

DEPARTMENT OF ENERGY**Federal Energy Regulatory
Commission****18 CFR Part 35**

[Docket No. RM04–7–005; Order No. 697–B]

**Market-Based Rates for Wholesale
Sales of Electric Energy, Capacity and
Ancillary Services by Public Utilities**

Issued December 19, 2008.

AGENCY: Federal Energy Regulatory
Commission.**ACTION:** Final rule; order on rehearing
and clarification.**SUMMARY:** The Federal Energy
Regulatory Commission affirms its basic
determinations in Order No. 697–A,
granting rehearing and clarification
regarding certain revisions to its
regulations and to the standards for
obtaining and retaining market-based
rate authority for sales of energy,
capacity and ancillary services to ensure
that such sales are just and reasonable.**DATES:** *Effective Date:* The amendments
to 18 CFR part 35 and the order onrehearing will become effective January
29, 2009.**FOR FURTHER INFORMATION CONTACT:**Michelle Barnaby (Technical
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20426, (202) 502–6462.**SUPPLEMENTARY INFORMATION:****TABLE OF CONTENTS**

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Before Commissioners: Joseph T.
Kelliher, Chairman; Suede G. Kelly,
Marc Spitzer, Philip D. Moeller, and
Jon Wellenhoff.

I. Introduction

1. On June 21, 2007, the Federal
Energy Regulatory Commission
(Commission) issued Order No. 697,¹
codifying and, in certain respects,
revising its standards for obtaining and
retaining market-based rates for public
utilities. In order to accomplish this, as
well as streamline the administration of
the market-based rate program, the
Commission modified its regulations at
18 CFR part 35, subpart H, governing

market-based rate authorization. The
Commission explained that there are
three major aspects of its market-based
regulatory regime: (1) Market power
analyses of sellers and associated
conditions and filing requirements; (2)
market rules imposed on sellers that
participate in Regional Transmission
Organization (RTO) and Independent
System Operator (ISO) organized
markets; and (3) ongoing oversight and
enforcement activities. The Final Rule
focused on the first of the three features
to ensure that market-based rates
charged by public utilities are just and
reasonable. Order No. 697 became
effective on September 18, 2007.

2. The Commission issued an order
clarifying four aspects of Order No. 697
on December 14, 2007.² Specifically,

that order addressed: (1) The effective
date for compliance with the
requirements of Order No. 697; (2)
which entities are required to file
updated market power analyses for the
Commission's regional review; (3) the
data required for horizontal market
power analyses; and (4) what constitute
“seller-specific terms and conditions”
that sellers may list in their market-
based rate tariffs in addition to the
standard provisions listed in Appendix
C to Order No. 697. The Commission
also extended the deadline for sellers to
file the first set of regional triennial
studies that were directed in Order No.
697 from December 2007 to 30 days
after the date of issuance of the
December 14 Clarification Order.

¹ *Market-Based Rates for Wholesale Sales of
Electric Energy, Capacity and Ancillary Services by
Public Utilities*, Order No. 697, FERC Stats. & Regs.
¶ 31,252 (Order No. 697 or Final Rule), *clarified*,
121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No.
697–A, 73 FR 25832 (May 7, 2008), FERC Stats. &
Regs. ¶ 31,268 (2008); *clarified*, 124 FERC ¶ 61,055
(2008) (July 17 Clarification Order).

² *Market-Based Rates for Wholesale Sales of
Electric Energy, Capacity and Ancillary Services by
Public Utilities*, 72 FR 72239 (Dec. 20, 2007), 121

FERC ¶ 61,260 (2007) (December 14 Clarification
Order).

3. On April 21, 2008, the Commission issued Order No. 697-A,³ in which it responded to a number of requests for rehearing and clarification of Order No. 697. In most respects, the Commission reaffirmed its determinations made in Order No. 697 and denied rehearing of the issues raised. However, with respect to several issues, the Commission granted rehearing or provided clarification.

4. On July 17, 2008, the Commission issued an order clarifying certain aspects of Order No. 697-A related to the allocation of simultaneous transmission import capability for purposes of performing the indicative screens.⁴ Specifically, that order granted the requests for rehearing with regard to footnote 208 of Order No. 697-A and clarified that in performing the indicative screen analysis, market-based rate sellers may allocate the simultaneous import limit capability on a pro rata basis (after accounting for the seller's firm transmission rights) based on the relative shares of the seller's (and its affiliates') and competing suppliers' uncommitted generation capacity in first-tier markets.⁵

5. In this order, the Commission responds to a number of requests for rehearing and clarification of Order No. 697-A.

6. For example, in response to requests for clarification concerning allocation of simultaneous transmission import limit capacity when conducting the indicative screens used in the horizontal market power analysis, the 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. With regard to the request that it clarify that the term "month" in paragraph 144 of Order No. 697-A means "calendar month," the Commission clarifies that the term "month" may be defined as a calendar month, consisting of 28 to 31 days, and is not limited to a 28 day period.

7. In response to a request for clarification that the Commission will

not rely on representations as to control of generation assets made by sellers absent a "letter of concurrence" from the party alleged to control the generation asset, the Commission clarifies that it will require a seller making an affirmative statement as to whether a contractual arrangement transfers control to seek a "letter of concurrence" from other affected parties identifying the degree to which each party controls a facility, and to submit these letters with its filing. The Commission also reiterates 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.

8. With regard to the definition of "inputs to electric power production" as it relates to sites for new generation development, the Commission denies the request that it clarify that only sites for which necessary permitting for a generation plant has been completed and/or sites on which construction for a generation plant has begun apply under the definition of "inputs to electric power production" in § 35.36(a)(4) of the Commission's regulations.

9. The Commission revises the definition of "affiliate" in § 35.36(a)(9) of its regulations to delete the separate definition for exempt wholesale generators (EWGs), explaining that use of the same definition for EWGs as for non-EWG utilities is appropriate and that the definition adopted in Order No. 697-A for non-EWG utilities will not affect the substance of the Commission's analysis for market power issues.

10. The Commission provides a number of other clarifications with regard to, among others, pricing of sales of non-power goods and services and the tariff provision governing sales at the metered boundary.

II. Discussion

A. Horizontal Market Power

1. Transmission Imports Background

11. In Order No. 697, the Commission adopted the proposal to continue to measure limits on the amount of capacity that can be imported into a relevant market based on the results of a simultaneous transmission import limit study.⁶ Thus, a seller that owns transmission will be required to conduct simultaneous transmission import limit studies for its home balancing authority area and each of its directly-

interconnected first-tier balancing authority areas consistent with the requirements set forth in the April 14 Order,⁷ as clarified in Pinnacle West Capital Corp.⁸ The Commission commented that "the SIL (simultaneous transmission import limit) study is 'intended to provide a reasonable simulation of historical conditions' and is not 'a theoretical maximum import capability or best import case scenario.'" ⁹ To determine the amount of transfer capability under the simultaneous transmission import limit study, the Commission stated that historical operating conditions and practices of the applicable transmission provider should be used and the analysis should reasonably reflect the transmission provider's Open Access Same-Time Information System operating practices. The Commission also stated that it will continue to allow sensitivity studies, but the sensitivity studies must be filed in addition to, not in lieu of, a simultaneous transmission import limit study.¹⁰

12. On rehearing in Order No. 697-A, the Commission clarified that for the reasons described in Order No. 697,¹¹ applicants are not required to address short-term firm reservations in the market power screens. The Commission explained that the Commission's Electric Quarterly Report Data Dictionary defines monthly as more than 168 consecutive hours up to one month, and seasonal as greater than one month and less than 365 consecutive days.¹² The Commission also explained that twenty-eight days fits within the definition of a month, and is a reasonable limit to separate short-term reservations from long-term reservations for purposes of the generation market power screens. Further, the Commission stated that since the market power screens are conducted for four seasonal periods, and they are designed to model historical conditions during the four seasonal peak periods, the screens must account for transmission reservations typical for each season. The Commission explained that it is not practical to require applicants to provide data on every transmission reservation, yet the Commission cannot

⁷ *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018, at P 95 (April 14 Order), *on reh'g*, 108 FERC ¶ 61,026, at P 45 (2004) (July 8 Order).

⁸ 110 FERC ¶ 61,127 (2005).

⁹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 (internal citations omitted).

¹⁰ *Id.* P 355.

¹¹ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 144 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 368).

¹² *Order Adopting Electric Quarterly Report Data Dictionary*, Order No. 2001-G, 120 FERC ¶ 61,270, at P 35 (2007).

³ *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268 (2008) (Order No. 697-A).

⁴ *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 124 FERC ¶ 61,055 (2008) (July 17 Clarification Order).

⁵ *Id.* P 5.

⁶ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354.

ignore the impact of transmission reservations on the potential for market power. It concluded that requiring applicants to account for reservations greater than one month in duration strikes a balance between allowing the screens to reasonably model historical conditions without requiring unreasonable amounts of information from applicants. Therefore, the Commission stated that it will require applicants to allocate their seasonal and longer transmission reservations to themselves from the calculated simultaneous transmission import limit, where seasonal reservations are greater than one month and less than 365 consecutive days in duration, as defined in the Commission's Electric Quarterly Report Data Dictionary.¹³

13. In addition, the Commission stated that it would allow sellers to use load shift methodology to calculate the simultaneous import limit while scaling their load beyond the historical peak load, provided they submit adequate support and justification for the scaling factor used in their load shift methodology and how the resulting simultaneous transmission import limit number compares had the company used a generation shift methodology.¹⁴

Requests for Rehearing

a. Allocation of Transmission Reservations

14. Southern Company Services, Inc.¹⁵ and E.ON U.S., on behalf of its subsidiaries, PacifiCorp and Public Service Company of New Mexico (collectively, E.ON) request that the Commission clarify or revise its discussion in paragraph 144 of Order No. 697–A concerning the allocation of simultaneous transmission import limit capacity when conducting the indicative screens. E.ON argues that, as currently written, Order No. 697–A could be interpreted to result in no simultaneous transmission import limit capacity being allocated to competing generation, resulting in grossly overstated market shares for a seller in its home or first-tier balancing authority areas.¹⁶ E.ON contends that the Commission's statement that "we will require applicants to allocate their seasonal and longer transmission reservations to themselves from the

calculated simultaneous transmission import limit, where seasonal reservations are greater than one month and less than 365 days in duration, as defined in the Commission's EQR [Electric Quarterly Report] Data Dictionary" may be interpreted to mean that, when conducting the indicative screens, simultaneous transmission import limit capacity is to be allocated first to an applicant up to the applicant's long-term firm point-to-point transmission rights into the subject balancing authority area, regardless of whether the seller has uncommitted capacity at the point of receipt of a transmission reservation that could actually be imported using the transmission reservation.¹⁷

15. E.ON argues that considering only transmission reservations and ignoring remote uncommitted capacity results in a situation where the indicative screens effectively assume that a seller has uncommitted capacity to import even when it has none. It argues that this assumption results in competing, importable capacity being "squeezed out" and thus being assumed unable to compete in the market at issue. Further, E.ON states that the approach indicated by paragraph 144 is a material change from the approach to simultaneous transmission import limit capacity allocation directed in the April 14 Order and the July 8 Order¹⁸ because it appears to ignore uncommitted capacity entirely. In addition, E.ON contends that the approach to simultaneous transmission import limit capacity allocation indicated by paragraph 144 is unfounded when the realities of energy markets and utility practices are considered. According to E.ON, paragraph 144 assumes that a seller has generating capacity at the point of receipt of the firm transmission path and that the seller has preemptive rights to use it, thus precluding competing sellers from using that transmission. It states that the Commission's statement in paragraph 143 that "[a]n applicant's firm transmission reservations represent transmission that is not available to competing suppliers" seems to echo this view.¹⁹

16. E.ON argues that many vertically integrated utilities with native load obligations hold long-term firm transmission rights to bring power home in quantities that exceed the quantity of the remote generation they own. E.ON

states that these firm transmission import rights are used to support native load and ensure that native load is supplied reliably and in a cost-effective manner, often by using the uncommitted generation of others. E.ON therefore argues that use of these transmission rights facilitates the importation of competing uncommitted generation.²⁰ Further, E.ON argues that under current Commission policy and the pro forma Open Access Transmission Tariff (OATT), the transmission capability under firm transmission reservations not scheduled by a specific day-ahead deadline is released to the market at large, on a non-discriminatory basis, after that deadline is passed.²¹ Thus, E.ON concludes that insofar as the Commission's indicative screens measure spot, as opposed to, forward generation market power, it would be unreasonable for the Commission to assume that firm transmission reservations in excess of the applicant's remote uncommitted capacity are not available to competing generation.²²

17. E.ON therefore requests that the Commission clarify, or find on rehearing, that in conducting the indicative screens, simultaneous transmission import limit capacity will be allocated first to an applicant only up to the lesser of the applicant's: (1) Remote generation in the balancing authority area that contains the point of receipt of the transmission right at issue; or (2) firm transmission rights of 28 days or longer in duration. E.ON argues that if the Commission does not issue such clarification or finding, it should clarify that simultaneous transmission import limit capacity will be allocated first to an applicant only up to the amount of firm transmission rights one year or greater in duration. Further, E.ON asserts that regardless of the Commission's action on the requested clarifications, the Commission should clarify that any applicant may seek to

²⁰ *Id.*

²¹ *Id.* (citing *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); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g*, Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890–B, 123 FERC ¶ 61,299 (2008)).

