

157 FERC ¶ 61,237
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Atlas Power Finance, LLC
Dynergy Inc.
Energy Capital Partners III, LLC
GDF Suez Energy North America, Inc.

Docket Nos. EC16-93-000

Dynergy Inc.
Energy Capital Partners III, LLC

EC16-94-000

ORDER CONDITIONALLY AUTHORIZING ACQUISITION
AND DISPOSITION OF JURISDICTIONAL FACILITIES AND PURCHASE OF
SECURITIES

(Issued December 22, 2016)

1. On March 25, 2016, pursuant to sections 203(a)(1) and 203(a)(2) of the Federal Power Act (FPA)¹ and part 33 of the Commission's regulations, Atlas Power Finance, LLC (Atlas Power Finance), Dynergy Inc. (Dynergy) and its public utility subsidiaries, Energy Capital Partners III, LLC (ECP III), and GDF Suez Energy North America, Inc. (GSENA) and its public utility subsidiaries (collectively, Applicants) filed a request in Docket No. EC16-93-000 for Commission approval of a transaction in which Atlas Power Finance will purchase GSENA (GSENA Transaction).² Also on March 25, 2016, pursuant to sections 203(a)(1) and 203(a)(2) of the FPA and part 33 of the Commission's regulations, Dynergy and its public utility subsidiaries and ECP III filed a request in Docket No. EC16-94-000 for Commission approval of a transaction in which a subsidiary

¹ 16 U.S.C. § 203(a)(1), (a)(2) (2012).

² Joint Application for Authorization of Disposition of Jurisdictional Assets and Purchase of Securities under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act, Docket No. EC16-93-000 (filed Mar. 25, 2016) (GSENA Application).

of ECP III, Terawatt Holdings, LP (Terawatt), will purchase shares of newly issued Dynegy common stock representing approximately 10 percent of the outstanding shares of Dynegy (Stock Purchase Transaction)³ (collectively with GSENA Transaction, Proposed Transactions).

2. We have reviewed the Proposed Transactions under the Commission's Merger Policy Statement.⁴ As discussed below, we conditionally authorize the Proposed Transactions as consistent with the public interest, subject to mitigation. If Applicants elect to proceed with the Proposed Transactions as authorized in this order, they are directed to submit within 30 days of the date of this order proposed mitigation that would be sufficient to remedy the competitive concerns identified below.

I. Background

A. Description of Applicants⁵

1. Atlas Power Finance

3. Applicants state that Atlas Power Finance is a wholly owned subsidiary of Atlas Power, LLC (Atlas Power), an entity formed by subsidiaries of Dynegy and ECP III as a joint venture to acquire and own GSENA. Applicants state that prior to the closing of the

³ Joint Application for Authorization of Disposition of Jurisdictional Assets and Purchase of Securities Under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act, Docket No. EC16-94-000 (filed Mar. 25, 2016) (Stock Purchase Application).

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) (Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997); see also *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008). 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).

⁵ Dynegy and ECP III are applicants to both of the Proposed Transactions in Docket Nos. EC16-93-000 and EC16-94-000.

GSENA Transaction, neither Atlas Power nor Atlas Power Finance will own any generation capacity or participate in any electric market in any way.⁶

2. Dynegy

4. Applicants state that Dynegy is a Delaware corporation and utility holding company. Through its public utility subsidiaries, Dynegy controls approximately 25,600 megawatts (MW) of electric generation and produces and sells electric energy, capacity, and ancillary services in various U.S. markets. Applicants state that Dynegy does not own or control any traditional franchised utilities with captive customers. Applicants note that other than its interest in Electric Energy, Inc. (Electric Energy), Dynegy does not own or control any transmission facilities other than facilities interconnecting its generation facilities to the grid.⁷

5. Applicants explain that Dynegy indirectly owns an 80 percent equity stake in Electric Energy. Electric Energy owns six parallel generation tie lines, which are approximately eight miles long. Because the lines could be used by an unaffiliated third party for transmission service, the Commission has required Electric Energy to file an open access transmission tariff (OATT) but has granted waiver of certain other transmission owner requirements.⁸

3. ECP III

6. Applicants state that ECP III is a Delaware limited liability company. ECP III does not own or control any traditional franchised utilities with captive customers, and neither it nor its affiliates own or control any transmission facilities other than limited and discrete transmission facilities subject to Commission-approved OATTs and limited interconnection equipment necessary to connect its generating facilities to the transmission grid.

7. Applicants state that, other than as described in the Applications, none of the owners or managers of ECP III own or control, directly or indirectly, 10 percent or more of the voting equity interests in any electric generation facility, any electric transmission or distribution facilities, or input to power production in the United States. In addition,

⁶ GSENA Application at 4.

⁷ GSENA Application at 4; Stock Purchase Application at 3-4.

⁸ GSENA Application at 4-5; Stock Purchase Application at 4.

none of the owners or managers of ECP III hold any officer or director position with any energy-related entity other than through ECP III and its affiliates.⁹

4. GSENA and its Public Utility Affiliates

8. Applicants state that GSENA is a Delaware corporation with headquarters in Houston, Texas. GSENA is a wholly owned, indirect subsidiary of ENGIE S.A. (ENGIE), a French *société anonyme* listed on the Brussels and Paris stock exchanges. Among other things, ENGIE holds ownership interests in a number of energy-related subsidiaries which, internationally, engage in: the production, transmission, and distribution of electricity; power marketing; production, transportation, and distribution of natural gas; the transport and distribution of liquefied natural gas; and the development and ownership of energy projects. Applicants also state that GSENA owns direct and indirect interests in certain energy facilities within the United States, which are described below.¹⁰

- Northeastern Power Company, an indirect, wholly owned subsidiary of GSENA, owns and operates an approximately 62 MW waste coal-fired generation facility located in McAdoo, Pennsylvania, within the PJM Interconnection, L.L.C. (PJM) market.
- Hopewell Cogeneration Limited Partnership, an indirect, wholly owned subsidiary of GSENA, owns and operates an approximately 429 MW natural gas-fired cogeneration facility located in Hopewell, Virginia, within the AP South submarket of PJM.
- Northeast Energy Associates, A Limited Partnership (NEA), in which GSENA has an indirect 50 percent interest, owns and operates a 300 MW natural gas-fired electric generating facility near Bellingham, Massachusetts, within the ISO New England Inc. (ISO-NE) market. Applicants state that NextEra Energy, Inc. (NextEra) indirectly owns the other 50 percent interest in NEA and has operational control of the Bellingham facility, and that the output of the Bellingham facility is consistently treated as NextEra-controlled generation for purposes of NextEra market power analyses submitted to the Commission.
- North Jersey Energy Associates, A Limited Partnership (NJEA), in which GSENA has an indirect 50 percent interest, owns and operates a 294 MW (summer

⁹ GSENA Application at 6; Stock Purchase Application at 5.

