141 FERC ¶ 61,207
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

NRG Energy, Inc. Docket No. EC12-134-000
GenOn Energy, Inc.

ORDER ON DISPOSITION OF JURISDICTIONAL FACILITIES AND MERGER

(Issued December 13, 2012)

TABLE OF CONTENTS

Paragraph Numbers

1. On August 10, 2012, pursuant to sections 203(a)(1) and 203(a)(2) of the Federal Power Act[1] (FPA) and Part 33 of the Commission's regulations,[2] NRG Energy, Inc. (NRG Energy) and GenOn Energy, Inc. (GenOn Energy) (together, with their public utility subsidiaries, Applicants) filed an application for the approval of a transaction pursuant to which NRG Energy will acquire and combine with GenOn Energy in a stock-for-stock transaction (Proposed Transaction).[3] The Commission has reviewed the Merger Application under the Commission's Merger Policy Statement.[4] As discussed below, we will authorize the Proposed Transaction as consistent with the public interest.

I. **Background**

A. **Description of the Parties**

1. **NRG Energy**

2. NRG Energy is an integrated wholesale power generation and retail electricity company that engages in three related electricity businesses. NRG Energy states that it is a wholesale power generator that engages in the ownership and operation of power

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[1] 16 U.S.C. § 824b(a)(1) and (a)(2) (2006).

[2] 18 C.F.R. § 33, *et seq.* (2012).

[3] *Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger Under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act*, Docket No. EC12-134-000 (Aug. 10, 2012) (Merger Application). Applicants state that all subsidiaries of NRG Energy and GenOn Energy that are public utilities subject to the Commission's jurisdiction are seeking Commission authorization under section 203. A list of these subsidiaries is included in the Merger Application as Exhibit B, List of Energy Subsidiaries and Affiliates.

[4] *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). *See also Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

generation facilities; the trading of energy, capacity and related products; and the transacting in and trading of fuel and transportation services. NRG Energy also explains that it is a retail electric supply company engaged in the sale of electricity, energy services, and "cleaner energy products" to retail electricity customers in deregulated markets primarily through three of its subsidiaries.[5] NRG Energy states that it is focused on the deployment and commercialization of alternative energy technologies.[6]

2. GenOn Energy

3. GenOn Energy is a wholesale generation company that, through its subsidiaries, owns or controls electric generating capacity located near major metropolitan load centers in the Eastern PJM Interconnection, LLC (PJM), and Northeast and Western regions. GenOn Energy states that it also engages in integrated asset management and proprietary trading operations. GenOn Energy explains that its customers are principally Independent System Operators (ISO) and Regional Transmission Organizations (RTO), and investor-owned utilities. GenOn Energy states that its generating portfolio is diversified across fossil fuel and technology types, operating characteristics, and several regional power markets.[7]

3. Plus Merger Corporation

4. Plus Merger Corporation (Merger Sub) is a Delaware Corporation and a wholly-owned subsidiary of NRG Energy.[8]

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[5] Merger Application at 3.

[6] Applicants include an organizational chart showing the pre-transaction organizational structure of NRG Energy in Exhibit C-1, NRG Energy, Inc. Organizational Structure, of the Merger Application. Applicants also provide descriptions of all individual NRG Energy entities that are subject to the Commission's jurisdiction as public utilities in Exhibit B-1, List of NRG Public Utility Subsidiaries and Affiliates, of the Merger Application.

[7] Applicants include an organizational chart showing the pre-transaction organizational structure of GenOn Energy in Exhibit C-2, GenOn Energy, Inc. Organizational Structure (direct and indirect), of the Merger Application. Applicants also provide descriptions of all individual GenOn Energy entities that are subject to the Commission's jurisdiction as public utilities in Exhibit B-2, List of GenOn Public Utility Subsidiaries and Affiliates, of the Merger Application.

[8] Merger Application at 4.

B. Description of Proposed Transaction

5. Applicants explain that, under the terms of a merger agreement entered into by NRG Energy, Merger Sub, and GenOn Energy (Merger Agreement), subject to regulatory approvals and the satisfaction of certain obligations of the parties, Merger Sub will merge with and into GenOn Energy.[9] Applicants state that GenOn Energy will continue as the surviving entity and become a wholly-owned subsidiary of NRG Energy, which will retain its name.

6. Applicants explain that, upon completion of the Proposed Transaction, GenOn Energy stockholders will receive 0.1216 of a share of NRG Energy common stock for each share of GenOn Energy common stock that they hold.[10] According to Applicants, NRG Energy shareholders will own approximately 71 percent of the combined company while GenOn Energy shareholders will own approximately 29 percent of the combined company.[11]

II. Notice of Filing

7. Notice of the Merger Application was published in the *Federal Register*, 77 Fed. Reg. 50,095 (2012), with interventions and protests due on or before August 31, 2012. The comment date was subsequently extended to October 9, 2012.[12]

8. Notice of Applicants' September 10, 2012 supplemental filing was published in the *Federal Register*, 77 Fed. Reg. 58,121 (2012), with interventions and protests due on or before October 9, 2012.

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[9] The Merger Agreement is included in Exhibit I, Contracts with Respect to the Disposition of Facilities, of the Merger Application.

[10] According to Applicants, based on the closing price of NRG Energy common stock on the New York Stock Exchange on July 20, 2012, the last trading day before the public announcement of the Merger Agreement, GenOn Energy shareholders would receive a value of $2.20 per share, a 20.6 percent premium. Merger Application at 4.

[11] Merger Application at 4. Applicants include an organizational chart showing the post-Proposed Transaction organizational structure of the merged company in Exhibit C-3, NRG Energy, Inc. Organizational Structure, of the Merger Application.

[12] Errata Notice Extending Comment Date (Issued Aug. 15, 2012), Docket No. EC12-134-000.

9. Notice of Applicants' September 28, 2012 supplemental filing was published in the *Federal Register*, 77 Fed. Reg. 61,402 (2012), with interventions and protests due on or before October 9, 2012.

10. Timely motions to intervene were filed by Monitoring Analytics, LLC; PJM Industrial Customer Coalition; Duquesne Power, LLC; and Duquesne Light Company.

11. CPV Shore, LLC (CPV Shore) filed a timely motion to intervene and comments.[13] Applicants filed an answer to CPV Shore's comments.[14]

12. On October 25, 2012, the New Jersey Board of Public Utilities (New Jersey BPU) filed an untimely motion to intervene.

13. On November 14, 2012, Applicants filed copies of regulatory approvals related to the Merger Application that they have received from other regulatory authorities.[15]

14. On December 5, 2012, Applicants filed a motion for expedited consideration.

III. **Discussion**

A. **Procedural Matters**

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[16] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

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[13] *Motion to Intervene and Comments of CPV Shore, LLC*, Docket No. EC12-134-000 (Oct. 4, 2012) (CPV Shore Comments).

[14] *Answer and Motion for Expedited Consideration of NRG Energy, Inc. and GenOn Energy, Inc.*, Docket No. EC12-134-000 (Oct. 10, 2012) (Applicants' Answer).

[15] Specifically, Applicants provided copies of an approval issued by the Public Utility Commission of Texas and the "Threshold Determination" issued by the Nuclear Regulatory Commission. Applicants also noted that the Department of Justice notified Applicants that it had terminated its review under the Hart-Scott-Rodino Act. *NRG Energy, Inc. and GenOn Energy, Inc.*, Transmittal Letter at 1, Docket No. EC12-134-000 (Nov. 14, 2012).

[16] 18 C.F.R. § 385.214 (2012).

16. Although the New Jersey BPU states that its motion to intervene was filed within the timeframe established by Rule 210(b),[17] 18 C.F.R. § 385.210(b) (2012), the Commission notes that the intervention date in this proceeding was October 9, 2012. Given the New Jersey BPU's interest in this proceeding and the absence of undue prejudice or delay, however, we will grant the late-filed motion to intervene pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure.[18]

17. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure[19] prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We will accept Applicants' answer to CPV Shore's comments because it has provided information that assisted us in our decision-making process.[20]

B. Analysis Under Section 203

18. Section 203(a)(4) requires the Commission to approve a transaction if it determines that the transaction will be consistent with the public interest.[21] The Commission's analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[22] Section 203(a)(4) also requires the Commission, before it approves a transaction, to find that the transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest."[23] The Commission's regulations establish verification and informational

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[17] *New Jersey Board of Public Utilities' Motion to Intervene* at 1, Docket No. EC12-134 (October 25, 2012).

[18] 18 C.F.R. § 385.214(d) (2012).

[19] 18 C.F.R. § 385.213(a)(2) (2012).