²² *Id.* at 11.

¹³ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 144.

¹⁴ *Id.* P 145.

¹⁵ Southern Company Services, Inc. filed its request for clarification or rehearing acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Southern Companies Power Company (collectively, Southern Companies).

¹⁶ E.ON Rehearing Request at 5.

¹⁷ *Id.* at 8 (quoting Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 144).

¹⁸ *Id.* at 9 (citing April 14 Order, 107 FERC ¶ 61,018 at P 95, *order on reh'g*, July 8 Order, 108 FERC ¶ 61,026 at P 45).

¹⁹ *Id.* at 10 (citing Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 143).

demonstrate in its filing that the allocation of simultaneous transmission import limit capacity to it overstates the amount of power that it actually imports (or understates the competing importable generation) and that an alternative approach to allocating simultaneous transmission import limit capacity is more accurate.²³

18. Similarly, Southern Companies state that paragraph 144 contains language that might be construed as intent by the Commission to dispense with its consideration of whether a transmission reservation of an applicant must be tied to a remote generation resource in order to be reflected in the simultaneous transmission import limit calculation. Southern Companies argue that, historically, this factor was significant in the simultaneous transmission import limit calculation process. They explain that under the process set forth in the July 8 Order, only the portion of an applicant's uncommitted remote generation capacity with firm or network reservations was modeled in base case and subtracted from available simultaneous transmission import capability, and the remaining simultaneous transmission import limit capacity was allocated proportionally among applicants and other suppliers based on relative proportions of uncommitted capacity in areas that are first-tier to the area under study.²⁴

19. Southern Companies assert that in Order No. 697, the Commission appeared to alter this regime by reducing the minimum period for which an accounting of reservations was required, and therefore expanding the pool of such reservations to be accounted for.²⁵ Southern Companies also contend that Order No. 697 remains unclear as to whether the Commission intends to change the procedure of the July 8 Order with respect to the importance of a generating resource linked to seasonal and long-term transmission reservations.²⁶ In addition, Southern Companies state that they do not believe the Commission intended to make such a change since this change would: (1) Inject additional inconsistency insofar as the Commission has affirmed the July 8 Order and its simultaneous transmission import limit calculation methods elsewhere in Order Nos. 697 and 697–A; and (2) reduce the relevance the

Commission has placed on fact-specific determinations, as opposed to generic presumptions, regarding the requisite amount of control that justifies assigning a given amount of generation capacity to the applicant.²⁷ For purposes of the indicative screens, Southern Companies argue that it is wrong to presume that such reservations would be used to effect delivery of the applicant's uncommitted generation, as opposed to effecting delivery of the purchase of short-term capacity from a third party. Southern Companies state that transmission service that is unscheduled is released by the transmission provider for purchase by others on a non-firm basis. Therefore, Southern Companies request that the Commission clarify that it did not intend to overrule or otherwise alter the procedures set forth in the July 8 Order regarding the significance of generating capacity being linked to a firm or network reservation. Southern Companies request that the Commission clarify that applicants preparing simultaneous transmission import limit analyses and accounting for seasonal and long-term transmission reservations should only account for those seasonal and long-term transmission reservations that possess a linked generating resource, then, for any simultaneous transmission import limit capability that is not linked to remote generating resources, applicants are to apply the traditional pro rata principles, as set forth in the July 8 Order and affirmed in Order No. 697.²⁸

b. Definition of “Month”

20. Edison Electric Institute (EEI), Southern Companies and E.ON each request that the Commission clarify that the term “month” in paragraph 144 means “calendar month” which can range in length from 28 to 31 days, not merely 28 days.²⁹ EEI states that at paragraph 144 of Order No. 697–A, the Commission states that it “will require applicants to allocate their seasonal and

longer transmission reservations to themselves from the calculated SIL [simultaneous transmission import limit], where seasonal reservations are greater than one month and less than 365 consecutive days in duration, as defined in the Commission's EQR [Electric Quarterly Report] Data Dictionary.”³⁰ EEI supports this clarification, and states that it concurs, consistent with the conclusion of the Commission, that striking the balance at reservations greater than one month and less than 365 days will permit the reasonable modeling of “historical conditions without requiring unreasonable amounts of information from applicants.”³¹ However, EEI requests clarification of the statement in paragraph 144 that “[t]wenty-eight days fits within the definition of a month, and is a reasonable limit to separate short-term reservations from long-term reservations for purposes of the generation market power screens.”³²

21. Specifically, EEI argues that to allow consistent use of the terminology, the Commission should clarify that it does not intend by its “[t]wenty-eight days” statement to undo the clarification set out in paragraph 144, that short-term reservations are up to one month, and long-term reservations are greater than one month. Southern Companies similarly argue that the presence of the “[t]wenty-eight days * * *” statement offers the potential for confusion because taken in isolation and without the full context of the Commission's express clarifications in paragraph 144, this statement might be represented by some as a reiteration by the Commission of its statements in Order No. 697, and that such an interpretation would create dueling and irreconcilable directions in the same paragraph.³³ EEI states that the Commission expressly indicates in paragraph 144 that the term “month” means a calendar month (which varies in length from 28 to 31 days), through its reference to the Commission's definition in the Commission's Electric Quarterly Report Data Dictionary. Both Southern Companies and EEI note that the Electric Quarterly Report Data Dictionary nowhere indicates the term “month” is capped at 28 days. They state that the Electric Quarterly Report Data Dictionary defines the term “Monthly” as greater than 168

²⁷ *Id.* at 13. In this regard, Southern Companies notes that that the Commission has struck in Order Nos. 697 and 697–A “the appropriate balance on respecting representations of control, agreeing to rely on representations made by sellers regarding control, while requiring sellers to ‘seek a letter of concurrence’ from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing.” *Id.* at n.15 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187; Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 150).

²⁸ *Id.* at 14.

²⁹ EEI Rehearing Request at 15–16; Southern Companies Rehearing Request at 14–15. E.ON supports EEI's request concerning this issue, incorporates it by reference, and asks the Commission to grant the clarification requested by EEI on this issue. E.ON Rehearing Request at 2.

³⁰ EEI Rehearing Request at 15 (quoting Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 144).

³¹ *Id.*

³² *Id.*

³³ Southern Companies at 15 (citing *General Chemical Corp. v. U.S.*, 817 F.2d 844, 857 (D.C. Cir. 1987)).

²³ *Id.*

²⁴ Southern Companies Rehearing Request at 11–12 (citing April 14 Order, 107 FERC ¶ 61,018, *order on reh'g*, July 8 Order, 108 FERC ¶ 61,026 at P 45).

²⁵ *Id.* at 12 (citing Order No. 697 at P 368).

²⁶ *Id.*

consecutive hours and less than or equal to one month, and the term "Seasonal" as greater than one month and less than 365 consecutive days. EEI notes that for both of these definitions, "month" is left undefined, and thus presumably at its accepted meaning of calendar month.³⁴

Commission Determination

22. In response to Southern Companies' and E.ON's comments regarding allocation of simultaneous transmission import limit capacity when conducting the indicative screens, we clarify that the Commission's statement in paragraph 144 of Order No. 697-A is not intended to revise its approach to the simultaneous transmission import limit allocation, as suggested in the rehearing requests of Southern Companies and E.ON. We therefore clarify and reaffirm that we 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).

23. Further, as the Commission clarified in the July 17 Clarification Order,³⁵ to determine the respective shares of uncommitted generation capacity to be used in performing the market power analysis, a seller should determine the amount of firm transmission capacity³⁶ the seller has into the study area and assume that any seller's uncommitted first-tier generation capacity fully utilizes the seller's firm transmission rights. Then, to the extent the seller has remaining uncommitted first-tier generation capacity,³⁷ the remaining simultaneous transmission import limit capability is allocated on a *pro rata* basis to import the remaining uncommitted first-tier generation capacity of both the seller and competing suppliers.

24. With regard to E.ON's request that the Commission clarify that any applicant may seek to demonstrate in its filing that the allocation of simultaneous transmission import limit capacity to it

overstates the amount of power that it actually imports (or understates the competing importable generation) and that an alternative approach to allocating simultaneous transmission import limit capacity is more accurate, we reiterate that, as we stated in the Final Rule and in Order No. 697-A, applicants may submit additional sensitivity studies, including a more thorough import study as part of the delivered price test. However, we reaffirm that any such sensitivity studies must be filed in addition to, and not in lieu of, a simultaneous transmission import limit capacity study.³⁸ As we explained in the Final Rule, sensitivity studies are intended to provide the seller with the ability to modify inputs to the simultaneous transmission import limit study such as generation dispatch, demand scaling, the addition of new transmission and generation facilities (and the retirement of facilities), major outages, and demand response.³⁹

25. With regard to the request of EEI, Southern Companies and E.ON that we clarify that the term "month" in paragraph 144 of Order No. 697-A means "calendar month," we clarify that the term "month" may be defined as a calendar month, consisting of 28 to 31 days, and is not limited to a 28-day period. We did not intend to undo the clarification that short-term reservations are up to one month, and long-term reservations are greater than one month by stating in Order No. 697-A at paragraph 144 that "twenty-eight days fits within the definition of a month, and is a reasonable limit to separate short-term reservations from long-term reservations for purposes of the generation market power screens."⁴⁰ With regard to Southern Companies' argument that the presence of the "twenty-eight days" statement offers the potential for confusion, we reaffirm our finding that applicants are not required to address short-term firm reservations in the market power screens, and we reiterate that "we will require applicants to allocate their seasonal and longer transmission reservations to themselves from the calculated SIL [simultaneous transmission import limit], where seasonal reservations are greater than one month and less than 365 consecutive days in duration, as defined in the Commission's EQR

[Electric Quarterly Report] Data Dictionary."⁴¹

2. Further Guidance Regarding Control and Commitment of Capacity Background.

26. In Order No. 697, the Commission concluded that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. The Commission explained that no single factor or factors necessarily results in control. It further explained that the electric industry remains a dynamic, developing industry, and no bright-line standard will encompass all relevant factors and possibilities that may occur now or in the future. The Commission stated that if a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens.⁴²

27. The Commission determined that the circumstances or combination of circumstances that convey control vary depending on the attributes of the contract, the market and the market participants. Therefore, it concluded that it would be inappropriate to make a generic finding or generic presumption of control, but rather that it is appropriate to continue making determinations of control on a fact-specific basis.⁴³ The Commission explained, however, that it will continue its historical approach of relying on a set of principles or guidelines to determine what constitutes control. Thus, the Commission stated that it continues to consider the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market. It explained that its guiding principle is that *an entity controls the facilities when it controls the decision-making over sales of electric energy, including discretion as to how and when power generated by these facilities will be sold*.⁴⁴

28. The Commission also declined to adopt commenters' suggestions that it require all relevant contracts to be filed for review and determination by the Commission as to which entity controls a particular asset (e.g., with an initial application, updated market power analysis, or change in status filing).

³⁴ EEI Rehearing Request at 16; Southern Companies Rehearing Request at 15 (citing *Order Adopting EQR Data Dictionary*, Order No. 2001-G, 120 FERC ¶ 61,270, at P 35 (2007)).

³⁵ 124 FERC ¶ 61,055 at P 31-32.

³⁶ See, e.g., Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 368. "Firm transmission capacity" includes network and firm point-to-point.

³⁷ In performing the indicative screens, to the extent the seller does not have any uncommitted generation capacity in the first-tier markets or its uncommitted generation capacity in the first-tier markets is fully accounted for through recognition of the seller's firm transmission rights, no simultaneous import limit capability allocation is needed between the seller and competing suppliers.

³⁸ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 146; Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 355.

³⁹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 355.

⁴⁰ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 144.

⁴¹ *Id.*

⁴² Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 174.