¹⁰ GSENA Application at 8-14.

seasonal rating) natural gas-fired facility in Sayreville, New Jersey, within PJM. Applicants state that NextEra indirectly owns the other 50 percent interest in NJEA and has operational control of the Sayreville facility, and that the output of the Sayreville facility is consistently treated as NextEra-controlled generation for purposes of NextEra market power analyses submitted to the Commission.

- ANP Bellingham Energy Company, LLC, an indirect, wholly owned subsidiary of GSENA, owns an approximately 612 MW gas-fired, combined-cycle electrical power generating facility and associated interconnection facilities located in Bellingham, Massachusetts, within ISO-NE.
- ANP Blackstone Energy Company, LLC, an indirect, wholly owned subsidiary of GSENA, owns an approximately 612 MW gas-fired, combined-cycle electrical power generating facility and associated interconnection facilities located in the town of Blackstone, Massachusetts, within ISO-NE.
- Milford Power, LLC, an indirect, wholly owned subsidiary of GSENA, owns a 237 MW gas-fired, combined-cycle electrical power generating facility near Milford, Massachusetts, within ISO-NE.
- Armstrong Power, LLC, an indirect, wholly owned subsidiary of GSENA, owns an approximately 842 MW natural gas-fired generating facility and associated interconnection facilities in Armstrong County, Pennsylvania, within PJM.
- Calumet Energy Team, LLC, an indirect, wholly owned subsidiary of GSENA, owns an approximately 331 MW natural gas-fired electric generating facility in Chicago, Illinois, within PJM.
- Pleasants Energy, LLC, an indirect, wholly owned subsidiary of GSENA, owns an approximately 421 MW natural gas-fired generating facility in Pleasants County, West Virginia, within PJM.
- Troy Energy, LLC, an indirect, wholly owned subsidiary of GSENA, owns and controls an approximately 842 MW natural gas-fired generating facility and associated interconnection facilities in Wood County, Ohio, within PJM.

5. Terawatt

9. Applicants state that Terawatt is a limited partnership organized under the laws of the State of Delaware that is directly and wholly owned by: (i) Terawatt Holdings GP, LLC (Terawatt Holdings GP), a limited liability company, as general partner; and (ii) four affiliated investment funds, each of which is a limited partnership: (a) Energy Capital Partners III, LP; (b) Energy Capital Partners III-A, LP; (c) Energy Capital Partners III-B (Terawatt IP), LP; and (d) Energy Capital Partners III-C, LP (collectively,

Terawatt Partnerships). Terawatt Holdings GP is also directly and wholly owned by the Terawatt Partnerships.

10. Applicants further state that Terawatt Partnerships are directly and wholly owned by: (i) Energy Capital Partners GP III, LP (ECP GP III), a limited partnership, as general partner; and (ii) various passive limited partner investors (collectively, Passive Terawatt Partnership Investors). ECP GP III is directly owned by: (i) ECP III as general partner; and (ii) various passive limited partner investors.¹¹

B. Description of the Proposed Transactions

1. GSENA Transaction (Docket No. EC16-93-000)

11. Applicants explain that the terms and conditions of the GSENA Transaction are described in the Stock Purchase Agreement between Atlas Power Finance, GSENA, and International Power, S.A., a subsidiary of ENGIE and the direct owner of GSENA. Applicants state that, under the terms of the Stock Purchase Agreement, Atlas Power Finance will purchase all of the outstanding shares of GSENA for \$3.3 billion, subject to certain adjustments to account for certain changes between the date of the Stock Purchase Agreement and the date of closing. Applicants also state that substantially simultaneously with the closing of the GSENA Transaction, GSENA will be merged into Atlas Finance MergeCo. LLC, a wholly owned subsidiary of Atlas Power Finance, with GSENA as the surviving company.¹²

12. Applicants note that, in addition, as part of the GSENA Transaction, GSENA will undergo an internal reorganization in which certain of its subsidiaries that are not being sold to Atlas Power Finance will be transferred to other ENGIE subsidiaries. Applicants explain that the most relevant aspect of the reorganization is the sale of approximately 1,400 MW of hydroelectric facilities owned by GSENA to Public Sector Pension Investment Board and that these facilities will not be acquired by Atlas Power Finance.¹³ Applicants also state that approximately 1,175 MW (summer rating) of owned or controlled capacity is being transferred out of GSENA as part of an internal corporate

¹¹ Stock Purchase Application at 5-6.

¹² GSENA Application at 14-15.

¹³ Applicants state that the sale of this capacity is subject to a separate FPA section 203 request and is not part of the instant Application. GSENA Application at 15. The Commission approved this transaction on May 23, 2016. *FirstLight Hydro Generating Co.*, 155 FERC ¶ 62,136 (2016).

reorganization before the GSENA Transaction and will be retained by an ENGIE subsidiary. Completion of this reorganization is a condition of the closing of the GSENA Transaction.¹⁴

13. Applicants additionally state that Dynegy will have the right, but not the obligation, to purchase some or all of the ECP III indirect interest in Atlas Power. On June 15, 2016, Applicants filed a supplement to the GSENA Application notifying the Commission that Dynegy and ECP III have agreed that Dynegy has the right to purchase all of ECP III's interests in Atlas Power prior to the closing of the GSENA Transaction. Applicants state that this purchase will have no effect on the Commission's assessment of any of the public interest standards under section 203 of the FPA for the GSENA Transaction, and that the Competitive Analysis Screen submitted with the GSENA Application fully considered the competitive effects of combining the generation assets of Dynegy and GSENA.¹⁵ On July 29, 2016, Applicants filed a notice stating that Dynegy became the 100 percent owner of Atlas Power.

2. Stock Purchase Transaction (Docket No. EC16-94-000)

14. Applicants explain that the terms and conditions of the Stock Purchase Transaction are described in a Stock Purchase Agreement pursuant to which Terawatt will purchase newly issued Dynegy common stock equal to approximately 10 percent of Dynegy's outstanding shares for a total price of \$150 million. Applicants assert that the purpose of the Stock Purchase Transaction is to provide partial funding for Dynegy's obligations with respect to the GSENA Transaction. Therefore, the Stock Purchase Transaction cannot close unless the GSENA Transaction also closes.¹⁶ However,

¹⁴ Applicants state that this internal reorganization is subject to blanket authorization pursuant to section 33.1(c)(6) of the Commission's regulations, 18 C.F.R. § 33.1(c)(6), and thus no separate FPA section 203 application will be submitted. GSENA Application at 15.

