similarly, E.ON states that, if an affiliate of a market-based rate seller acquires an interest in or builds 100 MW or more of energy-limited generation, the Commission may already have on file five years of historical average capacity ratings or EIA-derived data for the energy-limited generation and argues that it would be a "mismatch" to apply nameplate rating to the energy-limited generation for the purposes of triggering any notice of change in status filing requirement.[283] Therefore, E.ON requests that, to the extent the 100 MW threshold remains, the Commission revise its regulations in section 35.42(a)(1) to provide that a market-based rate seller submit a notice of change in status where there are "cumulative net increases . . . of 100 MW or more of nameplate capacity *or as otherwise has been reported to the Commission*."[284] Idaho Power adds that while using nameplate ratings across all generation types may provide consistency, it does not

[280] Solomon/Arenchild at 3.

[281] *Id.*

[282] *Id.*; EEI at 15.

[283] E.ON at 13.

[284] *Id.* E.ON's proposed change is illustrated in italics.

provide a proper basis for evaluation when comparing, for example, variable generation (i.e., wind, solar) with thermal generation (i.e., natural gas).[285]

222. Other commenters argue that notices of change in status need not be filed in certain circumstances.[286] FirstEnergy argues that the Commission's approval of a transaction under section 203 of the FPA should obviate the need for a subsequent change in status report and further Commission review under section 205 of the FPA.[287] FirstEnergy states that it is unaware of any instance in which the Commission authorized a merger of generation facilities under section 203 of the FPA and later found that the merged entity fails the standard for selling electricity at market-based rates in any relevant geographic market.[288] FirstEnergy further claims that its recommendation will reduce the regulatory burden on sellers without adversely affecting the Commission's ability to protect consumers.[289]

223. Additionally, AEP and E.ON argue that the Commission should eliminate altogether the notice of change in status requirement for sellers within RTOs. AEP explains that, to the extent market power concerns are implicated by a market-based rate seller's acquisition or new affiliation, the extensive Commission-approved RTO market

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[285] Idaho Power at 3-4.

[286] *See, e.g.*, FirstEnergy at 10, 11; AEP at 6; E.ON at 8-9, 11.

[287] FirstEnergy at 10.

[288] *Id.*

[289] *Id.* at 11.

monitoring and mitigation rules adequately prevent the exercise of market power without the need for the seller to file an additional report.[290]

224. E.ON requests that the Commission clarify that a notice of change in status filing is not necessary where an affiliate of a market-based rate seller is granted market-based rate authorization.[291] E.ON also recommends that the Commission revise its policies so that only one substantive filing is submitted to the Commission.[292]

225. NextEra claims that this notice of change in status proposal is confusing in light of another NOPR proposal to eliminate the requirement to provide indicative screens where all of a seller's and its affiliates' generation in the relevant market is committed under long-term power purchase agreements.[293] NextEra states that the proposed revised text of section 35.42(a)(1) of the Commission's regulations provides only a bright line test for notices of change in status based on nameplate capacity in the relevant geographic market and first-tier markets, thus ignoring the long-term power purchase agreements.[294] NextEra suggests that, if the Commission adopts this new

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[290] AEP at 6. E.ON makes similar arguments. *See* E.ON at 8-9 (emphasizing that the notice of change in status would simply repeat what the market-based rate seller has already told the Commission, namely, that the market-based rate seller is relying on RTO mitigation).

[291] E.ON at 11.

[292] *Id.* (arguing that an initial market-based rate application of the new affiliate should suffice to address all other relevant, affiliated market-based sellers).

[293] NextEra at 11.

[294] *Id.*

requirement, it should explain how section 35.42(a) of the Commission's regulation should be interpreted when generation is subject to a long-term power purchase agreement.[295] EEI encourages the Commission to find additional ways to streamline the change in status reporting requirements. EEI offers two examples: (1) the Commission should indicate that minor changes in organization or other information covered by the change in status reporting requirements need not be reported individually but can be cumulated to include with a next change in status filing, and (2) the Commission should consider providing additional relief from change in status reporting to companies based on the Commission's experience with the change in status requirements over the past decade (e.g., the Commission should consider increasing the 100 MW thresholds).[296]

226. EPSA notes that sellers are required to report a change in status when an additional 100 MW in a relevant geographic market is attained, but states that it is unclear whether the change in status reporting requirement is then "reset" and a notice of change in status is necessary when another 100 MW of controlled generation is obtained, or once the 100 MW threshold is attained, if all new controlled generation in excess of 100 MW must be reported.[297] EPSA seeks clarification that a notice of change

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[295] *Id.* at 12.

[296] EEI at 16.

[297] EPSA at 11-12.

in status must be submitted each time a seller attains a cumulative 100 MW of controlled generation.[298]

227. FirstEnergy recommends that, in addition to the proposal to relieve RTO/ISO sellers from the obligation to file the indicative screens, the Commission should relieve RTO/ISO sellers from the obligation to submit notices of change in status relating to increases in generation capacity. Similarly, AEP recommends that the Commission relieve RTO/ISO sellers from the obligation to submit notices of change in status altogether. EEI encourages the Commission to consider providing broader relief from change in status reporting to utilities with FERC-approved market power mitigation measures to reduce the burden associated with the market-based rate program. EEI states that the same principles underlying the proposed exemption of sellers with FERC-approved market power mitigation from providing the indicative horizontal market screens in their market power updates could apply equally to the overall change in status reporting requirements.

c. Commission Determination

228. We adopt the NOPR proposal with certain modifications and clarifications. In the NOPR, the Commission proposed to apply the 100 MW threshold to a seller's and/or its affiliates' generation capacity in each relevant market and first tier market(s), and to also apply the 100 MW threshold to each new relevant market (not previously studied) in which a seller and/or its affiliates acquire a cumulative net increase of 100 MW. The

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[298] *Id.*

NOPR also proposed to require that the 100 MW threshold for change in status filings be calculated based solely on a generator's nameplate capacity rating.

229. We believe that the Solomon/Arenchild and NextEra comments with respect to the calculation of the 100 MW threshold have merit[299] and that generation capacity in the first tier markets should not be treated the same as capacity located in the seller's relevant geographic market/study area. We recognize that 100 MW located outside of the study area is only equivalent to 100 MW inside when there is a long-term firm transmission reservation to import the 100 MW.

230. Therefore, we will modify the proposal set forth in the NOPR. The 100 MW threshold for reporting a change in status will apply to a seller's and/or its affiliates' net generation capacity additions in each individual market, but will exclude markets and balancing authority areas that are first-tier to the seller's study area. This means a seller need not consider its and its affiliates new generation, including generation from long-term purchase agreements, in first-tier areas in determining whether it has reached the 100 MW threshold.

231. However, we confirm that, consistent with the NOPR, 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. To find otherwise would allow a loophole where an applicant could request and be granted market-based rate authority

[299] NextEra at 11; Solomon/Arenchild at 4.

with a small amount of generation in one market, qualify as a Category 1 seller, and then accumulate large amounts of generation in other markets in the same region such that the seller could become Category 2 in the region without notifying the Commission. In addition, applying the 100 MW threshold to each new relevant market ensures that sellers study the generation acquired in any additional market that meets or exceeds this threshold.

232. Further, we believe that the comments opposing the Commission's proposal to require use of nameplate capacity to calculate the 100 MW change in status threshold have merit.[300] Therefore, we will revise the NOPR proposal and 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.[301]

233. We disagree with FirstEnergy's contention that section 203 approvals should obviate the need for subsequent change in status filings for further Commission review under section 205. The Commission's analyses under sections 203 and 205 consider different criteria for approving transactions; therefore, it is not a given that a seller that passes a section 203 analysis will pass a section 205 analysis. Furthermore, the data

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[300] *E.g.*, E.ON at 13 ; EEI at 15; Idaho Power at 3-4; Solomon/Arenchild at 3.

[301] However, consistent with our finding in this Final Rule regarding use of nameplate capacity for solar photovoltaic facilities, for change in status threshold purposes, sellers should use nameplate capacity for such facilities. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 104.

required for the Commission's analyses under FPA sections 203 and 205 differ; section 203 filings are prospective, with studies based on projected data, whereas the change in status filings under section 205 require studies based on historical data.

234. Additionally, we reject AEP's, E.ON's, FirstEnergy's, AEP's, and EEI's requests that the Commission eliminate the change in status requirements for sellers located in RTOs/ISOs.[302] AEP states that the Commission-approved market monitoring and mitigation rules adequately prevent the exercise of market power without the need for the seller to file an additional report.[303] As explained above, we are not prepared at this time to adopt the NOPR proposal to relieve sellers in RTO/ISO markets of the obligation to file indicative screens.[304] Therefore, we will not relieve sellers in RTO/ISO markets of their obligation to file notices of change in status.

235. We reject EEI's request to report minor changes in organization or other information covered by the change in status requirements cumulatively with another change in status filing instead of in separate change in status filings. Any change in other information covered by the change in status requirements must be reported within 30 days of the change. We interpret EEI's request to be that "minor change" be permitted to be filed more than 30 days after the change, i.e., at the time of the next change in status

[302] AEP at 3; E.ON at 8-9.

[303] AEP at 6.

[304] Moreover, we note that the NOPR did not propose to completely eliminate the requirement for RTO sellers to file triennial updated market power analyses but instead proposed to eliminate the need to file indicative screens with their triennials.

filing. Timely notice of reportable changes in status are part of the Commission's *ex post* analysis;[305] it is not appropriate to exempt any changes from being reported within 30 days, particularly given that it is unclear when, if at all, those changes would ever be reported.

236. Additionally, we reject EEI's proposal to increase the 100 MW change in status reporting threshold.[306] We believe that the 100 MW threshold is reasonable, particularly given the trend towards building smaller units. Further, changing the value of the megawatt threshold was not proposed in the NOPR; thus, the proposal is outside the scope of this rulemaking.

237. With regard to E.ON's request that the Commission clarify that the "any relevant market" language is limited to the applicable geographic region and applicable first-tier markets,[307] we clarify that *any relevant market* refers to a market in which a seller

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[305] *Cal. ex rel. Harris v. FERC.*, 784 F.3d 1267, 1276 (9th Cir. 2015) ("When we approved market-based ratemaking in *Lockyer*, we repeatedly emphasized the importance of the 'dual requirement of an ex ante finding of the absence of market power *and* sufficient post-approval reporting requirements.'" (citing *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004)).

[306] EEI at 16.

[307] E.ON at 10. E.ON uses the following example: If a seller owns or controls a generation facility in the PJM market and obtained market-based rate authorization, the fact that a new affiliate may own or control 100 MW or more of new generation in the CAISO market has no relevance to whether the seller in the PJM market lacks horizontal market power.

already has generation located and acquires an additional 100 MW or a new market that the seller had not studied previously.

238. Additionally, in response to E.ON's requests that the Commission clarify if a seller needs to submit a change in status if it acquires generation in an RTO market where it sells energy products, and clarify whether a seller has to file a change in status when an affiliate is granted market-based rate authority, we clarify as follows. A seller should submit a change in status when it acquires generation in any market, including an RTO market where it sells electric products. Further, if a seller's affiliate is granted market-based rate authority, and that results in 100 MW or more of new generation capacity in a market, then the seller will have to file a corresponding change in status. Therefore, we reject E.ON's recommendation to revise the change in status policy so that only one substantive filing is submitted to the Commission.[308]

239. In response to NextEra's contention that the notice of change in status proposal is confusing because it conflicts with the NOPR proposal to eliminate the requirement to provide indicative screens where all of a seller's and its affiliates' generation in the relevant market is committed under long-term power purchase agreements, we clarify as follows.[309] For purposes of the change in status requirement in section 35.42(a)(1), long-term firm purchases should be treated as seller or affiliate-owned or controlled

[308] E.ON at 11 (arguing that an initial market-based rate application of the new affiliate should suffice to address all other relevant, affiliated market-based sellers).

[309] NextEra at 11.

generation capacity in the determination of the 100 MW threshold. Thus, a seller need not make a change in status filing every time it enters into a new long-term firm purchase agreement, but would need to submit a change is status when its overall cumulative increase in generation is 100 MW. The seller would need to revise its asset appendix to include the long-term purchase agreement(s). In addition, we clarify that a market-based rate seller that adds new generation capacity that is fully committed to a non-affiliated buyer need not count that capacity toward the 100 MW threshold.

240. We clarify in response to EPSA that if a seller acquires more than 100 MW, it should report all of the newly acquired generation to ensure that the net change in generation capacity is reported in a timely manner. Furthermore, once a seller files a change in status for a net increase of 100 MW or more of generation capacity, the threshold is effectively reset such that the seller must file a change in status each time it acquires an additional 100 MW or more of generation capacity.

2. New Affiliation and Behind-the-Meter Generation

a. Commission Proposal

241. Market-based rate sellers are required to make a change in status filing when, among other requirements in section 35.42 of the Commission's regulations, they become affiliated with entities that: (1) own or control generation; (2) own or control inputs to electric power production; (3) own, operate, or control transmission facilities; or (4) have a franchised service territory. There currently is no 100 MW threshold for reporting new affiliations (but there is a 100 MW threshold for net increases for a seller's owned or controlled generation facilities). In the NOPR, the Commission proposed to revise the

change in status regulations to include a 100 MW threshold for reporting new affiliations. That is, 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. The Commission noted that the 100 MW threshold for reporting new generation strikes the proper balance between the Commission's duty to ensure that market-based rates are just and reasonable and the Commission's desire not to impose an undue regulatory burden on market-based rate sellers.[310] Similarly, the Commission stated that applying the 100 MW threshold to new affiliations might ease the reporting burden on sellers without diminishing the Commission's ability to identify possible market power. Therefore, the Commission proposed to revise section 35.42(a)(2) of the Commission's regulations to add a 100 MW threshold for reporting certain new affiliations.

242. The Commission also clarified that the requirement to submit a notice of change in status to report affiliation with new generation, transmission, or intrastate gas pipelines includes reporting that asset in the seller's asset appendix. The Commission proposed to amend section 35.42(c) to clarify that sellers must include all new affiliates and any assets owned or controlled by the new affiliates in the asset appendix.

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[310] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, Order No. 652, FERC Stats. & Regs. ¶ 31,175, at P 68, *order on reh'g*, 111 FERC ¶ 61,413 (2005).

243. The Commission further proposed in the NOPR that "all assets" include behind-the-meter generation and qualifying facilities.[311] However, the Commission proposed to allow sellers to aggregate their behind-the-meter generation by balancing authority area or market into one line on the list of generation assets. Similarly, the Commission proposed to allow sellers to aggregate their qualifying facilities under 20 MW by balancing authority area or market into one line on the list of generation assets.

244. The Commission also proposed that sellers should include these assets in their indicative screens, as well as in their asset appendix and that sellers should include this generation when calculating the 100 MW change in status threshold and the 500 MW Category 1 threshold.

b. <u>Comments</u>

245. Commenters generally support the Commission's proposal to revise the change in status regulations to include a 100 MW threshold for reporting new affiliations.[312] Specifically, EEI supports the Commission's proposal and adds that the

[311] Accordingly, the appendix must list all generation assets owned (clearly identifying which affiliate owns which asset) or controlled (clearly identifying which affiliate controls which asset) by the corporate family by balancing authority area, and by geographic region, and provide the in-service date and nameplate or seasonal ratings by unit. As a general rule, any generation assets included in a seller's market power study should be listed in the asset appendix. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 895.

[312] *See, e.g.*, EEI at 15-16; FirstEnergy at 11-12; SunEdison at 9 (noting that this proposal is especially important to a company like SunEdison that routinely acquires or becomes affiliated with new entities that own small amounts of capacity); NRG Companies at 11-12; APPA/NRECA at 4; Golden Spread at 7.

Commission should consider allowing a seller the option to file an addendum to its Appendix B asset list with the change in status filing, instead of a complete new list, to show the specific changes in generation.[313] FirstEnergy also supports the Commission's proposal, but argues that, if the new affiliation has previously been reviewed by the Commission pursuant to its authority under section 203 of the FPA, the Commission will derive no significant benefit by requiring the seller to submit a notice of change in status relating to such affiliation and recommends that the reporting requirement be further limited.[314]

246. FirstEnergy supports the proposal to require generating capacity associated with qualifying facilities and behind-the-meter generation to be considered when determining the applicability of the Commission's rules for filing notices of change in status and updated market power analyses.[315] FirstEnergy contends that, to the extent qualifying facilities may be owned by or affiliated with entities owning other generation resources, there is no valid reason why owners of qualifying facilities and/or behind-the-meter generation resources should not be subject to the same rules as those applicable to other market participants.[316]

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[313] EEI at 16.

[314] FirstEnergy at 11.

[315] *Id.* at 12.

[316] *Id.*

247. Several commenters oppose the Commission's proposal to include behind-the-meter generation as part of the 100 MW change in status threshold.[317] NRG Companies and NextEra argue that requiring the inclusion of behind-the-meter generation in asset appendices and market power analyses would impose a substantial burden on sellers.[318] NRG Companies and NextEra also argue that no useful purpose will be served by the inclusion of behind-the-meter generation that is committed to on-site consumption and not available to the grid.[319] NRG Companies and NextEra add that such generation may involve net metering, which they state does not involve wholesale sales or transmission implicating the Commission's jurisdiction.[320]

248. NRG Companies, NextEra, and SunEdison argue that behind-the-meter generation does not contribute to market power and should be excluded from the asset

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[317] *See, e.g.*, NextEra at 12; NRG Companies at 2-3 (stating, however, that the proposal makes sense as to qualifying facilities); SunEdison 5-8.

[318] NRG Companies at 3 (stating that distributed generation projects can be developed and installed in very short time periods and tracking these projects with the frequency required to maintain accurate asset appendices would be burdensome on any entity whose affiliates are active in this area); NextEra at 12 (stating that the burden to include behind-the-meter generation will increase significantly, if there are numerous facilities within a corporate family).

[319] NextEra at 12-13 (stating that, because of their small size, such facilities are unlikely to affect meaningfully any evaluation of market power in the indicative screens and adding that there would be little or no value to the Commission in submitting a notice of change in status in addition to the initial applications and market power updates); NRG Companies at 2-3.

[320] NextEra at 13; NRG Companies at 2-3 (citing *Sun Edison LLC*, 129 FERC ¶ 61,146, at P 18 (2009) (*Sun Edison*)).

appendix.[321] SunEdison argues that it is inconsistent to require listing of assets that are not engaged in wholesale power sales in the interstate power market and therefore cannot and do not contribute to the seller's market share or market power.[322] SunEdison argues that, because the purpose of an asset appendix is to provide data to be used in the Commission's assessment of a seller's and its affiliates' market power in jurisdictional wholesale markets, the Commission should find that assets that do not participate in wholesale markets should not be included in the asset appendix.[323] SunEdison further contends that, since behind-the-meter facilities are not physically capable of engaging in coordinated interactions or arrangements with generation that sells power in jurisdictional markets, there is no need to include them in a seller's asset appendix.[324] SunEdison requests that, if the Commission determines it necessary to report behind-the-

[321] SunEdison at 4 (stating that the requirement will be "unduly burdensome" for a company that owns "hundreds of small behind-the-meter solar projects" and whose business plan is for it and its affiliates to develop and acquire "thousands of additional similar projects" and citing Commission precedent where the Commission held that net-metered sales do not represent jurisdictional wholesale sales or transmission). SunEdison also references the White House and U.S. Department of Energy initiative to streamline the permitting, installation, and interconnection processes and states that reducing unnecessary administrative burdens on companies that develop solar energy projects is one way to help achieve this goal. *Id.* at 4-5.