⁴³ *Id.* P 175.

⁴⁴ *Id.* P 176.

While the Commission noted that under section 205 of the FPA, the Commission may require any contracts that affect or relate to jurisdictional rates or services to be filed, the Commission explained that it uses a rule of reason with respect to the scope of contracts that must be filed and does not require as a matter of routine that all such contracts be submitted to the Commission for review. The Commission's historical practice has been to place on the filing party the burden of determining which entity controls an asset. Therefore, the Commission required a seller to make an affirmative statement as to whether a contractual arrangement transfers control and to identify the party or parties it believes control(s) the generation facility. However, the Commission explained that it retains the right at its discretion to request the seller to submit a copy of the underlying agreement(s) and any relevant supporting documentation.

29. The Commission also explained in Order No. 697 that it understands that affected parties may hold differing views as to the extent to which control is held by the parties. Thus, the Commission stated that it will also require that a seller making such an affirmative statement seek a "letter of concurrence" from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing. Absent agreement between the parties involved, or where the Commission has additional concerns despite such agreement, the Commission will request additional information which may include, but not be limited to, any applicable contract so that it can make a determination as to which seller or sellers have control.⁴⁵

30. In Order No. 697-A, the Commission determined that, given the increased level of investment in the electric utility industry as a result of the Energy Policy Act of 2005 (EPA 2005)⁴⁶ and its implementing rules and regulations, it was necessary to provide further guidance with respect to the representations that a seller should make regarding which entity controls a particular asset. The Commission stated that an increasing number of investors are acquiring interests in assets that may be relevant to a seller's market-based rate authority, and explained that it will continue to place on the filing party the burden of determining which entity controls an asset. The Commission stated that it will rely on the seller's representations regarding control,

absent extenuating circumstances. In order to provide further guidance to the industry, the Commission reiterated that the seller, in advising the Commission of its determinations of control, should specifically state whether a contractual arrangement transfers control and should identify the party or parties it believes control(s) the generation facility. The Commission stated that in doing so, the seller should make its representation in light of its discussion in Order No. 697 and cite to that order as the basis for which it has made its determination.⁴⁷

Requests for Rehearing

31. SoCal Edison requests that the Commission clarify that it will not rely on representations as to control of generation assets made by sellers absent a letter of concurrence from the party alleged to control the generation asset. SoCal Edison asserts that Order No. 697-A at paragraph 150 is not clear with regard to this issue, and that the Commission should make clear that its reference to "our discussion in Order No. 697" means 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'" and that the Commission will only rely on the seller's assertion of a lack of control if a letter of concurrence is submitted by the seller in accordance with paragraph 187 of Order No. 697-A.⁴⁸ It argues that if the Commission does not provide the requested clarification, the Commission erred in stating in paragraph 150 that it will rely on the assertion of a seller that another entity controls a generating asset owned by the seller, if that assertion is not supported by a letter of concurrence from the other entity.⁴⁹

32. SoCal Edison explains that under the market power screens, the more generation a seller "controls," the greater the possibility of failing one or more screens. It states that in Order No. 697, the Commission recognized that "'affected parties may hold differing views as to the extent to which control [over generation] is held by the parties.'" ⁵⁰ It also states that the Commission required that any seller making an affirmative statement of control seek a "'letter of concurrence'" from other affected parties identifying

the degree to which each party controls a facility and submit such letters with its filing. According to SoCal Edison, this approach is logical if the seller is trying to disclaim control over a generating facility because sellers have the incentive to claim that they lack control. However, SoCal Edison argues that in the absence of a letter of concurrence, the Commission should not assume that the seller lacks control of any particular generating asset identified in its Asset Appendix.⁵¹ Specifically, it argues that reliance on an assertion of a seller that it lacks control of a generation asset that it owns, absent a letter of concurrence from the other entity, is arbitrary and capricious and irrational, given that it is in the seller's best interest for purposes of a market power-related filing to control as few generation assets as possible.⁵²

33. Thus, SoCal Edison asserts that to the extent a seller represents that it controls generating assets, the Commission can rely on such representations, but, if the seller believes that another entity controls a generating asset, the seller should be required to provide a letter of concurrence. Absent such letters, SoCal Edison argues that the Commission should just assume the seller controls any assets that it owns.⁵³

Commission Determination

34. We will grant the clarification requested by SoCal Edison. As we stated in Order No. 697, we will require a seller, who is making an affirmative statement that a contractual arrangement transfers control, to seek a "letter of concurrence" from other affected parties identifying the degree to which each party controls a facility and submit these letters with its filing.⁵⁴ Further, we reiterate 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 agreement⁵⁵ and that the Commission will only rely on the seller's assertion of a lack of control of a generating facility that it owns if a letter of concurrence from other affected parties is submitted by the seller with its filing in accordance with paragraph 187 of Order No. 697. Absent agreement between the parties involved, or where the Commission has additional concerns

⁴⁷ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 150.

⁴⁸ SoCal Edison Rehearing Request at 3 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 183).

⁴⁹ *Id.* at 1 (citing Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 150).

⁵⁰ *Id.* at 2 (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187).

⁵¹ *Id.*

⁵² *Id.* (citing *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).

⁵³ *Id.* at 4.

⁵⁴ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187.

⁵⁵ *Id.* P 183.

⁴⁵ *Id.* P 187.

⁴⁶ Energy Policy Act of 2005, Public Law No. 109-58, 119 Stat. 594 (2005).

despite such agreement, the Commission will request additional information which may include, but not be limited to, any applicable contract so that we can make a determination as to which seller or sellers have control.⁵⁶

B. Vertical Market Power

Other Barriers to Entry

Background

35. Order No. 697 adopted the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but modified the requirements when addressing other barriers to entry.⁵⁷ It also provided clarification regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry) and modified the proposed regulatory text in that regard.⁵⁸

36. On rehearing, the Commission clarified that it was not its intent for the term "inputs to electric power production" to encompass every instance of a seller entering into a coal supply contract with a coal vendor in the ordinary course of business. The Commission clarified that Order No. 697 encompasses *physical* coal sources and ownership of or control over *who may access* transportation of coal via barges and railcar trains.⁵⁹ Thus, the Commission revised its definition of "inputs to electric power production" in § 35.36(a)(4) as follows: "Intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies."⁶⁰

Requests for Rehearing

37. The Electric Power Supply Association (EPSA) requests that the Commission clarify its definition of "inputs to electric power production" as it relates to sites for new generation capacity development.⁶¹ EPSA points out that in response to a request by Southern Companies, Order No. 697–A clarifies that the reference to coal-related inputs extends only to ownership of or control over who may

access transportation of coal via barges and railcar trains and was not intended "to encompass every instance of a seller entering into a coal supply contract with a coal vendor in the ordinary course of business."⁶² EPSA argues that consistent with the clarification granted with respect to coal-related inputs to generation, the Commission should clarify the "sites for new generation capacity development" clause of the definition of "inputs to power production" in order to ensure that a market-based rate seller is not required to file notifications of change in status every time it or one of its affiliates acquires land. Specifically, EPSA argues that market-based rate sellers and their affiliates regularly acquire land for any number of purposes, including a wide range of purposes unrelated, or only indirectly related, to the development of new generation. It contends that it is difficult to see what useful regulatory purpose is served by notifying the Commission of the acquisition of a piece of land when no steps have been taken to put that land to use as a site for generation.⁶³ Thus, EPSA requests clarification that the term "sites for new generation capacity development" means only sites with respect to which permits for new generation have been obtained or where construction of new generation is underway, and that this term does not encompass other land that could potentially be used for generation. EPSA argues that granting such clarification will prevent the Commission from being inundated with notifications of change in status relating to acquisitions of land, while ensuring that it still receives notices relating to changes in control over actual sites for generation development.

Commission Determination

38. We appreciate the concerns raised by EPSA that market-based rate sellers regularly acquire land for many purposes unrelated to developing new generation and that the term "sites for new generation capacity development" should not be construed so broadly as to require unnecessary notifications of change in status relating to acquisitions of land to be filed. However, we are concerned that EPSA's proposed clarification would define "sites for new generation capacity development" too narrowly. In particular, we disagree with EPSA's proposal that the term "sites for new generation capacity development" should mean only sites

with respect to which permits for new generation have been obtained or where construction of new generation is underway, and should not encompass land that could potentially be used for generation. We believe that "sites for new generation capacity development" should be construed to include ownership of land that could potentially be used for generation, not just sites for which permits for new generation have been obtained or where construction of new generation is underway. However, we clarify that "sites for new generation capacity development" does not include land that cannot be used for generation capacity development.⁶⁴ Therefore, we deny EPSA's request that we clarify that the term "sites for new generation capacity development" means only sites with respect to which permits for new generation have been obtained or where construction of new generation is underway.

39. In addition, in order to incorporate the clarification provided in Order No. 697–A that it was not the intent for the term "inputs to electric power production" to encompass every instance of a seller entering into a coal supply contract with a coal vendor in the ordinary course of business and the corresponding change to the regulatory text in § 35.36(a)(4),⁶⁵ we will revise § 35.37(e)(3) to read as follows: "Physical coal supply sources and ownership or control over who may access transportation of coal supplies."

C. Affiliate Abuse

1. General Affiliate Terms & Conditions Affiliate Definition

Background

40. In Order No. 697–A, the Commission clarified that the term "affiliate" for purposes of Order No. 697 and the affiliate restrictions adopted in § 35.39 of our regulations is defined as that term is used in the regulations adopted in the Affiliate Transactions Final Rule.⁶⁶ The Commission stated that it was taking this action in light of its goal to have a more consistent definition of affiliate for purposes of both EWGs and non-EWGs to the extent

⁶⁴ If a seller has acquired land but is explicitly prohibited from using that land for generation capacity development (for example, because of zoning requirements), it need not notify the Commission of the acquisition of that land.

⁶⁵ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 176.

⁶⁶ *Cross-Subsidization Restrictions on Affiliate Transaction*, Order No. 707, 73 FR 11013 (Feb. 29, 2008), FERC Stats. & Regs. ¶ 31,264 (Feb. 21, 2008) (Affiliate Transactions Final Rule), *order on rehearing*, Order No. 707–A, 73 FR 43072 (July 24, 2008), FERC Stats. & Regs. ¶ 31,272 (2008) (Affiliate Transactions Final Rule Rehearing).

⁵⁶ *Id.* P 187.

⁵⁷ Order No. 697 FERC Stats. & Regs. ¶ 31,252 at P 440.

⁵⁸ *Id.* P 440.

⁵⁹ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 176 (emphasis in original).

⁶⁰ *Id.*

⁶¹ EPSA Rehearing Request at 30 (citing 18 CFR 35.36(a)(4), 35.42(a)(1), (2) (2008)).

⁶² *Id.* at 31 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 176).

⁶³ *Id.*

possible, as well as to strengthen the Commission's ability to ensure that customers are protected.

41. The Commission explained that in the Affiliate Transactions Final Rule, it considered the use of the term affiliate in the context of the Affiliate Transactions NOPR, the Commission's Standards of Conduct for Transmission Providers, and other precedent.⁶⁷ In particular, the Commission considered its order in the 1995 *Morgan Stanley* case, in which it adopted distinct definitions of affiliate for EWGs and non-EWGs. The Commission noted there that section 214 of the Federal Power Act (FPA) required use of the Public Utility Holding Company Act of 1935 (PUHCA 1935) definition of affiliate to determine whether an electric utility is an affiliate of an EWG for purposes of evaluating EWG rates for wholesale sales of electric energy. The Commission thus stated in *Morgan Stanley* that the PUHCA 1935 definition of affiliate would apply to EWGs for matters arising under Part II of the FPA.⁶⁸ For all other public utilities, the Commission adopted a definition that in essence treats all companies under the common control of another company, as well as that controlling company, as affiliates. The Commission also stated in *Morgan Stanley* that a ten percent or greater voting interest creates a rebuttable presumption of control.⁶⁹ After reviewing the precedent established in *Morgan Stanley*, the Commission in the Affiliate Transactions Final Rule also reviewed FPA section 214 as revised by EPAct 2005 as well as the affiliate definitions contained in both PUHCA 1935⁷⁰ and the Public Utility Holding Company Act of 2005 (PUHCA 2005).⁷¹

⁶⁷ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 182 (citing *Morgan Stanley Capital Group, Inc.*, 72 FERC ¶ 61,082, at 61,436–37 (1995) (*Morgan Stanley*)).

⁶⁸ *Morgan Stanley*, 72 FERC ¶ 61,082 at 61,436–37.