¹⁵ Supplement to March 25, 2016 Joint Application for Authorization under FPA Section 203 of Atlas Power Finance, Docket No. EC16-93-000 (filed June 15, 2016) (Supplement). Applicants note that, even though ECP III will no longer have direct ownership interests in Atlas Power, the affiliation with ECP III assumed in the Competitive Analysis Screen is still appropriate because such affiliation is proposed in the Stock Purchase Transaction pending before the Commission in Docket No. EC16-94-000, which may close concurrently with the GSENA Transaction, as explained above. Supplement at 2 n.1.

¹⁶ Stock Purchase Application at 6-7.

Applicants note that the closing of the GSENA Transaction is not contingent upon Commission approval of the Stock Purchase Transaction.

II. Notice of Filing and Responsive Pleadings

15. Notice of the GSENA Application in Docket No. EC16-93-000 and of the Stock Purchase Application in Docket No. EC16-94-000 was published in the *Federal Register*, 81 Fed. Reg. 18,612 (2016), with interventions and protests due on or before May 24, 2016. On March 28, 2016, Public Citizen, Inc. filed a motion to intervene in Docket No. EC16-93-000.

16. Notice of the Supplement in Docket No. EC16-93-000 was published in the *Federal Register*, 81 Fed. Reg. 40,694 (2016), with interventions and protests due on or before June 29, 2016. None were filed.

17. On June 8, 2016, the Director of Electric Power Regulation – West requested that Applicants provide additional information with respect to the GSENA Application and the Stock Purchase Application (Data Request). On July 8, 2016, Applicants filed a response to the Data Request (Response). Notice of the Response was published in the *Federal Register*, 81 Fed. Reg. 47,169 (2016), with interventions and protests due on or before July 29, 2016. On July 29, 2016, Public Citizen filed a protest in Docket No. EC16-93-000. On August 4, 2016, Applicants filed in Docket Nos. EC16-93-000 and EC16-94-000 an answer to Public Citizen’s protest. On August 9, 2016, Public Citizen filed an answer to Applicants’ answer.

III. Discussion

A. Procedural Matters

18. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2016), Public Citizen’s timely, unopposed motion to intervene in Docket No. EC16-93-000 serves to make it a party to that proceeding.

19. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2016), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We accept Applicants’ and Public Citizen’s answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters**1. FPA Section 203 Standard of Review**

20. FPA section 203(a)(4) requires the Commission to approve proposed dispositions, consolidations, acquisitions, or changes in control if the Commission determines that the proposed transaction will be consistent with the public interest.¹⁷ The Commission's analysis of whether a proposed transaction is 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.¹⁸ FPA section 203(a)(4) also requires the Commission to find that the proposed 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."¹⁹ The Commission's regulations establish verification and informational requirements for entities that seek a determination that a proposed transaction will not result in inappropriate cross-subsidization or pledge or encumbrance of utility assets.²⁰

2. Analysis of the Proposed Transactions**a. Effect on Horizontal Competition****i. Applicants' Analysis**

21. Applicants note that their analysis takes into consideration the potential horizontal and vertical market power effects of both the GSENA Transaction and the Stock Purchase Transaction, because the Stock Purchase Transaction will close either after or concurrently with the GSENA Transaction.²¹

22. Applicants state that the Proposed Transactions will not have an adverse effect on competition. Applicants explain that, assuming consummation of the GSENA Transaction, there are six markets where the Applicants will have overlapping generation

¹⁷ 16 U.S.C. § 824b(a)(4).

¹⁸ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111.

¹⁹ 16 U.S.C. § 824b(a)(4).

²⁰ 18 C.F.R. § 33.2(j).

²¹ GSENA Application, Ex. J at 2-3.

capacity: (1) PJM; (2) ISO-NE; (3) New York Independent System Operator, Inc. (NYISO); (4) Midcontinent Independent System Operator, Inc. (MISO); (5) California Independent System Operator Corporation (CAISO); and (6) Electric Reliability Council of Texas (ERCOT).²² As ERCOT is not subject to the Commission's jurisdiction, Applicants conclude that PJM, ISO-NE, NYISO, MISO, and CAISO are the relevant geographic markets for purposes of analyzing the Proposed Transactions. Accordingly, Applicants performed a Delivered Price Test²³ for those markets, including any relevant submarkets.

23. Applicants' Delivered Price Test analyses include both the consolidation of the Dynegy and ECP III owned or controlled generation resulting from the Stock Purchase Transaction, as well as the capacity proposed to be acquired through the GSENA Transaction.²⁴ As a result, Applicants provide largely the same analysis for the Proposed Transactions for the PJM and ISO-NE markets, including any relevant submarkets. The one difference in the Applicants' analysis of the Proposed Transactions relates to the issue of whether there are submarkets within the ISO-NE energy market.

²² Applicants explain that the relevant markets are PJM and ISO-NE, including any relevant submarkets, for the GSENA Transaction and PJM, ISO-NE, NYISO, MISO, and CAISO, including any relevant submarkets, for the Stock Purchase Transaction. GSENA Application at 18; Stock Purchase Application at 10-11.

²³ The Delivered Price Test, or Competitive Analysis Screen, is used to determine the pre- and post-transaction market shares from which the change in market concentration, or the Herfindahl-Hirschman Index (HHI), 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 the relevant screen and warrants further review. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,129; *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).

²⁴ *See* GSENA Application at 19; Stock Purchase Application at 11.

Applicants limit this discussion to their analysis of the Stock Purchase Transaction. Applicants' analysis as to the NYISO, MISO, and CAISO markets is likewise limited to the Stock Purchase Transaction.

24. Applicants explain that, in addition to defining the geographic markets relevant to a proposed transaction, the Commission's regulations require applicants to examine the competitive effects of proposed transactions on all wholesale electricity products traded in the relevant geographic markets.²⁵ Applicants identify energy, long-term capacity, and certain ancillary services, specifically regulation and reserves, as the relevant products for purposes of their analysis.²⁶

(a) **Applicants' Analysis for PJM Markets**

(1) **PJM Energy Market**

25. Based on the results of the Delivered Price Test, Applicants conclude that the Proposed Transactions do not raise any competitive concerns in the PJM energy market or any PJM submarkets. Applicants state that, under the Economic Capacity²⁷ measure in the PJM market as a whole, the Proposed Transactions would result in HHI increases in the 10 season/load periods ranging from 17 to 22 points in an unconcentrated market. Under the Available Economic Capacity measure, Applicants determine that the Proposed Transactions would result in HHI increases ranging from 32 to 46 points in an unconcentrated market.²⁸

26. Applicants state that the results of the Delivered Price Test for the PJM East, 5004/5005, and AP South submarkets within PJM also indicate that the Proposed Transactions do not adversely affect competition in those markets. With respect to PJM East, Applicants state that the Proposed Transactions result in a season/load period maximum HHI increase of 12 points under the Economic Capacity measure and

²⁵ 18 C.F.R. § 33.3(c)(1).