[322] *Id.* at 5.

[323] *Id.* at 7.

[324] *Id.*

meter generation in the asset appendix, it should exempt from this requirement facilities with a net capacity of one MW or less.[325]

249. El Paso recognizes the increasing role of behind-the-meter generators in wholesale power markets and does not oppose the Commission's inclusion of behind-the-meter generation in the indicative screens.[326] However, El Paso cautions the Commission to recognize that for some systems, the output of these generators will have already been reflected in the net load reported in the FERC Form No. 714 (Annual Electric Control and Planning Area Report), thus resulting in double-counting a utility's capacity and, consequently, overestimating its supply.[327] El Paso requests that the Commission further refine its reporting directive to instruct sellers to include behind-the-meter generation in their indicative screens to the extent such generation is not already netted against load for purposes of their FERC Form No. 714 reporting.[328]

250. Other commenters seek clarification of the Commission's proposed changes to the change in status reporting requirements, as they relate to behind-the-meter

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[325] *Id.* at 9 (citing *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, Order No. 732, 75 Fed. Reg. 15,950 (Mar. 30, 2010), FERC Stats. & Regs. ¶ 31,306, at P 34 (2010) and comparing its argument for why behind-the-meter generation should not be included in a seller's asset appendix to the Commission's reasoning in Order No. 732 to exempt small facilities from the Commission's Qualifying Facility status filing requirement).

[326] El Paso at 4.

[327] *Id.*

[328] *Id.*

generation. Specifically, EPSA argues that, if a seller has behind-the-meter generation that is used solely to operate equipment for production (such as an oil or gas operation that uses behind-the-meter generation to produce oil or gas), such behind-the-meter generation should not be counted towards the 100 MW threshold because that generation is never offered or sold into the market. EPSA recommends the Commission clarify that any such behind-the-meter generation that is wholly self-consumed would not count towards the 100 MW threshold.[329] SoCal Edison requests the Commission clarify whether behind-the-meter generation includes generation not synchronized to the grid (i.e., generation that cannot be used for wholesale power sales), since all generation is typically behind *some* meter.[330] SoCal Edison does not believe, for example, that a back-up generator used to power a control center in the event of a power outage needs to be included in a seller's asset appendix and seeks confirmation to that effect.[331] SoCal Edison also requests that the Commission clarify whether it will permit sellers to aggregate long-term firm purchases from small generators (such as qualifying facilities under 20 MW) by balancing authority area or market into one line on the list of

[329] EPSA at 11.

[330] SoCal Edison at 19 (emphasis in original).

[331] *Id.*

generation assets.[332] SoCal Edison argues that such aggregation should be permitted to relieve the burden that otherwise would be imposed.[333]

c. **Commission Determination**

251. We adopt the NOPR proposal to establish a 100 MW threshold for reporting new affiliations in change of status filings. 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.[334] The 100 MW threshold for new affiliations will be determined in exactly the same manner as the 100 MW threshold is determined for other notices of change in status. As explained above, the 100 MW threshold will be determined for each relevant geographic market but will not consider generation capacity additions in first-tier markets. We believe the 100 MW threshold strikes a reasonable balance between reducing reporting burden on sellers while keeping the Commission informed about potential market power concerns. We clarify that the 100 MW reporting threshold for new affiliations is not separate nor distinct from the 100 MW thresholds for reporting power purchase agreements or owned generation as

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[332] *Id.* at 23.

[333] *Id.*

[334] However, 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.

discussed elsewhere in this Final Rule. In other words, if a seller becomes newly affiliated with 50 MW of generation in a balancing authority area or market and experiences an increase of 50 MW of owned generation in that same balancing authority area or market, the 100 MW reporting threshold would be triggered. Similarly, a seller with a newly acquired 50 MW power purchase agreement in that same balancing authority area of market would also trigger the reporting threshold.

252. However, we do 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 status threshold and to include such generation in the asset appendices and indicative screens.

253. We agree with El Paso that the output of behind-the-meter generation should be reflected in the load data reported in the FERC Form No. 714. That is, the load reported in FERC Form No. 714 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. Additionally, 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. Moreover, we clarify 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.

254. Given our decision not to require sellers to include behind-the-meter generation in their asset appendices, indicative screens, and for purposes of calculating

the 100 MW change in status threshold and 500 MW Category 1 threshold, we will not address the remaining requests for clarifications made by NRG Companies, NextEra, SunEdison, EPSA, and SoCal Edison.

255. Finally, we clarify that qualifying facilities that are exempt from FPA section 205[335] and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens. However, many qualifying facilities do have market-based rate authority and the capacity of these facilities should be reported in the screens, asset appendix and in determining the 100 MW threshold.

3. Reporting of Long-Term Firm Purchases

a. Commission Proposal

256. As discussed elsewhere in this Final Rule, the Commission proposed to require reporting of long-term firm purchases in the indicative screens and also proposed to include such contracts when determining the 100 MW threshold for change in status filings.[336]

b. Comments

257. The comments addressed in the discussion on treatment of long-term contracts generally encompass the issues in this section. However, SoCal Edison states that the Commission should clarify that it will permit long-term firm purchase aggregation from

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[335] *See* 18 CFR 292.601(c)(1).

[336] NOPR, Stats. & Regs. ¶ 32,702 at P 100.

small generators, such as qualifying facilities under 20 MW. SoCal Edison requests that such aggregation be permitted to relieve the burden that otherwise would be imposed.[337]

c. Commission Determination

258. The requirement to report long-term firm purchases in the asset appendix and indicative screens and to require that such contracts be counted towards the 100 MW threshold is discussed elsewhere in this Final Rule.[338] With respect to SoCal Edison's request regarding aggregation of long-term firm purchase agreements, we clarify that aggregation of such agreements will be permitted in the asset appendix if certain conditions are met. Specifically, we will allow aggregation of long-term firm purchase agreements from small generators only if the information in these columns in the asset appendix is identical for all agreements: "[E] Market / Balancing Authority Area," "[F] Geographic Region," "[G] Start Date (mo/da/yr)," and "[H] End Date (mo/da/yr)." Aggregating agreements with different start dates or end dates or agreements in different Market /Balancing Authority Areas would defeat the usefulness of collecting such information. We also clarify that a seller that meets these criteria can aggregate such agreements but would need to use column "[I] End Note" to report different docket numbers and/or names of the filing entities and seller(s) in the End Note list of the asset appendix.

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[337] SoCal Edison at 23.

[338] *See supra* Section IV.C.1.

D. Asset Appendix

259. The Commission proposed clarifications and revisions to the required appendix that contains the lists of generation and transmission assets.

1. Changes to the Existing Columns

a. Commission Proposal

260. The Commission proposed to make three changes to the existing columns in the asset appendix. The Commission proposed to change a column heading on both assets lists from “Balancing Authority Area” to “Market/Balancing Authority Area” to reflect the correct location for assets in organized markets as well as in balancing authority areas. The second proposal was to change a column heading on both asset lists from “Geographic Region (per Appendix D)” to “Geographic Region” because there have been changes to some regions since the Commission originally published the region map in Appendix D of Order No. 697. Finally, the Commission proposed to change the heading for the “Nameplate and/or Seasonal Rating” column of the generation list to “Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average” to clarify that this column requires capacity ratings in megawatts and to reflect that each submission in the asset appendix should use either “nameplate,” “seasonal,” or “five-year average” ratings to reflect the rating used throughout the filing for a particular generation technology. The Commission indicated that these proposed changes would ensure consistency across filings and allow the industry and Commission staff to better utilize the information contained in the asset lists.

261. The Commission further proposed to clarify that the asset lists should not contain any information other than what is required in the respective columns. For instance, sellers frequently include footnotes in their appendices that cause the appendices to become unwieldy and difficult to read or understand. Sellers sometimes explain in these footnotes that some facilities are partially owned, that some affiliates included in their asset lists may not actually be affiliates but are included out of an abundance of caution, or that a facility is expected to come on-line or off-line at some future date. The Commission discouraged any such footnotes and directed that any such representations be made in the filing transmittal letter.

262. Thus, the Commission proposed to modify the example of the required appendix found in Appendix B to Subpart H of Part 35 of the Commission's regulations to incorporate these changes.

b. Comments

263. Few commenters express concern about the Commission's proposed changes to the existing columns in the asset appendix.[339] Solomon/Arenchild are concerned that the proposal to change the heading for capacity ratings column from "Nameplate and/or Seasonal Rating" to "Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average" may introduce "another potential source of inconsistency across filings" and therefore suggest that the Commission add another column to the asset appendix to allow a seller to report nameplate or seasonal ratings, as well as the five-year average

[339] *See, e.g.*, Solomon/Arenchild at 7; EEI at 17.

rating, if the seller elects to use five-year average ratings.[340] EEI states that the Commission's proposed changes to existing columns seem appropriate, but would encourage the Commission not to change the geographic regions without advance notice and opportunity for comment by market participants in those regions.[341]

264. Several commenters oppose the Commission's proposal to clarify that asset lists should not contain any information other than what is required in the respective columns.[342] EPSA notes that the reason sellers include footnotes and other "extraneous information" is to avoid allegations that the sellers have misled the Commission.[343] EPSA requests that the Commission add a separate column to the asset appendix for explanatory notes and clarifications, instead of prohibiting the use of footnotes.[344] NRG Companies echo EPSA's concerns and state that sellers include explanatory notes to avoid misleading the Commission about matters that are too complex to be depicted fully and accurately in the prescribed fields.[345] NRG Companies add that providing the explanatory notes in the transmittal letter will not be an adequate substitute for

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[340] Solomon/Arenchild at 7 & Attachment 1 (illustrating their proposed additional column to the asset appendix).

[341] EEI at 17.

[342] *See, e.g.*, EEI at 18; El Paso at 5; EPSA at 13; NRG Companies at 6.

[343] EPSA at 13.

[344] *Id.*

[345] NRG Companies at 6.

appropriate notes in the asset appendix itself.[346] El Paso argues that discouraging sellers from adding footnotes to their asset appendices could cause confusion amongst industry particularly if the Commission creates a searchable public database from these asset appendices because sellers may unintentionally provide misleading information.[347] EEI notes that this clarification seems unnecessary and could inhibit sellers from including helpful information in the asset appendix.[348]

c. Commission Determination

265. We adopt the proposed changes to the existing columns in the asset appendix on both asset lists from "Balancing Authority Area" to "Market/Balancing Authority Area" to reflect the correct location for assets in organized markets, as well as in balancing authority areas. We also adopt the proposed column heading change from "Geographic Region (per Appendix D)" to "Geographic Region" because there have been changes to some regions since the Commission originally published the region map in Appendix D of Order No. 697. We note, with regard to EEI's comment, that removing the reference to Appendix D removes an outdated reference to the Appendix in Order No. 697. Further, to aid in identification of similarly named columns in the asset lists, we are

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[346] *Id.* at 7.

[347] El Paso at 5 (arguing that members of the public may not take the time to search the original transmittal letter that would explain a seller's ownership).

[348] EEI at 18.

adding an alphabetic label to each column in the asset lists in the new Asset Appendix.[349]

266. We do not adopt the proposal to change the heading for the "Nameplate and/or Seasonal Rating" column of the generation list to "Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average." Instead, in response to the Solomon/Arenchild comments, we will modify the generation asset list to clearly distinguish between the nameplate rating and an alternative rating of a generation facility. Specifically, we are removing the "Nameplate and/or Seasonal Rating" column and replacing it with three new Columns [J], [K], and [L], entitled "Capacity Rating: Nameplate (MW)", "Capacity Rating: Used in Filing (MW)", and "Capacity Rating: Methodology Used in [K]: (N)ampelate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative," respectively.[350] Sellers will populate Column [J] with the nameplate capacity rating of their facilities, Column [K] with the capacity rating attributed to that facility in the filing and any associated market power study, and Column [L] with the appropriate letter to indicate which rating

[349] For example, the first column in the generation asset list is "Filing Entity and its Energy Affiliates." We have labeled that column, above the column heading, as Column "[A]."

[350] As discussed in this Final Rule, sellers are allowed to use alternative rating methodologies for different generation technologies in their market power studies. The "Capacity Rating: Used in Filing (MW)" column is where sellers should report the actual value they used in the market power analysis. If a seller uses nameplate ratings, the values in Column [J] "Capacity rating nameplate (MW)" and Column [K] "Capacity rating: used in filing (MW)" will be the same.

methodology was used to derive the capacity rating used in Column [K].[351] Sellers will need to populate every column for all facilities in the generation asset list, even facilities that are not discussed in a given filing. If the instant filing does not contain a market power study, or a particular generation asset is not included in a market power study in that filing, sellers should include in the generation asset list the rating that it used the last time the asset was included in a market power study. We believe this format addresses Solomon/Arenchild's concern about consistency of the rating methodology across filings, while maintaining the ability to tie asset appendix ratings to those used in a market power analysis.

267. Finally, we adopt the NOPR proposal to prohibit footnotes from the asset appendices. However, in response to commenters' concerns about loss of clarity and information, we adopt EPSA's suggestion and add a separate column to the asset appendix for explanatory notes and clarifications. We are adding a column entitled "End Note Number (Enter text in End Note Tab)" as the final column in the generation list (Column [M]), transmission list (Column [J]), and, as discussed below, the new long-term firm power purchase agreement list (Column [I]), and creating an additional end notes list. The end notes list will have three columns: Column [A] "End Note Number;" Column [B] "List (Generation, PPA, or Transmission);" and Column [C]

[351] For example, for a seller that has decided to use nameplate ratings for all wind facilities in its market power studies and owns a 100 MW (nameplate) wind facility, the seller will place "100" in Column [J], "100" in Column [K], and "N" in Column [L].

"Explanatory Note." When a seller wants to provide more information about a particular facility in an asset appendix list, the seller will place a number in the appropriate end note column of the row listing that facility. Furthermore, the seller will then enter that number in Column [A] of the end notes list, specify in Column [B] which asset list this end note refers to, and finally, enter in Column [C] the explanatory text.

2. <u>Reporting Power Purchase Agreements</u>

a. <u>Commission Proposal</u>

268. The Commission also proposed to require sellers to include all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices, regardless of whether the seller has operational control over the generation capacity supplying the purchased power. The Commission stated that this approach will help size the market correctly and will establish consistent treatment of long-term firm sales and long-term firm purchases.[352] Other sections of this Final Rule discuss the conversion of a power purchase agreement measured in MWh into MW values that will be entered into the asset appendix and indicative screens.

b. <u>Comments</u>

269. Several commenters requested clarification regarding how to account for long-term firm purchases in the asset appendix. For example, SoCal Edison states that it will not be possible to fill out the asset appendix as currently proposed where a long-term firm purchase is not tied to a physical generating asset and suggests separating the appendix

[352] NOPR, FERC Stats. & Regs. ¶ 32,702 at PP 16, 79.

into two appendices – one for seller's/applicant's generation and one for seller's/applicant's long-term firm purchases.[353] SoCal Edison states that if the Commission does not change the asset appendix headings as requested, the Commission should hold a technical conference to address questions raised by the change in policy regarding the reporting of long-term firm purchases.[354] NextEra opposes the reporting of long-term power purchase agreements in the asset appendix but states that if the Commission decides to require this reporting it should allow the use of EIA regional data for facilities that do not yet have seasonal or a five-year average capacity rating.[355]

c. <u>Commission Determination</u>

270. We do not find the comments opposed to reporting of long-term firm purchases in the asset appendix to be persuasive and adopt the NOPR proposal to require sellers to report all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices. However, we agree with commenters that the format of the generation asset list is not well suited for reporting long-term purchases. Therefore, we are implementing SoCal Edison's recommendation to create a separate list for a seller's long-term firm purchases.[356] The new long-term purchases list has columns similar to the generation list, but removes several inapplicable columns (Generation

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[353] SoCal Edison at 21.

[354] *Id.* at 23.

[355] NextEra at 13-14.

[356] SoCal Edison at 21.

Name, Owned By, Controlled By, and Date Control Transferred), and adds "Start Date (mo/da/yr)" and "End Date (mo/da/yr)" columns.

271. NextEra requests that purchasers under a long-term firm power purchase agreement be allowed to use EIA regional data. As discussed above in the section on capacity ratings, we permit use of EIA regional data but only for energy-limited facilities that lack five years of operating data or for non-affiliated energy-limited facilities for which the seller cannot obtain operating data.[357] We also will require that sellers de-rate all generators using the same technology in a consistent manner. Thus, if a purchaser can identify which generation units are fulfilling a long-term firm PPA, it should use the same rating methodology for that facility in its market power study that it is using for other generation facilities utilizing that technology.

3. Clarifications Regarding the Existing Columns

a. Commission Proposal

272. The Commission noted that its post-Order No. 697 experience has been that, with respect to the column in the list of generation assets that is currently labeled "Nameplate and/or Seasonal Rating," some sellers report *only* the portion of the capacity that they own,[358] whereas other sellers report the entire capacity of the facility. Additionally,

[357] As discussed above, the Commission will not permit de-rating of solar photovoltaic facilities. *See supra* Section IV.A.6.c.i.

[358] The Commission noted that it has not permitted market-based rate sellers to dilute the ownership share of generation attributed to the seller or its affiliates based on multiplying successive shares of partial ownership in a company. *See Kansas Energy LLC, Trademark Merchant Energy, LLC*, 138 FERC ¶ 61,107, at P 28 (2012). Instead, (continued…)

some sellers include in their generation asset lists facilities in which they have claimed a relationship through only passive, non-controlling interests.

273. The Commission proposed the following clarifications with respect to the asset appendix: (1) a seller must enter the entire amount of a generator's capacity (in MWs) in the "Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average" column of the generation list even if the seller only owns part of a facility; (2) a seller should list only one of the following as a "use" in the "Asset Name and Use" column of the transmission list: transmission, intrastate natural gas storage, intrastate natural gas transportation, or intrastate natural gas distribution; and (3) entities and generation assets in which passive ownership interests have been claimed should not be included in the horizontal market power indicative screens or reported in the appendix.[359]

274. The Commission explained that if a seller does not believe that the entire capacity of a generation facility should be included in its indicative screens, it may explain its position in the transmittal letter filed with its horizontal market power screens, including letters of concurrence where appropriate,[360] and thus account for only its portion of that

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sellers must account for generation capacity owned or controlled by the seller and its affiliates for purposes of analyzing horizontal market power. *See id.* P 37.

[359] The Commission noted that sellers must demonstrate why such ownership interests should be deemed passive. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 116 n.129 (citing *AES Creative Resources, L.P. et al.*, 129 FERC ¶ 61,239 (2009) (*AES Creative*)).

[360] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187.

particular generation facility in the indicative screens. However, the entire capacity of the facility should be reflected in the list of generation assets in the appendix.