⁶⁹ *Id.* The Commission did this by adopting the definition of an affiliate found in its Standards of Conduct for Interstate Pipelines.

⁷⁰ 15 U.S.C. 79a *et seq.*

⁷¹ EPAct 2005 at 1261 *et seq.* Prior to its amendment by the Energy Policy Act of 2005, section 214 of the FPA, 16 U.S.C. 824m, read as follows:

No rate or charge received by an exempt wholesale generator for the sale of electric energy shall be lawful under section 824d of this title if, after notice and opportunity for hearing, the Commission finds that such rate or charge results from the receipt of any undue preference or advantage from an electric utility which is an associate company or an affiliate of the exempt wholesale generator. For purposes of this section, the terms "associate company" and "affiliate" shall have the same meaning as provided in section 2(a) of the Public Utility Holding Company Act of 1935.

EPAct 2005 amended section 214 of the FPA by substituting the reference to the PUHCA 1935

42. In Order No. 697–A, the Commission explained that after taking into account these differing definitions, and recognizing the need to provide greater clarity and consistency in its rules, the Commission found in the Affiliate Transactions Final Rule that it was important to try to adopt a more consistent definition in its various rules and also one that is sufficiently broad to allow the Commission to protect customers adequately.⁷² The Commission explained that on this basis, the definition of affiliate as adopted in the Affiliate Transactions Final Rule explicitly incorporated the PUHCA 1935 definition of an affiliate for EWGs, which uses a five percent voting interest threshold, rather than incorporate it by reference, as previously had been done. The definition in the Affiliate Transactions Final Rule also adopted a parallel definition of affiliate for non-EWGs, but with adjustments to reflect the ten percent voting interest threshold for non-EWGs that was utilized up to that time and to eliminate certain language not applicable or necessary in the context of the FPA. The Commission in Order No. 697–A then adopted in this rule the same definition of "affiliate" that it had adopted in the Affiliate Transactions Final Rule. The Commission therefore codified the definition of affiliate in its market-based rate regulations at § 35.36.

Requests for Rehearing and Order Requesting Supplemental Comments.⁷³

43. EPSA, the Mirant Entities (Mirant),⁷⁴ and Reliant Energy, Inc. (Reliant) argue on rehearing that the Commission erred in adopting a separate "affiliate" definition for EWGs.⁷⁵

definition of affiliate with a reference to the PUHCA 2005 definition. PUHCA 2005 defines an affiliate of a specified company as any company in which the specified company has a five percent or greater voting interest. Thus, as revised by EPAct 2005, the only EWG affiliate sales that are subject to FPA section 214 are sales by an EWG to a company in which it owns a five percent or greater voting interest.

⁷² Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 182.

⁷³ *Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 73 FR 51744 (Sept. 5, 2008), 124 FERC ¶ 61,213 (2008) (Order Requesting Supplemental Comments).

⁷⁴ The Mirant Entities are Mirant California, LLC, Mirant Delta, LLC, Mirant Potrero, LLC, Mirant Canal, LLC, Mirant Kendal, LLC, Mirant Bowline, LLC, Mirant Lovett, LLC, Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Potomac River, LLC, and Mirant Energy Trading, LLC.

⁷⁵ EPSA Rehearing Request at 5 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 182–83); Mirant Rehearing Request at 6–7; Reliant Rehearing Request at 2–3. These rehearing requests are

44. In response to the legal and policy arguments petitioners raised on rehearing in opposition to a separate definition of affiliate for EWGs, the Commission issued an order requesting supplemental comments on the definition of "affiliate" adopted in Order No. 697–A and codified in § 35.36(a)(9) of the Commission's regulations.⁷⁶ In the Order Requesting Supplemental Comments, the Commission explained that having again analyzed FPA section 214, and irrespective of any Commission precedent to the contrary, a reasonable interpretation of FPA section 214 is that it does not require the Commission to use a five percent threshold affiliate test for EWGs for all purposes under Part II of the FPA, and in particular for purposes of analyzing market concentration and market power.⁷⁷ The Commission also found the arguments in support of a single definition of affiliate, applicable to both EWGs and non-EWGs, to be persuasive. Therefore, upon reconsideration, the Commission stated that using the same definition for EWGs as for non-EWGs is appropriate and that the definition the Commission adopted in Order No. 697–A for non-EWG utilities would not affect the substance of the Commission's analysis of market power issues. The Commission explained that this definition is based on the structure of the PUHCA 1935 definition, but modified in several ways, including use of a ten percent threshold instead of five percent.⁷⁸

45. Therefore, in the Order Requesting Supplemental Comments, the Commission stated that it intends to revise the definition of affiliate in § 35.36(a)(9) of its regulations to delete the separate definition for EWGs and to revise the non-EWG part of the definition to delete the phrase "other than an exempt wholesale generator."⁷⁹ The Commission stated that before taking final action in response to the rehearing comments, however, it would seek supplemental comments on the

addressed in greater detail in the Order Requesting Supplemental Comments.

⁷⁶ Order Requesting Supplemental Comments, 124 FERC ¶ 61,213.

⁷⁷ Section 214 uses a five percent affiliate threshold with respect to determining whether the jurisdictional rates of an EWG are the result of a preference or advantage of an affiliate of the EWG. While an analysis of market power relates to an EWG's rates, it does not involve the specific issue of whether an EWG has received an undue preference or advantage with respect to a particular wholesale sale. *See id.* n.23.

⁷⁸ Order Requesting Supplemental Comments, 124 FERC ¶ 61,213 at P 11.

⁷⁹ *Id.* P 12.

proposed revised definition of affiliate in § 35.36(a)(9).

Comments.

46. EPSA and the Edison Electric Institute (EEI) submitted comments in response to the Order Requesting Supplemental Comments. EPSA “applauds” the Commission’s proposal to delete the separate definition of affiliate for EWGs and to make all entities subject to the ten percent threshold, and urges the Commission to move forward as proposed in the Order Requesting Supplemental Comments.⁸⁰ However, EPSA also requests that the Commission “make clear that codifying a technical definition of ‘affiliate’ is without prejudice to the Commission’s providing guidance on ‘control’ and ‘affiliation’ in both case-specific and generic proceedings.”⁸¹ In this regard, EPSA notes that its recently-submitted petition for guidance on “control” and “affiliation” issues relating to investments in publicly traded companies addresses common control and reporting issues that are separate from the issue in this proceeding on the technical definition of affiliate for purposes of the Commission’s market-based rate regulations.⁸² EPSA’s supplemental comments also reiterate EPSA’s argument that a separate definition of affiliate for EWGs and non-EWGs is not required by the FPA.⁸³ EPSA further argues that a separate definition of affiliate for EWGs puts EWGs at an unfair disadvantage in determining market power under the Commission’s market-based rate program since use of a five percent ownership threshold for EWGs imposes substantially greater burdens on EWGs for no useful regulatory purpose.⁸⁴

47. In its supplemental comments, EEI states that it supports the proposed change in the Order Requesting Supplemental Comments, and agrees with the Commission’s reasoning that section 214 of the FPA does not require use of a five percent threshold for EWGs for all purposes under the FPA.⁸⁵ EEI further states that the Affiliate Transactions Final Rule fully addresses the requirement in FPA section 214 that the Commission ensure that the rates received by an EWG do not result from the receipt of any undue preference or advantage from an electric utility which

is an associate company or an affiliate of the EWG. Thus, EEI concludes that there is no need to import the five percent threshold to market concentration and market power analyses under the market-based rate regulations. EEI also states that there is an advantage in terms of fairness and consistency to using the same ten percent threshold for both EWGs and non-EWGs in the market-based rate regulations.⁸⁶

Commission Determination.

48. As proposed in the Order Requesting Supplemental Comments, and for the reasons discussed therein and described above,⁸⁷ the Commission will revise the definition of affiliate in § 35.36(a)(9) of its regulations to delete the separate definition for EWGs and to revise the non-EWG part of the definition to delete the phrase “other than an exempt wholesale generator.” Specifically, the definition of affiliate in § 35.36(a)(9) is being revised to provide that an affiliate of a specified company means: (a) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company; (b) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company; (c) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm’s-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and (d) Any person that is under common control with the specified company. For purposes of paragraph (a)(9), owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control. This revision to the definition of affiliate in § 35.36(a)(9) of the market-based rate regulations does not preclude the Commission from providing guidance on control and affiliation in both case-specific and generic proceedings. We note that the issue of what constitutes control for FPA section 203 purposes and market-based rate purposes is the subject of a petition for guidance filed by EPSA in Docket No. PL09–3–000. This is an issue

of significance to the industry that the Commission intends to address in a separate docket, following consideration of EPSA’s petition in Docket No. PL09–3–000.

2. Power Sales Restrictions

Sales of Non-Power Goods and Services. Background.

49. In Order No. 697, the Commission held that sales of non-power goods or services by a franchised public utility with captive customers to a market-regulated power sales affiliate are to be at the higher of cost or market price, unless otherwise authorized by the Commission. The Commission also codified the requirement that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers will not be at a price above market, unless otherwise authorized by the Commission. The Commission explained that this requirement protects a utility’s captive customers against inappropriate cross-subsidization of market-regulated power sales affiliates by ensuring that the utility with captive customers does not pay too much for goods and services that the utility receives from a market-regulated power sales affiliate.⁸⁸

Requests for Rehearing

50. FP&L sought limited clarification or, in the alternative, reconsideration of Order No. 697 on the issue of pricing of non-power goods and services provided for affiliates by either franchised public utilities or their market-regulated power sales affiliates when those services are comparable to shared services provided by a centralized service company.⁸⁹

51. FP&L requests clarification that when a franchised public utility provides its market-regulated power sales affiliates with non-power goods or services, or a market-regulated power sales affiliate provides its affiliated franchised public utility with non-power goods and services, and those services are comparable to those provided by a centralized service company, then those non-power goods and services may be provided at fully loaded cost as a reasonable proxy for market price.⁹⁰ FP&L also requests that the Commission clarify that the grandfathering provision in the Affiliate Transactions Final Rule (which provides that the pricing rules adopted

⁸⁰ EPSA October 20, 2008 Supplemental Comments at 2.

⁸¹ *Id.*

⁸² *Id.* at n.5 (citing EPSA September 2, 2008 Petition for Guidance, Docket No. EL08–87–000).

⁸³ *Id.* at 3.

⁸⁴ *Id.* at 3–4.

⁸⁵ EEI October 20, 2008 Supplemental Comments at 2.

⁸⁶ *Id.* at 3.

⁸⁷ See *supra* P 43–44.

⁸⁸ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 597.

⁸⁹ FP&L March 24, 2008, Request for Clarification.

⁹⁰ *Id.* at 4.

therein are prospective only)⁹¹ also applies with respect to the requirements of Order No. 697 where existing inter-affiliate transactions involving non-power goods and services are comparable to those provided by a centralized service company.

Commission Determination

52. In Order No. 697–A, the Commission explained that issues similar to those raised here by FP&L also were raised on rehearing of the Affiliate Transactions Final Rule, which applies the same standards for the pricing of non-power goods and services as Order No. 697. The Commission stated that to ensure consistency in its approach to pricing of non-power goods and services between both rulemaking proceedings, the Commission would address FP&L's arguments concerning Order No. 697 in a supplemental order.⁹² We address below the arguments raised by FP&L in its March 24, 2008, request for clarification.

53. We deny FP&L's request for clarification that fully loaded cost is a reasonable proxy for market price. On rehearing of the Affiliate Transactions Final Rule, the Commission found the arguments in favor of permitting companies within a single-state holding company system that does not have a centralized service company to provide each other general administrative and management services to be persuasive, and therefore revised its rules to permit affiliates within a single-state holding company system, as defined by Commission rules, that do not have a centralized service company, to provide "at cost" to other affiliates in the system the kinds of services typically provided by centralized service companies and the goods to support those services.⁹³ In light of its determination to permit companies within a single-state holding company system that do not have a centralized service company to provide each other general administrative and management services at cost, the Commission explained that there was no need to grant FP&L's request for clarification that non-power goods and

services may be provided at fully loaded cost as a reasonable proxy for market price.⁹⁴ It also explained that "making fully loaded cost a proxy for market price unnecessarily clouds the distinction between at-cost and market pricing embodied in [the Commission's] rules."⁹⁵ Thus, consistent with our determination in the Affiliate Transactions Final Rule Rehearing, we will deny FP&L's request for clarification in the instant proceeding that fully loaded cost is a reasonable proxy for market price.