[20] *See, e.g.*, *Public Service Company of Colorado*, 138 FERC ¶ 61,025, at P 12 (2012); *Midwest ISO, Inc. v. PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,284, at P 51 (2010).

[21] 16 U.S.C. § 824b(a)(4) (2006).

[22] *See* Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111.

[23] 16 U.S.C. § 824b(a)(4) (2006).

requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or a pledge or encumbrance of utility assets.[24]

1. Effect on Competition

a. Horizontal Market Power

i. Applicants' Analysis

19. Applicants assert that their analysis indicates that the Proposed Transaction will not raise any horizontal market power concerns. Applicants state that they reviewed the amount of generation that NRG Energy and GenOn Energy each own or control in each potentially relevant geographic market, including the RTOs, ISOs and balancing authority areas (BAA) where Applicants' generation is located, and that they analyzed the markets where both Applicants own or control generation capacity.[25] Applicants summarize the amount and location of generation owned by each Applicant as follows:

Table 1. Generation owned by Applicants

Market (summer capacity)	NRG Energy (MW)	GenOn Energy (MW)
Common Markets		
PJM	1,462	12,306[26]
ISO-NE	2,272	1,358
NYISO	3,957	1,093
CAISO	3,022	5,477[27]

[24] 18 C.F.R. § 33.2(j) (2012).

[25] Merger Application at 6-7.

[26] Applicants state that this total does not include Potomac River, Niles (coal units) and Elrama because these plants will be fully retired or mothballed pending permanent shutdown on October 1, 2012. *Id.* n.9.

[27] Applicants explain that this total does not include the Contra Costa facility, since it will be replaced by Marsh Landing in 2013, which is included in their analysis. *Id.* n.10.

Entergy[28]	3,665	44
MISO	18[29]	372
NRG Energy Only		
Arizona	25	0
Nevada	46	0
New Mexico	20	0
ERCOT[30]	11,406	0
GenOn Energy Only		
Florida (FPC)	0	468
TVA[31]	0	848

Source: Merger Application at 7.

20. Applicants state that they have overlapping generation in six markets: PJM Interconnection LLC (PJM), ISO-NE, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), California Independent System Operator Corp. (CAISO), Entergy, and Midwest Independent Transmission System Operator, Inc. (MISO).

[28] According to Applicants, the Entergy wholesale generation market "comprises the Entergy Energy Services ("EES") BAA and a number of other control areas or BAAs ("Internal BAAs") that are traditionally treated as being entirely subsumed within the relevant market for Entergy Corporation, the dominant utility in the area." Merger Application, Exhibit J, Testimony of Julia Frayer (Frayer Test.) at 105. Applicants refer to the combined EES BAA and Internal BAAs as the "Entergy market" or "Entergy."

[29] Applicants state that this total includes two 8.8 MW generators located in the Dakota Electric Cooperative service territory that NRG Energy is acquiring. According to Applicants, these facilities are under long-term contract to Great River Energy, which provides wholesale electric service to 28 distribution cooperatives in Minnesota and Wisconsin. Merger Application at n.11.

[30] Electric Reliability Council of Texas.

[31] Tennessee Valley Authority.

Applicants assert, however, that there is only a *de miminis* overlap of generation capacity in MISO, where NRG Energy controls only 18 MW of capacity, well below 0.1 percent of capacity in the MISO market, under long-term sales agreements.[32] Therefore, Applicants contend that no Appendix A analysis of MISO is required under section 33.3(a)(2) of the Commission's regulations.[33] Similarly, Applicants assert that there is no requirement to conduct an Appendix A analysis of markets in Arizona, Florida, Nevada, New Mexico, ERCOT or TVA because there is no overlap of Applicants' generation in those markets.

21. Applicants state that they conducted an Appendix A analysis of the Proposed Transaction for each market where there is more than a *de minimis* overlap: PJM, ISO-NE, NYISO, CAISO and Entergy. Applicants assert that their Appendix A analysis indicates that there are no screen violations in any of the five markets analyzed and therefore the Proposed Transaction does not raise any market power concerns. Applicants conclude that the Commission should determine that the Proposed Transaction does not adversely affect competition.

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[32] Merger Application at 7.

[33] Applicants performed an Appendix A analysis, also referred to as a Delivered Price Test (DPT) or Competitive Analysis Screen, to determine the pre- and post-transaction market shares from which the market concentration or Herfindahl-Hirschman Index (HHI) change can be derived. The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1,000 points are considered to be unconcentrated; markets in which the HHI is greater than or equal to 1,000 but less than 1,800 points are considered to be moderately concentrated; and markets in which the HHI is greater than or equal to 1,800 points are considered to be highly concentrated. In a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,129; s*ee also Analysis of Horizontal Market Power under the Federal Power Act, Order Reaffirming Commission Policy and Terminating Proceeding,* 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).

22. Applicants performed their competitive analysis using both the Economic Capacity (EC) and Available Economic Capacity (AEC) measures.[34] As noted below, Applicants state that they focused on the EC analysis for all of the markets except Entergy because those markets include retail choice. For Entergy, Applicants state that they focused on the AEC analysis (although they also conducted an EC analysis) because the Commission has found that AEC is the more relevant product to analyze markets such as Entergy.[35] For each market analyzed, Applicants also studied whether 10 percent increases or decreases in the destination market prices resulted in screen violations.[36] Applicants also analyzed capacity and ancillary services markets where those markets exist.

23. In the September 10, 2012 and September 28, 2012 supplemental filings, Applicants provided additional information and analysis in support of the Merger Application.[37] According to Applicants, the information provided in the September 10 Supplement "does not change in any respect the competition analysis or the results of that analysis that was presented" in the Merger Application.[38] With respect to the September 28 Supplemental Filing, Applicants state that the information provided is "very minor in scope and does not change in any respect the competition analysis or the results of that analysis that was presented in the [Merger] Application."[39]

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[34] Each supplier's EC is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. AEC is based on the same factors but subtracts the supplier's native load obligation from its capacity and adjusts transmission availability accordingly.

[35] Merger Application at 32 (citing *Great Plains Energy, Inc.*, 121 FERC ¶ 61,069, at P 34 & n.44 (2007), *reh'g denied*, 122 FERC ¶ 61,177 (2008); *Nat'l Grid plc and KeySpan Corp.*, 117 FERC ¶ 61,080, at PP 27-28 (2006), *reh'g denied*, 122 FERC ¶ 61,096 (2008); *Westar Energy, Inc.*, 115 FERC ¶ 61,228, at P 72, *reh'g denied*, 117 FERC ¶ 61,011, at P 39 (2006); *Nev. Power Co. and GenWest LLC*, 113 FERC ¶ 61,265, at P 15 (2005)).

[36] Merger Application at 9.

[37] *NRG Energy, Inc. and GenOn Energy, Inc.*, Docket No. EC12-134-000 (Sept. 10, 2012) (September 10 Supplemental Filing); *NRG Energy, Inc. and GenOn Energy, Inc.*, Docket No. EC12-134-000 (Sept. 28, 2012) (September 28 Supplemental Filing).

[38] September 10 Supplemental Filing, Transmittal Letter at 2.

[39] September 28 Supplemental Filing, Transmittal Letter at 2.

(a) Delivered Price Test Results for PJM

24. Applicants state that NRG Energy owns approximately 1,500 MW of capacity and GenOn Energy owns approximately 12,300 MW of capacity in the PJM market.[40] Applicants state that together they own approximately 8.7 percent of the generation capacity in the PJM market. According to Applicants, prices within PJM can diverge for significant numbers of hours during the year due to internal transmission constraints, and so when considering market power issues in PJM, the Commission considers submarkets within PJM as well as the PJM RTO as a whole. Applicants state that, until recently, the only market identified by the Commission as a default submarket that must be analyzed in the context of market-based rates is the PJM East submarket. Applicants assert, however, that the Commission left open the possibility that other undefined submarkets might also need to be addressed, based on specific congestion data.[41] Applicants observe that in the recent merger of Exelon Corporation (Exelon) and Constellation Energy Group (Constellation) (Exelon-Constellation Merger), applicants in that case analyzed two additional submarkets: the AP South submarket, which consists of the portion of PJM that is east of the AP South interface, and the 5004/5005 submarket, which is defined by the 5004/5005 interface and is essentially the same as the AP South submarket, but excludes the Dominion zone.[42]

25. Applicants state that they analyzed the PJM market as a whole, the PJM East submarket, and the 5004/5005 submarket. Applicants explain that they did not analyze the AP South submarket because they do not own any generation assets in that submarket that are not also located in the 5004/5005 submarket.[43] Additionally, Applicants state that they analyzed relevant capacity and ancillary services markets in PJM. As

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[40] Applicants include a map detailing the location of each company's generation facilities in PJM on page 9 of the Merger Application.