275. The Commission noted that generating units within a single plant may be aggregated in a single row of the generation list if the information in the other columns is the same for all units, but separate plants cannot be aggregated into a single row. As discussed and adopted elsewhere in this Final Rule,[361] the Commission proposed that qualifying facilities less than 20 MW may be aggregated by balancing authority area or market into one line in the generation asset list. The Commission further clarified that each asset should be listed only once; if it is owned by more than one affiliate, all affiliate names should be included in the "Owned By" column. If a company or an affiliate is registered in the Commission's company registration database,[362] the Commission proposed to clarify that the name in the asset appendix for that company must appear exactly the same as in the registration database.

276. With respect to the "Date Control Transferred" column in both the generation and transmission asset lists, the Commission proposed to clarify that the "Date Control

[361] *See supra* Section IV.C.2.c.

[362] The term "company registration database" here refers to "FERC's Online Company Registration application" (*see* http://www.ferc.gov/docs-filing/etariff/implementation-guide.pdf). However, Commission orders have referred to this database as we have also issued orders referring to it as "Company Registration," (*see Filing Via the Internet, Revisions to Company Registration and Establishing Technical Conference*, 142 FERC ¶ 61,097 (2013)) or "Company Registration system" (*see Filing Requirements for El. Utility S.A., Order Updating Electric Quarterly Report Data Dictionary*, 146 FERC ¶ 61,169 (2014)).

Transferred" column should identify the date on which a contract or other transaction that transfers control over a facility became effective. The Commission noted that where appropriate, sellers may enter "N/A" in this field to indicate that it is not applicable to their asset(s) and explain why in the end note list.

277. With respect to the "Size" column in the list of transmission assets, the Commission proposed to clarify that the "Size" refers to both the length of the transmission line (i.e., feet or miles) and the capability of the line in voltage (kV). The Commission noted that sellers may aggregate their transmission assets by voltage. For instance, a seller that owns a transmission system with several hundred transmission lines might include two rows in the transmission asset list; one row with 200 miles of 138 kV lines listed in the "Size" column and another row with 100 miles of 230 kV lines listed in the "Size" column as long as all the other columns (e.g., owned by, controlled by, balancing authority area, geographic region, etc.) remain the same for all assets aggregated in that row. The name for such aggregated facilities should describe the lines that are being aggregated, e.g., "230 kV transmission lines."

i. Entire Amount of Generator's Capacity in Asset Appendix

(a) Comments

278. Several commenters express concern over the Commission's proposal to require a seller to include the entire amount of a generator's capacity in its asset appendix, even if

the seller only owns part of a facility.[363] Idaho Power, EEI, and FirstEnergy argue that this proposal may lead to double counting many generation facilities, or would otherwise lead to confusion.[364] FirstEnergy also argues that the proposal will result in the amount of generation capacity reported by a seller in its asset appendix to differ from the amount of generation capacity reflected in its indicative screens, which may cause confusion over the amount of generation capacity controlled by the reporting entity.[365] NextEra adds that the information in the asset appendix may not match the information in the transmittal letter, which only includes a seller's ownership interest in the generation facility where it has demonstrated its partial ownership (or lack of control over).[366] Idaho Power, NextEra, and El Paso suggest that, if the Commission adopts this requirement, it should add a column to the asset appendix to allow a seller to declare the percentage of the generation facility it owns or controls.[367]

[363] *See, e.g.*, Idaho Power at 2, 4; EEI at 17; FirstEnergy at 12-13; NextEra at 14-15; El Paso at 4-5.

[364] Idaho Power at 2, 4 (explaining that, if a seller enters the entire amount of the generator's capacity when it owns just a share of the generating asset, it is unclear how the Commission would ensure that the generation capacity is not being counted twice); EEI at 17 (explaining that, if multiple sellers have an interest in an asset, and each lists the asset's entire generation, the seller may over count the facility's capacity); FirstEnergy at 12-13 (explaining that each joint owner including the entire generating capacity of a jointly owned facility may result in double-counting).

[365] FirstEnergy at 12-13.

[366] NextEra at 14.

[367] Idaho Power at 2, 4; NextEra at 15 (expressing concern over the public having to search for the seller's transmittal letter in which the seller declares its partial interest);

(continued…)

(b) Commission Determination

279. We adopt the NOPR's proposed clarification that a seller must enter the entire amount of a generator's capacity in the generation asset list. In response to commenters' concerns that the NOPR proposal could result in double counting, confusion, or other inconsistencies, we believe we have addressed those concerns through the addition of capacity rating and end notes columns discussed above. Specifically, as discussed more fully above, we are adopting Solomon/Arenchild's proposal to add a new end notes column where sellers will be able to place explanatory notes.[368] To the extent a seller is attributing to itself less than a facility's full capacity rating, the seller can explain that in the end notes column.

ii. Size Column in Transmission Asset List

(a) Comments

280. SoCal Edison questions the continued need for mileage of transmission assets as required in the asset appendix for entities that own integrated transmission networks rather than number of interconnection customer's interconnection facilities. SoCal Edison argues that the total length in miles of a utility's integrated network transmission assets has no meaningful relationship to the ability to exercise vertical market power. SoCal Edison further argues that one of the aims of the distributed generation movement

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El Paso at 4-5 (recommending that the Commission add a "Percentage of Ownership/Control" column to the asset appendix that would allow a seller to identify the percentage of a generation facility that the seller owns or controls).

[368] *See supra* Section IV.D.1.c.

is to slow transmission growth, such that a lack of transmission system growth could merely reflect state preference for distributed generation over long-distance transmission. Finally, SoCal Edison argues that FERC Form No. 1 provides the Commission an annual update of the transmission mileage for major utilities and should prove sufficient for analysis. SoCal Edison recommends that the Commission explain the need to track mileage of transmission lines in service and how it relates to vertical market power, particularly in light of third parties' ability to build new transmission additions under Order No. 1000.[369]

(b) <u>Commission Determination</u>

281. We disagree with SoCal Edison that reporting the mileage of transmission assets as required in the asset appendix for entities that own integrated transmission networks is unnecessary for a transmission market power analysis. While we agree that the total length in miles of a utility's integrated network transmission assets has no direct relationship to the ability to exercise vertical market power, the asset appendix is not intended to provide a detailed study of a transmission owner's system. Instead, the transmission asset list, like the generation asset list, provides a comprehensive list of the assets owned or controlled by a market-based rate seller and identifies the relevant

[369] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

transmission assets of sellers in wholesale power markets. Collecting this information adds transparency to the market and allows the public the opportunity to provide comments on a seller's transmission assets. However, as noted in the NOPR, sellers are permitted to aggregate similar assets in a balancing authority area, which will reduce the burden associated with preparing the asset lists.[370]

iii. Passive Ownership

(a) Comments

282. Some commenters took issue with the Commission's proposal to clarify that entities and generation assets in which passive ownership interests have been claimed should not be reported in the asset appendix.[371] EEI states that the clarification seems appropriate, but vague.[372] EEI asks whether partial passive ownership by anyone is enough to exclude the asset from the asset appendix, or whether passive ownership as the seller's only interest in the asset is what is required for that seller to exclude the asset from its asset appendix.[373]

283. However, AAI cautions the Commission against eliminating the passive ownership interests reporting requirement. AAI argues that a passive interest can still affect competitive dynamics in the market because control is not the sole factor to

[370] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 118.

[371] *See, e.g.*, EEI at 17; AAI at 7-9.

[372] EEI at 17.

[373] *Id.*

determine whether an entity exercises market power.[374] AAI further argues that eliminating the reporting requirement could encourage generation owners to acquire undisclosed passive interests that enhance their incentive to engage in generation withholding and other abusive market behavior.[375]

(b) <u>Commission Determination</u>

284. We clarify that sellers should not include in their asset appendices entities and facilities for which they have claimed, and demonstrated to the Commission, that the only relationship is through passive, non-controlling interests consistent with *AES Creative* (i.e., where the seller has a strictly passive ownership interest in another entity, or another entity has a strictly passive ownership interest in the seller). This is consistent with current Commission practice. As noted in the NOPR, sellers must demonstrate why such a relationship should be deemed passive.[376] We are not persuaded by AAI's concerns that eliminating this reporting requirement could encourage generation owners to acquire undisclosed passive interests. We stress that we are not eliminating the requirement to demonstrate passivity; we are merely articulating our existing expectations. As noted above, we will continue to require that any seller that claims certain interests are passive or non-controlling must meet the standards set out in *AES Creative*.

[374] AAI at 7-8.

[375] *Id.* at 7-9

[376] NOPR, FERC Stats. & Regs. ¶ 32,702 at P 116 n.130 (citing *AES Creative*, 129 FERC ¶ 61,239).

iv. Other Issues

285. The Commission proposed clarifications regarding: populating the "Use" column in the transmission asset list; listing each asset once in an asset list; matching seller and affiliate names in the asset lists with the name registered in the Commission's company registration database where possible; and the use of the "Date Control Transferred" column in the transmission asset list.

(a) Comments

286. We did not receive any comments directly related to the aforementioned proposals. However, Solomon/Arenchild raised a concern related to clarifications regarding existing columns in the asset appendix. Solomon/Arenchild note that the proposed reporting of capacity values in generation asset list in the asset appendix may be inconsistent with the indicative screens. Specifically, Solomon/Arenchild state that there is a disconnect between the time period covered in the asset appendix and the time period covered in the indicative screens.[377] Solomon/Arenchild also state that the indicative screens cannot rely solely on the ratings reported in the asset appendix because both summer and winter seasonal ratings typically are used in the indicative screens while the current asset appendix only allows sellers to report one rating per generation unit.[378] Accordingly, Solomon/Arenchild recommend that the Commission specify that any generation sold or contracts terminated following the relevant study

[377] Solomon/Arenchild at 7-8.

[378] *Id.*

period be excluded from the historical study period of the triennial filing, and that any generation acquired or contracts begun since the historical study period be included in the indicative screens and asset appendix.[379]

(b) Commission Determination

287. We adopt the proposed clarifications regarding: populating the “Use” column in the transmission asset list; listing each asset once in an asset list; matching seller and affiliate names in the asset lists with the name registered in the Commission’s company registration database where possible; and to the use of the “Date Control Transferred” column in the transmission asset list.

288. In regard to the “Date Control Transferred” column, we further clarify that sellers should identify the date on which a contract or other transaction that transfers control over a facility becomes effective. Where appropriate, companies may enter “N/A” in this field to indicate that it is not applicable to their asset(s) and provide any further explanation in the new end notes column.

289. We do not adopt Solomon/Arenchild’s recommendation to modify the data in the market power analysis to match the data required for the asset appendix. In Order No. 697, the Commission stated “that when the Commission evaluates an application for market-based rate authority, the Commission’s focus is on whether the seller passes both

[379] *Id.* at Attachment 1 (noting that their recommendation conforms the indicative screens with the asset appendix that is part of the triennial filing, creates a “baseline” for any future notice of change in status filings, and more properly aligns the determination of when a change in status should be filed in the context of the 100 MW net change in capacity ownership for those entities that have sold generation or terminated contracts).

of the indicative screens based on unadjusted historical data. Likewise, when a seller fails one or both of the screens and the Commission evaluates whether that seller passes the DPT, the Commission's focus is on whether the seller passes the DPT based on unadjusted historical data"[380] We will continue to require that a seller's market power analysis rely on unadjusted historical data. To the extent that a seller's generation assets have changed between the historical time period used in the market power analysis and the current time period of the asset appendix, the seller should explain and reconcile any differences in its application. Sellers may also provide sensitivity runs along with the required historical studies to show whether changed circumstances since the end of the study period justify a different conclusion than what the data from the study period indicates.[381] The Commission has addressed the data disconnect issue by noting previously that the Commission will consider, on a case-by-case basis, clear and compelling evidence that seeks to demonstrate that certain changes in the market should be taken into account as part of the market power analysis in a particular case.[382] However, we provide the following guidance for preparing the studies and asset appendices for filings that commonly contain both asset appendices and market-power studies.

[380] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 301.

[381] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at PP 124-130.

[382] *Id.* P 130.

290. For initial applications where the seller has acquired an existing facility, sellers should prepare or rely on a study with historical data that transfers the MW values of the acquired generation from the Non-Affiliate Capacity rows to the Seller and Affiliate Capacity rows of their indicative screens and enter the information for the acquired facility in the generation asset list.

291. For initial applications where the seller has newly built generation, sellers should submit a study that increases the total capacity value of the market/balancing authority area in which the seller is physically located by the seller's newly built generation capacity. To accomplish this, the seller should use a previously approved study and add the value of their newly built generation to the total capacity value of the market/balancing authority area. Sellers must report this newly built generation in the generation asset list.

292. In triennials, there are occasions when a seller's generation fleet at the time of filing has changed since the close of the relevant study period. In these instances, sellers should explain the changes in the text of their filing, the end notes of the asset appendix if applicable, and if the changes are significant, the seller should provide a sensitivity analysis reflecting those changes.

293. Notices of change in status generally do not require indicative screens. However, sometimes a seller provides screens for changes that the seller considers significant enough to merit the submission of screens to show that it would not fail the indicative screens with these new assets. In this case, we clarify that any studies submitted by a

seller should use the most recently available historical data for the market, but include the seller's current generation portfolio, imports, and load and reserve obligations (if any).

294. We understand Solomon/Arenchild's concern that the indicative screens cannot solely rely on the ratings reported in the asset appendix. Based on our experience, sellers that use seasonal ratings for thermal generation in their indicative screens are likely to use either summer or winter ratings in their asset appendix. However, in some cases sellers that use seasonal ratings in their screens use nameplate ratings in their asset appendix. Therefore, we clarify that when sellers use seasonal ratings in their indicative screens, their asset appendix should include the capacity rating used for each generation unit in their pivotal supplier screen(s). Requiring sellers to report the capacity rating used in their pivotal supplier screen eliminates this inconsistency and allows us to maintain the simplicity of the asset appendix. In addition, this ensures that the generation asset list displays the seasonal rating of each generation unit at the time of peak demand, when capacity is most needed.[383]

4. Changes Regarding OATT Waiver and Citations in Transmission Asset List

a. Commission Proposal

295. The Commission has 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

[383] As previously noted, if a filing does not contain a market power study, or a particular generation asset is not included in a market power study, sellers should include in the asset appendix the rating that it used the last time the asset was included in a market power study.

appendix,[384] and the Commission stated in the NOPR that this should be reiterated and clarified going forward. Therefore, the Commission proposed to require any seller that has been granted waiver of the requirement to file an OATT for its facilities[385] to report in its transmission asset list the citation to the Commission order granting the OATT waiver for those facilities. The Commission proposed to modify the example of the asset appendix found in Appendix B to Subpart H of Part 35 of the Commission's regulations to add a new column in the transmission asset list for the citation to the Commission order accepting the OATT or granting waiver of the OATT requirement. Providing the citation to the Commission order accepting the OATT or granting waiver of the OATT requirement in the list of transmission assets was intended to facilitate the Commission's and market participants' verification that sellers were granted the appropriate authorizations or waivers.

b. <u>Comments</u>

296. While APPA/NRECA support the Commission's proposal to require a seller that has been granted waiver of the requirement to file an OATT for its facilities to cite the Commission order granting that waiver in its list of transmission assets in the asset

[384] "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)." Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 378.

[385] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 408.

appendix,[386] other commenters oppose it. Some commenters note that the Commission's proposal may be at odds with the Interconnection Customer Interconnection Facility (ICIF) rulemaking in Docket No. RM14-11-000 that was pending at the Commission at the time the comments were submitted.[387] SoCal Edison requests that the Commission reject this proposal because the new column will not provide useful information, in light of the proposed ICIF rulemaking, and may cause confusion.[388] NextEra suggests that the Commission synthesize the OATT waiver provisions in both pending rulemakings.[389]

297. Other commenters argue that the proposal is unnecessary and unclear.[390] Specifically, FirstEnergy states that, if the citation to the OATT or OATT waiver is in the transmittal letter, including the citation in the asset appendix is redundant and unnecessary.[391] FirstEnergy further states that, if a company transferred operational

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[386] APPA/NRECA at 5; *see also* Golden Spread at 7.

[387] SoCal Edison at 25 (explaining that the Commission is proposing a blanket waiver of all OATT, OASIS, and Standards of Conduct requirements to any public utility that is subject to such requirements solely because it owns, controls, or operates interconnection customer interconnection facilities and citing *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, 147 FERC ¶ 61,123, at P 35 (2014)); NextEra at 15; EEI at 17-18.

[388] SoCal Edison at 25.

[389] NextEra at 15.

[390] *See, e.g.*, AEP at 9; EEI at 17; and FirstEnergy at 13.

[391] FirstEnergy at 13.

control of its facilities to an RTO, a citation to the order authorizing the transfer should suffice.[392] AEP argues that the proposal to provide a citation to the OATT waiver is an extra imposition on sellers that is inconsistent with the stated purpose of the NOPR.[393] AEP and EEI state that OATTs are readily publicly available and therefore do not need to be included in the transmission asset list.[394] AEP further argues that it is unclear which OATT waiver citation a company like AEP would list because its filings are frequently revised and updated.[395]

c. <u>Commission Determination</u>

298. We adopt the proposal to require sellers to add a citation to the order accepting a seller's OATT. Further, we agree with FirstEnergy's suggestion that if a seller has transferred operational control of its facilities to an RTO/ISO, this cite should be to the order authorizing the transfer. Therefore, we have changed the text to the proposed column (Column [B]) of the transmission asset list from "Cite to Order Accepting OATT or granting OATT waiver" to "Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO." The change to remove "granting OATT waiver" is discussed below.

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[392] *Id.* at 14.

[393] AEP at 9.

[394] *Id.*; EEI at 17.

[395] AEP at 9; *see also* EEI at 17.

299. We do not agree with AEP's assertion that this requirement is an extra imposition upon sellers. Further, in regard to AEP and EEI's comments, we understand that OATT information is already publicly available. However, sellers are already required to supply this information as part of their demonstration that they meet the Commission's vertical market power requirements. The new column provides a convenient location for sellers to provide the information and for the Commission or third-parties to find the information. We clarify that sellers are not expected to change the citation every time they revise or update their OATTs. Similar to Column [B] "Docket # where market-based rate authority was granted" in the generation asset list, we expect sellers to provide citation to the initial order accepting a seller's OATT or accepting the seller's transfer of transmission facilities to an RTO/ISO in Column [B] of the transmission asset list. This will minimize any burden associated with including this information in the transmission asset list.

300. However, we do not adopt the NOPR proposal to require sellers to add a citation to orders granting the seller waiver of the OATT requirements. We agree with SoCal Edison that this requirement will not provide useful information, in light of the Final Rule in the ICIF proceeding.[396]

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[396] *See 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).

5. Electronic Format

a. Commission Proposal

301. Currently, virtually all of the asset appendices are submitted to the Commission using PDF format. Staff is unable to perform calculations on PDF files, or to search, or sort the data contained in the asset lists. Staff therefore frequently transfers the information included in the asset lists into spreadsheets for sorting, comparison purposes, and internal calculations, and in doing so has found numerous submission errors from sellers. In the NOPR, the Commission stated that if it provided a sample electronic spreadsheet and required sellers to submit the assets lists in an electronic spreadsheet, it would reduce filing burdens, improve accuracy, decrease the number of staff inquiries to sellers regarding submission errors, and result in a more efficient use of resources.