54. With regard to FP&L's argument that the Commission should make clear that the grandfathering language in the Affiliate Transactions Final Rule also applies with respect to the requirements of Order No. 697 where existing inter-affiliate transactions involving non-power goods and services are comparable to those provided by a centralized service company,⁹⁶ we note that the Commission previously addressed and rejected this argument. In the Commission's order granting an extension of time in the Affiliate Transactions rulemaking proceeding,⁹⁷ the Commission explained "[o]ur 'grandfathering' of preexisting contracts, agreements and arrangements was only for purposes of compliance of [the Affiliate Transactions Final Rule]. To the extent public utilities were required to comply with the same or similar pricing restrictions pursuant to a merger order or in conjunction with a market-based rate authorization, our action to make Order No. 707 compliance prospective only did not change any such obligations under other orders or rules. That is, pricing restrictions imposed pursuant to a merger order, a market-based rate authorization order or the Commission's market-based rate rules are not within the scope of [the Affiliate Transactions Final Rule] and, consequently, the [Affiliate Transactions Final Rule] grandfathering provision does not relieve a public utility of its obligations under other orders and rules with respect to contracts, agreements or arrangements entered into prior to March 31, 2008."⁹⁸

3. Market-Based Rate Affiliate Restrictions

Risk Management Employees Under the No-Conduit Rule

Background

55. In Order No. 697, with regard to the independent functioning requirement in the affiliate restrictions, the Commission adopted a "no-conduit rule" that prohibits a franchised public utility with captive customers and a market-regulated power sales affiliate from using anyone, including asset managers, as a conduit to circumvent the affiliate restrictions.⁹⁹ Otherwise, Order No. 697 did not specifically address the sharing of risk management employees.

56. On rehearing of Order No. 697, the Commission determined that "risk management personnel do not fall within the scope of the independent functioning rule, so long as they are acting in their roles as risk management personnel rather than as marketing function employees, as defined in the standards of conduct. Of course, such risk management employees remain subject to the no-conduit rule and may not pass market information to marketing function employees."¹⁰⁰

Requests for Rehearing

57. EEI stated that the Commission's clarification with regard to risk management personnel is consistent with the Commission's focus in the Commission's evolving standards of conduct on clarifying that personnel who are neither transmission function nor marketing function employees are primarily governed by the no-conduit rule. However, EEI states that the regulatory text of Order No. 697, in the affiliate restrictions provisions at 18 CFR 35.39(c), does not reflect this clarification or fully reflect the evolution of the standards of conduct. It further states that Order No. 697–A does not modify the regulatory text to reflect these changes.

58. Therefore, EEI encourages the Commission to amend the regulatory text at 18 CFR 35.39(c) to reflect that all employees who are neither transmission nor wholesale marketing function employees are not within the scope of the independent functioning rule, but remain subject to the no-conduit rule. EEI argues that this change would conform regulations under Orders No.

⁹¹ *Id.* at 13 (citing Affiliate Transactions Final Rule, FERC Stats. & Regs. ¶ 31,264 at P 85).

⁹² The Commission noted that it need not address all issues raised in a proceeding at one time. Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 222 (citing *Mobil Oil Exploration & Producing Southeast, Inc. v. United Distribution Companies*, 498 U.S. 211 (1991) (holding that an agency enjoys broad discretion in determining procedurally how best to handle related yet discrete issues)); *Colorado Office of Consumer Counsel v. FERC*, 490 U.S. 954 (DC Cir. 2007) (holding that the Commission need not revisit all elements of a tariff upon finding one aspect to be unjust and unreasonable).

⁹³ Affiliate Transactions Final Rule Rehearing, FERC Stats. & Regs. ¶ 31,272 at P 23.

⁹⁴ *Id.* P 24–31.

⁹⁵ *Id.* P 31.

⁹⁶ FP&L March 24, 2008, Request for Clarification at 13–14.

⁹⁷ *Cross-Subsidization Restrictions on Affiliate Transactions*, 122 FERC ¶ 61,280, at n.5 (2008).

⁹⁸ *Id.* at n.5. See also Affiliate Transactions Final Rule Rehearing, FERC Stats. & Regs. ¶ 31,272 at P 78.

⁹⁹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 561 (codified at 18 CFR 35.39(g)).

¹⁰⁰ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 256 (citing *Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 73 FR 16228 (March 27, 2008), FERC Stats. & Regs. ¶ 32,630 (March 21, 2008)).

697 and 697-A to the Commission's current approach in the standards of conduct, moving away from the corporate separation approach to the functional approach, while recognizing the need for shared employees. Further, EEI asserts that this approach would be consistent with the Commission's statement in Order No. 697 that "the requirements and exceptions in the affiliate restrictions should follow those requirements and exceptions codified in the standards of conduct, where applicable."¹⁰¹

Commission Determination.

59. As EEI notes, the Commission clarified in Order No. 697-A that risk management personnel do not fall within the scope of the independent functioning rule so long as they are acting in their roles as risk management personnel rather than as marketing function employees, as defined in the standards of conduct. As an initial matter, in response to EEI's request for rehearing, we believe that clarification of the statement in Order No. 697-A would be helpful. In particular, the reference in Order No. 697-A to "marketing function employees as defined in the standards of conduct" may have been misleading because the affiliate restrictions address franchised public utilities with captive customers and market-regulated power sales affiliates, not "marketing function employees as defined in the standards of conduct." Accordingly the clarification in Order No. 697-A should not have included the reference to marketing function employees. When the Commission stated that risk management personnel do not fall within the scope of the independent functioning rule so long as they are acting in their roles as risk management personnel, the intent was that a franchised public utility with captive customers and its market-regulated power sales affiliates should be permitted to share risk management personnel subject to the no conduit rule. In other words, risk management personnel may perform risk management activities on behalf of both a franchised public utility with captive customers and its market-regulated power sales affiliates. However, risk management personnel are prohibited from acting as a conduit for disclosing market information subject to the information sharing prohibition in section 35.39(d)(1). With this clarification, we do not believe that it is

necessary to amend the regulatory text at 18 CFR 35.39(c) as requested by EEI.

D. Mitigation

Protecting Mitigated Markets Sales at the Metered Boundary. Background.

60. In Order No. 697, the Commission stated that it would continue to apply mitigation to all sales in the balancing authority area in which a seller is found, or presumed, to have market power.¹⁰² However, the Commission said it would allow mitigated sellers to make market-based rate sales at the metered boundary between a balancing authority area in which a seller is found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority, under certain circumstances.¹⁰³ The Commission also adopted a requirement that mitigated sellers wishing to make market-based rate sales at the metered boundary between a balancing authority area in which the seller was found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority maintain sufficient documentation and use a specific tariff provision for such sales.¹⁰⁴

61. On rehearing in Order No. 697-A, the Commission revised the tariff language governing market-based rate sales at the metered boundary to conform with the discussion in the December 14 Clarification Order regarding use of the term "mitigated market." The Commission stated that, as explained in the December 14 Clarification Order, "balancing authority area in which a seller is found, or presumed, to have market power" is a more accurate way to describe the area in which a seller is mitigated.¹⁰⁵

62. In addition, after considering comments regarding the difficulty of determining and documenting intent, the Commission decided in Order No. 697-A to eliminate the intent element of the tariff provision, which stated that

¹⁰² Although the Commission used the term "mitigated market" in Order No. 697, the Commission later determined that "balancing authority area in which a seller is found, or presumed, to have market power" is a more accurate way to describe the area in which a seller is mitigated. December 14 Clarification Order, 121 FERC ¶ 61,260 at P 7 & n.10.

¹⁰³ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 817 (citing North American Electric Reliability Corporation, *Glossary of Terms Used in Reliability Standards* at 2 (2007), available at ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf).

¹⁰⁴ *Id.* P 830.

¹⁰⁵ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 333.

"any power sold hereunder is not intended to serve load in the seller's mitigated market." Because the Commission eliminated the seller's intent requirement, it modified the tariff provision to require that "the mitigated seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated."¹⁰⁶ In this regard, the Commission noted that "[t]o provide additional regulatory certainty for mitigated sellers, the Commission clarified that once the power has been sold at the metered boundary at market-based rates, the mitigated seller and its affiliates may not sell that same power back into the mitigated balancing authority area, whether at cost-based or market-based rates."¹⁰⁷ The Commission also stated that because it was eliminating the intent requirement, it need not address issues raised regarding documentation necessary to demonstrate the mitigated seller's intent.

63. Further, in response to a request for clarification submitted by Pinnacle, the Commission clarified that mitigated sellers and their affiliates are prohibited from selling power at market-based rates in the balancing authority area in which a seller is found, or presumed, to have market power.¹⁰⁸ Accordingly, the Commission clarified that an affiliate of a mitigated seller is prohibited from selling power that was purchased at a market-based rate at the metered boundary back into the balancing authority area in which the seller has been found, or presumed, to have market power. The Commission stated that to the extent that the mitigated seller or its affiliates believe that it is not practical to track such power, they can either choose to make no market-based rate sales at the metered boundary or limit such sales to sales to end users of the power, thereby eliminating the danger that they will violate their tariff by re-selling the power back into a balancing authority in which they are mitigated.¹⁰⁹

Requests for Rehearing

64. In response to the Commission's modification of the condition on sales of market-based power at the border between a mitigated market and unmitigated market to state that "the Seller and its affiliates [may] not sell the same power back into the balancing authority area where the seller is

¹⁰⁶ *Id.* P 334.

¹⁰⁷ *Id.* at n.464.

¹⁰⁸ *Id.* P 335.

¹⁰⁹ *Id.* P 336.

¹⁰¹ *Id.* (quoting Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 550).

mitigated.’’¹¹⁰ E.ON argues that the Commission should delete this condition imposed on border sales or clarify (1) what is meant by the term “same power” and (2) that neither a seller nor its affiliate will be found in violation of this condition if the affiliate did not know that it was the “same power” being sold into the mitigated market.

65. E.ON states that use of the term “same power” causes confusion, as it is unclear what practical need exists for the condition generally.¹¹¹ E.ON submits that the condition is unnecessary insofar as where a given seller is prohibited from selling market-based power into a given market, it is almost certain that any affiliate of that seller is also prohibited from making such sales, except under an agreement that predates the mitigation for that market (a grandfathered agreement).¹¹² E.ON argues that in the limited case of such an agreement, the “same power” condition need not apply because sales under such a grandfathered agreement are permitted to continue after a finding of market power by the seller and its affiliates because the agreement was not tainted by market power and/or the buyer is protected from the exercise of market power. E.ON asserts that under these circumstances, there is no reason not to allow the “same power” sold by a mitigated seller to be resold into the mitigated market by an affiliate under such a grandfathered agreement.¹¹³

66. Further, E.ON argues that the term “same power” is facially ambiguous and impossible to define or apply in a practical manner. E.ON submits that power cannot be “color coded” so that a buyer knows exactly the source of the power received. E.ON states that where one single transmission tag indicates a change of specific transfers of possession of a block of power among several parties, it may be reasonable to assume the power sold and resold is the “same power.” However, E.ON argues that beyond this limited situation, it is unclear what the Commission would consider to be the “same power.” It asks whether it is the same power if Party A sells 100 MW to Party B at Bus X, and Party B, who is not affiliated with Party A and using a different transmission tag, wheels 100 MW to Bus Y and then sells 100 MW at Bus Y to Party C, who is an

affiliate of Party A. E.ON also argues that Party A and Party C would have no meaningful ability to avoid dealing in the “same power” short of very unreasonable steps. It asserts that Party A and Party C could both cease making border sales, or Party A and Party C could require Party B to tell Party A and/or Party C that they are linked in the sale by Party B in order to avoid this risk. According to E.ON, such an obligation is not assumed by parties in any current structure of power sales transactions, and it would not be a burden the Commission should expect Party B to be willing to undertake.¹¹⁴

67. E.ON also contends that sellers of power often do not know the ultimate fate of power sold, and that a seller does not normally concern itself with the buyer’s ultimate plans for the power, particularly once the seller’s risk of loss and title has been transferred to the buyer. It submits that it is not normal industry practice for a seller of power to seek assurances or commitments from a buyer about what the buyer intends to do with the power, and that such activities could raise antitrust or other anticompetitive concerns.¹¹⁵ Further, it argues that the Commission should not assume each seller is aware of all sales and purchases of power at the same location in the same hour by its affiliates because the affiliate restriction regulations promulgated by the Commission prevent any kind of sharing of “‘market information’” between a “‘franchised public utility’” and its “‘market-regulated power sales affiliate.’”¹¹⁶ E.ON therefore contends that two affiliates could theoretically deal in the “same power” without having any intent to do so.