[41] Merger Application at 10-11.

[42] *Id.* n.18 (citing *Exelon Corp*., 138 FERC ¶ 61,167, at P 26 (2012)).

[43] Applicants explain that, since the 5004/5005 submarket is essentially the same as the AP South submarket, the difference being that the 5004/5005 submarket excludes the Dominion Zone, their market shares in the AP South submarket will always be lower than in the 5004/5005 submarket. Thus, HHI increases resulting from the Proposed Transaction will also be lower in the AP South submarket than in the 5004/5005 submarket. Applicants assert that since the HHI increases resulting from the Proposed Transaction do not exceed the Commission's screens in the 5004/5005 submarket, the lower HHI increases in the AP South submarket will also pass the Commission's screens. Merger Application at 11.

mentioned above, Applicants' analyses of PJM and the PJM submarkets focus primarily on EC. The results of Applicants' analysis are summarized below.

(1) <u>Analysis of PJM as a Whole</u>

26. Applicants state that their analysis shows that, under the EC measure, the PJM market as a whole is unconcentrated in all periods post-transaction, except in the Summer Off-Peak and Winter Off-Peak seasons/load periods, where the post-merger HHI values are 1,006 and 1,066, respectively.[44] Although the HHI values during these seasons/load periods fall within the range of values for moderately concentrated markets, Applicants explain that the HHI values increase by only one point during these seasons, and therefore there are no screen violations and no horizontal competition concerns in the PJM market as a whole.[45] Similarly, Applicants state that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[46]

(2) <u>Analysis of PJM East Submarket</u>

27. Applicants state that their analysis shows that, under the EC measure, the PJM East submarket is, post-transaction, moderately concentrated in all periods in the PJM East submarket, except for the Summer Off-Peak season/load period. Applicants note, however, that the HHI increases in those seasons/load periods are all below 30 points and therefore well below the 100 point threshold for screen violations in moderately concentrated markets.[47] Applicants' analysis also shows that the Summer Off-Peak season/load period is highly concentrated with an HHI value of 2,058, but the post-transaction HHI increase is zero points because the level of market concentration remains the same post-transaction.[48] Applicants state that there are no screen violations in the

[44] The Commission notes that, according to Applicants' analysis, the post-transaction HHI value for the Shoulder Off-Peak season/load period is 1,013. *Id.* at 12.

[45] The post-transaction HHI increase in the Shoulder Off-Peak season/load period is also one point. *Id.*

[46] *Id.* at 12-13.

[47] *Id.* at 13. The post-transaction HHI values range from 1,423 to 1,779; the HHI increases range from zero to 26 points. *Id.*

[48] *Id.*

destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[49]

(3) Analysis of PJM 5004/5005 Submarket

28. Applicants state that their analysis shows that, under the EC measure, the 5004/5005 submarket is moderately concentrated post-transaction in all seasons/load periods, with post-transaction HHI values ranging from 1,181 to 1,497.[50] Applicants explain that in all cases, the HHI increases are all well below the 100 point threshold for screen violations in moderately concentrated markets and, therefore, there are no screen violations and no horizontal competition concerns in this market.[51] Applicants assert that market concentration will decrease further once Exelon divests over 2,600 MW of generation in the 5004/5005 submarket as required pursuant to the Commission's approval of the Exelon-Constellation Merger.[52] Applicants state that their analysis does not include this divestiture. Applicants further state that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[53]

(4) Analysis of PJM Capacity Markets

29. Applicants contend that the Proposed Transaction will not have an adverse effect on capacity markets in PJM because the effect of the Proposed Transaction in the PJM-wide Reliability Pricing Model market is small. According to Applicants' analysis, post-transaction the market is unconcentrated (the post-merger HHI value is 807) and the HHI increase is only 12 points. Therefore, Applicants maintain that there are no screen violations in the PJM Reliability Pricing Model market.[54]

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[49] *Id.*

[50] Merger Application at 14.

[51] The HHI increases range from four to 37 points. *Id.*

[52] *Id.* We note that the Commission authorized the divestiture to Raven Power LLC in a delegated order. *Constellation Power Source Generation, Inc.*, 141 FERC ¶ 62,017 (2012). We note that the applicants made a filing on November 30, 2012 indicating that they closed the transaction.

[53] Merger Application at 14.

[54] *Id.* at 15.

30. Applicants further state that they analyzed the effect of the Proposed Transaction on relevant locational deliverability areas, specifically the Mid-Atlantic Area Council (MAAC) locational deliverability area, which is the only locational deliverability area in the 2013/2014 auction where both Applicants own generation assets. Applicants contend that, while the MAAC locational deliverability area is and would remain moderately concentrated post-transaction,[55] the post-transaction HHI increase of 33 points is well below the 100 point threshold for moderately concentrated markets. Therefore, Applicants maintain that there is no screen violation in this locational deliverability area and the Proposed Transaction will not create competitive concerns in the PJM capacity markets.[56]

(5) <u>Analysis of PJM Ancillary Services Markets</u>

31. Applicants state that PJM provides regulation and synchronized reserve services through market-based mechanisms. Applicants explain that the regulation market is RTO-wide, while the synchronized reserves market is divided into two regions: ReliabilityFirst Corporation and South. The ReliabilityFirst Corporation region has several sub-regions, including the Mid-Atlantic zone. Applicants also state that PJM operates a Day-Ahead Schedule Reserves market.[57]

32. Applicants contend that the Proposed Transaction does not have an adverse effect on any of these ancillary services markets in PJM. Applicants state that NRG Energy does not control any generation with regulation capacity in PJM, and therefore there is no increase in market power in the regulation market resulting from the Proposed Transaction. Also, Applicants maintain that NRG Energy did not have any sales of Tier 2 synchronous reserves in PJM in recent years and GenOn Energy's sales were a very small share of the total amount of Tier 2 synchronous reserves. Therefore, Applicants assert that there are no market power concerns in the synchronous reserves market resulting from the Proposed Transaction.[58]

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[55] The pre-transaction HHI value is 1,207; the post-transaction HHI value is 1,240. *Id.*

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

[57] Merger Application at 16.

[58] *Id.*

33. Applicants further assert that NRG Energy and GenOn Energy each made less than one percent of the total Day-Ahead Schedule Reserves sales in PJM in 2011. They contend that the implied HHI increase in the Day-Ahead Schedule Reserves market resulting from the Proposed Transaction is one HHI point, which is not a market power concern.[59]

(b) <u>Delivered Price Test Results for ISO-NE</u>

34. Applicants state that NRG Energy owns approximately 2,300 MW of capacity in Connecticut and GenOn Energy owns approximately 1,400 MW of capacity in Massachusetts. Together, Applicants state that they own approximately 11.5 percent of the generation capacity in the ISO-NE market.[60]

35. Applicants claim that "[u]nlike PJM, the Commission traditionally has analyzed the [ISO-NE] market solely as a single market."[61] Applicants further state that they did not identify any relevant submarkets that should be analyzed. Applicants explain that "transmission congestion and price differentials within [ISO-NE] have been reduced considerably in recent years, at least partly as a result both of transmission expansion projects and of the construction of new generation."[62] Applicants state that, as a consequence, "there no longer is any material transmission congestion separating Southwest Connecticut or Connecticut from the rest of [ISO-NE]."[63] Applicants also state that NRG Energy's generation facilities are located entirely within Connecticut and GenOn Energy's generation facilities are located entirely in Massachusetts, and thus "there is no overlap of generation in any potential submarket within [ISO-NE]."[64] Citing Commission precedent, Applicants note that the Commission has stated that it will not require applicants to "'submit a [Delivered Price Test] for an identified submarket if the applicants do not have overlapping generation within the submarket and lack firm transmission rights to import capacity into that market.'"[65] Applicants state that the

[59] *Id.*

[60] *Id.* at 16-17.

[61] *Id.* at 17 (citing *NSTAR*, 136 FERC ¶ 61,016 at P 48; *USGen New England Inc.*, 109 FERC ¶ 61,361, at PP 16, 23 (2004)).

[62] *Id.*

[63] *Id.*

[64] *Id.*

[65] *Id.* at 18 (quoting *Order Reaffirming Commission Policy and Terminating Proceeding*, 138 FERC ¶ 61,109 at P 43).