²⁶ GSENA Application, Ex. J at 15; Stock Purchase Application, Ex. J at 20.

²⁷ Each supplier's "Economic Capacity" is the amount of capacity that could compete in the relevant market given market prices, running costs, and transmission availability. "Available Economic Capacity" is based on the same factors but subtracts the supplier's native load obligation from its capacity and adjusts transmission availability accordingly.

²⁸ GSENA Application at 20-21; Stock Purchase Application at 12-13.

27 points under the Available Economic Capacity measure in an unconcentrated market. Regarding the AP South submarket, Applicants state that the Proposed Transactions result in a season/load period maximum HHI increase of 6 points under the Economic Capacity measure and 18 points under the Available Economic Capacity measure in a moderately concentrated market. Similarly, Applicants state that the Proposed Transactions yield HHI increases of 5 points or less for Economic Capacity and 12 points or less for Available Economic Capacity in the 5004/5005 market in any given season/load period, which is unconcentrated in all time periods.²⁹

(2) PJM Capacity Market

27. Applicants contend that the Proposed Transactions raise no concerns in the PJM capacity market. Applicants calculate their post-transaction market share will be approximately 8 percent with a corresponding HHI change of 20 points in the Reliability Pricing Model, which Applicants argue demonstrates a lack of any competitive issues. Applicants also study the Eastern Mid-Atlantic Area Council (EMAAC) Local Deliverability Area (LDA) because it cleared at a separate price in the most recent Reliability Pricing Model auction. Applicants state that their post-transaction market share of the EMAAC LDA will be approximately 2 percent, and the Proposed Transactions only cause an HHI increase of 3 points.³⁰

(3) PJM Reserve and Regulation Markets

28. With respect to the regulation and reserve markets, Applicants submit that there is insufficient data to perform concentration analyses using the HHI. However, Applicants note that recent reports by the PJM Market Monitor indicate that participant behavior and market performance in PJM's regulation market was competitive in 2015. In addition, Applicants state that the amount of offered and eligible regulation was 1.81 times the amount of regulation required in 2014; therefore, Applicants conclude that the oversupply of regulation capacity is unlikely to be affected by the Proposed Transactions.³¹

²⁹ GSENA Application at 21-24; Stock Purchase Application at 13-16.

³⁰ GSENA Application at 25-26; Stock Purchase Application at 16-17.

³¹ See GSENA Application at 26-27, Ex. J at 32 (citing Monitoring Analytics, *2015 State of the Market Report for PJM* 359, 363 (Mar. 2016), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml); Stock Purchase Application at 18, Ex. J at 47 (same).

29. Applicants state that PJM operates markets for both primary reserves and non-synchronized reserves. Applicants rely on reports by the PJM Market Monitor which conclude that participant behavior and market performance were competitive for Tier 2 synchronized reserves. Specifically, the amount of offered and eligible synchronized reserves was 8,549 MW in the RTO Reserve Zone, of which 3,114 MW was available in the Mid-Atlantic Dominion Reserve Subzone, which was significantly greater than the 1,450 MW of demand in the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. PJM also operates a Day-Ahead Scheduling Reserve market to acquire its supplemental (30-minute) reserve requirements. Applicants assert that market structure and performance in 2015 were deemed competitive by the PJM Market Monitor, noting that the average available hourly Day-Ahead Scheduling Reserve was 36,396 MW, almost six times greater than the average cleared MW of 6,245 MW.³²

(b) **Applicants' Analysis for ISO-NE Markets**

(1) **ISO-NE Energy Market**

30. With respect to both of the Proposed Transactions, Applicants state that the results of the Delivered Price Test for the ISO-NE energy market demonstrate that the Proposed Transactions raise no competitive concerns. Specifically, Applicants find that the Proposed Transactions will result in HHI changes in the various season/load periods ranging from 17 to 112 points under the Economic Capacity measure and from 34 to 164 points under the Available Economic Capacity measure, in an unconcentrated market.³³

31. For purposes of the Stock Purchase Transaction, Applicants explain that Dynegy and ECP III are both affiliated with generation capacity in the Connecticut and Southwest Connecticut submarkets in ISO-NE.³⁴ Applicants assert, however, that the Connecticut

³² See GSENA Application at 27-28, Ex. J at 32-33 (citing Monitoring Analytics, *2015 State of the Market Report for PJM* 359, 361-62, 369 (Mar. 2016), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml); Stock Purchase Application at 18-19, Ex. J at 47-48 (same).

³³ GSENA Application at 29; Stock Purchase Application at 20-21.

³⁴ Applicants note that, because GSENA owns no generation capacity in either the Connecticut or Southwest Connecticut submarkets, there is no overlap of generation capacity in those submarkets for purposes of the GSENA Transaction. Accordingly, Applicants' analysis on the issue of submarkets in the ISO-NE energy market pertains only to the Stock Purchase Transaction. See GSENA Application at 29-30; Stock Purchase Transaction at 23.

and Southwest Connecticut submarkets in ISO-NE are no longer relevant submarkets. Applicants argue that there have been numerous transmission upgrades in ISO-NE, approximately six of which directly increase the transfer capability into or within the Connecticut region. Specifically, Applicants assert that transmission capacity from ISO-NE into Connecticut and Southwest Connecticut has increased from 2,500 MW in 2001 to 3,700 MW in 2016, and from 1,700 MW in 2001 to 3,200 MW in 2016, respectively.³⁵

32. In addition, Applicants present transmission congestion and price separation data, which Applicants argue demonstrates that Connecticut and Southwest Connecticut are no longer submarkets. With respect to transmission constraints, Applicants state that there were only two real-time transmission constraints within ISO-NE that were binding for more than 1 percent of the hours in years 2014 through 2015, and neither was binding for more than 2 percent of the hours in that period. Applicants further state that there were 18 day-ahead constraints that were binding for more than 1 percent of the total hours, of which seven were binding for more than 5 percent of the total hours in the 2014 through 2015 period. However, Applicants assert that these constraints are either on generation tie lines into or out of ISO-NE, or that they have no effect on Connecticut or Southwest Connecticut.³⁶

33. Applicants also present price separation and price correlation analyses as evidence that Connecticut and Southwest Connecticut are no longer submarkets. Applicants compare average prices in Connecticut and Southwest Connecticut against average prices in reference areas immediately outside and adjacent to Connecticut.³⁷ For day-ahead prices, Applicants calculate percent price differences in Connecticut and Southwest

³⁵ Stock Purchase Application at 24-26, Ex. J at 33-34 (citing ISO-NE, *Background on Recent Changes to Connecticut Import Limits* 27 (July 2013), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/jul22232013/a11_ct_transfer_limits.pdf). *See also* Stock Purchase Application, Ex. J at 34-35 (citing ISO-NE, *2018-2019 Forward Capacity Auction Obligations* (Feb. 2015), http://iso-ne.com/static-assets/documents/2015/02/fca_9_obligations.xlsx; ISO-NE, *2019-2020 Forward Capacity Auction Obligations* (Feb. 2016), http://www.iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx).