302. Therefore, the Commission proposed to require market-based rate sellers to submit the Appendix B asset lists in an electronic spreadsheet format that can be searched, sorted, and otherwise accessed using electronic tools. The Commission proposed to post on the Commission's website sample asset lists in formatted electronic spreadsheets and to require sellers to submit the asset appendix in the form and format of the sample electronic asset list spreadsheets.[397]

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[397] The Commission proposed that if a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission website. Specifically, it must have the same exact columns and descriptive text as the sample spreadsheet. The Commission further proposed that the file must be submitted in one of the spreadsheet file formats accepted

(continued…)

303. An example of the electronic spreadsheet for the asset appendix with the proposed new columns and column headings was included as Appendix B to the NOPR.

b. <u>Comments</u>

304. Commenters generally support the Commission's proposal to require sellers to submit the asset appendix in an electronic spreadsheet format; however, several commenters request clarification or modification of the proposal.[398] EPSA requests clarification on the specific fields that would be required in the electronic format, and the methodology that should be used to submit the electronic forms.[399] E.ON urges the Commission to thoroughly vet the process to ensure ease of use and submission by market participants, which may require a public test period.[400] EEI states that, "if the Commission simply intends to require market-based rate applicants and sellers to file the information in standard electronic formats, such as Adobe, Excel, and Word, that would be fine. Such straightforward electronic filing will simply mirror the current FERC eFiling process, which has eased the burden of filing documents at FERC. If, however, the Commission has in mind that market-based rate applicants and sellers must provide

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by the Commission for electronic filing. NOPR, FERC Stats. & Regs. ¶ 32,702 at P 63 n.71. *See* FERC, Acceptable File Formats (January 2012), *available at* http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp.

[398] *See, e.g.*, APPA/NRECA at 5 (supporting the Commission's proposal and requesting no clarifications or modifications); Solomon/Arenchild at 6-7; EPSA at 12; E.ON at 13, 14.

[399] EPSA at 12

[400] E.ON at 13.

the information using rigid new formats, e.g. with pre-defined rows and columns using XML data, EEI asks the Commission to engage in further dialogue with the regulated community first, to ensure that the format changes are reasonable, clear, and workable."[401]

c. Commission Determination

305. We adopt the NOPR proposal to require sellers to submit the asset appendix in an electronic spreadsheet format.

306. EEI apparently misconstrued this proposal and we clarify here that the electronic format requirement for the asset appendix is specifically designed to stop the submission of asset appendices in Word or PDF format and instead require that these be submitted in a workable electronic file format such as Excel. We adopt the NOPR requirements of a "workable electronic spreadsheet,"[402] provide an example on our website, and provide the

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[401] EEI at 18.

[402] "'Workable electronic spreadsheet' refers to a machine readable file with intact, working formulas as opposed to a scanned document such as an Adobe PDF file." NOPR, FERC Stats. & Regs. ¶ 32,702 at P 63 n.70. Additionally:

> If a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission website. Specifically, it must have one worksheet for each of the indicative screens and each screen must have the same exact rows, columns, and descriptive text as the sample worksheets. Cells requiring negative values must be pre-programmed to only allow negative values. Likewise, cells with calculated values must contain a working formula that calculates the value for that cell. Finally, the file must be submitted in one

(continued…)

electronic filing requirements for such a filing.[403] Furthermore, we clarify that this requirement is not dependent upon any particular technology such as Extensible Markup Language (XML), and instead can use any one of a number of Commission accepted spreadsheet formats.[404] In response to EPSA, we clarify that the entire asset appendix (including all relevant lists) should be submitted in the electronic format. Sellers should submit the electronic asset appendix as an attachment to their filings, following the Commission's electronic filing requirements described above.

307. Finally, we replace the example appendix found in Appendix B to Subpart H of Part 35 of the Commission's regulations with the Appendix B in this Final Rule.

6. <u>Database</u>

a. <u>Commission Proposal</u>

308. The Commission sought comment regarding whether in the future it would be beneficial to develop a comprehensive searchable public database of the information contained in the asset appendix, which would eventually replace the pre-formatted spreadsheet. The Commission noted that such an approach would allow market-based rate sellers to update their asset appendices when circumstances change. The

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of the spreadsheet file formats accepted by the Commission for electronic filing. *See* FERC, Acceptable File Formats (Jan. 2012), *available at* http://www.ferc.gov/docs-filing/elibrary/accept-fileformats.asp.

NOPR, FERC Stats. & Regs. ¶ 32,702 at P 63 n.71.

[403] *Id.* P 123 n.135.

[404] *Id.* P 65 n.73; *see also supra* Section IV.A.4.c.

Commission sought comments regarding whether such a database would be useful, how the database might be created, standardized and maintained, and the frequency with which it should be updated. The Commission further sought input on the usefulness of including unique identifiers for the affiliate companies and generation assets in such a database, e.g., the company registration database and the EIA Power Plant Code and Generator ID, respectively, where those identifiers exist. The Commission also sought comment on the difficulty of reporting and the usefulness of including in such a database the percentage each affiliate owns of each of its assets.

b. <u>Comments</u>

309. While APPA/NRECA, Golden Spread, and E.ON support the Commission's proposal to develop a comprehensive, searchable public database of the information contained in the asset appendix,[405] several other commenters expressed concern.[406] SoCal Edison and EEI argue that including contract data in the database would raise concerns about confidentiality.[407] EEI states that the database would need to be designed in close coordination with the regulated community to ensure a useful result,

[405] APPA/NRECA at 5; Golden Spread at 7; E.ON at 14 (stating that a database would be particularly useful if the Commission ultimately adopts its proposal to redefine relevant markets for generation-only balancing authority areas, and it would provide market participants and market-based rate sellers with access to megawatt generation data needed for horizontal market power analyses).

[406] *See, e.g.*, SoCal Edison at 26; EEI at 18; Idaho Power at 2-3.

[407] SoCal Edison at 26; EEI at 18 (adding that including contract data in the database would create additional information collection burdens and would also raise concerns about the disclosure of Critical Energy Infrastructure Information (CEII)).

minimize the regulatory burden, and address confidentiality and critical energy infrastructure information (CEII) concerns.[408] Idaho Power states that, in some cases, proprietary information of a generator's capacity would be masked in a public database, impacting the usefulness of the database.[409]

310. Other commenters raise issues related to maintaining the database's integrity.[410] SoCal Edison, EEI, and AEP state that the database could omit qualifying facilities' generation and non-jurisdictional entities' generation.[411] SoCal Edison also argues that it would be difficult to assemble information from the asset appendix about long-term firm purchases into a meaningful database.[412] Solomon/Arenchild support the database, in theory, but state that the database would require continual, time-consuming, and cumbersome maintenance to maintain its integrity.[413] They further state that for such a database to provide meaningful information, one would need to be able to readily identify duplicates, overlaps etc., or the utility of the database will be undermined. NextEra echoes Solomon/Arenchild's concern and state that the burdens associated with

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[408] EEI at 18.

[409] Idaho Power at 2-3.

[410] *See, e.g.*, SoCal Edison at 26; EEI at 18; AEP at 10; Solomon/Arenchild at 6-7; NextEra at 15; EPSA at 14.

[411] SoCal Edison at 26 (adding also that the data may not be particularly useful due to joint ownership issues); EEI at 18; AEP at 10.

[412] SoCal Ed. at 26.

[413] Solomon/Arenchild at 6-7

maintaining such a database would outweigh the benefits.[414] EPSA expresses concern over whether the industry or the Commission will be responsible for updating the database and how the accuracy of the information will be ensured.[415]

311. EPSA also seeks clarification on whether the database would eventually replace the asset appendix, or if both a database and an asset appendix would be required.[416] EPSA states that, if both a database and an asset appendix will be required of all market-based rate sellers, then such requirements would run counter to the Commission's stated intentions to streamline the information required and reduce the regulatory burden on market-based rate sellers. EPSA suggests that, if sellers will be required to use the database for documentation of assets, the seller should be responsible for updating and maintaining its data on the database.[417]

312. AEP does not see the need for the Commission to host a comprehensive searchable public database, stating that the information is available through other means and creating the database would impose another reporting obligation on sellers.[418]

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[414] NextEra at 15.

[415] EPSA at 14.

[416] *Id.*

[417] *Id.*

[418] AEP at 9.

c. Commission Determination

313. We will not direct the creation of a comprehensive public database as part of this rulemaking. In the NOPR, we sought industry comment on the usefulness of a potential database and for input on how the database might be created and maintained. While some commenters raise valid concerns about the structure, confidentiality, burden and maintenance of the database, others recognize the potential utility of a well-designed and properly administered database.[419] Similarly, we continue to recognize the potential value of the database and may consider the creation of a database in the future.

E. Category 1 and Category 2 Sellers

1. Commission Proposal

314. In Order No. 697, the Commission created a category of market-based rate sellers, Category 1 sellers, that are exempt from the requirement to periodically submit updated market power analyses in accordance with the regional reporting schedule. Category 1 sellers include wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's

[419] APPA/NRECA at 5; Golden Spread at 7; E.ON at 14; Solomon/Arenchild at 6-7.

generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power concerns.[420]

315. In the NOPR, the Commission proposed to clarify the distinction in determining the seller category status of power marketers and power producers. For purposes of determining seller category status for each region, a power marketer should include all affiliated generation capacity in that region. Power producers only need to include affiliated generation that is located in the same region as the power producer's generation assets. The Commission explained that the reason behind this distinction is that a power marketer with no generation assets in the ground is assumed to have no home market; it is thus assumed to be equally likely to make sales in any region. In contrast, although a power producer has authorization to make sales in other regions, it is assumed that the majority of its sales will be in the region(s) in which it owns generation assets.

316. Thus, the Commission proposed to clarify that a power marketer with no generation assets may qualify as a Category 1 seller in any region where: (1) its affiliates own or control, in aggregate, 500 MW or less of generation capacity; (2) it is not affiliated with anyone that owns, operates or controls transmission facilities; (3) it is not affiliated with a franchised public utility; and (4) it does not raise other vertical market

[420] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 853-863; *see also* 18 CFR 35.36(a)(2).

power issues. The Commission noted that the above is consistent with the Commission's treatment of power marketers since the issuance of Order No. 697.

317. The Commission also proposed to clarify that a power producer may qualify as a Category 1 seller in any region in which the power producer itself owns generation and the power producer and its affiliates own or control, in aggregate, 500 MW of generation capacity or less, as long as the power producer is not affiliated with anyone that owns, operates or controls transmission facilities in that region, is not affiliated with a franchised public utility in that region, and does not raise other vertical market power issues. In addition, unlike power marketers, a power producer may qualify as a Category 1 seller in a region where the power producer itself does not own or control any generation or transmission assets but where it has affiliates that are Category 2 sellers.[421]

318. Therefore, the Commission proposed to revise the regulation at 18 CFR 35.36(a)(2) and clarify that in order to qualify for Category 1 status, a seller must meet *all* of the requirements. Failure to satisfy *any* of these requirements results in a Category 2 designation.

2. <u>**Comments**</u>

319. EEI recommends that the Commission modify its proposed clarifications regarding Category 1 and Category 2 sellers. EEI encourages the Commission to allow

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[421] The Commission noted that a mitigated seller cannot use an affiliated power producer in another region as a conduit to sell in a mitigated balancing authority area because all affiliates of a mitigated seller are prohibited from selling at market-based rates in any balancing authority area or market where the seller is mitigated. Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 335.

power marketers to demonstrate that their sales from particular capacity are confined to particular regions and thus should be counted accordingly in determining their category status.[422] EEI adds that the Commission should modify the definition of a Category 1 seller from "no more than 500 MW generation ownership and/or control" to "no more than 500 MW of uncommitted resources owned and/or controlled."[423] EEI contends that some companies have always had negative uncommitted resources because they are net buyers, and so should not be required to make updated market power analysis filings or change in status filings.[424]

3. Commission Determination

320. We adopt the proposed clarifications regarding Category 1 and Category 2 sellers and the corresponding regulatory changes to 18 CFR 35.36(a)(2) as proposed in the NOPR.

321. In response to EEI's comment to allow power marketers to demonstrate that sales from particular capacity are confined to a particular region, the Commission has found that category seller status is based on the region in which generation capacity is owned or controlled by the seller and its affiliates in aggregate rather than where sales are made in an effort to keep the definition and demonstration of a seller's category status simple and

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[422] EEI at 19.

[423] *Id.*

[424] *Id.*

straightforward.[425] Since sales change frequently, we believe basing the category seller status definition on sales could create an additional burden on sellers to demonstrate that their and their affiliates' sales are confined to a particular region. However, we note that to the extent that any seller wishes to limit its market-based rate authority to a particular region or set of regions in its tariff, it is free to do so. If a seller does not have market-based rate authority in a particular region, it will not have an obligation to file regular updated market-power analyses for that region.

322. EEI also proposed that the category seller status designation be based on whether a seller owns or controls uncommitted resources in a region. We reject this proposal as beyond the scope of what was proposed in the NOPR. Moreover, the test for category seller status was intended to be a bright line test that would be easy to administer.[426] The Commission has previously found that "aggregate capacity in a given region best meets our goal of ensuring that we do not create regulatory barriers to small sellers seeking to compete in the market while maintaining an ample degree of monitoring and oversight that such sellers do not obtain market power."[427] We do not believe that a seller with over 500 MW of capacity is the type of seller that the Commission intended to exclude from periodic updated market power analyses, regardless of whether the seller's capacity happens to be committed at a particular point in time.

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[425] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 864-868.

[426] *Id.* P 864.

[427] *Id.* P 865; Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 360.

F. Corporate Families

1. Corporate Organizational Charts

a. Commission Proposal

323. In the NOPR, the Commission proposed to require sellers to provide an organizational chart, in addition to the existing requirement[428] to provide written descriptions of their affiliates and corporate structure or upstream ownership, for initial applications for market-based rate authority, updated market power analyses and notices of change in status reporting new affiliations.

324. The Commission noted that it has seen increasingly complex organizational structures as private equity funds and other financial institutions take ownership positions in generation and utilities.[429] The Commission stated that requiring the filing of an organizational chart would make reviewing market-based rate filings more efficient, increase transparency, and synchronize information about corporate structure that the Commission receives from sellers with market-based rate authority with similar

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[428] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 181, n.258 (also requiring sellers seeking market-based rate authority to describe the business activities of their owners, stating whether they are in any way involved in the energy industry).

[429] We note that the Commission recently issued a NOPR seeking comment on a proposal to require each RTO and ISO to electronically deliver to the Commission data from market participants that lists market participants' "connected entities," including entities that have certain ownership, employment, debt or contractual relationships to the market participant, and describes the nature of such relationships. *See Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, Docket No. RM15-23-000, 80 FR 58382 (Sept. 29, 2015), 152 FERC ¶ 61,219 (2015).

information that the Commission receives under section 203 of the FPA.[430] The Commission proposed to require that sellers provide an organizational chart similar to that which the Commission requires from section 203 applicants. Specifically, the Commission noted that section 33.2(c)(3) of its regulations[431] provides that section 203 applicants must include: a description of the applicant, including, among other things, organizational charts depicting the applicant's current and proposed post-transaction corporate structures (including any pending authorized but not implemented changes) indicating all parent companies, energy subsidiaries and energy affiliates unless the applicant represents that the proposed transaction does not affect the corporate structure of any party to the transaction. The Commission proposed that market-based rate sellers be required to provide, in addition to the already required written descriptions of their affiliates and corporate structure or upstream ownership, an organizational chart depicting the market-based rate seller's current corporate structures (including any pending authorized but not implemented changes) indicating all upstream owners, energy subsidiaries and energy affiliates. The Commission believed that the increased burden on market-based rate sellers would be minimal as most sellers have this organizational chart available.

325. Thus, the Commission proposed to revise the text in section 35.37(a)(2) of the Commission's regulations to add this requirement for purposes of initial applications

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[430] 16 U.S.C. 824b.

[431] *See* 18 CFR 33.2(c)(3).

and updated market power analyses. The Commission also proposed that such organizational chart be required for any notice of change in status involving a change in the ownership structure that was in place the last time the seller made a market-based rate filing with the Commission. Therefore, the Commission proposed to revise the text in section 35.42(c) accordingly.

b. <u>Comments</u>

326. Many commenters oppose the Commission's proposal to require sellers to provide an organizational chart, in addition to written descriptions of their affiliates and corporate structure or upstream ownership, for initial applications for market-based rate authority, updated market power analyses, and notices of change in status reporting new affiliations.[432] However, APPA/NRECA and Golden Spread support the proposal.[433]

327. Several commenters submit that this proposal would impose a burden on sellers disproportionate to any benefit received, requiring significant investigation into numerous affiliate relationships.[434] EPSA notes that, even if a market-based rate entity already has an organizational chart, often those charts are not developed and used for the purpose of showing control, but rather to demonstrate how finances flow throughout the

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[432] *See, e.g.*, EPSA at 15-17; E.ON at 14-16; NextEra at 16; EEI at 19; FirstEnergy at 14-16; NRG Companies at 3-6; AEP at 9.

[433] APPA/NRECA at 5; Golden Spread at 7.

[434] *See, e.g.*, EPSA at 15-17 (noting that not all market-based rate sellers have these organization charts readily available and that many sellers have hundreds of affiliates); E.ON at 14-15; NextEra at 16; EEI at 19; NRG Companies at 3-4; AEP at 9.

various companies.[435] Consequently, EPSA argues that the charts would require significant revisions to comply with the Commission's proposal.[436]

328. EPSA proposes that, if the Commission implements the proposal, the Commission should limit the entities depicted in the organizational chart to include only public utilities subject to the Commission's jurisdiction rather than all affiliates within a seller's corporate structure.[437] Other commenters state that the Commission does not need an organizational chart to evaluate market power concerns and that an organizational chart does not provide meaningfully different or material information to the Commission than is currently required.[438] Specifically, FirstEnergy argues that, because the evaluation of a market-based rate application treats the seller and its affiliates as a single entity, the complex internal relationships among affiliated entities that might be illustrated in an updated organizational chart are not relevant to the Commission's evaluation of whether an entity should enjoy market-base rate authority.[439]

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[435] EPSA at 16.

[436] *Id.*

[437] *Id.* at 15-16.

[438] *See, e.g.*, E.ON at 15-16; NextEra at 16; EEI at 19; FirstEnergy at 14-16; NRG Companies at 5.

[439] FirstEnergy at 15.