Commission held, in the *USGen* proceeding, that "there was no need to consider submarkets in the [ISO-NE] market when the applicants' generation did not overlap in any submarket."[66] Thus, Applicants conclude that it is unnecessary for them to consider any submarkets in ISO-NE.[67] Applicants state that this conclusion is consistent with "the way that the RTO markets work" because units located outside of a submarket will not influence the locational marginal price in the submarket when congestion separates the submarket from the rest of the RTO. Applicants explain that, for example, GenOn Energy's generation units in Massachusetts will not influence locational marginal prices in Connecticut if transmission congestion causes the Massachusetts and Connecticut markets to separate. Applicants maintain that they have appropriately limited their analysis to ISO-NE as a whole.[68]

36. Applicants note that their analysis of the ISO-NE market focuses on EC, and that they also analyzed the ISO-NE Forward Capacity Market and the relevant ancillary services markets in ISO-NE.[69]

(1) <u>Analysis of ISO-NE Market</u>

37. Applicants state that their analysis shows that, post-transaction, the ISO-NE market is unconcentrated in all seasons/load periods under the EC measure. Accordingly, Applicants conclude that there are no screen violations and no horizontal competition concerns in this market.[70] Applicants also state that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[71]

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[66] *Id.* (citing *USGen New England*, 109 FERC ¶ 61,361 at P 24).

[67] *Id.* at 17-18 (citing *Order Reaffirming Commission Policy and Terminating Proceeding*, 138 FERC ¶ 61,109 at P 43; *USGen New England*, 109 FERC ¶ 61,361 at P 24).

[68] *Id.* at 16-17.

[69] *Id.* at 18-19.

[70] Applicants' analysis shows that the post-transaction HHI values range from 460 to 528, and the HHI changes range from zero to 49 points. *Id.* at 19.

[71] *Id.*

(2) Analysis of ISO-NE Forward Capacity Market

38. Applicants contend that the Proposed Transaction will not have an adverse effect on the Forward Capacity Market, which is the centralized capacity market operated by ISO-NE. Applicants assert that their analysis shows that the Forward Capacity Market is "very unconcentrated" both before and after the Proposed Transaction.[72] Therefore, Applicants conclude that there are no screen violations in the Forward Capacity Market and that the Proposed Transaction does not create any competitive concerns in the ISO-NE capacity markets.[73]

(3) Analysis of ISO-NE Ancillary Services Markets

39. Applicants state that for ancillary services, ISO-NE operates both a reserve and regulation market. Applicants explain that non-spinning reserves are procured through a locational forward reserve market, through bi-annual auctions for ten-minute non-spinning and thirty-minute operating reserves. Applicants state that there is no distinct spinning reserve market in New England. Additionally, Applicants explain that there is a real-time regulation market in New England and that ISO-NE sets a regulation service requirement for each month, by day-type and hour, which can either be self-scheduled by load serving entities or purchased through the ISO-NE administered regulation market, where there is an hourly regulation clearing price.[74]

40. Applicants explain that there is no overlap in Applicants' reserves capability in the local ISO-NE reserves zones, and that the HHI increase for the ISO-NE reserves market across all zones and all products is only 30 points based on Applicants' capabilities relative to total offers made in recent auctions.[75] Therefore, Applicants contend that there are no competitive concerns in the non-spinning reserves market.

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[72] *Id.* at 20. The pre- and post-transaction HHI values are 355 and 390, respectively.

[73] *Id.* at 19-20.

[74] *Id.* at 20.

[75] *Id.* at 21.

41. Applicants further state that NRG Energy does not own any generation with regulation capacity in ISO-NE and therefore argue that there is no increase in market power in the regulation market resulting from the Proposed Transaction.[76]

(c) <u>Delivered Price Test Results for NYISO</u>

42. Applicants state that NRG Energy owns approximately 4,000 MW of capacity and GenOn Energy owns approximately 1,100 MW of capacity in the NYISO market, which together represents approximately 14.4 percent of the generation capacity in that market.[77] Applicants state that the Commission "traditionally has analyzed the NYISO market solely as a single market."[78] Nevertheless, Applicants state that they have examined whether there are any NYISO submarkets that should be analyzed. Applicants explain that NYISO has 11 internal load zones and that there is no single zone in which Applicants both own generation. According to Applicants, however, "congestion on the Central East Interface creates a potential submarket in which both of the Applicants own generation."[79] Applicants describe this submarket as consisting "of the New York East (zones F-I), New York City (zone J), and Long Island (zone K) zones."[80] Applicants refer to this potential submarket as the East of Central East submarket.[81]

43. Applicants state that to be conservative, they analyzed the NYISO market as a whole as well as the East of Central East submarket. Additionally, Applicants analyzed the New York Installed Capacity and relevant Ancillary Services markets in NYISO. Applicants state that they focus their analysis on EC because New York has implemented retail competition.[82]

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[76] *Id.*

[77] Applicants provide a map detailing the location of each company's generation facilities located in the NYISO market on page 21 of the Merger Application.

[78] *Id.* at 22.

[79] *Id.*

[80] *Id.*

[81] *Id.* Applicants also studied the New York City and Rest of New York submarkets as sensitivities. *Id.* n.38.

[82] *Id.* at 22.

(1) Analysis for NYISO Market

44. Applicants state that their analysis demonstrates that, post-transaction, the NYISO market is unconcentrated in all periods under the EC measure.[83] As such, Applicants assert that there are no screen violations and no horizontal competition concerns in this market. Additionally, Applicants contend that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[84]

(2) Analysis for NYISO East of Central East Submarket

45. Applicants state that their analysis shows that, post-transaction, the East of Central East submarket is unconcentrated under the EC measure in all but two seasons/load periods. Applicants explain that in the Summer Off-Peak and Shoulder Off-Peak seasons/load periods the post-transaction HHI is moderately concentrated, with values of 1,035 and 1,014, respectively, but GenOn Energy has no economic capacity in these periods and therefore the HHI increase is zero points. Based on these results, Applicants contend that there are no screen violations and no horizontal competition concerns in this market. Applicants also state that their analysis shows that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen failures under the AEC measure.[85]

(3) Analysis for NYISO Installed Capacity Markets

46. Applicants state that there is no overlap of generation in the local Installed Capacity market of New York City because GenOn Energy owns no generation in the New York City zone. Therefore, Applicants state that the only capacity market that needs to be analyzed in New York is the Rest of State Installed Capacity market, which covers the entire New York Control Area. Applicants contend that their analysis shows that the Proposed Transaction does not have an adverse effect on this Installed Capacity market, and that the New York Control Area Installed Capacity market is unconcentrated

[83] Merger Application at 23. The post-transaction HHI values range from 650 to 959; the HHI increases range from zero to 42 points. *Id.*

[84] *Id.*

[85] *Id.* at 24.

both before and after the Proposed Transaction.[86] Applicants assert that there are no screen violations and thus the Proposed Transaction does not raise competitive concerns with respect to this market.[87]

(4) <u>Analysis for NYISO Ancillary Services Market</u>

47. Applicants explain that NYISO has three categories of ancillary services products that it procures on a market basis: spinning reserves, non-spinning reserves, and regulation. Applicants state that the regulation market is a New York Control Area-wide market, with a single market clearing price. However, Applicants state that NYISO has locational reserve requirements that result in differences between the Eastern and Western New York reserves prices.[88]

48. Applicants contend that the Proposed Transaction does not have an adverse effect on the NYISO ancillary services markets. Applicants assert that NRG Energy does not sell regulation capacity in the New York Control Area regulation market, and that GenOn Energy's only NYISO unit that does sell regulation in the New York Control Area Market is rarely dispatched and therefore rarely provides regulation service. Accordingly, Applicants maintain that there is no increase in market power in the regulation market resulting from the Proposed Transaction.[89]

49. Applicants further state that GenOn Energy owns no spinning reserves in the West spinning reserves market, and that there are only minimal changes in HHI in the East spinning reserves market based on the relative capabilities and actual sales for GenOn Energy and NRG Energy. Applicants indicate that the HHI increases are 42 points based on capabilities and 22 points based on sales. Therefore, Applicants contend that no competitive concerns are raised by the Proposed Transaction in the spinning reserves market.[90]

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[86] According to Applicants' analysis, the post-merger HHI values are 742 and 756 during the Summer and Winter, respectively. The HHI increase during Summer is 49 points; the HHI increase in Winter is 51 points. *Id.*

[87] *Id.* at 24-25.

[88] *Id.* at 25.