³⁶ *Id.* at 31-34, Ex. J at 39-40.

³⁷ Applicants designate West Central Massachusetts, Southeast Massachusetts, and Rhode Island as the reference areas for their price separation analyses. *Id.* at 34, Ex. J at 39, n.87.

Connecticut ranging from -4.5 percent to 2.7 percent and -4.8 percent to 3.3 percent, respectively. For real-time prices, Applicants calculate percent price differences in Connecticut and Southwest Connecticut ranging from -1.9 percent to 2 percent and -2.5 percent to 2.6 percent, respectively. Applicants state these results indicate that there is no price separation in the Connecticut or Southwest Connecticut submarkets. With respect to price correlations between Connecticut and the reference areas, Applicants estimate correlation coefficients ranging from 0.921 to 1.000. For price correlations between Southwest Connecticut and the reference areas, Applicants calculate correlation coefficients ranging from 0.920 to 1.000.³⁸ Applicants conclude that these price correlation coefficients provide additional evidence that there are no frequently binding transmission constraints separating Connecticut or Southwest Connecticut from the rest of ISO-NE.³⁹

(2) ISO-NE Capacity Market

34. According to Applicants, neither of the Proposed Transactions raises any competitive concerns in the ISO-NE Forward Capacity Market conducted through Forward Capacity Auctions. Applicants argue that the relevant market for the capacity product is the RTO-wide market because the Southeast New England (SENE) zone did not clear separately in the most recent auction. Based on the approximately 39,000 MW of qualified capacity in Forward Capacity Auction 10, Applicants calculate that, after consummation of the Proposed Transactions, they would be affiliated with approximately 9.4 percent of qualified capacity in ISO-NE, and market concentration would increase by 17 points. Applicants note that Connecticut and Southwest Connecticut were not modeled by ISO-NE as separate zones for the capacity market.⁴⁰

(3) ISO-NE Reserve and Regulation Markets

35. In their analysis of both of the Proposed Transactions, Applicants assert that, in the most recent forward reserve market auction, supply offered for the 10-Minute Non-Spinning Reserves in Rest of System was 1.9 times the supply cleared. Additionally,

³⁸ *Id.* at 27-31.

³⁹ *Id.* at 30-31.

⁴⁰ See GSENA Application at 30-31, Ex. J at 23-24 (citing ISO-NE, *2019-2020 Forward Capacity Auction Obligations* (Feb. 2016), http://www.iso-ne.com/static-assets/documents/2016/02/fca_10_obligations.xlsx); Stock Purchase Application at 21-22, Ex. J at 28-29 (same).

the supply offered for 30-Minute Operating Reserves in Rest of System was 2.1 times the supply cleared. With respect to the regulation market, Applicants explain that, on average, more than 600 MW of available supply competed to provide less than 60 MW of regulation service. Applicants conclude that minor consolidation resulting from the Proposed Transactions is unlikely to have harmful competitive effects in the ISO-NE reserve and regulation markets.⁴¹

(c) **Applicants' Analysis of NYISO, MISO, and CAISO**

36. Applicants conclude that the Stock Purchase Transaction does not raise any competitive concerns in the NYISO energy market based on the results of the Delivered Price Test.⁴² Applicants indicate that the Stock Purchase Transaction would result in HHI increases in any season/load period ranging from 9 to 39 points under the Economic Capacity measure and from 25 to 98 points under the Available Economic Capacity measure, in a market that is unconcentrated in all season/load periods. Applicants further assert that the results of the price sensitivity analyses are not materially different.⁴³

37. Applicants conclude that the Stock Purchase Transaction does not raise any competitive concerns in the MISO energy market based on the results of the Delivered Price Test. Applicants find that the Stock Purchase Transaction will cause HHI increases

⁴¹ See GSENA Application at 31-32, Ex. J at 24-25 (citing ISO-NE, *Forward Reserve Auction Market Results 2015-16* (Sep. 2015), https://www.iso-ne.com/static-assets/documents/2015/09/fr_auction_win2015-16.pdf; ISO-NE, *Forward Reserve Auction Results Summer 2015* (Apr. 2015), https://www.iso-ne.com/static-assets/documents/2015/04/fr_auction_sum2015.pdf); Stock Purchase Application at 22-23, Ex. J at 29-30 (same). See also GSENA Application, Ex. J at 25 (citing ISO-NE, *2014 Annual Markets Report* (May 2015), <https://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf>; Potomac Economics, Ltd., *2014 Assessment of the ISO New England Electricity Markets* (June 2015), https://www.iso-ne.com/static-assets/documents/2015/06/isone_2014_emm_report_6_16_2015_final.pdf); Stock Purchase Application, Ex. J at 29 (same).

⁴² Applicants explain that, in addition to the PJM and ISO-NE markets, including any relevant submarkets therein, the relevant geographic markets for the Stock Purchase Transaction are NYISO, MISO, and CAISO. As such, Applicants' analysis as to these markets focuses on the potential competitive effects of the Stock Purchase Transaction alone.

⁴³ Stock Purchase Application at 36-37.

in any season/load period ranging from 0 to 1 points under the Economic Capacity measure and 7 to 16 points under the Available Economic Capacity measure. Applicants maintain that the results of their price sensitivity analyses are not materially different.⁴⁴

38. For the CAISO energy market, Applicants' Delivered Price Test indicates that the Stock Purchase Transaction will result in HHI increases in any season/load period ranging from 2 to 3 points under the Economic Capacity measure and from 12 to 23 points under the Available Economic Capacity measure, in a market that is unconcentrated except for two season/load periods where the market is moderately concentrated.⁴⁵ Applicants also maintain that the Delivered Price Test screens are also passed for price sensitivities for the Economic Capacity and Available Economic Capacity measure in CAISO.⁴⁶

ii. Applicants' Response to the Data Request

39. In the Data Request, Applicants were directed to, among other things, expand their analysis of the effect of the Proposed Transactions on capacity markets to include all relevant import-constrained capacity zones as relevant geographic markets. As part of the capacity market analysis, Applicants were directed to perform a Delivered Price Test and pivotal supplier analysis for each relevant import-constrained capacity zone.