68. Pinnacle argues that the Commission should clarify that resales of mitigated border purchases are not permanently banned from reentering the mitigated area. Specifically, Pinnacle argues that the Commission’s statement that “an affiliate of a mitigated seller is prohibited from selling power that was purchased at a market-based rate at the metered boundary back into the balancing authority area in which the seller has been found, or presumed, to have market power” is inaccurate as phrased.¹¹⁷ Pinnacle asserts that this statement appears to presume that power purchased at market-based rates from any party cannot be resold at cost-based rates. Pinnacle states that it is not aware of any prohibition against

purchasing at market-based rates and reselling that same power at cost-based rates as long as affiliates are not in the chain of sale. Further, Pinnacle argues that virtually all purchases by a mitigated seller in its mitigated area will be purchased at market-based rates, and states that if the Commission’s statement were true, it would preclude mitigated sellers from ever purchasing power from any party at the metered boundary of its mitigated area to serve wholesale load in the mitigated area at cost-based rates.¹¹⁸

69. In addition, Pinnacle argues that although the Commission’s statement that “[t]o the extent that the mitigated seller or its affiliates believe that it is not practical to track such power, they can either choose to make no market-based rate sales at the metered boundary or limit such sales to sales to end users of the power, thereby eliminating the danger that they will violate their tariff by re-selling the power back into a balancing authority in which they are mitigated” eases documentation requirements for real-time sales, Pinnacle is concerned that such a requirement will reduce liquidity in the market by precluding longer term market-based rate sales at the metered boundaries of mitigated sellers.¹¹⁹ Pinnacle states that any long-term sales made, particularly to marketers, may change hands multiple times. It also argues that tracking power back to the original seller, and original point of purchase, to guarantee that none of the energy it is purchasing was originally part of the long-term sale made by its affiliate to the marketer will be nearly impossible on a real-time basis when a mitigated seller is trying to make a short-term purchase. Therefore, Pinnacle argues that the mitigated seller would effectively be precluded from making anything other than real-time sales to a marketer on the slim chance that some of that power might come back into the control area on a short-term basis in a subsequent purchase.¹²⁰

70. Further, Pinnacle states that even without the intent requirement, a seller in a long-term sale in many cases would only be able to track the path of the power through NERC tags after the power is delivered, since for a longer term sale, a tag is not created at the time the transaction is executed. Pinnacle states that it believes that counterparties will likely not agree to limitations on where the power can sink on term deals, particularly as neither Order No. 697

¹¹⁰ E.ON Rehearing Request at 11 (quoting Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 339).

¹¹¹ *Id.* at 4 (citing *Paralyzed Veterans of Amer. v. D.C. Arena L.P.*, 117 F.3d 579, 584 (D.C. Cir. 1997), cert. denied sub nom *Abe Pollin, et al. v. Paralyzed Veterans of Amer.*, 523 U.S. 1003 (1998)).

¹¹² *Id.* at 12 (citing *MidAmerican Energy Co.*, 123 FERC ¶ 61,013, at P 37 (2008)).

¹¹³ *Id.*

¹¹⁴ *Id.* at 14.

¹¹⁵ *Id.* at 13.

¹¹⁶ *Id.* at 13-14 (quoting 18 CFR 35.36 *et seq.*).

¹¹⁷ *Id.* at 4 (quoting Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 335).

¹¹⁸ *Id.*

¹¹⁹ *Id.* (quoting Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 336).

¹²⁰ *Id.* at 5.

nor Order No. 697-A require contractual limits. Pinnacle explains that an example that illustrates this situation occurs “if APS sold power at Pinnacle Peak (a border of the Phoenix Valley Load Pocket, the Pinnacle West Companies’ mitigated area) for a year to a marketer, and then later, on a day during the season mitigated for [Pinnacle], APS’s affiliate purchased power from the same marketer to serve load in the Phoenix Valley Load Pocket, this transaction would violate the regulations as currently written, even though there was no intent to bring the power back into the mitigated area at the time of the sale.”¹²¹

71. Pinnacle explains that since there is no way to predict when the power is going to be needed in the mitigated area and from whom it may be purchased, the only way to ensure that this scenario does not occur inadvertently is for mitigated sellers to make no market-based rate sales at their mitigated borders for anything other than real-time sales. Pinnacle states that otherwise, all of the mitigated affiliates (including the initial border seller) would be precluded from purchasing power anywhere to serve load in their mitigated areas because they could not be sure that the power was not originally a market-based border sale.¹²² According to Pinnacle, even sales to serve load outside the mitigated area are not guaranteed to remain out of the mitigated area since load may decrease or transmission problems getting the power to the purchaser’s load may require the purchaser to sell the power back to the mitigated seller or an affiliate, resulting in its possible return to the mitigated area. On this basis, Pinnacle asks the Commission to clarify that if a sale is made at a metered boundary point and there is no contemporaneous arrangement with the counter-party to return the power to the mitigated market area, then there is no ongoing requirement to track the power to ensure that it never reenters the mitigated market through an incidental sale.

72. Pinnacle also submits that the Commission erred by providing default tariff language that defines the mitigated area to be a seller’s balancing authority area. Pinnacle argues that the Commission should clarify that the default tariff language for metered boundary sales is at the boundary of the mitigated area. Pinnacle argues that not all mitigated sellers are mitigated in an entire balancing authority area, and that in the case of the Pinnacle West

Companies, the Commission has determined that the mitigation is limited to the Phoenix Valley Load Pocket (a small portion of the APS Balancing Authority Area) during the summer months only.¹²³ Pinnacle requests that the Commission clarify that the tariff provision is meant to encompass only the mitigated area of each seller, and requests that the Commission revise this language to state that “the mitigated seller and its affiliate do not sell the power back into the *seller’s mitigated market*.” If the Commission declines to make this revision, Pinnacle seeks rehearing of the requirement, arguing that restrictions on sales should be limited to the more focused mitigated area defined for mitigated companies when the mitigation is for less than an entire balancing authority area.¹²⁴

73. Wisconsin Electric states that it has a Commission-approved market-based rate tariff that permits it to make wholesale sales at or beyond the metered boundary of the Wisconsin-Upper Michigan System (WUMS) region, and that provides that the WUMS restriction does not apply to Wisconsin Electric’s transactions in the Midwest ISO energy market. It requests that the Commission clarify, or in the alternative, grant rehearing of Order No. 697-A to make clear that Order No. 697-A does not modify the terms of Wisconsin Electric’s market-based rate tariff or the manner in which wholesale sales are conducted in the Midwest ISO energy market. Specifically, Wisconsin Electric argues that the Commission should make clear that Wisconsin Electric remains able to sell energy into the Midwest ISO energy market without “at or beyond the metered boundary” restrictions or requirements to obtain transmission to effectuate the transaction.

74. In addition, Wisconsin Electric argues that the Commission should make clear that, for bilateral energy and capacity transactions that are not covered by the Midwest ISO tariff, Wisconsin Electric, as a mitigated seller subject to an “at or beyond the metered boundary” limitation, or the purchaser may use network transmission service to effectuate the sale at or beyond the metered boundary if allowable. Wisconsin Electric argues that while network service is normally used to serve load rather than make off-system sales,¹²⁵ the Commission should permit

network service to be used in this instance. It submits that mitigated sellers will be unable to compete if they are forced to bear the costs of point-to-point transmission service to transmit the power to the metered boundary, and further asserts that the requirement to bear such transmission costs will render useless the ability to make sales at the metered boundary, because the point-to-point transmission costs layered on top of the energy and capacity costs would likely render the sale uneconomic. Wisconsin Electric therefore concludes that wholesale customers in balancing authority areas in which the mitigated seller is authorized to make market-based sales will be left with fewer purchase options.¹²⁶

75. Finally, Wisconsin Electric argues that the Commission should clarify that the metered boundary will not be the entire Midwest ISO footprint after the Midwest ISO ancillary services market becomes operational. In particular, it states that when the ancillary services market becomes operational, the Midwest ISO region will become a single balancing authority area, with the former balancing authorities becoming “local balancing authorities.” Thus, Wisconsin Electric concludes that the WUMS region will consist of a combination of “local balancing authority areas” within the Midwest ISO balancing authority area, rather than the current combination of balancing authority areas. Wisconsin Electric states that it lacks authority to make certain bilateral market-based rate sales within the WUMS region and is authorized to make such sales at or beyond the metered boundary between WUMS and neighboring regions.¹²⁷ It argues that commencement of operations under the ancillary services market will have no effect on Wisconsin Electric’s market power, and that the Commission should make clear that the same geographic boundaries will continue to apply with respect to Wisconsin Electric’s market-based rate authority after the ancillary services market becomes operational so that following commencement of operations under the ancillary services market, Wisconsin Electric will still be permitted to make bilateral market-based sales at or beyond the metered boundary between WUMS and neighboring regions, and to make market-based sales within the Midwest ISO energy market.¹²⁸

¹²³ *Id.* at 3 (*Pinnacle West Capital Corp.*, 120 FERC ¶ 61,153, at P 38 (2007), *order on compliance filing and clarification*, 122 FERC ¶ 61,035 (2008)).

¹²⁴ *Id.*

¹²⁵ *Id.* at 5 (citing *In re SCANA Corp.*, 118 FERC ¶ 61,028 (2007)).

¹²⁶ *Id.*

¹²⁷ *Id.* at 6 (citing *Wisconsin Elec. Power Co.*, Docket No. ER98-855-009, (Apr. 18, 2008) (unpublished letter order)).

¹²⁸ *Id.* at 6-7.

¹²¹ *Id.* at 6.

¹²² *Id.*

Commission Determination

76. We appreciate E.ON's concerns regarding the difficulty of defining the term "same power." For this reason, we will revise the tariff provision for market-based rate sales at the metered boundary, which incorporated the provision that the "Seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated," to state that "if the Seller wants to sell at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing authority area from the outside." A seller that includes this provision in its market-based rate tariff should update its tariff with the revised provision the next time that it files revised tariff sheets, a triennial review, or a change in status report.

77. With regard to the requests of E.ON and Pinnacle that the Commission clarify that neither a seller nor its affiliate will be found in violation of this tariff provision if the seller's affiliate did not know that it was the "same power" being sold into the mitigated market, as explained above, we are revising the tariff provision for sales at the metered boundary to remove the language stating "the mitigated seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated" and replacing it with "if the Seller wants to sell at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing authority areas from the outside." We note that this revised tariff language will prevent a mitigated seller making market-based rate sales at the metered boundary from selling power into the mitigated market through its affiliates. In other words, sellers may choose to make no market-based rate sales at the metered boundary, or to limit such sales to sales to end users of the power, thereby eliminating the danger they will violate their tariff by re-selling power back into a balancing authority in which they are mitigated.¹²⁹ In Order No. 697–A, in response to Pinnacle's request for clarification of Order No. 697, the Commission clarified that "a series of transactions involving what Pinnacle describes as a 'coincidental sale' that may result in an affiliate re-selling power back into the balancing authority area in which the seller has been found,

or presumed to have market power are prohibited by Order No. 697. This is because mitigated sellers and their affiliates are prohibited from selling power at market-based rates in the balancing authority area in which a seller is found, or presumed, to have market power."¹³⁰ Order No. 697–A therefore clarified that an affiliate of a mitigated seller is prohibited from selling power that was purchased at a market-based rate at the metered boundary back into the balancing authority area in which the seller has been found, or presumed, to have market power.¹³¹ To provide additional regulatory certainty for mitigated sellers, the Commission clarified that "once the power has been sold at the metered boundary at market-based rates, the mitigated seller and its affiliates may not sell that same power back into the mitigated balancing authority area, whether at cost-based or market-based rates."¹³²

78. With regard to Pinnacle's assertion that the Commission's statement at paragraph 335 of Order No. 697–A that "an affiliate of a mitigated seller is prohibited from selling power that was purchased at a market-based rate at the metered boundary back into the balancing authority area in which the seller has been found, or presumed, to have market power" appears to presume that power purchased at market-based rates from any party cannot be resold at cost-based rates, we clarify that entities that are not affiliated with the seller may sell power back into the mitigated market.

79. With regard to Pinnacle's request that we clarify that the tariff language for sales of power at market-based rates at the metered boundary is meant to encompass only the mitigated area of each seller, we note that we have granted Pinnacle's request to permit it to revise its tariff language for metered boundary sales to replace "balancing authority area where the seller is mitigated" with "seller's mitigated market."¹³³ However, we permitted Pinnacle to revise its tariff language in this regard because it is not mitigated in an entire balancing authority area; rather Pinnacle is mitigated in the Phoenix Valley Load Pocket, a small portion of the APS balancing authority area, during the summer months only. We will permit such tariff revisions only on a case-by-case basis. Thus, other

mitigated sellers seeking to modify their tariffs in this regard must submit a filing at the Commission pursuant to section 205 of the FPA, and should explain why they should be permitted to revise their tariff language for sales of power at market-based rates at the metered boundary.