[89] *Id.*

[90] *Id.*

50. Additionally, Applicants state that GenOn Energy does not have non-spinning reserve capability in New York. Applicants assert that with no overlap of non-spinning reserve capability in either the East or West region, there are no competitive market concerns raised by the Proposed Transaction in consideration of NYISO's non-spinning reserves market.[91]

(d) <u>Delivered Price Test Results for CAISO</u>

51. Applicants state that NRG Energy owns approximately 3,000 MW of capacity[92] and GenOn Energy owns approximately 5,500 MW of capacity[93] in the CAISO market, which together represents approximately 14 percent of the CAISO market. Applicants explain that large amounts of this capacity – 1,254 MW for NRG Energy and 2,739 MW for GenOn Energy – have been contracted to third parties under long-term contracts and thus are not controlled by Applicants. Applicants contend that after accounting for these long-term contracts, Applicants together control approximately eight percent of the generation capacity in the CAISO market.[94]

52. Applicants state that although the Commission has traditionally analyzed the CAISO market solely as a single market, Applicants have identified "occasional transmission constraints that lead to differences in locational market prices."[95] Applicants explain that these differences could suggest a southern California submarket, known as the South of Path 15 submarket, where Applicants both own generation. Applicants state that congestion on Path 15 has significantly declined in recent years and that there is a strong argument that there is no market separation. However, Applicants

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[91] *Id.*

[92] Applicants note that, in order to be conservative, their analysis includes NRG Energy's proposed repowering of its El Segundo Energy Center and NRG Energy's utility-scale solar generation projects that are coming online in 2012 through 2014. *Id.* n.44.

[93] Applicants also adopted a conservative approach with respect to calculating GenOn Energy's ownership of generation capacity, and thus include repowering of GenOn Energy's Marsh Landing in their analysis. *Id.* n.45.

[94] *Id.*at 26. Applicants provide a map detailing the location of each company's generation facilities located in the CAISO market on page 26 of the Merger Application.

[95] *Id.* at 26-27.

state that, to be conservative, they analyzed the South of Path 15 submarket in addition to the CAISO market as a whole.[96]

53. Applicants state that their analysis of the CAISO market "focuses on [EC] rather than AEC because [ ] there is retail competition in this market."[97] Applicants did not analyze a centralized capacity market because such a market does not exist in CAISO. Applicants did analyze the relevant ancillary services markets as there are market-based ancillary services markets administered by the CAISO.

(1) Analysis of CAISO Market

54. Applicants assert that their analysis shows that, post-transaction, the CAISO market is unconcentrated under the EC measure during all seasons/load periods.[98] As such, Applicants argue that there are no screen violations and no horizontal competition concerns in this market. Additionally, Applicants contend that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen violations under the AEC measure.[99]

(2) Analysis of California South of Path 15 Submarket

55. Applicants state that their analysis shows that, post-transaction, the South of Path 15 submarket is moderately concentrated under the EC measure during all seasons/load periods, with HHI values ranging from 1,043 to 1,325.[100] However, Applicants state that the HHI increases, which range from zero to 56 points, are all well below the 100-point threshold for screen violations in moderately concentrated markets, and contend that there are no screen violations and no horizontal competition concerns in the South of Path 15 submarket.[101] Applicants further assert that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent

[96] *Id.* at 27.

[97] *Id.*

[98] According to Applicants' analysis, the post-transaction HHI values range from 716 to 946; the HHI changes range from zero to 16 points. *Id.* at 28.

[99] *Id.*

[100] *Id.* at 29.

[101] *Id.*

or minus 10 percent cases of this submarket, and no screen violations under the AEC measure.[102]

56. Applicants state that they also conducted certain other sensitivity analyses related to the San Onofre Nuclear Generation Station (SONGS) units which have been taken out of service due to damage to the units. First, Applicants state that they performed an analysis assuming that both SONGS units are out of service. Second, Applicants state that they conducted a sensitivity analysis that assumes certain GenOn Energy contracts expiring in the medium term are not renewed. Third, Applicants combined the SONGS and contract sensitivities. Applicants contend that in all cases, the sensitivities passed all screens.[103]

(3) <u>Analysis for CAISO Ancillary Services Market</u>

57. Applicants state that the ancillary services market in the CAISO market consists of four products: regulation up, regulation down, spinning reserves, and non-spinning reserves. Applicants contend that the Proposed Transaction will not have an adverse effect on any of these ancillary services markets in CAISO. Applicants explain that they each "sold less than [one] percent of all CAISO regulation sales in 2011, and thus the combination of the two companies will not raise any competitive concerns in the regulation markets."[104] Additionally, Applicants state that they each sold less than one percent of CAISO's spinning and non-spinning reserve requirements in 2011, and thus the combination of the two companies will not raise any competitive concerns in the spinning and non-spinning reserves markets.[105]

(e) <u>Delivered Price Test Analysis for Entergy</u>

58. Applicants contend that there is very little generation overlap between NRG Energy and GenOn Energy in the Entergy market. Applicants state that while NRG Energy owns 3,665 MW of capacity in Entergy, GenOn Energy's sole capacity located in this market is its 50 percent share of the Sabine qualifying facility unit in Texas, which

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[102] *Id.*

[103] *Id.*

[104] *Id.* at 30.

[105] *Id.*

represents 44 MW of capacity, not including the energy usage of the plant's steam host.[106]

59. Additionally, Applicants state that NRG Energy's portfolio of generation in Entergy is partially committed under a series of market-based, long-term, full requirements contracts with 10 electric cooperatives in Louisiana. Applicants further state that NRG Energy makes market-based firm power sales to the Cities of Conway, West Memphis, and North Little Rock in Arkansas, and three municipal entities in Texas. Applicants explain that all of these contracts are served by NRG Energy's affiliate, Louisiana Generating LLC (Louisiana Generating), and that Louisiana Generating's peak load exceeded 2,800 MW in 2011. Applicants state that Louisiana Generating's peak load is expected to grow at more than two percent per annum over the next several years. Applicants contend that these long-term firm power sales significantly decrease NRG Energy's uncommitted capacity in Entergy.[107]

60. Applicants assert that the minimal level of overlap in Entergy supports a finding that there is only a *de minimis* overlap in the market and that no Appendix A analysis of the Entergy market is required. However, in order to be conservative, Applicants conducted an Appendix A analysis for Entergy which focuses on AEC. Applicants explain that their analysis of Entergy relies on AEC because the Commission has held that AEC is the more relevant product to analyze for transactions between entities located in markets, such as Entergy, that are dominated by large utilities with long-term retail native load obligations and no prospect of retail competition in the foreseeable future.[108]

61. Applicants state that their analysis demonstrates that, post-transaction, the Entergy market is unconcentrated under the AEC measure during all seasons/load periods and that there are no screen violations and no horizontal competition concerns in this market.[109] Similarly, Applicants state that their analysis shows that there are no screen violations in the destination market price sensitivities in either the destination market price plus 10 percent or minus 10 percent cases, and no screen violations under the EC measure.[110]

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[106] *Id.* Applicants provide a map detailing the location of each company's generation facilities in Entergy on page 31 of the Merger Application.

[107] *Id.* at 30-31.

[108] *Id.* at 31-32.

[109] The post-transaction HHI values range from 564 to 965; the HHI increases range from zero to 41 points. *Id.* at 32.

[110] *Id.* at 32-33.

Applicants note that there are no market-based capacity or ancillary services markets in Entergy.

ii. **Commission Determination**

62. We agree with Applicants' conclusion that the Proposed Transaction will not create horizontal market power concerns. As an initial matter, we find that Applicants correctly focused on the following relevant geographic markets and submarkets where Applicants demonstrate an overlap in ownership of facilities by NRG Energy and GenOn Energy: PJM and the PJM East and 5004/5005 submarkets within PJM, ISO-NE, NYISO, CAISO and Entergy. With respect to MISO, we agree with Applicants that the overlap in ownership of Applicants' generating capacity is *de minimis*, and therefore an analysis of the MISO market is not necessary. With respect to the other possible submarkets in NYISO and CAISO that Applicants studied, we will not recognize them at this time, as discussed below.

63. While the Proposed Transaction involves the combination of two large independent power producers, Applicants' analysis of the Proposed Transaction shows that it will not result in increases in market concentration that exceed the thresholds established by the Commission for any relevant product in the relevant geographic markets. Applicants generally performed their analysis in accordance with previous Commission guidance,[111] but did deviate from the Commission's guidance in some respects. For example, Applicants failed to model transmission costs for generation located outside of the relevant destination market as required in 18 C.F.R § 33.3(c)(4). In addition, Applicants appear to have used an incorrect *pro rata* allocation method for imports into the study area (the model appears to allocate imports from first tier BAAs independently rather than allocating uncommitted capacity from an aggregated first tier).[112] Moreover, we expect applicants performing DPTs to conduct their studies using

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[111] *See, e.g.*, Merger Policy Statement at Appendix A. *See also*, Order No. 642, FERC Stats. & Regs. ¶ 31,111, *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018, at Appendix E (2004) (April 14 Order).