(a) Delivered Price Test Analysis

40. Applicants state that they were unable to provide a Delivered Price Test for the capacity product because there is no Commission guidance on how to perform such a Delivered Price Test for the capacity market and there are no detailed publicly available data for going-forward costs on a unit-specific basis. Applicants explain that publicly available data on generation capacity going-forward costs are necessary to determine "for all generation potentially available, which generation that did not clear could have responded to a five percent price increase, which is required for a full Delivered Price Test."⁴⁷ However, because Applicants have the confidential data on the prices at which Applicants' generation was offered into and cleared the capacity markets, Applicants state they were able to calculate HHI increases based on cleared and offered capacity.

⁴⁴ *Id.* at 37-38.

⁴⁵ *Id.* at 38-39.

⁴⁶ *Id.*, Ex. J at 14.

⁴⁷ Response at 5.

41. Applicants focus their analysis on the HHI increases in the PJM and ISO-NE capacity markets that result from both of the Proposed Transactions. In the PJM capacity market, Applicants state that there are five LDAs where their generation overlaps: Mid-Atlantic Area Council, EMAAC, Pennsylvania Power & Light, Commonwealth Edison (COMED), and American Transmission Systems, Inc. With respect to cleared capacity, Applicants calculate HHI increases for the PJM-wide market and each relevant LDA ranging from 0 points in the Pennsylvania Power & Light LDA to 49 points in the COMED LDA. With respect to offered capacity, Applicants calculate HHI increases for the PJM-wide market and each relevant LDA ranging from 0 points in the Pennsylvania Power & Light LDA to 37 points in the COMED LDA. For the ISO-NE capacity market, Applicants calculate HHI increases of 21 points with respect to cleared capacity and 18 points with respect to offered capacity. For the SENE capacity zone, which Applicants state is the only capacity zone in ISO-NE where Applicants have overlapping generation, Applicants calculate HHI increases of 46 points with respect to cleared capacity and 37 points with respect to offered capacity. Applicants assert that, because all of the HHI increases fall below 50 points, the Proposed Transactions do not raise any competitive concerns in the PJM or ISO-NE capacity markets, even if those markets were highly concentrated.⁴⁸

(b) Pivotal Supplier Analysis

42. Applicants analyze whether they would have been a pivotal supplier in the LDAs within the PJM capacity market and in the capacity zones within the ISO-NE capacity market with respect to both of the Proposed Transactions. Applicants construct their pivotal supplier analysis for each relevant capacity zone by first measuring whether the supplies of Dynegy, ECP III, or GSENA were needed to meet the minimum annual resource requirements in the 2019/2020 Base Residual Auction for PJM or the local sourcing requirements in Forward Capacity Auction 9 for ISO-NE. Applicants then calculate whether the supply of Atlas Power would have been needed to meet zonal demand requirements.

43. For each relevant LDA in PJM, Applicants determine that none of Dynegy, ECP III, or GSENA was pivotal before the Proposed Transactions and that Atlas Power would not be pivotal after the Proposed Transactions. For the SENE capacity zone in ISO-NE, Applicants state that, although Dynegy and ECP III were not pivotal prior to the Proposed Transactions, GSENA was pivotal before the Proposed Transactions. Applicants assert that, “[b]ecause GSENA was pivotal before the Proposed Transactions, Atlas Power necessarily will be pivotal after the Proposed Transactions.”⁴⁹ Applicants

⁴⁸ *Id.* at 6-7.

⁴⁹ *Id.* at 9.

argue that the pivotal status of Atlas Power only reflects the pre-transaction status of GSENA and does not indicate that the Proposed Transactions raise market power concerns.

iii. Commission Determination

44. In analyzing whether a proposed transaction will adversely affect horizontal competition, the Commission examines the effects on concentration in the generation markets and whether the proposed transaction otherwise creates the incentive and ability to engage in behavior harmful to competition, such as withholding of generation.⁵⁰ Based on Applicants' representations and the results of Applicants' Delivered Price Test, we find that the Stock Purchase Transaction will not have an adverse effect on competition in the NYISO, MISO, or CAISO markets.⁵¹ As discussed further below, based on Applicants' representations and the results of Applicants' Delivered Price Test, we find that the Proposed Transactions will also not have an adverse effect on horizontal competition in the PJM or ISO-NE energy or ancillary services markets, or any relevant submarkets therein.

45. However, based on Applicants' representations and Commission analyses, we find that Applicants have not demonstrated that the Proposed Transactions will not adversely affect competition in the PJM and ISO-NE capacity markets. Specifically, Applicants have not demonstrated that the GSENA Transaction will not adversely affect competition both within the COMED LDA in the PJM capacity market and within the SENE capacity zone in the ISO-NE capacity market. Further, Applicants have not demonstrated that the Stock Purchase Transaction will not have an adverse effect on competition in the SENE capacity zone in ISO-NE. Accordingly, we conditionally authorize the Proposed Transactions subject to mitigation, as discussed below.

(a) Energy and Reserve and Regulation Markets

(1) PJM

46. Applicants' Delivered Price Test and price sensitivity analyses demonstrate that the Proposed Transactions pass the market power screens in all season/load periods under both the Economic Capacity and Available Economic Capacity measures in the PJM

⁵⁰ *Nev. Power Co.*, 149 FERC ¶ 61,079, at P 28 (2014).

⁵¹ Our determination with respect to the NYISO, MISO, and CAISO markets relates only to the Stock Purchase Transaction because the GSENA Transaction does not involve generation capacity in NYISO, MISO, or CAISO. *See supra* PP 36-38.

energy market. Additionally, the results of Applicants' Delivered Price Test for the PJM East, 5004/5005, and AP South submarkets are not materially different than the results for the PJM market. Based on these results, we conclude that the Proposed Transactions will not adversely affect horizontal competition in the PJM energy market.

47. We also conclude that the Proposed Transactions will not adversely affect horizontal competition in the PJM Reserve and Regulation Services markets. Applicants represent that the PJM Market Monitor has concluded that participant behavior and market performance in PJM's regulation market was competitive in 2015, and that the amount of offered and eligible regulation was 1.81 times the amount of regulation required in 2014. Based on these representations, we agree that the Proposed Transactions do not raise competitive concerns with respect to the PJM reserve or regulation markets.