329. If the Commission adopts this proposal, some commenters suggest that the Commission provide further guidance regarding which affiliated entities should be included in the organizational chart.[440] E.ON requests that the Commission clarify the meaning of "energy affiliate" and "energy subsidiary" and suggests that the meaning be limited to affiliates and subsidiaries that (1) own or control electric generation or inputs to electric power production in the relevant market or balancing authority area; (2) own, operate, or control electric transmission facilities in the relevant market or balancing authority area; or (3) have a franchised service territory in the relevant market or balancing authority area.[441] EPSA requests clarification of how the Commission would treat sellers that are part of joint ventures, whether they would be exempt from the organizational chart or require particular treatment in the organizational chart.[442]

330. Some commenters assert that if the Commission adopts this proposal, the Commission should allow exemptions for specific filers.[443] AEP notes that Order No. 717 eliminated a similar previous requirement for transmission providers to post an organizational chart of all affiliates, finding such a requirement to be an "undue burden

[440] E.ON at 15; EPSA at 16.

[441] E.ON at 15.

[442] EPSA at 16.

[443] *See, e.g.*, AEP at 19; EEI at 19; FirstEnergy at 15-16.

on transmission providers."[444] AEP also suggests that only filings that impact the organizational structure should require an organizational chart.[445] EEI similarly proposes that an organizational chart should not be required if "that applicant demonstrates that the proposed transaction does not affect the corporate structure of any party to the transaction."[446] FirstEnergy suggests that there should be no need for a seller to submit an organizational chart (1) if the seller and its affiliates operate within an RTO with Commission-approved market monitoring and mitigation procedures and rely on such procedures to address horizontal market power concerns or (2) if a seller has become affiliated with a new entity that owns generation or transmission assets and where the transaction has been approved by the Commission pursuant to its authority under section 203 of the FPA.[447]

331. If the Commission adopts the organizational chart proposal, some commenters suggest that the Commission allow flexibility for meeting this proposal.[448] The NRG Companies suggest that the Commission allow sellers to submit simplified

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[444] AEP at 9 (citing *Standards of Conduct for Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280, at P 243 (2008)).

[445] *Id.*

[446] EEI at 19.

[447] FirstEnergy at 15-16 (arguing that the requirement should be limited to circumstances in which the information may be useful to its review of an application for market-based rate authority).

[448] NRG Companies at 5; AEP at 10.

organizational charts that omit intermediate holding companies, energy subsidiaries and affiliates not relevant to the analysis in the applicable filings.[449] AEP proposes that market-based rate sellers be allowed to provide a link to an organizational chart on their websites or other accessible location.[450]

c. Commission Determination

332. We adopt the corporate organizational chart requirement with modifications and clarifications, as discussed below. We disagree with commenters' concerns that filing such charts will impose an undue burden on sellers. The Commission already requires sellers to file organizational charts for filings under FPA section 203, and, as EPSA notes, some companies already have organizational charts for other purposes. Furthermore, as acknowledged by some commenters, the information that the Commission would require in organizational charts does not materially differ from what is currently provided in narrative form in market-based rate filings. Thus, presenting this same information in a graphic format should not be unduly burdensome. Similarly, presenting organizational charts in market-based rate filings, rather than through links to a corporate website as proposed by AEP, should not be unduly burdensome.

333. However, in response to commenters' concerns, we provide further guidance regarding the extent to which upstream owners and affiliates need to be included in the corporate organizational charts. First, we find that the terms "energy subsidiaries" and

[449] NRG Companies at 5.

[450] AEP at 10.

"energy affiliates," as used in the FPA section 203 context and as originally proposed in the NOPR, are not meaningful in the market-based rate context. Instead, we clarify that instead of "indicating all upstream owners, energy subsidiaries, and energy affiliates" in the organizational chart, as proposed in the NOPR, filers should indicate all affiliates, as defined under section 35.36(a)(9) of the Commission's market-based rate regulations. Second, to minimize burdens on filers and to simplify the charts, we clarify that if an entity is owned by multiple individual investors, such investors may be grouped in the organizational chart as long as they are identified elsewhere in the filing.

334. We caution applicants to examine all upstream ownership information to ensure that all affiliates are captured in the chart. Applicants should not assume that upstream owners are not affiliates of the applicant without looking further up the ownership chain. For example, suppose the applicant (Company A) has four upstream owners (Companies B, C, D, and E) each of which owns 8 percent of the voting shares of A. If Company F owns 100 percent of the voting interests in Companies B, C, D, and E, under the Commission's affiliate definition, Company F indirectly owns 32 percent of Company A and should be listed in the chart as an affiliate of Company A. Furthermore, since Companies A, B, C, D, and E are all under the common control of Company F, Companies B, C, D, and E also are affiliated with Company A under the Commission's definition and should be depicted as such in the organizational chart, even though they own less than 10 percent of the voting interests in Company A. Further, as the Commission clarified in *Tonopah Solar Energy, LLC*, applicants are not permitted to use

a derivative share method to calculate ownership interests in downstream partially-owned entities for purposes of identifying affiliates.[451]

335. Consistent with our clarifications above, we will revise the regulatory text in 35.37(a)(2) to clarify that the organizational chart must include affiliates, without any further reference to "upstream owners," "energy subsidiaries," or "energy affiliates." We will also revise the regulatory text in section 35.42(c) of the Commission's regulations to require the submission of an organizational chart that depicts the seller's prior and new affiliations unless the change in status does not affect the seller's affiliations.

2. Single Corporate Tariff

a. Commission Proposal

336. In the NOPR, the Commission noted that when a corporate family has more than one affiliated seller, it may use a joint tariff. The Commission committed to clarify on its website how a corporate family that chooses to submit a joint master corporate tariff should identify its designated filer and what each of the other filers should submit into their respective eTariff databases. This information can be found on the Commission's website at http://www.ferc.gov/industries/electric/gen-info/mbr/tariff/joint.asp.

b. Comments

337. EEI appreciates the Commission's recognition that allowing joint filings for corporate families provides economy of effort to companies.[452] EEI encourages the

[451] *Tonopah Solar Energy*, *LLC*, 151 FERC ¶ 61,203, at PP 11-12 (2015).

Commission to continue working with companies to enable companies to file joint tariffs within their corporate families.[453]

c. Commission Determination

338. There is no opposition to the Commission's NOPR clarification. We reiterate that when a corporate family has more than one affiliated seller, it may use a joint master tariff. Filing instructions for entities wishing to use a joint tariff are available on the Commission's website, as stated above.

G. Part 101 and 141 Waivers

1. Commission Proposal

339. In the NOPR, the Commission noted that it has granted certain entities with market-based rate authority, such as power marketers and independent power producers, waiver of the Commission Uniform System of Accounts requirements, specifically Parts 41, 101, and 141 of the Commission's regulations, except sections 141.14 and 141.15. The Commission clarified that any waiver of Part 101 granted to a market-based rate seller is limited such that the waiver of the provisions of Part 101 that apply to hydropower licensees is *not* granted with respect to licensed hydropower projects. The Commission stated that hydropower licensees are required to comply with the requirements of the Uniform System of Accounts pursuant to 18 CFR Part 101 to the extent necessary to carry out their responsibilities under Part I of the FPA, particularly

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[452] EEI at 20.

[453] *Id.*

sections 4(b), 10(d) and 14 of the FPA.[454] The Commission further noted that a licensee's status as a market-based rate seller under Part II of the FPA does not exempt it from accounting responsibilities as a licensee under Part I of the FPA.[455] Thus, hydropower licensees that received waiver of Part 101 of the Commission's regulations as part of their market-based rate applications under Part II of the FPA are cautioned that such waivers do not relieve them of their obligations to comply with the Uniform System of Accounts to the extent necessary to carry out their responsibilities under Part I of the FPA with respect to their licensed projects.

340. The Commission further directed market-based rate sellers that own licensed hydropower projects to ensure that their market-based rate tariffs reflect appropriate

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[454] In *Trafalgar Power Inc.*, 87 FERC ¶ 61,207, at 61,798 n.46 (1999) (*Trafalgar Power*), the Commission stated:

> Under [s]ection 14 of the FPA, the Federal government may take over a project upon expiration of the project's licensee, conditioned upon the government's payment to the licensee of the 'net investment of the licensee in the project or projects taken.' Section 4(b) requires licensees to file a statement showing the 'actual legitimate original cost of construction of such project' to enable the Commission to determine 'the actual legitimate cost of and the net investment in' the project. Section 10(d) requires licensees to establish an amortization reserve account that will reflect excess or surplus earnings of their licensed project if such earnings have accumulated in excess of a reasonable rate of return upon the 'net investment' in the project during a period beginning after the first twenty years of operations. Pursuant to [s]ection 10 (d) of the FPA the amount transferred to the amortization reserve may be used to reduce a licensee's net investment in the project, and if, after expiration of the license, the government takes over the project under [s]ection 14, it will be required to compensate the licensee for its net investment in the project, reduced by the amortization reserve for the project.

[455] *See Seneca Gen., LLC et al.*, 145 FERC ¶ 61,096, at P 23 n.20 (2013) (*Seneca Gen*) (citing *Trafalgar Power*, 87 FERC at 61,798).

limitations on any waivers that previously have been granted. Specifically, to the extent that the hydropower licensee has been granted waiver of Part 101 as part of its market-based rate authority, the licensee's market-based rate tariff limitations and exemptions section should be revised to provide that the seller has been granted waiver of Part 101 of the Commission's regulations with the exception that waiver of the provisions that apply to hydropower licensees has not been granted with respect to licensed hydropower projects. Similarly, to the extent that a hydropower licensee has been granted waiver of Part 141 as part of its market-based rate authority, it should ensure that the limitation and exemptions section of its market-based rate tariff specifies that waiver of Part 141 has been granted, with the exception of sections 141.14 and 141.15 (which pertain to the filing by hydropower licensees of Form No. 80, Licensed Hydropower Development Recreation Report, and the Annual Conveyance Report).[456]

341. The Commission stated that these market-based rate tariff compliance filings are to be made the next time the hydropower licensee proposes a change to its market-based rate tariff, files a notice of change in status pursuant to 18 CFR 35.42, or submits an updated market power analysis in accordance with 18 CFR 35.37. In addition, going forward, any market-based rate seller requesting waivers of Parts 101 and/or 141 should include these limitations in their market-based rate tariffs, regardless of whether they own any licensed hydropower projects. This will ensure that hydropower licensees understand

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[456] *See Domtar Maine*, *LLC*, 133 FERC ¶ 61,207, at P 23 (2010).

the limitations on Parts 101 and 141 waivers. To the extent that the market-based rate seller is not a licensee, these limitations should not have any effect as they only deny waiver of certain provisions affecting licensees. If a market-based rate seller becomes a hydropower licensee after it receives market-based rate authority, it must file revisions to its market-based rate tariff to reflect the limitations in its Parts 101 and 141 waivers within 30 days of the effective date of its license.

2. Comments

342. Some commenters oppose the Commission's clarification that hydropower licensees are required to comply with the requirements of the Uniform System of Accounts pursuant to 18 CFR Part 101 to the extent necessary to carry out their responsibilities under Part I of the FPA.[457] They submit that the Commission in Order No. 697 decided against repealing waivers of the accounting requirements given to certain market-based rate entities, finding 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."[458] In addition, they assert that hydropower licensees with market-based rate authorizations neither sell at cost-based rates nor have captive customers.

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[457] EPSA at 17-18; NHA at 2-10; EEI at 21-22. *But see* APPA/NRECA at 5; Golden Spread at 7.

[458] *See, e.g.*, EPSA at 18 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 985).

343. Further, these commenters contend that requiring licensees to bring their accounts into conformance with the Uniform System of Accounts is not only unnecessary, but also would be costly and burdensome, require substantial work, and impose potential costs associated with hiring new accounting personnel, while yielding no identified benefit. According to commenters, hydropower licensees can already satisfy the statutory requirements in FPA Part I by employing Generally Applicable Accounting Principles.

344. National Hydropower Association (NHA) contends that the regulatory burden imposed on hydropower licensees to conform to the Uniform System of Accounts is disproportionate to the concern underlying the Commission's clarification of hydropower licensees' responsibilities, particularly sections 4(b), 10(d), and 14 of the FPA. According to NHA, the calculation of net investment and amortization reserves only becomes relevant in case of a federal takeover of the project under section 14 of the FPA and during relicensing, if the project is awarded to a competing applicant.[459] Further, NHA argues that there has not been a federal takeover of a licensed hydroelectric project and the Commission has yet to issue a new license to a competing applicant since the enactment of the FPA. Accordingly, NHA argues that the remote likelihood that a licensee will be paid its "net investment" for a project should allow licensees flexibility when complying with the FPA Part I statutory provisions identified in the NOPR.[460]

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[459] NHA at 6 (citing 16 U.S.C. §§ 807(a); 808(a)(1)).

[460] *Id.* at 7-8.

Additionally, NHA argues that, in similar circumstances where the Commission addressed the FPA compliance obligations in light of an evolving electric industry, the Commission chose to eliminate a regulatory burden.[461] Therefore, NHA asserts that since hydropower licensees can rely on Generally Accepted Accounting Principles to comply with applicable provisions of FPA Part I, the Commission's concerns regarding the FPA Part I provisions would not be implicated by allowing hydropower licensees to use Generally Accepted Accounting Principles to fulfill their statutory obligations. Thus, commenters ask the Commission to find that hydropower licensees can meet FPA Part I statutory requirements if they follow Generally Accepted Accounting Principles. However, if the Commission determines that licensees must comply with Part 101 in order to fulfill their statutory obligations under FPA Part I, then commenters request that the Commission: (1) provide guidance regarding which requirements of Part 101 it considers necessary to comply with FPA Part I;[462] (2) only apply this policy prospectively;[463] and (3) delay implementation of this policy for at least one year to provide sufficient time to allow affected licensees to bring their accounting ledgers into compliance.[464] Regarding which specific accounts the Commission would expect

[461] *Id.* at 8 (citing *Payment of Dividends From Funds Included in Capital Account*, 148 FERC ¶ 61,020 (2014)).

[462] EEI at 22; EPSA at 18; NHA at 8-9.

[463] EEI at 22; EPSA at 18; NHA at 8-9.

[464] EEI at 22; NHA at 8-9.

licensees to maintain, NHA and EEI state the Commission should limit the number of accounts it deems necessary for a hydropower licensee to carry out its responsibilities under FPA Part I in order to minimize cost and burden for companies.[465]

3. <u>Commission Determination</u>

345. We affirm the NOPR clarification that any waiver of Part 101 granted to a market-based rate seller is limited such that the waiver of the provisions of Part 101 that apply to hydropower licensees is *not* granted with respect to Commission-licensed hydropower projects. We recognize that in Order No. 697, the Commission concluded that "the costs of complying with the Commission's [Uniform System of Accounts] requirements and, specifically Parts 41, 101, and 141 of the Commission's regulations, outweigh any incremental benefits of such compliance where the seller only transacts at market-based rates."[466] However, a licensee's status as a market-based rate seller under Part II of the FPA does not exempt it from accounting responsibilities as a hydropower licensee under Part I of the FPA.[467] Thus, while hydropower licensees may have received waiver of Part 101 of the Commission's regulations as part of their market-based rate authorizations under Part II of the FPA, that waiver does not relieve them of their obligations to comply with the Uniform System of Accounts to the extent

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[465] EEI at 22: NHA at 9.

[466] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 985.

[467] *See Seneca Gen.*, 145 FERC ¶ 61,096 at P 23 n.20 (citing *Trafalgar Power*, 87 FERC at 61,798).

necessary to carry out their responsibilities under Part I of the FPA with respect to their licensed projects. Moreover, we note that such responsibilities to maintain the information required for compliance with Part 101 existed prior to the establishment of the Commission's market-based rate program.

346. Regarding comments that the Commission's clarification is not only unnecessary, but also would be costly and burdensome, require substantial work, and impose potential costs associated with hiring new accounting personnel, while yielding no identified benefit, we disagree. We find that use of Generally Accepted Accounting Principles will not satisfy the statutory requirements under FPA sections 4(b),[468] 14,[469] and 10(d).[470] Further, although NHA contends that the chances are remote that the United States federal government would take over a hydropower project under FPA section 14, the chance still exists. Under Part 101 of the Commission's regulations, licensed hydropower projects are required to maintain records that may be used to calculate net investment in the event that the Commission recommends that the United States federal government take over a hydropower project under FPA section 14 (or another entity takes over the license pursuant to FPA section 15). Thus, there is a need for licensees to

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[468] 16 U.S.C. § 797(b) (relating to determining actual legitimate original cost of and net investment in a licensed project).

[469] 16 U.S.C. § 807 (regarding the right of the Federal government to take over a project by paying the licensee its net investment).

[470] 16 U.S.C. § 803(d) (relating to surplus accumulated in excess of a specified reasonable rate of return and requirement to maintain amortization reserves that may be applied from time to time to reduce net investment).

maintain adequate books and records in case either of those situations occur. However, we will attempt to minimize the burden of compliance as discussed below.

347. We find that a hydropower licensee that sells only at market-based rates may meet its obligations to comply with the Uniform System of Accounts by following General Instruction No. 16 under Part 101 of the Commission's regulations.[471] Accordingly, we clarify that hydropower licensees that make sales only at market-based rates and that have been granted Commission waiver of Part 101 as part of their market-based rate tariffs may satisfy the requirements in Part 101 of the Commission's regulations by following General Instruction No. 16 under Part 101. We find that doing so will not be unduly burdensome. However, we further clarify that hydropower licensees that have a cost-based rate tariff on file with the Commission are still required to comply with the full requirements of FPA sections 4(b), 10(d), and 14 and the amortization reserve article in their licenses.

348. We deny commenters' request that the Commission implement these clarifications prospectively and delay the implementation for at least one year to provide sufficient time to allow affected licensees to bring their accounting ledgers into compliance. We find it is not unduly burdensome for a hydropower licensee that sells only at market-based rates to meet its longstanding obligation to comply with the

[471] 18 CFR pt. 101 (General Instruction No. 16).

Uniform System of Accounts by following General Instruction No. 16 under Part 101 of the Commission's regulations.

349. Accordingly, as discussed in the NOPR, we will direct market-based rate sellers that own licensed hydropower projects to ensure that their market-based rate tariffs reflect appropriate limitations on any waivers that previously have been granted. Specifically, to the extent that the hydropower licensee has been granted waiver of Part 101 as part of its market-based rate authority, the licensee's market-based rate tariff limitations and exemptions section should be revised to provide that the seller has been granted waiver of Part 101 of the Commission's regulations with the exception that waiver of the provisions that apply to hydropower licensees has not been granted with respect to licensed hydropower projects. Similarly, to the extent that a hydropower licensee has been granted waiver of Part 141 as part of its market-based rate authority, it should ensure that the limitation and exemptions section of its market-based rate tariff specifies that waiver of Part 141 has been granted, with the exception of sections 141.14 and 141.15 (which pertain to the filing by hydropower licensees of Form No. 80, Licensed Hydropower Development Recreation Report, and the Annual Conveyance Report).[472] As explained in the NOPR, these market-based rate tariff compliance filings are to be made the next time the hydropower licensee proposes a change to its market-based rate tariff, files a notice of change in status pursuant to 18 CFR 35.42, or submits

[472] *See Domtar Maine*, *LLC*, 133 FERC ¶ 61,207 at P 23.

an updated market power analysis in accordance with 18 CFR 35.37. In addition, going forward, any market-based rate seller requesting waivers of Parts 101 and/or 141 should include these limitations in its market-based rate tariffs, regardless of whether it owns any licensed hydropower projects. This will ensure that hydropower licensees understand the limitations on Parts 101 and 141 waivers. To the extent that the market-based rate seller is not a licensee, these limitations should not have any effect as they only deny waiver of certain provisions affecting licensees.