80. With regard to Wisconsin Electric's arguments on rehearing, we grant Wisconsin Electric's request for clarification that Order No. 697–A did not modify the terms of Wisconsin Electric's market-based rate tariff (which allowed Wisconsin Electric to sell energy into the Midwest ISO energy market without "at or beyond the metered boundary" restrictions) or the manner in which wholesale sales are conducted in the Midwest ISO energy market.¹³⁴ We further note that, subsequent to the filing of its rehearing request in this proceeding, the Commission accepted a tariff filing by Wisconsin Electric that removed from its market-based rate tariff the provision prohibiting Wisconsin Electric from making bilateral market-based rate sales in WUMS.¹³⁵

81. With regard to Wisconsin Electric's request for clarification that the same geographic boundaries will continue to apply with respect to Wisconsin Electric's market-based rate authority after the Midwest ISO ancillary services market becomes operational, so that following commencement of operations under the Midwest ISO ancillary services market Wisconsin Electric will still be permitted to make bilateral market-based sales at or beyond the metered boundary between WUMS and neighboring regions and to make market-based sales within the Midwest ISO energy market, we find that this request for clarification is moot. As explained above, the Commission accepted Wisconsin Electric's filing removing the tariff restriction prohibiting it from making market-based rate sales in WUMS.¹³⁶ Thus, Wisconsin Electric is no longer subject to a limitation that bilateral sales at market-based rates must be made at the metered boundary between WUMS and neighboring regions. Similarly, Wisconsin Electric's request for clarification that, for bilateral energy and capacity transactions that are not covered by the Midwest ISO tariff, Wisconsin Electric, as a mitigated seller subject to an "at or beyond the metered

¹³⁰ *Id.* P 335.

¹³¹ *Id.*

¹³² Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at n.464.

¹³³ Arizona Public Service Co., Docket No. EL08–1104–000, at 1 (July 3, 2008) (unpublished letter order).

¹³⁴ *Wisconsin Electric Power Co.*, 110 FERC ¶ 61,340, *reh'g denied*, 111 FERC ¶ 61,361 (2005).

¹³⁵ *Wisconsin Electric Power Company*, Docket No. ER08–1176–000 (Aug. 22, 2008) (unpublished letter order).

¹³⁶ *Id.*

¹²⁹ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 336.

boundary" limitation, or the purchaser may use network transmission service to effectuate the sale at or beyond the metered boundary if allowable is also moot in light of the removal of the WUMS restriction in Wisconsin Electric's tariff.

82. To the extent that Wisconsin Electric is also asking on rehearing that the Commission clarify that any mitigated seller with authority to make sales at the metered boundary may use its network transmission service (as opposed to point-to-point service) to transport the electric energy to or beyond the metered boundary to the extent that transmission service is necessary to engage in wholesale sales at or beyond the metered boundary, we will deny that request. The Commission rejected a similar argument by Oklahoma Gas & Electric (OG&E) in Order No. 697–A, and Wisconsin Electric has failed to persuade us on rehearing that our determination in that regard was in error. Similar to the arguments raised by Wisconsin Electric, OG&E claimed that a mitigated seller's ability to compete will be undermined if it attempts to transact with a purchaser willing to use the purchaser's existing network transmission service. OG&E complained that because a mitigated seller must incur transmission costs to deliver the power in this scenario to the metered boundary rather than simply to a generator bus in the balancing authority area in which a seller is found, or presumed, to have market power, the mitigated seller would be unable to bid on a "power only" basis and would be forced to pay an additional transmission cost that is redundant due to the purchaser's ability to use its network service if the mitigated seller could sell at the generator bus. In response to these arguments, the Commission found that OG&E's concern regarding mitigation undermining a seller's ability to compete fails to appreciate that mitigated sellers are prohibited from making sales at a generator bus in that particular balancing authority area because they have been shown to have, or conceded, market power in that market area. The Commission stated that OG&E had failed to adequately address how the Commission could effectively monitor sales at generator bus locations to ensure that improper sales are not being made in the balancing authority area in which a seller is found, or presumed, to have market power. In this regard, the Commission reiterated that commenters in the rulemaking proceeding had noted the complex administrative problems

that would be associated with trying to monitor compliance with such a policy.¹³⁷ The Commission explained that mitigated sellers thus lose the privilege of market-based rate sales at generator bus locations within a balancing authority area in which a seller is found or presumed to have market power, and that, unlike sales at the generation bus bar within a mitigated balancing authority area, sales made at the metered boundary for export do lend themselves to being monitored for compliance, and these sales do not unduly disadvantage customers or competitors.¹³⁸

E. Implementation Process

1. Category 1 and 2 Sellers Background

83. In Order No. 697, the Commission created a category of market-based rate sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses. These 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, FERC Stats. & Regs. ¶ 31,036); 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 seller's generation assets; and that do not raise other vertical market power issues."¹³⁹ Market power concerns for Category 1 sellers will be monitored through the change in status reporting requirement¹⁴⁰ and through ongoing monitoring by the Commission's Office of Enforcement. Category 2 sellers (all sellers that do not qualify for Category 1) are required to file regularly scheduled updated market power analyses in addition to change in status reports.

84. In addition, to ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission modified the timing for the submission

of updated market power analyses.¹⁴¹ Order No. 697 requires analyses to be filed for each seller's region on a pre-determined schedule, rotating by geographic region where two regions are reviewed each year, with the cycle repeating every three years.¹⁴²

85. On rehearing in Order No. 697–A, the Commission upheld its determination to create a category of market-based rate sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses and its decision to adopt a regional review. The Commission also clarified, consistent with its December 14 Clarification Order, that revised Appendix D to Order No. 697–A makes clear that transmission owners and their affiliates have earlier filing periods than the other entities required to file in each region.¹⁴³

Requests for Rehearing

86. Wisconsin Electric requests that the Commission clarify that Wisconsin Electric's triennial market power update filing is due when all Category 2 sellers other than transmission owners or their affiliates are obligated to make such filings. Wisconsin Electric states that it transferred ownership of its transmission facilities to American Transmission Company, LLC (American Transmission Company). Thus, it argues that it is not a transmission owner and is not affiliated with a transmission owner with market-based rate authority, and therefore its next triennial filing would be due in June 2009.¹⁴⁴

Commission Determination

87. We will grant Wisconsin Electric's request, and clarify that because Wisconsin Electric has divested its transmission to American Transmission Company,¹⁴⁵ Wisconsin Electric falls within the category of all other Category 2 sellers in the Central region. Accordingly, Wisconsin Electric must submit its updated market power analysis at the Commission at the same time non-transmission owning utilities

¹⁴¹ Previously, updated market power analyses were submitted within three years of any order granting a seller market-based rate authority, and every three years thereafter.

¹⁴² See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at Appendix D. The regions include the Northeast, Southeast, Central, Southwest Power Pool, Southwest, and Northwest.

¹⁴³ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 374 (citing December 14 Clarification Order, 121 FERC ¶ 61,260 at P 9).

¹⁴⁴ Wisconsin Electric Rehearing Request at 7.

¹⁴⁵ Wisconsin Electric Power Co., 90 FERC ¶ 61,346 (2000).

¹³⁷ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 320 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 818).

¹³⁸ *Id.* P 322–23.

¹³⁹ 18 CFR 35.36(a)(2).

¹⁴⁰ See 18 CFR 35.42.

in the Central region file their updated market power analyses.¹⁴⁶

2. Market-Based Rate Tariff Clarifications

Background

88. In Appendix C of Order No. 697, the Commission provided certain standard tariff provisions that sellers must include in their market-based rate tariffs to the extent they are applicable based on the services provided by the seller. The Commission stated that it will post these provisions on its Web site and update them as appropriate.¹⁴⁷ In Order No. 697–A, the Commission clarified that if a seller makes sales of ancillary services in certain RTO/ISOs, the seller must include the standard ancillary services provision(s) in its tariff, as applicable, without variation.¹⁴⁸

Requests for Rehearing

89. With respect to the standard applicable ancillary service tariff provision(s) set forth in Appendix C to Order No. 697–A, EEI states that Appendix C has not yet been updated to reflect that the Commission has approved the market power study performed by the Midwest ISO Independent Market Monitor. EEI encourages the Commission to add Midwest ISO to Appendix C, with an effective date matching the start of the market.¹⁴⁹

Commission Determination

90. The tariff provision for the Midwest ISO ancillary services market has been included in Appendix C and is available on the Commission's Web site.¹⁵⁰ The effective date of the tariff sheet with the required tariff provision for the Midwest ISO ancillary services market should match the start date of the Midwest ISO ancillary services market accepted by the Commission.

F. Clarifications of the Commission's Regulations

91. In Order No. 697–A, the Commission found that based on its further consideration of the regulations,

several provisions should be changed to provide additional clarity.¹⁵¹

Triggering Events for Change in Status Filings

Background

92. In Order No. 697, the Commission adopted a regulation requiring sellers to timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. In particular, § 35.42 specifies that a change in status includes, but is not limited to, “ownership or control of generation capacity that results in net increases of 100 MW or more.”¹⁵²

93. Upon further consideration, in Order No. 697–A, the Commission clarified that a change in status also includes long-term firm capacity purchases that result in net increases of 100 MW or more. The Commission explained that this is consistent with a seller's obligation to include long-term firm capacity purchases in determining uncommitted capacity, which is used in the indicative screens.¹⁵³ The Commission stated that revision to the regulation is appropriate because the Commission's April 14 Order, reaffirmed in Order No. 697, stated that 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.”¹⁵⁴ Thus, the Commission explained that long-term firm capacity purchases that result in net increases of 100 MW or more are a “departure from the characteristics the Commission relied upon in granting market-based rate authority.” Accordingly, the Commission revised § 35.42(a)(1) so that a change in status includes, but is not limited to, “ownership or control of generation capacity and long-term firm purchases of generation capacity that result in net increases of 100 MW or more.” The Commission stated that because sellers may not have been on notice that this was the Commission's intent, it will not hold any sellers responsible for failure to report such changes in status prior to the effective date of this order, which will be 30 days after issuance in the **Federal Register**.¹⁵⁵

Requests for Rehearing

94. EPSA requests that the Commission clarify Order No. 697–A's inclusion of long-term capacity purchases as a trigger for changes in status filings.

95. EPSA argues that although the Commission intended to provide additional clarity, the Commission's new reference to “long-term firm capacity purchases” is more confusing than illuminating. It argues that capacity purchases, which are distinct from energy purchases, are found primarily in RTOs/ISOs with forward capacity markets, and less frequently, in bilateral transactions with load serving entities that require additional capacity for planning purchases. EPSA asserts that the April 14 Order, on which the Commission relies, appears to be both broader in one respect than the new § 35.42(a)(1) requirement, and narrower in another. First, according to EPSA, the relevant portion of the April 14 Order appears to address long-term energy and capacity transactions, both of which fall into the ambit of firm purchases of generation, while Order No. 697–A appears to focus solely on long-term firm capacity purchases. Second, EPSA argues that the April 14 Order appears to require the element of control in the calculation of uncommitted capacity, while the modification to § 35.42(a)(1) promulgated in Order No. 697–A appears to place all “long-term firm purchases of generation capacity” into the calculation, regardless of control.¹⁵⁶

96. EPSA argues that to the extent the Commission intended to include all long-term firm energy purchases in cumulating generation increases, or to include all long-term firm capacity and energy purchases regardless of control, this aspect of Order No. 697–A appears inconsistent with the Commission's prior orders. Specifically, EPSA asserts that in the Order No. 652 rehearing order, the Commission clarified that “to the extent * * * a contract for a fixed quantity delivered energy does not confer control, it need not be reported [as a change in status].”¹⁵⁷ EPSA also states that more recently, the Commission concluded that the sale of a firm liquidated damages (LD) energy product under the EEI Master Power Purchase and Sale Agreement “would not reflect a departure from the characteristics the Commission relied

¹⁴⁶ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at Appendix D–2.

¹⁴⁷ Order, No. 697, FERC Stats. & Regs. ¶ 31,252 at P 918.

¹⁴⁸ *Id.* P 387 (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 916–917; Appendix C (for a listing of the standard ancillary services provisions); *Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,275, at P 14 & n.22 (2007) (directing seller to conform with Appendix C)).

¹⁴⁹ EEI Rehearing Request at 18.