(2) ISO-NE

48. As a preliminary matter, we find that, based on Applicants' binding transmission constraint and price separation analyses, Connecticut and Southwest Connecticut are no longer submarkets in the ISO-NE energy market and therefore do not require separate analysis in the Delivered Price Test for purposes of the Stock Purchase Transaction. We consider the critical issue in defining relevant geographic markets to be whether transmission constraints are "binding such that no additional imports from outside the region are possible, [in which case] the region should be defined as a separate relevant geographic market."⁵² When the combined assets are located in an RTO/ISO, the Commission will typically consider the "geographic region under the control of the RTO/ISO as the default relevant geographic market . . . , unless the Commission already has found the existence of a submarket."⁵³ The Commission has also stated that proposals to use an alternative geographic market must include a "demonstration regarding whether there are frequently binding transmission constraint[s] during

⁵² *FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 52 (2010) (*FirstEnergy*); *see also Exelon Corp.*, 112 FERC ¶ 61,011, at P 124 (2005).

⁵³ *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 235 (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 No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

historical seasonal peaks and other competitively significant times that prevent competing supply from reaching [customers] within the proposed alternative geographic market.”⁵⁴ Applicants have demonstrated that recent data supports the conclusion that transmission constraints into Connecticut and Southwest Connecticut do not bind frequently and do not cause significant price separation. We conclude that Connecticut and Southwest Connecticut are not separate geographic markets at this time because the constraints have not been frequently binding and therefore do not prevent competing supply from reaching customers within the Connecticut and Southwest Connecticut areas.

49. The results of Applicants’ Delivered Price Test for the ISO-NE energy market indicate that the Proposed Transactions will result in HHI increases in any season/load period ranging from 17 to 112 points under the Economic Capacity measure and 34 to 164 points under the Available Economic Capacity measure, in an unconcentrated market. Based on the results of Applicants’ Delivered Price Test, we find that the Proposed Transactions will not adversely affect competition in the ISO-NE energy market.

50. Regarding the reserve market, Applicants represent that in the most recent Forward Reserve Market auction, supply offered for the 10-Minute Non-Spinning Reserves in Rest of System was 1.9 times the supply cleared, and that the supply offered for 30-Minute Operating Reserves in Rest of System was 2.1 times the supply cleared. With respect to the regulation market, Applicants assert that, on average, more than 600 MW of available supply competed to provide less than 60 MW of regulation service. Based on these representations, we conclude that the Proposed Transactions will not adversely affect competition for ancillary services in ISO-NE.

(b) Capacity Markets

(1) PJM

51. Applicants indicate that, for every relevant LDA, the Proposed Transactions do not cause an HHI increase greater than 50 points or Atlas Power to become pivotal. We find that the 49 point HHI increase in the COMED LDA warrants a deeper examination of competitive concerns that could arise as a result of the GSENA Transaction.⁵⁵

⁵⁴ *NRG Energy Holdings, Inc.*, 146 FERC ¶ 61,196, at P 80 (2014); *Exelon Corp.*, 138 FERC ¶ 61,167, at P 32 (2012) (Exelon); *see also Ameren Energy Generating Co.*, 145 FERC ¶ 61,034, at P 55 (2013) (Ameren); *FirstEnergy*, 133 FERC ¶ 61,222 at P 52.

⁵⁵ We note that the COMED LDA is a relevant geographic market only for purposes of the GSENA Transaction.

52. In this regard, we note that the Commission's thresholds are guidelines, not "bright-lines." As articulated in the Merger Policy Statement, "[t]here will undoubtedly be instances where concentration statistics may fall just above or just below the thresholds for concern and some additional analysis or judgement [sic] is needed."⁵⁶ That is the case here, where Applicants' analysis of the COMED LDA results in a 49 point increase in the HHI relative to a threshold of 50, in a market which is highly concentrated, as discussed below.

53. Although Applicants state they do not have the data necessary to calculate individual company market shares and thus cannot determine whether the COMED LDA is highly concentrated, our analysis indicates that the COMED LDA is highly concentrated. Using summer capacity ratings and forced outage data available through a database used by Applicants to populate their Delivered Price Test, Ventyx,⁵⁷ we estimated the unforced capacity,⁵⁸ a proxy for offered capacity, for each generating unit in the COMED LDA. Using Ventyx holding company data, we then calculated each market participant's market share of unforced capacity in the COMED LDA, the sum of the squares of which yield the market HHI level. Using this methodology, we estimate that the COMED LDA has a pre-transaction market HHI level of 2,021 points, which indicates the market is highly concentrated.

54. We find that Applicants' HHI analysis alone does not adequately demonstrate that the Proposed Transactions will not adversely affect competition in the highly concentrated COMED LDA. As such, we consider Applicants' pivotal supplier analysis.⁵⁹ The Commission has stated that merger analysis should be as forward-looking

⁵⁶ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,134.

⁵⁷ Ventyx, also known as Velocity Suite, ABB Enterprise Software, refers to these ratings as "Net Summer Capacity MW." We used Ventyx data for our analysis because it is widely used by industry for populating models and analyses. *See, e.g.*, GSENA Application at Ex. J-5. However, we note that Commission use of Ventyx data here should not be viewed as an endorsement of Ventyx.

⁵⁸ Unforced capacity is the MW value of a capacity resource in the PJM capacity market. We estimated a generating unit's unforced capacity value as a function of its summer capacity rating and its outage rating. This function takes the unit's summer capacity rating and multiplies it by (1 - unit's outage rate). We specifically used the Equivalent Demand Forced Outage Rate from the Generating Availability Data System for the outage rating.

⁵⁹ The Commission reviews all section 203 applications on a case-by-case basis. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,118. We acknowledge

(continued ...)

as practicable.⁶⁰ Applicants calculate that, without Atlas Power, there would be a sufficient supply of unforced capacity available to meet the COMED minimum annual resource requirement. As Applicants explain, Atlas Power would not currently be pivotal in this scenario. However, we note that there are two large generators—the Quad Cities Generating Station (Quad Cities)⁶¹ and Unit 4 of the Will County Generating Station (Will County)⁶²—in the COMED LDA with an aggregate unforced capacity of approximately 2,223 MW that plan to retire within the next two and four years, respectively. We find it appropriate here to factor the retirements of Quad Cities and Will County⁶³ into the calculation of whether Atlas Power will be pivotal as a result of the GSENA Transaction in the COMED LDA for two reasons. First, these retirements

that this is the first instance where we have used and relied on a pivotal supplier analysis in a section 203 proceeding. We also note that the Commission is considering incorporating pivotal supplier analyses more generally into its review of section 203 applications. *Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act*, 156 FERC ¶ 61,214 (2016). However, use of a pivotal supplier analysis is appropriate here as a supplement to Applicants' HHI analysis, which is only marginally below the threshold for concern. Furthermore, the pivotal supplier analysis provides the Commission additional, necessary information to determine how the Proposed Transactions will affect competition in import-constrained capacity zones.