350. If an existing market-based rate seller becomes a hydropower licensee and the Commission previously accepted the seller's market-based rate tariff with full waivers without the limitations relating to hydropower licensees discussed herein, the seller must file revisions to its market-based rate tariff to reflect the limitations in its Parts 101 and 141 waivers within 30 days of the effective date of its hydropower license.

H. Miscellaneous Issues

1. Regional Reporting Schedule

a. Commission Proposal

351. In the NOPR, the Commission noted that that section 35.37(a)(1) of the Commission's regulations requires Category 2 sellers to submit a market power analysis according to the regional schedule contained in Order No. 697. The Commission proposed to revise section 35.37(a)(1) so that instead of referring to the schedule contained in Order No. 697, section 35.37(a)(1) would to refer to an updated regional

reporting schedule posted on the Commission's website.[473] The Commission noted that the revised regional reporting schedule and associated map may be found on the Commission's website at http://www.ferc.gov/industries/electric/gen-info/mbr/triennial/when.asp.

b. <u>Comments</u>

352. EEI encourages the Commission to confer with the regulated community before making changes in the schedule and map, to ensure that those changes are workable and appropriate.[474] Additionally, EEI states that one significant step that the Commission could undertake to reduce the burden on Category 2 sellers would be to extend the time frame for submitting updated analyses from every three years to every four to five years. EEI states that the Commission would continue to receive change in status filings as needed in the interim that would alert the Commission of changes occurring in a given market that might raise potential market power concerns, and if the Commission is concerned about those changes, the Commission already has the right to ask for more information or even an updated market power analysis from the seller filing the change in status report.[475]

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[473] The NOPR also included an updated region map in Appendix D.

[474] EEI at 22.

[475] *Id.* at 23.

c. **Commission Determination**

353. We adopt the NOPR's proposal to revise section 35.37(a)(1) of the Commission's regulations with regard to the regional reporting schedule. The regional reporting schedule and associated map can be found on the Commission's website.[476] In response to EEI's request that the Commission confer with the regulated community before making changes to the regional reporting schedule, we clarify that we are not changing the regional reporting schedule; we simply are changing the regulation to refer to the up-to-date schedule posted on the Commission's website. Our intention is to make the reporting schedule more transparent and accessible. We do not adopt EEI's suggestion to extend the time frame for submitting updated market power analyses from every three years to every four to five years. This suggestion is outside the scope of the NOPR. In any event, we believe that three years is a reasonable reporting schedule for filing updated market power analyses. EEI contends that sellers would submit change in status filings in the interim period. But change in status filings, while important, often lack the level of detail provided in updated market power analyses, such as indicative screens or SIL studies. Finally, in response to EEI's request that the Commission confer with the regulated community before making changes to the regional reporting schedule, we note that the region map is reflective of circumstances (such as mergers) that already have

[476] The regional reporting schedule and region map can be found on the Commission's website at http://www.ferc.gov/industries/electric/gen-info/mbr/triennial/when.asp. Additionally, we include the regional reporting schedule in Appendix C of this Final Rule and the region map in Appendix D of this Final Rule.

taken place. Future changes to the map would occur if, for example, a seller moved from an RTO in one region to an RTO in another region.

2. Affirmative Statement

a. Commission Proposal

354. In the NOPR, the Commission noted that in Order No. 697, as part of the vertical market power analysis, the Commission stated that it would require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. The Commission further noted that the requirement is codified at section 35.37(e)(4). The Commission explained that although the Commission stated in Order No. 697 that the obligation applies both to the seller and its affiliates,[477] many sellers have not mentioned their affiliates when making their affirmative statements. Therefore, the Commission proposed to revise section 35.37(e)(4) (which was proposed elsewhere in the NOPR to be renumbered as section 35.37(e)(3)) to make clear that the affirmative statement requirement applies to the seller and its affiliates.

b. Comments

355. APPA/NRECA and Golden Spread support clarifying that an applicant for market-based rate authority must affirmatively state, on behalf of itself and its affiliates, that they have not and will not erect barriers to entry in the relevant market(s).[478]

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[477] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447.

[478] APPA/NRECA at 5; Golden Spread at 7.

c. Commission Determination

356. We adopt the proposal in the NOPR concerning the affirmative statement. No adverse comments were filed with respect to this proposal. As noted above, this obligation already applies both to the seller and its affiliates. However, because many sellers have not mentioned their affiliates when making their affirmative statements, we adopt the proposal to revise the regulations to make it clear that the affirmative statement requirement applies to the seller and its affiliates. The revised regulation will appear at section 35.37(e)(3).

3. Comments of Barrick

a. Comments

357. Barrick Goldstrike Mines (Barrick) notes that the Commission previously found that "mitigated sellers *and their affiliates* are prohibited from selling power at market based rates in the balancing authority area in which the seller is found, or presumed, to have market power."[479] Barrick also notes that, in Order No. 697, the Commission recognized that wholesale sales made at the metered boundary for export lend themselves to being monitored for compliance and concluded to allow mitigated sellers to make such sales.[480] Barrick further notes that in Order No. 697, to ensure that the

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[479] Barrick at 6 (citing Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 at P 42) (emphasis added by Barrick). Barrick states that "affiliate" is broadly defined in the market-based rate regulation and may need to be refined to be limited to the relationship between a franchised public utility with captive customers and its associated market-regulated power sales company. *Id.*

[480] *Id.* at 7 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 820).

mitigated seller and its directly related companies did not sell the same power purchased by a third party at the metered boundary back into the balancing authority area where the seller is mitigated, the Commission imposed record keeping requirements for these sales.[481] Barrick states that, "rather than dealing with the additional regulatory burdens and risk of non-compliance," mitigated sellers may instead *choose* not to make any market-based rate sales at the metered boundary and that this is problematic.[482] Barrick argues that permitting affiliates to choose not to sell at a metered boundary hinders the development of more robust competition. Barrick also represents that Berkshire Hathaway Energy Company's affiliates have elected not to sell in a market based on a rebuttable presumption that a seller has market power, but have done nothing to rebut or substantiate that presumption.[483] Barrick suggests that the Commission reevaluate the mitigation rules and the definition of "affiliate" in certain cases.[484]

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[481] *Id.*

[482] *Id.* (emphasis by Barrick).

[483] *Id.* at 8-9.

[484] In particular, where (a) no RTO or ISO exists in the region so parties must depend on bilateral contracts; (b) dominant utility power suppliers with geographically large balancing authority areas and common ownership due to consolidation are present; (c) construction of electric generation facilities in these geographically large balancing authority areas is dominated by the utility power suppliers because they have relatively easy access to funding through retail ratepayer funding; and (d) dominant utility power suppliers are refusing to sell wholesale power into balancing authority areas, even where they have not been found to have market power. *Id.* at 7-8 (arguing that Order No. 697 did not adequately anticipate the possibilities brought about by the repeal of PUHCA of 1938, so now entities, are becoming too big to regulate with traditional rules).

358. Barrick further asserts that Order No. 697 should be amended in such a way to allow full optimization of imbalance energy across the broader footprint of CAISO Energy Imbalance Market[485] (EIM) and the sharing of other resources within the Northwest Power Pool.[486] Barrick states that the mitigation rules adopted in Order No. 697 cause imbalance energy across the broader CAISO EIM footprint to not be optimized despite the fact that transmission between the entities in the EIM is available, resulting in the inefficient implementation of the CAISO EIM.[487]

b. Commission Determination

359. With respect to Barrick's requests to revisit the Commission's findings in Order No. 697 that "mitigated sellers and their affiliates are prohibited from selling power at market-based rates in the balancing authority area in which the seller is found, or presumed, to have market power" and the definition of "affiliate," at least in certain

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[485] *Id.* at 10, 13 (citing *Cal. Indep. Sys. Operator Corp.*, Transmittal Letter, Docket No. ER14-1836-000 (filed Feb. 28, 2014) and *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 (2014)).

[486] *Id.* at 10-13.

[487] *Id.* at 11 (explaining that CAISO and NV Energy will be able to purchase and sell five-minute real-time energy under a market-driven regime for meeting energy imbalance needs, and CAISO and PacifiCorp will be able to purchase and sell five-minute real-time energy under a market-driven regime for meeting energy imbalance needs, but PacifiCorp and NV Energy will not be able to purchase and sell five-minute real-time energy under a market-driven regime for meeting energy imbalance needs).

cases, we find that they are beyond the scope of this rulemaking. Accordingly, we will not address Barrick's comments in this Final Rule.[488]

V. Section-by-Section Analysis of Regulations

1. Section 35.36 Generally

360. This section defines certain terms specific to Subpart H and explains the applicability of Subpart H.

361. The NOPR proposed to redefine "Category 1 Seller" in paragraph (a)(2) to clarify the distinction in determining the seller category status of power marketers and power producers. Specifically, that for purposes of determining category status, a power marketer should include all affiliated generation capacity in that region, but that a power producer only needs to include affiliated generation that is located in the same region as the power producer's generation assets.

362. The Final Rule adopts the regulatory text changes proposed in the NOPR regarding the definition of Category 1 Seller in paragraph (a)(2).

2. Section 35.37 Market power analysis required

363. This section describes the market power analysis the Commission employs, as discussed in the preamble, and when sellers must file one. It is intended to identify the key aspects of the analysis.

364. The NOPR proposed to change the reference in paragraph (a)(1) for the location

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[488] Additionally, reply comments were filed in response to Barrick's comments but they are not permitted in this proceeding.

of the regional reporting schedule from Order No. 697 to the Commission's website. The NOPR proposed to add a requirement in paragraph (a)(2) that sellers include as part of their updated market power analyses, an organizational chart depicting their current corporate structure, indicating all upstream owners, energy subsidiaries and energy affiliates. The NOPR proposed to revise paragraph (c)(4) to specify that sellers must file their indicative screens in an electronic spreadsheet format. The NOPR proposed to add paragraph (c)(5) to require that sellers use the format provided in Appendix A of subpart H of part 35 and, if applicable, file SIL Submittals 1 and 2 in the electronic spreadsheet format provided on the Commission's website. The NOPR also proposed to add paragraph (c)(6) to provide that sellers in RTO/ISO markets with Commission-approved market monitoring and mitigation may, in lieu of submitting the indicative screens, include a statement that they are relying on such mitigation to address any potential horizontal market power concerns. The NOPR proposed to remove paragraph (e)(2) to remove the requirement that sellers address sites for generation capacity development as part of their market power analyses and to renumber paragraphs (e)(3) and (e)(4) as paragraphs (e)(2) and (e)(3) respectively and to revise new paragraph (e)(3) to clarify that the vertical market power affirmative statement must be made on behalf of the seller and its affiliates.

365. The Final Rule adopts the regulatory text changes proposed in the NOPR regarding the location of the schedule for updated market power filings in paragraph (a)(1). The Final Rule also adopts the NOPR proposal to revise the language in paragraph (a)(2) to require an organizational chart; however the language varies from that

proposed in the NOPR to limit the organizational chart to depicting affiliates as discussed in the Corporate Families discussion above. The Final Rule also adopts the NOPR regulatory text changes to paragraphs (c)(4) and (c)(5) regarding submission of the indicative screens and SIL Submittals 1 and 2 in electronic spreadsheet formats. Consistent with the Horizontal Market Power discussion, the Final Rule does not adopt the NOPR proposal to add a new paragraph allowing sellers in RTO/ISO markets to rely on market monitoring and mitigation in lieu of submitting indicative screens. The Final Rule adopts the NOPR proposal to amend the language of paragraph (e)(3) to clarify that the affirmative statement must be made on behalf of the seller and its affiliates.

3. Section 35.42 Change in status reporting requirement

366. The NOPR proposed several revisions to the regulation, including a change to paragraph (a)(1) to clarify that the 100 MW reporting threshold is not limited to market previously studied and includes both the relevant market and any first-tier markets. The NOPR proposed a change to paragraph (a)(2)(i) to apply a 100 MW threshold for reporting new affiliations and to include in that threshold long-term firm purchases of capacity and/or energy and to included cumulative increases in the first-tier markets as well as the relevant market. The NOPR also proposed to revise paragraph (c) to require sellers to submit organizational chart unless the change in status does not affect the seller’s structure. In addition, the NOPR proposed revisions to paragraph (b) to remove a reference to change in status filings to report acquisition of control of sites for new

generation capacity development and to remove paragraphs (d) and (e), which address site control reporting, which is being eliminated as explained in the Notices of Change in Status discussion.

367. The Final Rule adopts the proposed edits to paragraph (a) except as discussed herein. In paragraphs (a)(1) and (a)(2)(i), the language proposed in the NOPR including first-tier markets is not included in accordance with the Notices of Change in Status discussion and the requirement is limited to 100 MW or more change in any *individual* relevant geographic market. The Final Rule adopts the NOPR proposal to add a 100 MW threshold to the change in status reporting requirement and, consistent with the Capacity Ratings discussion, adds language in paragraph (a)(2)(i) to specify that energy-limited resources may use a five-year capacity rating for purposes of calculating the threshold.

368. Consistent with the Vertical Market Power – Land Acquisition Reporting discussion, the Final Rule adopts the proposals to remove references to reporting new sites for generation capacity development, removing paragraphs (d) and (e) in their entirety and deleting the reference to site reporting from paragraph (b).

369. Finally, the Final Rule adopts the proposed edits to paragraph (c) except as discussed herein. Consistent with the Corporate Organizational Charts discussion, the Final Rule does not include the reference to upstream owners and energy subsidiaries, and requires only that the organizational charts indicate all affiliates.

4. Miscellaneous

VI. **Information Collection Statement**

370. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[489] 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.

371. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[490] In the NOPR, the Commission solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission included a table that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements.

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[489] 5 CFR 1320.11(b) (2015).

[490] 44 U.S.C. 3507(d) (2012).

Comments

372. In response to the Commission's proposals regarding changes to the indicative screen reporting requirements, EEI notes that, if the Commission wants sellers to submit the indicative screens in Appendix A in formats other than the standard formats, such as Adobe, Excel, or Word, the Commission should acknowledge that requiring the use of more complex formats and new details in Appendix A will entail some additional burden on sellers filing the information, at least during the initial round of using such formats.[491]

Commission Determination

373. We revise the Information Collection Statement estimates contained in the NOPR because the Commission has made several changes to its NOPR proposal in this Final Rule, which are discussed below.

374. First, we do not adopt in the Final Rule the NOPR proposal to eliminate the requirement in section 35.37[492] to file the indicative screens as part of a horizontal market power analysis for any seller in an RTO if the seller is relying on Commission-approved monitoring and mitigation to mitigate any potential market power it may have. The NOPR presupposed a decrease in its burden estimate regarding this proposal, and we have adjusted the burden estimate in the table below to reflect that this burden will not change from current regulations.

[491] EEI at 10.

[492] 18 CFR 35.37.

375. Second, we will modify the NOPR's proposal to require sellers to file corporate organizational charts including all upstream owners, energy subsidiaries, and energy affiliates in initial market-based rate applications and related filings. The organizational charts will still be required, but they will be limited to include the seller's affiliates as defined in section 35.36(a)(9) of the Commission's regulations rather than all upstream owners, "energy subsidiaries" and "energy affiliates." This modification of the NOPR proposal constitutes a small burden decrease from the NOPR. Because the corporate organizational chart filing is similar to that proposed in the NOPR, we are not modifying the estimated public reporting burdens for this proposed reporting requirement in the table below. We believe that the revised burden estimates below are representative of the average burden on filers.

376. Third, we do not adopt the NOPR proposal to clarify that sellers must report behind-the-meter generation in the indicative screens and asset appendices, and have such generation count toward change in status and category status thresholds. These changes represent a small decrease in burden due to the reduction in filings from not including behind-the-meter generation as part of the 100 MW generation threshold to trigger filing a notice of change in status for new affiliations.

377. Fourth, we modify the NOPR's proposed changes to the asset appendix by (1) requiring separate worksheets in the Asset Appendix for long-term PPAs and end notes, (2) adding new columns to the generation asset list for explanatory end note numbers and information regarding capacity ratings, and (3) adding new columns to the transmission list for citation to the order accepting the OATT or approving transfer of

transmission facility to an RTO/ISO and explanatory end note numbers. The NOPR presupposed a burden decrease in its burden estimate regarding this proposal, and we have adjusted the burden estimate in the table below to reflect that, as amended, the burden will not change from current regulations. While these changes represent a small increase in burden, this burden is counterbalanced by the decrease in burden from eliminating the proposed requirements to report behind-the-meter generation in indicative screens and for change in status and seller category thresholds. Thus, we believe that the overall burden will not change when these two changes are averaged together.

378. In response to EEI's comment that the use of more complex formats for indicative screens will entail additional burden, Commission regulations already require the submission of indicative screens, and the Final Rule adopts the NOPR proposal to require these screens in electronic format. We view this as a *de minimis* decrease in burden for several reasons. While the new rows in the indicative screens may appear to require additional information to complete the screens (e.g., rows A1, B1, L1, M, U, and V in the market share screen), the information entered in these new rows is simply disaggregated information that was previously required, but often erroneously aggregated into values in other rows. Requiring sellers to explicitly enter this information will reduce computation errors and subsequent phone calls from staff to correct problems in the screens. Also, these new screens are workable electronic spreadsheets with pre-programmed formulas in certain cells that compute intermediate and final cell values. Embedding these pre-programmed formulas into the worksheet

will reduce the amount of time that sellers will spend creating and calculating the indicative screens, increase the accuracy of the values entered (e.g., sellers will now enter only positive values and no longer have to enter values surrounded by parentheses to indicate a negative value), and eliminate computation errors that sellers have frequently made in the past. Thus, we consider the electronic format and the additional columns of information in the indicative screens to average out to be a *de minimis* decrease in burden for filers and project that the average burden on filers will not change from current regulations.

FERC-919 (Final Rule in RM14-14-000)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[493] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
New Applications for Market-Based Rates (18 CFR 35.37	213	1	213	250[494] $21,268	53,250 $4,529,998	$21,268

[493] The Commission estimates this figure based on the Bureau of Labor Statistics data (for the Utilities sector, at http://www.bls.gov/oes/current/naics2_22.htm, plus benefits information at http://www.bls.gov/news.release/ecec.nr0.htm). The salaries (plus benefits) for the three occupational categories are:

- Economist: $67.75/hour
- Electric Engineer: $59.62/hour
- Lawyer: $128.02/hour

($67.57 + $59.62 + $128.02) ÷ 3 = $85.07

[494] The Commission notes that the estimate of 250 hours per new application is a conservative estimate and most likely overstates burden because some sellers (i.e., power marketers with no generation to study and sellers that only have fully committed generation) will not have to file indicative screens with their initial applications.