[112] In Order No. 697, the Commission clarified that *pro rata* allocation is used to assign shares of simultaneous transmission import capability to uncommitted generation capacity in aggregated first-tier BAAs to determine how much uncommitted generation capacity can enter the study area. *See, Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at n.361 & P 375, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g,* Order

(continued…)

two years of market data in the DPT model for each relevant geographic market when determining the destination market price for each season/load period.[113] As we recently observed, two years of data may provide a more robust price series.[114] For example, relying on only one year of data could improperly skew DPT results if unusual circumstances arose during that year, such as unusual weather, plant outages, or other system conditions.

64. We find that these deviations, when corrected, do not materially impact the results of Applicants' studies. With respect to failing to model transmission costs accurately, this deviation had a *de minimis* impact on the HHI results in this case because Applicants were only considering imports from the first-tier markets, which would not have had a large amount of transmission costs added to them, and because those imports were pro-rated and limited to the corresponding simultaneous transmission import limit (SIL) values. In addition, while in some situations using an oversimplified *pro rata* allocation methodology could invalidate the conclusion of a DPT, we have determined that in this case the large amount of uncommitted generation in the particular study areas negates this possible flaw in Applicants' model, and we will thus accept the results of their study. As discussed in further detail below, Applicants' analysis shows that the Commission's competitive market screen thresholds are not exceeded under either the EC or AEC measures at the calculated destination market prices, or when the destination market prices are increased or decreased by 10 percent. Accordingly, Applicants have shown that the Proposed Transaction does not raise the concern that Applicants will gain the ability to withhold generation in any relevant market for the purpose of raising prices to their benefit. In addition, Applicants have provided analyses of the impact of the Proposed Transaction on the capacity and ancillary services markets, and these analyses show that the Proposed Transaction will not have adverse competitive effects on these markets.

No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom.* Montana *Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011).

[113] *See Arizona Public Service Company*, 141 FERC ¶ 61,154, at P 28 (2012) (*Arizona Public Service Company*) (noting that applicants' DPT results were flawed based on the use of one year of market data rather than two). *See also* 18 C.F.R. § 33.3(d)(6) (2012)

[114] *Arizona Public Service Company*, 141 FERC ¶ 61,154 at P 30.

(a) PJM

(1) PJM as a Whole

65. For the PJM market as a whole, we find that Applicants pass the Commission's competitive market screens for changes in market concentration during all season/load periods under both the EC and AEC measures.[115] Additionally, Applicants pass the Commission's screens when the destination market prices are increased and decreased by 10 percent. Based on Applicants' analyses, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the PJM market as a whole.

(2) PJM East Submarket

66. The Commission has recognized PJM East as a relevant submarket within PJM.[116] We find that, for this submarket, Applicants pass the Commission's competitive market screens for changes in market concentration during all season/load periods under both the EC and AEC measures. Additionally, Applicants pass the Commission's screens when the destination market prices are increased and decreased by 10 percent. Based on Applicants' analysis, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the PJM East submarket.

(3) PJM 5004/5005 Submarket

67. The Commission has recognized the 5004/5005 and AP South submarkets as relevant submarkets within PJM.[117] Although Applicants studied the 5004/5005 submarket, they did not study the AP South submarket. Nevertheless, we accept Applicants' studies because Applicants do not own any generation in the AP South submarket that is not also located in the 5004/5005 submarket. Therefore, studying the AP South submarket would not provide any additional information to the Commission

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[115] The Commission notes that although EC may be the more relevant measure for energy markets where retail competition exists, Applicants' analyses under the AEC measure is also appropriate because while some states within PJM have implemented retail choice, Indiana, Kentucky, North Carolina, Tennessee, Virginia, and West Virginia have not.

[116] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252.

[117] *See Exelon Corp.* 138 FERC ¶ 61,167 at P 31.

regarding potential increases in market concentration following the Proposed Transaction that is not already captured by Applicants' study of the 5004/5005 submarket.[118]

68. We find that Applicants pass the Commission's competitive market screens for increases in market concentration in the 5004/5005 submarket during all season/load periods under both the EC and AEC measures. Additionally, Applicants pass the Commission's competitive market screens when destination market prices are increased and decreased by 10 percent. Based on Applicants' analysis, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the 5004/5005 submarket.

(4) PJM Capacity and Ancillary Services Market

69. As noted above, Applicants' analysis shows that, post-transaction, the PJM Reliability Pricing Model market will remain unconcentrated and the HHI will increase by only 12 points. Accordingly, we conclude that the Proposed Transaction will not have an adverse effect on competition in the PJM Reliability Pricing Model market. Similarly, we find that the combination of the installed capacity owned by NRG Energy and GenOn Energy also does not raise horizontal market power concerns in the smaller MAAC locational deliverability area. Although Applicants' analysis shows that the MAAC locational deliverability area is moderately concentrated, the HHI will only increase by 33 points, which is below the 100 point threshold for moderately concentrated markets. We conclude that the Proposed Transaction will not have an adverse effect on competition in the MAAC locational deliverability area. With respect to the PJM ancillary services market, we find that the Proposed Transaction does not raise competitive concerns because of the limited nature of NRG Energy's resources in the regulation, synchronous reserves, and day ahead scheduling reserves markets. Accordingly, we conclude that the Proposed Transaction will not adversely affect horizontal competition in these markets.

[118] As Applicants explain in the Merger Application, the 5004/5005 submarket is essentially the same as the AP South submarket, but it excludes the Dominion Zone (thus the 5004/5005 submarket is smaller than the AP South submarket). Merger Application at 10-11. Since Applicants' market shares in the AP South submarket will always be lower than in the 5004/5005 submarket, HHI increases resulting from the Proposed Transaction will also be lower in the AP South submarket than in the 5004/5005 submarket. *See also* n.43, *supra*.

(b) <u>ISO-NE</u>

70. We find that Applicants pass the Commission's competitive market screens for changes in market concentration during all season/load periods under both the EC and AEC measures in the ISO-NE market. Additionally, Applicants pass the Commission's screens when the destination market price is increased and decreased by 10 percent. Based on Applicants' analyses, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the ISO-NE market.

71. We note that Applicants' claim that the Commission "traditionally has analyzed the [ISO-NE] market solely as a single market"[119] is not correct. The Commission has also historically analyzed the Connecticut and Southwest Connecticut submarkets within ISO-NE.[120] However, in this case we will not require Applicants to study the Connecticut and Southwest Connecticut submarkets within ISO-NE because, as Applicants explain, there is no overlap between GenOn Energy and NRG Energy in the Connecticut and Southwest Connecticut submarkets.

72. Based on Applicants' market share in the unconcentrated ISO-NE Forward Capacity Market and the small HHI change post-transaction, we conclude that the Proposed Transaction will not have an adverse effect on horizontal competition in the ISO-NE Forward Capacity Market. In addition, since NRG Energy does not provide regulation service in New England, we find that the Proposed Transaction will not have an adverse effect on the ISO-NE regulation market.

(c) <u>NYISO</u>

(1) <u>NYISO Market</u>

73. We find that Applicants pass the Commission's competitive market screens for changes in market concentration for the NYISO market during all seasons/load periods under both the EC and AEC measures. Additionally, Applicants pass the Commission's screens when the destination market price is increased and decreased by 10 percent. Based on Applicants' analysis, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the NYISO market.

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[119] Merger Application at 17.

[120] *See, e.g.*, *Atlantic Renewables Projects II*, 135 FERC ¶ 61,227, at P 13, n.8 (2011) (Northeast SIL Order).

74. We note that Applicants' claim that the Commission "traditionally has analyzed the NYISO market solely as a single market"[121] is not correct. The Commission has also historically analyzed the New York City and Long Island submarkets within NYISO.[122] In fact, Applicants provided a study of the New York City submarket as a sensitivity.[123] Nevertheless, because Applicants' ownership of generation does not overlap in the New York City submarket, such analysis is not relevant to our findings in this order.

(2) <u>NYISO East of Central East Submarket</u>

75. We will not consider the East of Central East submarket as a relevant geographic market within the NYISO because the record in this case does not support the recognition of such a submarket.[124] Applicants have not shown an increase in frequency in binding transmission constraints during historical peaks and other competitively significant times that prevent competing supply from reaching customers within the proposed alternative geographic market.[125] In any event, we note that Applicants' study for the proposed East of Central East submarket is flawed. Among other issues, Applicants' calculated SIL value is based on data from a source that does not adhere to the principle of simultaneity,[126] which is a requirement for an acceptable SIL study value.[127]

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[121] Merger Application at 22.

[122] *See, e.g.*, Northeast SIL Order, 135 FERC ¶ 61,227 at P 5, n.8.

[123] Merger Application at n.38.