¹⁵⁰ <http://www.ferc.gov/industries/electric/gen-info/mbr.tariff.asp>.

¹⁵¹ Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 527.

¹⁵² *Id.* P 528.

¹⁵³ *Id.* P 530 (citing April 14 Order, 107 FERC ¶ 61,018 at P 95, 100).

¹⁵⁴ *Id.* (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 38) (footnote omitted).

¹⁵⁵ *Id.* P 531.

¹⁵⁶ EPSA Rehearing Request at 28 (citing Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 530–31).

¹⁵⁷ *Id.* at 29 (quoting *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, 111 FERC ¶ 61,413, at P 12 (2005) (rehearing of Order No. 652)).

upon in granting market-based rate authority and therefore would not necessitate the filing of a change in status report” because the product “‘by itself gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity.’”¹⁵⁸

97. EPSA therefore requests guidance with respect to the following questions in order to facilitate full compliance with the Commission’s change in status reporting regulations: (1) Does the change articulated in Order No. 697–A require sellers to include only long-term firm capacity purchases in their cumulative generation count for change-in-status purposes, or are they to include long-term firm energy purchases as well? (2) If sellers are to include only long-term firm capacity purchases in their cumulative generation count, did the Commission intend this terminology to encompass transactions in addition to the traditional capacity purchases as outlined above? (3) If sellers are to include long-term firm energy purchases in their cumulative generation counts for change-in-status purposes, are they to include all long-term firm energy purchases or only those that confer some element of control, as implied by the Commission’s April 14 Order, its order on rehearing of Order No. 652, and in the recent Integrys decision? and (4) If only contracts that confer control are to be included (whether capacity only, or energy and capacity), are entities with market-based rates permitted to exclude from their calculation those long-term firm energy contracts that contain either liquidated damage provisions or other provisions that permit the seller to retain a complete and unrestricted right to choose a generating resource or a monetized replacement resource?¹⁵⁹

98. EPSA submits that how the Commission addresses these questions will not only impact change in status reporting, but will also have significant bearing on the data sellers assemble and analyze in their updated market power analyses to the extent “long-term firm purchases” and “long-term firm sales” (as listed on the Commission’s standard screen format for the pivotal supplier analysis) are no longer limited to transactions which confer control, or alternatively are limited to capacity purchases and sales only.¹⁶⁰

Commission Determination

99. In response to the first question posed by EPSA regarding whether Order No. 697–A requires sellers to include long-term energy purchases in addition to long-term firm capacity purchases in their cumulative generation count for change-in-status purposes, we find that to the extent a contract for a fixed quantity of delivered energy does not confer control, it need not be reported.¹⁶¹ Consistent with the Commission’s determination in Integrys that the sale of a “Firm (LD)” product, as defined in the EEI Master Power Purchase & Sale Agreement, by itself gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity, we reiterate that the sale of the Firm (LD) product would not reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority and therefore would not necessitate the filing of a change in status report.¹⁶² We note that in reaching this determination, the Commission relied on the representations of Integrys Energy Group, Inc. that the purchaser under a Firm (LD) product has no ability to withhold energy from the market or otherwise use the product as part of a capacity withholding strategy.¹⁶³ For example, the Commission relied on the fact that the purchaser cannot force the seller to back down the output of any generator, and the fact that if the purchaser refuses to receive delivery, that refusal does not keep the power from entering the market because the seller has the right to resell the Firm (LD) product, as well as to receive damages from the purchaser. However, to the extent a long-term energy purchase would allow the purchaser to control generation capacity, it needs to be reported. A determination of whether a long-term firm energy purchase confers control over generation capacity to the purchaser must be based on a review of the totality of the circumstances on a fact-specific basis. Therefore, sellers who are uncertain as to whether they must include long-term energy purchases in their cumulative generation count because the facts and circumstances surrounding their long-

term energy purchase(s) differ from the facts relied on by the Commission in the Integrys order will need to obtain guidance from the Commission by making a filing at the Commission. Sellers will need to provide information on the facts, terms and circumstances concerning the long-term energy purchase(s) in their filing. The Commission will evaluate each such filing on a case-by-case basis and will make a determination based on those specific facts and circumstances.

100. With regard to EPSA’s second question concerning whether sellers are to include only long-term firm capacity purchases in their cumulative generation count, and whether the Commission intended this terminology to encompass transactions in addition to traditional capacity purchases, we clarify that as the Commission explained in Integrys, where a purchase “does not result in a transfer of control of generation capacity to the purchaser” it does not have to be reported by the purchaser in a change in status report under the Commission’s regulations.¹⁶⁴ However, we note that the Commission’s finding in Integrys was limited to the facts described by the Integrys group, and was dependent on the specific terms and conditions for a Firm (LD) product, as defined by the EEI Master Power Purchase and Sale Agreement. Thus, as the Commission explained in Integrys, different or additional facts, terms, or conditions could change the Commission’s analysis of whether other types of transactions transfer control of generation capacity to the purchaser.¹⁶⁵

101. With regard to EPSA’s third question (if sellers are to include long-term firm energy purchases in their cumulative generation counts for change in status purchases, are they to include all long-term firm energy purchases or only those that confer some element of control), we clarify that, as stated above, only long-term firm energy purchases that confer some element of control must be included in a seller’s cumulative generation counts for change in status reports.¹⁶⁶ A long-term firm energy purchase by itself gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity.¹⁶⁷ As explained above, a determination of whether a long-term firm energy purchase confers control

¹⁵⁸ *Id.* (quoting *Integrys Energy Group, Inc.*, 123 FERC ¶ 61,034, at P 11 (2008) (*Integrys*)).

¹⁵⁹ *Id.* at 29–30.

¹⁶⁰ *Id.* at 30.

¹⁶¹ *Integrys*, 123 FERC ¶ 61,034 at P 11 (regarding energy only contracts in *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, 111 FERC ¶ 61,413, at P 12 (2005) (rehearing of Order No. 652) the Commission concluded that “‘to the extent * * * a contract for a fixed quantity of delivered energy does not confer control, it need not be reported.’”).

¹⁶² *Id.*

¹⁶³ *Id.* P 7.

¹⁶⁴ *See id.*

¹⁶⁵ *Id.*

¹⁶⁶ *Id.* (citing *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, 111 FERC ¶ 61,413 at P 12).

¹⁶⁷ *Id.*

over generation capacity must be based on a review of the totality of the circumstances on a fact-specific basis.

102. EPSA's fourth question (if only contracts that confer control are to be included in their cumulative generation count (whether capacity only, or energy and capacity), are entities with market-based rates permitted to exclude from their calculation those long-term firm energy contracts that contain either liquidated damage provisions or other provisions that permit the seller to retain a complete and unrestricted right to choose a generating resource or a monetized replacement resource) requires a fact-specific determination. As the Commission explained in *Integrus*, different or additional facts, terms, or conditions could change the Commission's analysis. Thus, whether long-term firm energy contracts that contain either liquidated damage provisions or other provisions that permit the seller to retain a complete and unrestricted right to choose a generating resource result in a transfer control of generation capacity to the purchaser is an issue to be determined on a case-by-case basis.¹⁶⁸ We will not make a generic finding on whether contracts with such provisions are exempt from being included in a market-based rate seller's cumulative MW total for change in status reports.¹⁶⁹

III. Information Collection Statement

103. The Office of Management and Budget (OMB) regulations require that OMB approve certain information collection requirements imposed by an agency.¹⁷⁰ The Final Rule's revisions to the information collection requirements for market-based rate sellers were approved under OMB Control Nos. 1902-0234. While this order clarifies aspects of the existing information collection requirements for the market-based rate program, it does not add to these requirements. Accordingly, a copy of this order will be sent to OMB for informational purposes only.

IV. Document Availability

104. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to

view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

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

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

V. Effective Date

107. Changes to Order No. 697-A adopted in this order on rehearing will become effective January 29, 2009.

List of Subjects in 18 CFR Part 35

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

By the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

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

■ 2. In § 35.36, paragraph (a)(9) is revised to read as follows:

§ 35.36 Generally.

(a) * * *

(9) *Affiliate* of a specified company means:

(i) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company;

(ii) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with

power to vote, directly or indirectly, by the specified company;

(iii) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and

(iv) Any person that is under common control with the specified company.

(v) For purposes of paragraph (a)(9), owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control.

* * * * *

■ 3. In § 35.37, paragraph (e)(3) is revised to read as follows:

§ 35.37 Market power analysis required.

(e) * * *

(3) Physical coal supply sources and ownership or control over who may access transportation of coal supplies.

* * * * *

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

Appendix C to Order No. 697-A

Required Provisions of the Market-Based Rate Tariff

Compliance With Commission Regulations

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

Limitations and Exemptions Regarding Market-Based Rate Authority

[Seller should list all limitations (including markets where seller does not have market-based rate authority) on its market-based rate authority and any exemptions from or waivers granted of Commission regulations and include relevant cites to Commission orders].

Seller Category

Seller Category: Seller is a [insert Category 1 or Category 2] seller, as defined in 18 CFR 35.36(a).

¹⁶⁸ *Id.* Although EPSA also asked this question in connection with contractual provisions that permit the seller to retain a complete and unrestricted right to choose a "monetized replacement resource," EPSA does not define the term "monetized replacement resource" in its rehearing request. As a result, we do not include that term in our response above.

¹⁶⁹ Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, 111 FERC ¶ 61,413, at P 12 (2005).

¹⁷⁰ 5 CFR 1320.11.

Include All of the Following Provisions That Are Applicable

Mitigated Sales

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area; (ii) if the Seller wants to sell at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing authority area from the outside. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i) and (ii) above.

Ancillary Services

RTO/ISO Specific—Include All Services the Seller Is Offering

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

Midwest ISO: Seller offers regulation service and operating reserve service (which include a 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and to others that are self-supplying ancillary services to Midwest ISO.

Third Party Provider

Third-party Ancillary Services: Seller offers [include all of the following that the seller is

offering: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves]. Sales will not include the following: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

[FR Doc. E8-30757 Filed 12-29-08; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 284

[Docket No. RM08-1-001; Order No. 712-A]

Promotion of a More Efficient Capacity Release Market

December 22, 2008.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule; correction.

SUMMARY: The Federal Regulatory Commission (FERC) is correcting a final rule that appeared in the **Federal Register** of December 1, 2008 (73 FR 72692). The document revised regulations governing interstate natural gas pipelines to reflect changes in the market for short-term transportation services on pipelines and to improve the efficiency of the Commission's capacity release program.

DATES: *Effective Date:* This rule will become effective December 31, 2008.

FOR FURTHER INFORMATION CONTACT:

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David Maranville, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, David.Maranville@ferc.gov, (202) 502-6351.

SUPPLEMENTARY INFORMATION: In FR Doc. E8-28217 appearing on page 72692 in the **Federal Register** of Monday, December 1, 2008, the following corrections are made:

§ 284.8(h) [Corrected]

1. On page 72714, in the first column, in § 284.8 Release of Capacity by Interstate Pipelines, in paragraph (h)(1)(i), "A release of capacity to an asset manager as defined in paragraph (h)(4) of this section" is corrected to read "A release of capacity to an asset manager as defined in paragraph (h)(3) of this section;"

§ 284.8(h) [Corrected]

2. On page 72714 in the first and second columns, in § 284.8 Release of Capacity by Interstate Pipelines, in paragraph (h)(1)(ii), "A release of capacity to a marketer participating in a state-regulated retail access program as defined in paragraph (h)(5) of this section" is corrected to read "A release of capacity to a marketer participating in a state-regulated retail access program as defined in paragraph (h)(4) of this section"

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. E8-30910 Filed 12-29-08; 8:45 am]

BILLING CODE 6717-01-P

PENSION BENEFIT GUARANTY CORPORATION

29 CFR Parts 4001, 4211, and 4219

RIN 1212-AB07

Methods for Computing Withdrawal Liability; Reallocation Liability Upon Mass Withdrawal; Pension Protection Act of 2006

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Final rule.

SUMMARY: This final rule amends PBGC's regulation on Allocating Unfunded Vested Benefits to Withdrawing Employers (29 CFR part 4211) to implement provisions of the Pension Protection Act of 2006 that provide for changes in the allocation of unfunded vested benefits to withdrawing employers from a multiemployer pension plan, and that require adjustments in determining an employer's withdrawal liability when a multiemployer plan is in critical status. Pursuant to PBGC's authority under section 4211(c)(5) of ERISA to prescribe standard approaches for alternative withdrawal liability methods, the final rule also amends this regulation to provide additional modifications to the