Triennial Market Power Analysis in Category 2 Seller Updates (18 CFR 35.37)	83	1	83	250 $21,268	20,750 $1,765,203	$21,268
Quarterly Land Acquisition Reports [18 CFR 35.42(d)]	0	0	0	0 $0	0 $0	$0
Change in Status Reports [18 CFR 35.42(a)], With Screens	27	1	27	250 $21,268	6,750 $574,222	$21,268
Change in Status reports [18 CFR 35.42(a)], No Screens	186	1	186	20 $1,701	3,720 $316,460	$1,701
TOTAL			**509**		**84,470** **$7,185,883**	**$14,118**

After implementation of the proposed changes, the total estimated annual cost of burden to respondents is $7,185,882.90 [84,470 hours × $85.07[495]) = $7,185,882.90].

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

[495] The Commission estimates this figure based on the Bureau of Labor Statistics data (for the Utilities sector, at http://www.bls.gov/oes/current/naics2_22.htm, plus benefits information at http://www.bls.gov/news.release/ecec.nr0.htm). The salaries (plus benefits) for the three occupational categories are:

- Economist: $67.75/hour
- Electric Engineer: $59.62/hour
- Lawyer: $128.02/hour

($67.57+$59.62+$128.02) /3 = $85.07

Action: 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.

Frequency of Responses:

Initial Applications: On occasion.

Updated Market Power Analyses: Updated market power analyses are filed every three years by Category 2 sellers seeking to retain market-based rate authority.

Land Acquisitions: We will eliminate this requirement under the Final Rule.

Change in Status Reports: On occasion.

Necessity of the Information:

Initial Applications: In order to receive market-based rate authority, the Commission must first evaluate whether a seller has the ability to exercise market power. Initial applications help inform the Commission as to whether an entity seeking market-based rate authority lacks market power, and whether sales by that entity will be just and reasonable.

Updated Market Power Analyses: Triennial updated market power analyses allow the Commission to monitor market-based rate sellers to detect changes in market power or potential abuses of market power. The updated market power analysis permits the Commission to determine that continued market-based rate authority will still yield rates that are just and reasonable.

Change in Status Reports: The change in status requirement provides the Commission with information regarding changes that could affect facts the Commission relied upon in granting market-based rate authority and thus permits the Commission to ensure that rates and terms of service offered by market-based rate sellers remain just and reasonable.

Internal Review: The Commission has reviewed the reporting requirements and made a determination that revising the reporting requirements will ensure the Commission has the necessary data to carry out its statutory mandates, while eliminating unnecessary burden on industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

379. 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 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 e-mail to OMB at oira_submission@omb.eop.gov. Comments submitted to OMB should refer to FERC-919 and OMB Control Number 1902-0234.

VII. Environmental Analysis

380. 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.[496] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural, or that do not substantially change the effect of the regulations being amended.[497] The actions here fall within this categorical exclusion in the Commission's regulations.

VIII. Regulatory Flexibility Act

381. The Regulatory Flexibility Act of 1980 (RFA)[498] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. Thus, the Commission estimates that the rulemaking will impose only a minimal additional burden on responsible entities, as described below.

382. The final rule in RM14-14-000 is expected to impose an additional burden on 2,002 entities. Comparison of the applicable entities with FERC's small business data

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[496] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[497] 18 CFR 380.4(a)(2)(ii).

[498] 5 U.S.C. 601-612 (2012).

indicates that approximately 1,634, or 82 percent[499] of the 2,002 entities are small entities affected by this Final Rule.[500]

383. On average, each small entity affected may have a one-time cost of $4,207.19, representing 84,470 hours at $67.57/hour (for economists), $59.62/hour (for electrical engineers), and $128.02/hour (for lawyers). These figures represent the implementation burden of the changes to FERC-919 per the RM14-14-000 Final Rule, as explained above in the information collection statement. Accordingly, the Commission certifies that this rulemaking will not have a significant economic impact on a substantial number of small entities. The Commission seeks comment on this certification.

IX. Document Availability

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

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[499] 81.6 percent.

[500] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company’s number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this Final Rule, we use a 750 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121), Fossil Fuel Generation (NAICS code 221112), or Nuclear Power Generation (NAICS code 221113).

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

386. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's 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.

X. Effective Date and Congressional Notification

387. This Final Rule is effective **[insert date 90 days after publication in the Federal Register]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, and Government Accountability Office.

List of subjects in 18 CFR Part 35

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

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

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

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

2. Amend § 35.36 by revising paragraph (a)(2) to read as follows:

§ 35.36 Generally.

(a) * * *

(2) *A Category 1 Seller* means a Seller that:

(i) Is either a wholesale power marketer that controls or is affiliated with 500 MW or less of generation in aggregate per region or a wholesale power producer that owns, controls or is affiliated with 500 MW or less of generation in aggregate in the same region as its generation assets;

(ii) Does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or has been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036);

(iii) Is not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the Seller's generation assets;

(iv) Is not affiliated with a franchised public utility in the same region as the Seller's generation assets; and

(v) Does not raise other vertical market power issues.

* * * * *

3. Amend § 35.37 as follows:

a. In paragraph (a)(1), remove the phrase “contained in Order No. 697, FERC Stats. & Regs. ¶ 31,252” and add in its place “posted on the Commission’s website.”

b. Revise paragraphs (a)(2) and (c)(4).

c. Add paragraph (c)(5).

d. Remove paragraph (e)(2) and redesignate paragraphs (e)(3) through (4) as paragraphs (e)(2) through (3), respectively.

e. Revise newly redesignated paragraph (e)(3).

The revisions and additions read as follows:

§ 35.37 Market Power analysis required.

(a) * * *

(2) When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets, in the form provided in Appendix B of this subpart, and an organizational chart. The organizational chart must depict the Seller’s current corporate structure indicating all affiliates.

* * * * *

(c) * * *

(4) When submitting the indicative screens, a Seller must use the format provided in Appendix A of this subpart and file the indicative screens in an electronic spreadsheet format. A Seller must include all supporting materials referenced in the

indicative screens.

(5) Sellers submitting simultaneous transmission import limit studies must file Submittal 1, and, if applicable, Submittal 2, in the electronic spreadsheet format provided on the Commission's website.

* * * * *

(e) * * *

(3) A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it and its affiliates have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

* * * * *

4. Amend § 35.42 as follows:

a. Revise paragraphs (a)(1), (a)(2), and (c).

b. In paragraph (b), remove the phrase ", other than a change in status submitted to report the acquisition of control of a site or sites for new generation capacity development,".

c. Remove paragraphs (d) and (e).

The revisions 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 nameplate capacity in any individual relevant geographic market, or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

(2) Affiliation with any entity not disclosed in the application for market-based rate authority that:

(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 energy-limited resources, five-year average capacity factors, in any individual relevant geographic market;

(ii) Owns or controls inputs to electric power production;

(iii) Owns, operates or controls transmission facilities; or

(iv) Has a franchised service area.

* * * * *

(c) When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of all assets, including the new assets and/or affiliates reported in the change in status, in the form provided in Appendix B of this subpart, and an organizational chart. The organizational chart must depict the

Seller's prior and new corporate structures indicating all affiliates unless the Seller demonstrates that the change in status does not affect the corporate structure of the Seller's affiliations.

5. Revise Appendix A to Subpart H to read as follows:

Appendix A to Subpart H of Part 35

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part I – Pivotal Supplier Analysis

Staff Notes:

The file differs from the file published in the NOPR:
1. All entered values must be positive (no parenthesis/negative numbers)
2. The formulas (and the text in the row description) have been changed to reflect number 1.
3. The text in row 13 "Date of Filing" has been replaced with "Data Year"
4. Instruction**:** *Enter all numeric values as positive numbers (blue values)*

Don't enter values into an outlined cell (black values)

Applicant-> **Company X, LLC (TO)**
Market -> **Company X BAA**
Data Year -> **Dec 2011-Nov 2012**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	1,500	worksheet X
A1	Remote Capacity (from outside the study area)	200	worksheet X
B	Long-Term Firm Purchases (from inside the study area)	70	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	500	worksheet X
D	Uncommitted Capacity Imports	0	worksheet X
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	300	worksheet X
E1	Remote Capacity (from outside the study area)	50	worksheet X
F	Long-Term Firm Purchases (from inside the study area)	40	worksheet X
F1	Long-Term Firm Purchases (from outside the study area)	40	worksheet X
G	Long-Term Firm Sales (in and outside the study area)	60	worksheet X
H	Uncommitted Capacity Imports	2,500	worksheet X
I	Study Area Reserve Requirement	300	worksheet X
J	Amount of Line I Attributable to Seller, if any	200	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,840	
	Load		
L	Balancing Authority Area Annual Peak Load	1,500	worksheet X
M	Average Daily Peak Native Load in Peak Month	1,200	worksheet X
N	Amount of Line M Attributable to Seller, if any	900	worksheet X
O	Wholesale Load (L-M)	300	
P	Net Uncommitted Supply (K-O)	2,540	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	370	

Result of Pivotal Supplier Screen (Pass if Line Q < Line P) **Pass**
(Fail if Line Q > Line P)

Total Imports (Sum D,H), as filed by Seller ->	2,500
% of SIL for Seller's imported capacity ->	0.00
% of SIL for Other's imported capacity ->	1.00
SIL value* ->	2,500
Do Total Imports exceed the SIL value? ->	No

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part II – Market Share Analysis

Staff Notes:

The file differs from the file published in the NOPR:

1. All entered values must be positive (no parenthesis/negative numbers)
2. The formulas (and the text in the row description) have been changed to reflect number 1.
3. Instruction**:** *Enter all numeric values as positive numbers (blue values)*

Don't enter values into an outlined cell (black values)

Applicant-> **Company X, LLC (TO)**
Study Area -> **Company X BAA**
Data Year -> **Dec 2011-Nov 2012**

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	**Reference**
		As filed by the Applicant/Seller				
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	1,000	900	1,500	1,000	worksheet X
A1	Remote Capacity (from outside the study area)	400	300	200	200	worksheet X
B	Long-Term Firm Purchases (inside the study area)	60	40	70	30	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	200	200	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	500	500	500	500	worksheet X
D	Seasonal Average Planned Outages	150	50	80	100	worksheet X
E	Uncommitted Capacity Imports	0	0	0	0	worksheet X
	Capacity Deductions					
F	Average Peak Native Load in the Season	1,000	900	1,200	800	worksheet X
G	Amount of Line F Attributable to Seller, if any	700	700	900	600	worksheet X
H	Amount of Line F Attributable to Non-Affiliates, if any	300	200	300	200	
I	Study Area Reserve Requirement	200	200	300	100	worksheet X
J	Amount of Line I Attributable to Seller, if any	100	100	200	80	worksheet X
K	Amount of Line I Attributable to Non-Affiliates, if any	100	100	100	20	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	250	200	300	150	worksheet X
L1	Remote Capacity (from outside the study area)	50	50	50	50	worksheet X
M	Long-Term Firm Purchases (inside the study area)	30	30	30	30	worksheet X
M1	Long-Term Firm Purchases (from outside the study area)	40	30	40	20	worksheet X
N	Long-Term Firm Sales (in and outside the study area)	50	30	60	50	worksheet X
O	Seasonal Average Planned Outages	10	20	10	20	worksheet X
P	Uncommitted Capacity Imports	2,000	1,500	2,500	1,300	worksheet X
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	1,910	1,460	2,450	1,260	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	210	90	290	150	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,120	1,550	2,740	1,410	
T	**Seller's Market Share** (R÷S)	9.9%	5.8%	10.6%	10.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	2,000	1,500	2,500	1,300	
V	SIL value*	2,000	1,500	2,500	1,300	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

6. Revise Appendix B to Subpart H to read as follows:

Appendix B to Subpart H of Part 35

	Instructions for completing the Asset Appendix list: 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: ##XX-XXX-XXX where "##" is either "ER" or "QF" and "X" is a digit	If applicable, Docket Number where MBR or QF status was originally granted. Can be an ER, EL or QF Docket.
[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]	Market / Balancing Authority Area	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For BAAs 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, APsouth, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC defined Balancing Authority Area name.
[H]	Geographic Region	Specific Text	One of the six MBR regions: Northeast, Southeast, Central, SPP, Southeast, Southwest; or "N/A"
[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 for that unit(s)
[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.
[M]	End Note Number (Enter text in End Note Tab)	Integer	The number of the explanatory note in "End Notes" worksheet that refers to this entry. The numbers should be ascending integers throughout the appendix. If there are three notes in the Generation worksheet tab, then the first end note in the Transmission tab should be "four" (please do not start over with a new numbering sequence)

	Instructions for completing the Asset Appendix list: Long-term Purchased Power 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]	Docket # where MBR authority was granted	Text in the form: ##XX-XXX-XXX where "##" is either "ER" or "QF" and "X" is a digit	Same instruction as the Generation Assets Tab.
[C]	Seller Name	Free Form Text	Name of the Entity that is selling the energy or capacity.
[D]	Amount of PPA (MW)	Numeric. Either an integer or fixed width numeric with one decimal	Contracted amount of MW of the PPA. If the contract is for the entire output of a specific generation facility, you may de-rate the facility 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 section. Energy only contracts must be converted from MwH to MW and only report contracts one year or longer
[E]	Market / Balancing Authority Area	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For BAAs please use the NERC defined name	The RTO/ISO, RTO/ISO submarket, or NERC defined balancing authority area where the generation or capacity is physically located.
[F]	Geographic Region	Specific Text	Same instruction as the Generation Assets Tab
[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]	End Note Number (Enter text in End Note Tab)	Integer	Same instruction as the Generation Assets Tab

	Instructions for completing the Asset Appendix list: Transmission and Natural Gas Assets		
Column	**Title**	**Format**	**Description**
[A]	Filing Entity and its Energy Affiliates		Same instruction as the Generation Assets Tab
[B]	Cite to order accepting OATT or the order approving the transfer of transmission facilities to an RTO or		Commission cite to the order accepting the Filing Entity's or its Energy Affiliates' current OATT, or the order transferring control of 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		Same instruction as the Generation Assets Tab
[E]	Controlled By		Same instruction as the Generation Assets Tab
[F]	Date Control Transferred		Same instruction as the Generation Assets Tab
[G]	Market / Balancing Authority Area		Same instruction as the Generation Assets Tab
[H]	Geographic Region		Same instruction as the Generation Assets Tab
[I]	Size (length and kV)	Free Form Text	Description of the size in 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 Note Tab)		Same instruction as the Generation Assets Tab

	Instructions for completing the Asset Appendix list: End Notes		
Column	**Title**	**Format**	**Description**
[A]	End Note Number	Integer	Should match an End Note number in the "Generation Assets", "PPA" or "Transmission" lists
[B]	List (Generation, PPA or Transmission)	The words "Generation", "PPA", or "Transmission"	Indicates which asset list the end note is located
[C]	Explanatory Note	Free Form Text	Text providing the clarification or explanatory note.

Asset Appendix: Generation Assets

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

[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 Note Tab)

Asset Appendix: Long-Term Purchased Power Agreements (PPA)

This is an example of the required appendix listing the filing entity and all its long -term purchased power agreements that must be submitted with some market-based rate filings.

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]
				Location				
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority Area	Geographic Region	Start Date (mo/da/yr)	End Date (mo/da/yr)	End Note Number (Enter text in End Note Tab)

Asset Appendix: Transmission Assets / Natural Gas Assets

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 some market-based rate filings.

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: (length and kV)	End Note Number (Enter text in End Note Tab)

Asset Appendix: End Notes

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 some market-based rate filings.

End Notes for Entries in the Generation, Long-term PPA and Transmission Lists

[A]	[B]	[C]
End Note Number	List (Generation, PPA or Transmission)	Explanatory Note

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

Appendix C

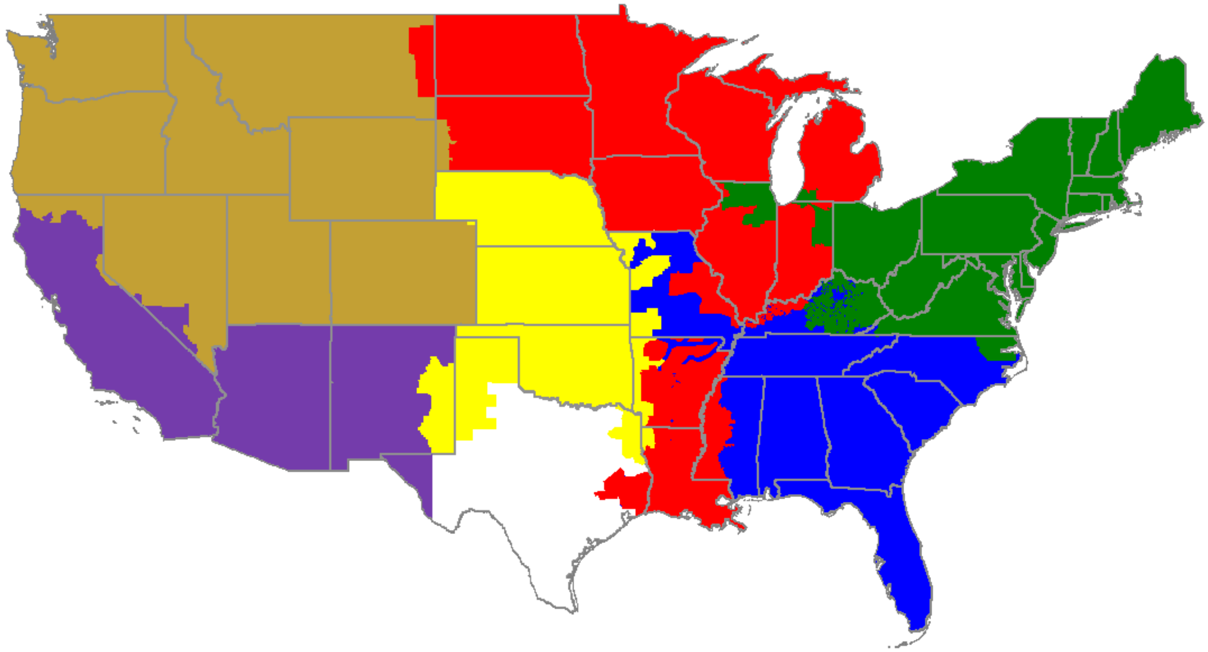
Schedule for Transmission Owning Utilities with Market-based Rate Authority that are Designated as Category 2 Sellers in the Region							
Entities Required to File		**Study Period**					**Filing Period (anytime during this month)**
Northeast	Transmission Owning Utilities	December	2011	to	November	2012	December: 2013
Southeast	Transmission Owning Utilities	December	2011	to	November	2012	June: 2014
Central	Transmission Owning Utilities	December	2012	to	November	2013	December: 2014
SPP	Transmission Owning Utilities	December	2012	to	November	2013	June: 2015
Southwest	Transmission Owning Utilities	December	2013	to	November	2014	December: 2015
Northwest	Transmission Owning Utilities	December	2013	to	November	2014	June: 2016
Northeast	Transmission Owning Utilities	December	2014	to	November	2015	December: 2016
Southeast	Transmission Owning Utilities	December	2014	to	November	2015	June: 2017
Central	Transmission Owning Utilities	December	2015	to	November	2016	December: 2017
SPP	Transmission Owning Utilities	December	2015	to	November	2016	June: 2018
Southwest	Transmission Owning Utilities	December	2016	to	November	2017	December: 2018
Northwest	Transmission Owning Utilities	December	2016	to	November	2017	June: 2019
Northeast	Transmission Owning Utilities	December	2017	to	November	2018	December: 2019
Southeast	Transmission Owning Utilities	December	2017	to	November	2018	June: 2020
Central	Transmission Owning Utilities	December	2018	to	November	2019	December: 2020
SPP	Transmission Owning Utilities	December	2018	to	November	2019	June: 2021
Southwest	Transmission Owning Utilities	December	2019	to	November	2020	December: 2021
Northwest	Transmission Owning Utilities	December	2019	to	November	2020	June: 2022
Northeast	Transmission Owning Utilities	December	2020	to	November	2021	December: 2022
Southeast	Transmission Owning Utilities	December	2020	to	November	2021	June: 2023
Central	Transmission Owning Utilities	December	2021	to	November	2022	December: 2023
SPP	Transmission Owning Utilities	December	2021	to	November	2022	June: 2024
Southwest	Transmission Owning Utilities	December	2022	to	November	2023	December: 2024
Northwest	Transmission Owning Utilities	December	2022	to	November	2023	June: 2025