[124] We note that our finding in this order does not foreclose the possibility of considering the East of Central East submarket as a relevant geographic market in the future. The Commission has previously noted that New York experiences west-to-east transmission constraints. *See, e.g., Central Hudson Gas & Electric Corporation, et al.*, 86 FERC ¶ 61,062, at 61,233 (1999).

[125] *See AEP Power Marketing, Inc.*, 124 FERC ¶ 61,274, at PP 24-25 (2008) (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 268. *See also Boralex Livermore Falls LP*, 122 FERC ¶ 61,033, *order on reh'g*, 123 FERC ¶ 61,279, at P 25 (2008)).

[126] Merger Application, Exhibit J, Frayer Test. at 72 (citing New York Control Area Installed Capacity Requirements for Period May 2012 – April 2013).

[127] *See, e.g.*, April 14 Order, 107 FERC ¶ 61,018 at Appendix E (specifying that import capability of the study area is the simultaneous transfer limit from the aggregated first-tier market area into the study area).

Accordingly, since Applicants were not required to study this submarket, the Commission will not address the results of Applicants' study.

(3) NYISO Capacity and Ancillary Services Markets

76. Applicants' analysis shows that the NYISO installed capacity markets are unconcentrated during the summer and winter, and that the markets remain so after the Proposed Transaction closes. Accordingly, we conclude that the combination of Applicants' capacity will not have an adverse effect on competition in the installed capacity markets in the NYISO.

77. We also agree with Applicants that the Proposed Transaction has no adverse competitive effect on the ancillary services markets in the NYISO because there is no overlap between NRG Energy and GenOn Energy with respect to regulation, non-spinning reserve, and 10-minute spinning reserve capability in the Western portion of the NYISO. Additionally, there is only limited overlap between NRG Energy and GenOn Energy of 10-minute spinning reserve capability in the Eastern portion of the NYISO market. Accordingly, we conclude that the Proposed Transaction will not adversely impact competition in the markets for these products.

(d) CAISO

(1) CAISO Market

78. We find that Applicants pass the Commission's competitive market screens for changes in market concentration during all seasons/load periods under both the EC and AEC measures in the CAISO market. Additionally, Applicants pass the Commission's screens when the destination market price is increased and decreased by 10 percent.

79. We note that in analyzing the CAISO market Applicants used the same methodology for calculating SILs that the Commission previously accepted in *Pacific Gas & Electric Company*, 131 FERC ¶ 61,270 (2010) (*Pacific Gas*). Applicants, however, applied the methodology using updated path ratings[128] so that the SIL values Applicants used in the Merger Application are larger than the SIL values accepted in

[128] Specifically, Applicants used the updated transmission path ratings published by the Western Electric Coordinating Council (WECC) in the WECC 2012 Path Rating Catalogue.

Pacific Gas.[129] Nevertheless, if Applicants had used the lower SIL values previously accepted by the Commission, Applicants would still pass the Commission's competitive market screens. Accordingly, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in the CAISO market.

(2) CAISO South of Path 15 Submarket

80. We will not consider Applicants' analysis of the South of Path 15 submarket within the CAISO because there is no evidence in the record of ongoing persistent binding transmission constraints that would not allow competing supplies to enter the South of Path 15 submarket.[130] In addition, Applicants' study for the proposed South of Path 15 submarket is flawed. Among other issues, Applicants' calculated SIL value is based on data from a source that appears not to adhere to the principle of simultaneity,[131] which is a requirement for an acceptable SIL study value.[132] Since, however, Applicants were not required to study this submarket, the Commission will not address the results of Applicants' study.

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[129] For example, in *Pacific Gas*, the Commission accepted SIL values of 9,802 MW during winter, 9,368 MW during summer, and 10,683 MW during the shoulder seasons for the CAISO. *Pacific Gas*, 131 FERC ¶ 61,270 at P 14. Applicants used SIL values of 14,677 during winter, 12,440 during summer, and 13,525 during the shoulder seasons. Merger Application, Exhibit J, Frayer Test. at Figure 11.

[130] We note that the California Department of Market Monitoring found that, in the day-ahead market, Path 15 was congested for 52 hours in the south to north direction during the year 2011. CAISO Department of Market Monitoring, 2011 Annual Report on Market Issues and Performance at Table 7.2, Impact of congestion on day-ahead prices by load aggregation point (February – December) (April 2012), *available at* http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf. According to the CAISO Department of Market Monitoring, that congestion occurred during the fourth quarter and was due to scheduled maintenance on Path 15. *Id.* at 135, *see also* 135-137.

[131] Merger Application, Exhibit J, Frayer Test. at 38.

[132] *See, e.g.*, April 14 Order, 107 FERC ¶ 61,018 at Appendix E. *See also Analysis of Horizontal Market Power Under the Federal Power Act*, 138 FERC ¶ 61,109, at P 40 (2012) (affirming previous Commission guidance provided in *Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 at Appendix B (2011) (providing specific directions and required reporting format for SIL studies)).

(3) CAISO Ancillary Services Market

81. Based on Applicants' analysis, which shows that NRG Energy and GenOn Energy each sold less than one percent of all CAISO regulation sales and less than one percent each of California's spinning and non-spinning reserve requirements during 2011, we conclude that the Proposed Transaction will not have an adverse effect on the CAISO ancillary services markets.

(e) Entergy

82. Although we find that the Proposed Transaction will not have an adverse effect on horizontal competition in Entergy, we note that in studying this market Applicants relied on SIL values specified in an application filed by Acadia Power Partners, LLC pursuant to FPA section 203 in Docket No. EC10-43-000. Applicants also included a study of Entergy based on a second study which used SIL values accepted by the Commission in *Duke Energy Carolinas, LLC,* 138 FERC ¶ 61,134 (2012) (2012 Southeast SIL Order) as a sensitivity. Based on this second study, we find that Applicants pass the Commission's competitive screens for changes in market concentration during all season/load periods under both the EC and AEC measures in Entergy.[133] In addition, Applicants pass the Commission's competitive market screens when the destination market prices are increased and decreased by 10 percent under the EC measure, and increased and decreased by 20 percent under the AEC measure. Accordingly, we find that the Proposed Transaction will not have an adverse effect on horizontal competition in Entergy, but remind Applicants, and all applicants submitting Delivered Price Tests, to use values for imports from SIL studies approved by the Commission, or to perform their own studies in accordance with Commission guidance.[134]

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[133] We note that Applicants used Electric Quarterly Report (EQR) data blended with system lambda to calculate a destination market price. As explained previously, the Commission prefers the use of actual market prices rather than price proxies such as system lambda. *See Arizona Public Service Company*, 141 FERC ¶ 61,154 at P 30 (2012); *Duke Energy Corporation*, 136 FERC ¶ 61,245 at P 121 (2011). While Applicants' approach only affected six off-peak hourly observations, and had an immaterial impact on the price calculations and ultimately the DPT results, we believe this is an inappropriate methodology to apply where, as in this case, sufficient EQR observations are available in the instant case to calculate the destination market price, without system lambda adjustments.

[134] *See Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 at Appendix B (2011) (providing specific directions and required reporting format for SIL studies).

b. Vertical Market Power

i. Applicants' Analysis

83. Applicants contend that the Proposed Transaction does not raise any vertical market power issues. Applicants assert that the Proposed Transaction does not raise any potential for abuse of natural gas transportation market power because Applicants do not own any natural gas transmission or distribution assets to serve unaffiliated competing generation facilities.[135] Therefore, Applicants conclude that the Proposed Transaction will not result in Applicants' ability to leverage control over such assets to benefit their electric generation facilities.[136]

84. Additionally, Applicants state that the Proposed Transaction will not raise any potential for abuse of electric transmission market power because Applicants do not own or control any electric transmission facilities except for facilities used to interconnect generating facilities with the transmission grid. As such, Applicants contend that the Proposed Transaction does not increase Applicants' ability to use their ownership or control of transmission facilities to give themselves a competitive advantage in energy markets.[137]

85. Applicants further argue that the Proposed Transaction will not raise any potential for increased abuse of market power with respect to other inputs to the generation of electricity because Applicants do not possess any market power with respect to any other inputs to the generation of electricity. Therefore, Applicants contend that the Proposed Transaction does not raise any vertical market power issues with respect to such other inputs to the generation of electricity.[138]

ii. CPV Shore Comments

86. CPV Shore states that it is currently in negotiations with GenOn Energy regarding CPV Shore's need for a limited easement to access the Raritan River substation (Substation), which is surrounded by land owned and controlled by a GenOn Energy

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[135] Applicants note that GenOn Energy owns the Hudson Valley Gas Corporation, which owns a Hinshaw natural gas pipeline, but that that pipeline exclusively serves GenOn Energy's Bowline generation facility and does not serve any unaffiliated generation facilities that compete with Applicants. Merger Application at n.61.