Appendix C1

Schedule for Non-Transmission Owning Utilities with Market-based Rate Authority that are Designated as Category 2 Sellers in the Region								
Entities Required to File		**Study Period**						**Filing Period (anytime during this month)**
Northwest	Non-Transmission Owning Utilities	December	2010	to	November	2011		December: 2013
Northeast	Non-Transmission Owning Utilities	December	2011	to	November	2012		June: 2014
Southeast	Non-Transmission Owning Utilities	December	2011	to	November	2012		December: 2014
Central	Non-Transmission Owning Utilities	December	2012	to	November	2013		June: 2015
SPP	Non-Transmission Owning Utilities	December	2012	to	November	2013		December: 2015
Southwest	Non-Transmission Owning Utilities	December	2013	to	November	2014		June: 2016
Northwest	Non-Transmission Owning Utilities	December	2013	to	November	2014		December: 2016
Northeast	Non-Transmission Owning Utilities	December	2014	to	November	2015		June: 2017
Southeast	Non-Transmission Owning Utilities	December	2014	to	November	2015		December: 2017
Central	Non-Transmission Owning Utilities	December	2015	to	November	2016		June: 2018
SPP	Non-Transmission Owning Utilities	December	2015	to	November	2016		December: 2018
Southwest	Non-Transmission Owning Utilities	December	2016	to	November	2017		June: 2019
Northwest	Non-Transmission Owning Utilities	December	2016	to	November	2017		December: 2019
Northeast	Non-Transmission Owning Utilities	December	2017	to	November	2018		June: 2020
Southeast	Non-Transmission Owning Utilities	December	2017	to	November	2018		December: 2020
Central	Non-Transmission Owning Utilities	December	2018	to	November	2019		June: 2021
SPP	Non-Transmission Owning Utilities	December	2018	to	November	2019		December: 2021
Southwest	Non-Transmission Owning Utilities	December	2019	to	November	2020		June: 2022
Northwest	Non-Transmission Owning Utilities	December	2019	to	November	2020		December: 2022
Northeast	Non-Transmission Owning Utilities	December	2020	to	November	2021		June: 2023
Southeast	Non-Transmission Owning Utilities	December	2020	to	November	2021		December: 2023
Central	Non-Transmission Owning Utilities	December	2021	to	November	2022		June: 2024
SPP	Non-Transmission Owning Utilities	December	2021	to	November	2022		December: 2024
Southwest	Non-Transmission Owning Utilities	December	2022	to	November	2023		June: 2025

Appendix D

Generalized Map of Geographic Regions



Northeast (ISO-NE, NYISO, PJM)

Southeast (SERC and FRCC NERC Regions, excluding for PJM and MISO members)

Central (Midcontinent Independent System Operator (MISO) and members of the Midwest Reliability Organization (MRO) that are not part of another RTO)

Southwest Power Pool (SPP NERC Region, excluding MISO members)

Southwest (Arizona, most of California, part of Nevada and the portions of New Mexico and Texas within the Western Interconnection)

Northwest (The remainder of the Western Interconnection)

Appendix E

Required Reporting for Simultaneous Import Limit (SIL) Studies, with Numerical Examples

Submittal 1: Summary Table of the Components Used to Calculate SIL Values

Table 1: SIL Computation

Instructions:

1 Delete the text 'XX' in the heading 'Study Period' and enter the last two digits of the years in the study period.
2 Delete the text 'Name of Home BAA/Market' and enter the name of the study area.
3 If you are studying more than one first-tier area, copy the relevant columns of Table 1 to empty columns on the right of this spreadsheet for each of the first-tier areas studied.
4 If you are studying first-tier areas, replace the text 'Name of First-Tier BAA/Market' with the name of the first-tier area(s).
5 Do not enter data in the white-background cells as these contain formulas which compute the cell values, enter all megawatt values as non-negative integers in rows 1 through 3, 7 and 9 (the blue-shaded cells).
6 Note that row 5 in Table 1 is the sum of the seasonal columns from row 9 of Table 2.
7 Include an electronic copy of this spreadsheet, or a workable electronic spreadsheet with the same format and formulas as the sample spreadsheet on the Commission Web site, with your filing.
8 The SIL Study Values (i.e., row 10 of Table 1) must be filed as part of a public document. (see note below)*
NOTE: See the footnotes below for further instruction and references to prior Commission direction on the component or calculation in that row.

Study Period: December 1, 20XX to November 30, 20XX

		Name of Home BAA/Market				Name of First-Tier BAA/Market			
	Description of Component	**Winter (MW)**	**Spring (MW)**	**Summer (MW)**	**Fall (MW)**	**Winter (MW)**	**Spring (MW)**	**Summer (MW)**	**Fall (MW)**
1	**Simultaneous Incremental Transfer Capability** The most limiting First Contingency Incremental Transfer Capability (FCITC), Normal Incremental Transfer Capability (NITC) or equivalent values. *Note i*	1,700	1,800	1,900	2,000	3,000	3,200	3,400	3,600
2	**Modeled Net Area Interchange** (NAI) Enter a positive value and indicate the direction of flow in row 3 below. *Note ii*	500	600	700	800	200	300	400	500
3	**Interchange Direction** Indicate whether the Study Area NAI is export or import.	Import	Import	Import	Import	Export	Export	Export	Export
4	**Total Simultaneous Transfer Capability** (row 4 = row 1 +/- row 2). *Note iii*	2,200	2,400	2,600	2,800	2,800	2,900	3,000	3,100
5	**Long-Term Firm Transmission Reservations** Sum of the long-term firm transmission reservations from Table 2. *Note iv*	620	300	620	300	460	360	460	360
6	**Calculated SIL Value** (row 6 = row 4 - row 5). *Note v*	1,580	2,100	1,980	2,500	2,340	2,540	2,540	2,740
7	**Historical Peak Load** (Identify source if not from FERC Form No. 714). *Note vi*	1,400	1,900	2,500	2,000	1,400	1,900	2,500	2,000
8	**Adjusted Historical Peak Load** (row 8 = row 7 - row 5). *Note vii*	780	1,600	1,880	1,700	940	1,540	2,040	1,640
9	**Uncommitted First-Tier Generation** Amount of uncommitted generation modeled in the first-tier area. *Note viii*	13,580	12,800	14,500	12,800	13,580	12,800	14,500	12,800
10	**SIL Study Value** (row 10 = the minimum of the values entered in rows 6, 8 and 9 for each season). Use these SIL Study Values in the Market Share Screens. *Note ix*	780	1,600	1,880	1,700	940	1,540	2,040	1,640

*** To the extent a filer intends to request privileged treatment for any portion of Submittals 1 or 2, such filing must comply with 18 CFR 388.112, including the justification for privileged treatment, i.e., why the information is exempt from disclosure under the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. 552 (2012)**

Submittal 2: Identify Long-Term Firm Transmission Reservations Used to Import Power from Generating Resources in the First-Tier Area to Serve Historical Peak Load in the Study Area

Table 2: Long-Term Firm Transmission Reservations

Instructions:

1 Delete the text 'Name of Home BAA/Market' and enter the name of the study area.
2 If you are studying more than one first-tier area, copy the relevant columns of Tables 1 and 2 to empty columns on the right of this spreadsheet for each of the first-tier areas studied.
3 If you are studying first-tier areas, replace the text 'Name of First-Tier BAA/Market' with the name of the first-tier area(s).
4 Enter all megawatt values as non-negative integers in rows 1 through 3 and 5 through 7 (the blue-shaded cells).
5 Do not enter data in the white-background cells as these cells contain formulas to compute the value in that cell.
6 Enter text to complete the “Description of Component” column as necessary in each row (e.g., enter the name of plant, describe the Power Purchase Agreement or Transaction to serve non-affiliate embedded load.)
7 Use a separate line to report each Remote Plant/ Power Purchase Agreement/ Transaction to serve non-affiliate embedded load by inserting a new rows into the table under the existing rows for that component. For instance, to report a third Power Purchase Agreement for an affiliate, insert a new row between the existing row "2a" and row "3" and label that row "2b"
8 Row 9, Sum of affiliate and non-affiliated reservations, will automatically sum the long-term reservations in that column and place the total into the same seasonal column in Submittal 1, row 5, Long-Term Firm Transmission Reservations.
9 Include an electronic copy of this spreadsheet, or a workable electronic spreadsheet with the same format and formulas as the sample spreadsheet on the Commission Web site, with your filing. (see note below)*

		Name of Home BAA/Market				Name of First-Tier BAA/Market			
		Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
	Description of Component	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
	Affiliates								
1	MW Share of Remote Plant #1	100	-	100	-	50	50	50	50
1a	MW Share of Remote Plant #2	50	50	50	50	100	-	100	-
1b	MW Share of Remote Plant #3	45	-	45	-	-	50	-	50
2	Power Purchase Agreement where the energy is imported into the study area with long-term firm reservations	75	75	75	75	80	80	80	80
2a	Power Purchase Agreement where the energy is imported into the study area with long-term firm reservations	25	25	25	25				
3	Transaction to serve non-affiliated load embedded in the study area using external generation	10	0	10	0				
3a	Transaction to serve non-affiliated load embedded in the study area using external generation	5	0	5	0				
4	Sum of affiliated long-term firm reservations	310	150	310	150	230	180	230	180
	Non-Affiliates								
5	MW Share of Remote Plant #1	100	-	100	-	50	50	50	50
5a	MW Share of Remote Plant #2	50	50	50	50	100	-	100	-
5b	MW Share of Remote Plant #3	60	-	60	-	-	50	-	50
6	Power Purchase Agreement where the energy is imported into the study area with long-term firm reservations	50	50	50	50	80	80	80	80
6a	Power Purchase Agreement where the energy is imported into the study area with long-term firm reservations	25	25	25	25				
7	Transaction to serve non-affiliated load embedded in the study area using external generation	15	15	15	15				
7a	Transaction to serve non-affiliated load embedded in the study area using external generation	10	10	10	10				
8	Sum of non-affiliated long-term firm reservations	310	150	310	150	230	180	230	180
9	Sum of affiliated and non-affiliated long-term firm reservations (enter value in row 5 of Table 1 above)	620	300	620	300	460	360	460	360

*** To the extent a filer intends to request privileged treatment for any portion of Submittals 1 or 2, such filing must comply with 18 CFR 388.112, including the justification for privileged treatment, i.e., why the information is exempt from disclosure under the mandatory public disclosure requirements of the Freedom of Information Act, 5 U.S.C. 552 (2012)**

Endnotes for Table 1:

[i] *See generally AEP Service Corp.*, 131 FERC ¶ 61,146, at P 5 (2010) (*AEP*) ("FCITC is calculated in the power flow model and represents the additional power that can flow into a study area by increasing available uncommitted generation in the first-tier area while simultaneously decreasing generation in the study area.").

Enter an integer value for the FCITC or incremental SIL value. A negative FCITC or incremental SIL value may indicate a serious modeling error such as an N-0 or N-1 base case overload and must be addressed or explained.

[ii] *See generally AEP*, 131 FERC ¶ 61,146 at P 5 ("The net area interchange is also determined in the seasonal power flow model and represents 'the sum of a study area's scheduled energy transactions' already flowing into and out of the study area at the seasonal peak that is modeled." (citing *CP&L*, 128 FERC ¶ 61,039 at P 9)).

Enter a non-negative integer value for Net Area Interchange. Different sellers apparently use different nomenclature to represent net imports into a study area. Here, the direction of the interchange, either export from or import into the study area, is explicitly declared in the text in row 3 and the direction is not indicated by the sign of the interchange value. *See generally AEP*, 131 FERC ¶ 61,146 at P 14 ("The Commission previously has given guidance on how to combine the FCITC and net area interchange values in calculating the SIL. However, this guidance was based on the assumption that the industry standard was to report a study area exporting power as a positive value (a positive net area interchange). SPP, however, used the reverse notation, causing some SPP Transmission Owners to subtract net area interchange from the FCITC value when they should have added." (footnote omitted)).

[iii] *See generally AEP*, 131 FERC ¶ 61,146 at P 14 ("For a study area whose net area interchange represents net exports from the study area, the SIL value is equal to FCITC minus net exports. Therefore, net exports from a study area reduce the SIL value. Conversely, for a study area whose net area interchange represents net imports into the study area, the SIL value is equal to FCITC plus net imports. Therefore, net imports into a study area increase the SIL value."); *CP&L Clarification Order*, 129 FERC ¶ 61,152 at P 23 n.15.

[iv] *See generally* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 368 ("[T]he Commission will require sellers to account for firm and network transmission reservations having a duration of longer than 28 days."); *id*. P 368 n.375 ("The simultaneous import limit study must account for short-term firm transmission rights including point-to-point on-peak/off-peak transmission reservations (firm or network transmission commitments) which have been stacked, or successively arranged, into an aggregated point-to-point transmission reservation longer than 28 days."); *id*. P 369 ("[W]e clarify that the seller's firm, network, and grandfathered transmission reservations longer than 28 days, including reservations for designated resources to serve retail load, shall be fully accounted for in the simultaneous import limit study."); Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 142 ("[W]e clarify that the use of simultaneous TTC in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin.").

[v] *See generally* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 144 ("Therefore, we will require applicants to allocate their seasonal and longer transmission reservations to themselves from the calculated SIL, where seasonal reservations are greater than one month and less than 365 consecutive days in duration, as defined in the Commission's EQR Data Dictionary."); Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at P 6 "[T]he Commission clarifies and reaffirms that it will require applicants to allocate their seasonal and longer transmission reservations to themselves from the calculated simultaneous transmission import limit *only* up to the uncommitted first-tier generation capacity owned, operated or controlled by the seller and its affiliates.").

[vi] *See generally CP&L Clarification Order*, 129 FERC ¶ 61,152 at P 26 ("We clarify that seasonal, historical peak load is one limitation on the SIL values reported in the indicative screens and the Delivered Price Test. This SIL value limitation applies to both scaling methodologies when conducting a SIL study (load-shift and generation-shift methodologies)." (footnote omitted)); *id.* P 26 n.16 ("The other two limitations are: (1) when transmission equipment reaches an operating limit during the energy transfer calculation portion of the SIL study (these are 'the real-life physical limitations of first-tier balancing authority areas that impede power flowing from remote first-tier resources into the seller's study area'; and (2) when the available uncommitted generation in the first-tier area is exhausted and no transmission equipment has reached an operating limit during the scaling process." (citations omitted)).

Here, enter the highest hourly net energy for load value for each season from FERC Form No. 714 or equivalent and identify the source of the data if not FERC Form No. 714. Do not enter the average seasonal peak load value used in the wholesale market share screen because it is not the single, highest hourly load recorded for each season.

[vii] *Puget Sound Energy, Inc*., 135 FERC ¶ 61,254, at P 16 (2011) ("The transmission capability associated with these study area import reservations also must be subtracted from the study area's native load to accurately represent the amount of study area native load available to being served by first-tier area generation when the study area native load limits the calculated SIL value. For example, PGE's calculated SIL values exceeded its peak load in each season, so PGE correctly limited its SIL values to peak load. PGE then subtracted its affiliated long-term firm transmission reservations from its seasonal peak load to derive its adjusted or net SIL values, which it used in its updated market power analysis. PGE's calculation appropriately limited its SIL values to the amount of its study area load open to competition from non-affiliated, first-tier generators." (footnotes omitted)).

[viii] *See generally* April 14 Order, 107 FERC ¶ 61,018 at Appendix E ("[T]he applicant shall scale up available generation in the exporting (aggregated first tier areas)…."); *CP&L Clarification Order*, 129 FERC ¶ 61,152 at P 26 & n.16.

[ix] *See generally Public Service Company of New Mexico*, 133 FERC ¶ 61,031 at P 12-13 (accepting SIL values limited by peak load and reduced by amount of transmission reservations allocated to transmission owners' remote resources brought into the study area to serve native load); *AEP*, 131 FERC ¶ 61,146 at P 13 ("Because each of the SPP Transmission Owners was to subtract its own reservations in calculating its final SIL values, this value should account for the largest quantity of transmission reservations into the study area, thus providing a reasonable estimate of remaining import capability to use in the preliminary market power screens."); *CP&L Clarification Order*, 129 FERC ¶ 61,152 at P 26 ("The SIL value reported in the indicative screens and the Delivered Price Test, however, cannot exceed the seasonal historical peak load value.").

Appendix F

List of Commenters and Acronyms

Commenter	Short Name/Acronym
American Antitrust Institute	AAI
American Electric Power Service Corporation	AEP
American Public Power Association and National Rural Electric Cooperative Association	APPA/NRECA
Avista Corporation and Puget Sound Energy, Inc.	Avista/Puget
Barrick Goldstrike Mines	Barrick
Romkaew Broehm and Gerald A. Taylor	Broehm/Taylor
E.ON Climate & Renewables North America LLC	E.ON
Edison Electric Institute	EEI
El Paso Electric Company	El Paso
Electric Power Supply Association	EPSA
FirstEnergy Service Company	FirstEnergy
Golden Spread Electric Cooperative, Inc.	Golden Spread
Idaho Power Company	Idaho Power Company
Indicated Western Utilities (Arizona Public Service Company; Idaho	Indicated Utilities

Power Company; NV Energy, Inc.; PacifiCorp; and Portland General Electric Company)	
National Hydropower Association	NHA
NextEra Energy, Inc.	NextEra
Potomac Economics, Ltd.	Potomac Economics
Southeast Transmission Owners (Duke Energy Carolinas, LLC; Duke Energy Progress, Inc.; Louisville Gas and Electric Company and Kentucky Utilities Company; South Carolina Electric & Gas Company; and Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company)	Southeast Transmission Owners
Southern California Edison Company	SoCal Edison
Julie R. Solomon and Matthew E. Arenchild	Solomon/Arenchild
SunEdison Inc.	SunEdison
NRG Companies (over 120 entities wholly or partially owned subsidiaries of NRG Energy, Inc.)	NRG Companies
Transmission Access Policy Study Group	TAPS