[136] *Id.* at 34.

[137] *Id.*

[138] *Id.*

affiliate.[139] According to CPV Shore, it requires access to the Substation to interconnect its generating facility to the Substation as provided for in CPV Shore's interconnection plans and in the interconnection studies that have largely been completed.[140] CPV Shore explains that the Substation is the Point of Interconnection specified in CPV Shore's interconnection studies conducted by PJM. CPV Shore states that if GenOn Energy's affiliate, which has exclusive, discretionary control over access to the Substation, refuses to grant the limited easement, it would be an exercise of vertical market power and a barrier to entry to wholesale power markets.[141] CPV Shore notes that GenOn Energy asserts in the Merger Application that it does not own or control inputs into generation that would allow it to exercise vertical market power, but that control over competitor access to the Substation is an "input" to generation.[142]

iii. Applicants' Answer

87. In response to CPV Shore's comments, Applicants state that GenOn Energy is acting in good faith to make arrangements to allow CPV Shore to interconnect with the Substation, and requested that Jersey Central Power & Light Company (Jersey Central), the owner of the Substation, consult with CPV Shore to identify the appropriate route for the requested easement. Applicants further explain that GenOn Energy has submitted a draft of the easement to both Jersey Central and CPV Shore, and that it is not aware of any issues raised by either party regarding the draft. According to Applicants, GenOn Energy believes that an easement agreement will be executed. Therefore, Applicants contend that GenOn is not refusing to grant the easement requested, and that CPV Shore's comments are not grounds for the Commission to deny approval of the Proposed Transaction.[143]

iv. Commission Determination

88. We find that the Proposed Transaction does not raise any vertical market power concerns. Applicants do not own or control fuel transmission facilities, with the exception of a Hinshaw pipeline owned by a GenOn Energy subsidiary that is used to exclusively serve a GenOn Energy generation facility, or sufficient inputs to generation

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[139] CPV Shore Comments at 4.

[140] *Id.*

[141] *Id.*

[142] *Id.* at 5.

[143] Applicants' Answer at 2.

to impact vertical market power. Applicants do not have the ability to erect barriers to entry in any market.

89. With respect to the issues raised by CPV Shore, we find that they are unrelated to the Proposed Transaction and therefore beyond the scope of this proceeding.[144] The Commission observes that in Applicants' Answer, GenOn Energy states that it is "acting in good faith to put the necessary arrangements in place to allow CPV Shore to interconnect with the Substation" and that it has submitted a draft of the easement agreement to both Jersey Central and CPV Shore for their consideration.[145] We also note that GenOn states that it is not aware of any issues raised by Jersey Central or CPV Shore related to that draft agreement, and believes that a mutually agreeable easement agreement should be executed in the ordinary course of business. Finally, issues that are not related to our analysis under FPA section 203 can be resolved in another, more appropriate forum and will not be addressed here.[146]

2. Effect on Rates

a. Applicants' Analysis

90. Applicants argue that the Proposed Transaction cannot have an adverse impact on rates because Applicants charge only market-based rates for jurisdictional services and do

[144] *Boston Edison Company*, 117 FERC ¶ 61,083 at P 34 (rejecting concern raised by commentor because change was not product of merger and thus had no "direct connection" to merger).

[145] Applicants' Answer at 2.

[146] *See, e.g.*, *Great Plains Energy Incorporated,* 121 FERC ¶ 61,069 at 50 (2007) (Commission will not condition FPA section 203 approval on matters that should be addressed in another proceeding or forum); *Northeast Generation Company*, 117 FERC ¶ 61,068 at P 17 (2006) (consideration of environmental concerns are best suited to the docket addressing the shoreline management plan in question); *Boston Edison*, 117 FERC ¶ 61,083 at P 44 (2006) (rejecting argument that applicant could breach existing contracts as a consideration under FPA section 203 analysis and finding that if applicant breaches the contracts that it assumes, other party has recourse under FPA section 206).

not have any wholesale requirements or transmission customers that are charged under regulated cost-based rates.[147]

b. Commission Determination

91. We find that the Proposed Transaction will not have an adverse effect on rates. Applicants will continue to make wholesale sales of electric energy and ancillary services at market-based rates.[148] We also note that nothing in the Merger Application indicates that rates to customers will increase as a result of the Proposed Merger, and no customer argues otherwise.

3. Effect on Regulation

a. Applicants' Analysis

92. Applicants assert that the Proposed Transaction will not have any impact on the jurisdiction of the Commission or any state public utility commission over any of the Applicants or any of their affiliates or subsidiaries. Applicants state that they, their affiliates, and their subsidiaries will remain subject to regulation after the Proposed Transaction closes to the same extent each was regulated before the Proposed Transaction. Additionally, Applicants state that they do not own any traditional utility company that provides retail sales and distribution service under cost-based rates subject to state utility commission jurisdiction. Therefore, Applicants contend that there are no affected state commissions and therefore no need for the Commission to consider the effect of the Proposed Transaction on state utility commission regulation.[149]

b. Commission Determination

93. We find that neither state nor federal regulation will be impaired by the Proposed Transaction. The Commission's review of a transaction's effect on regulation focuses on ensuring that it does not result in a regulatory gap at the federal or state level.[150] We find that the Proposed Transaction will not create a regulatory gap at the federal level, because the Commission will retain its regulatory authority over Applicants after the transaction.

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[147] Merger Application at 35. Applicants note that NRG Energy does have wholesale full requirements customers in Louisiana and Texas but those customers are served by NRG Energy pursuant to its market-based rate authority and those rates are not subject to the Commission's cost-based regulation.

[148] *See Union Electric Co.*, 114 FERC ¶ 61,255, at P 45 (2006).

[149] Merger Application at 35-36.

[150] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

We note that no party alleges that regulation would be impaired by the Proposed Transaction, and no state commission has contested Applicants' assertion that there are "no affected state commissions" and requested that the Commission address the issue of the effect on state regulation.

4. Cross-subsidization

a. Applicants' Analysis

94. Applicants contend that none of the Commission's cross-subsidization concerns are raised in the Proposed Transaction because neither of the Applicants owns a traditional utility associate company. Nevertheless, Applicants verify that, based on the facts and circumstances known to them or that are reasonably foreseeable, the Proposed Transaction will not result in, at the time of the transaction or in the future, cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company including: (1) any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company; (2) any new issuance of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; (3) any new pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or (4) any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.[151]

b. Commission Determination

95. Based on the representations as presented in the Merger Application, we find that the Proposed Transaction will not result in cross-subsidization or the pledge or encumbrance of utility assets for the benefit of an associate company.

96. When a controlling interest in a public utility is acquired by another company, whether a domestic company or a foreign company, the Commission's ability to adequately protect public utility customers against inappropriate cross-subsidization may be impaired unless it has access to the acquirer's books and records. Section 301(c) of

[151] Merger Application at 36-37 and Exhibit M.

the FPA[152] gives the Commission authority to examine the books and records of any person who controls, directly or indirectly, a jurisdictional public utility insofar as the books and records relate to transactions with or the business of such public utility. The approval of this transaction is based on such ability to examine books and records.

C. Reliability and Cyber Security Standards

97. Information and/or systems connected to the bulk power system involved in this transaction may be subject to reliability and cyber security standards approved by the Commission pursuant to FPA section 215. Compliance with these standards is mandatory and enforceable regardless of the physical location of the affiliates or investors, information databases, and operating systems. If affiliates, personnel or investors are not authorized for access to such information and/or systems connected to the bulk power system, a public utility is obligated to take the appropriate measures to deny access to this information and/or the equipment/software connected to the bulk power system. The mechanisms that deny access to information, procedures, software, equipment, and the like, must comply with all applicable reliability and cyber security standards. The Commission, North American Electric Reliability Corporation, or the relevant regional entity may audit compliance with reliability and cyber security standards.

The Commission orders:

(A) The Proposed Transaction is hereby authorized, as discussed in the body of this order.

(B) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates, or determinations of cost, or any other matter whatsoever now pending or which may become before the Commission.

(C) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(D) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(E) Applicants shall make appropriate filings under section 205 of the FPA, as necessary, to implement the Proposed Transaction.

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[152] 16 U.S.C. § 825(c) (2006).

(F) Applicants must inform the Commission within 30 days of any material change in circumstances that would reflect a departure from the facts the Commission relied upon in authorizing the Proposed Transaction.

(G) Applicants shall notify the Commission within 10 days of the date on which the Proposed Transaction is consummated.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.