⁶⁰ See Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,887.

⁶¹ On June 20, Exelon Corporation, which owns the Quad Cities Generating Station, sent a Certification of Permanent Cessation letter to the U.S. Nuclear Regulatory Commission, stating that it plans to permanently cease power operations at the facility by June 1, 2018. Exelon Corp., Certification of Permanent Cessation of Power Operations (June 20, 2016), <http://www.nrc.gov/docs/ML1617/ML16172A151.pdf>. We note that, on December 7, the Future Energy Jobs Bill was signed into law in Illinois, which may affect the retirement of the facility.

⁶² NRG Energy, which owns the Will County Electric Generating Station, intends to retire the only remaining unit, Unit 4, in 2018. PJM, *Future Deactivations* (Sept. 19, 2016), <https://www.pjm.com/~media/planning/gen-retire/pending-deactivation-requests.ashx>.

⁶³ The Commission has considered prospective retirements in previous section 203 proceedings. See, e.g., *Ameren*, 145 FERC ¶ 61,034 at P 57.

are included in PJM's list of future deactivations with retirement dates of June 2018 for Quad Cities and May 2020 for Will County. Therefore, Quad Cities and Will County will not participate in the 2020/2021 Base Residual Auction. Second, these facilities have already undergone reliability studies to determine the impact of their retirement on the PJM system. Factoring in the 2,223 MW of planned retirements leaves an insufficient supply of unforced capacity available to meet the COMED LDA minimum annual resource requirement, which means that Atlas Power's capacity is needed.⁶⁴ With all other factors held constant, we calculate that Atlas Power will be pivotal in the COMED LDA for the 2020/2021 Base Residual Auction.

55. Accordingly, we find that, absent mitigation, Applicants have not demonstrated that the GSENA Transaction will not adversely affect competition in the COMED LDA. As a result, we conditionally authorize the GSENA Transaction subject to Applicants proposing mitigation that addresses the competition concerns in the COMED LDA that result from the GSENA Transaction. This approach is consistent with the Merger Policy Statement, in which the Commission noted that the merger guidelines "contemplate using remedies to mitigate any harm to competition."⁶⁵ The Commission explained that "[t]here will be mergers where, at the end of an analysis, market power concerns persist but that could be made acceptable with measures to mitigate potential market power problems."⁶⁶ Therefore, if Applicants elect to proceed with the GSENA Transaction, Applicants are directed to make a compliance filing within 30 days of the date of this order proposing mitigation that would be sufficient to remedy the competitive concerns in the COMED LDA that result from the GSENA Transaction. Applicants could propose mitigation that includes divestitures of generation in the COMED LDA,⁶⁷ or Applicants

⁶⁴ The Commission used Ventyx data to obtain the unforced generation capacity MW of the two facilities.

⁶⁵ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,118.

⁶⁶ *Id.*

⁶⁷ We note that, on November 2, 2016, the Commission approved Dynegy's request for authorization to sell its 50 percent interest in Elwood Energy LLC (Elwood), which owns a 1,350 MW gas-fired peaking facility located in Will County, Illinois, within the COMED LDA of the PJM market. *Elwood Energy LLC*, Docket No. EC16-174-000, (Nov. 2, 2016) (delegated letter order). The transaction was consummated on November 21, 2016. In the compliance filing, Applicants may provide an analysis that demonstrates how the Elwood transaction would fit into their proposed mitigation plan for the competitive concerns in the COMED LDA.

may propose other mitigation measures to address the competitive concerns that we have identified that result from the GSENA Transaction.

(2) **ISO-NE**

56. In the SENE capacity zone, GSENA was pivotal pre-transaction with approximately 1,273 MW of qualified capacity. After consummation of the Proposed Transactions, Atlas Power will be pivotal with approximately 1,497 MW of qualified capacity in the SENE capacity zone. Applicants argue that because GSENA is pivotal prior to the Proposed Transactions and Atlas Power will remain pivotal after the Proposed Transactions, the Proposed Transactions will have no adverse effect on competition. We disagree. Being pivotal implies that a seller has the ability to unilaterally increase the market price, and the seller's incentive to do so increases as it becomes more pivotal. Because the Proposed Transactions would result in an increase in the degree to which Atlas Power is pivotal, we find that Applicants have not demonstrated that the Proposed Transactions will not have an adverse effect on competition in the SENE capacity zone in the ISO-NE capacity market. Specifically, we are concerned with a seller's ability to exercise market power in the ISO-NE Forward Capacity Auction when its resources enter or exit the market, and thus, Applicants should tailor mitigation to address that concern.⁶⁸ For example, Applicants may consider, among other steps, divestiture of generation units or a commitment to keep resources in the ISO-NE capacity market for a specified period of time.

57. Therefore, we will conditionally authorize the Proposed Transactions subject to mitigation that addresses the competition concerns in the SENE capacity zone that result from the Proposed Transactions. If Applicants elect to proceed with the Proposed Transactions, Applicants are directed to make a compliance filing within 30 days of the date of this order proposing mitigation that would be sufficient to remedy the competitive concerns in the SENE capacity zone that result from the Proposed Transactions.

b. Effect on Vertical Competition

i. Applicants' Analysis

58. Applicants claim that the Proposed Transactions do not present any vertical market power concerns. Applicants state that none of Applicants or their affiliates owns a 10 percent or greater voting interest in or controls any electric transmission facilities, other than the limited equipment necessary to interconnect individual generating facilities

⁶⁸ See ISO-NE, Tariff, § III.13.1.2.3 Qualification Process for Existing Generating Capacity Resources (46.0.0).

to the transmission grid and the limited and discrete transmission facilities owned by Electric Energy and various ECP III affiliates, which are subject to a Commission-approved OATT or which have waivers from the requirement to file an OATT. Furthermore, Applicants state that none of Applicants or their affiliates has any ownership interest in or control of fuel supplies, fuel delivery systems, other inputs to electricity markets, or any new sites for electric generation that could raise barriers to entry in any of the relevant markets.⁶⁹

ii. Commission Determination

59. In analyzing whether a proposed transaction presents vertical market power concerns, the Commission considers the vertical combination of upstream inputs, such as transmission or natural gas, with downstream generating capacity. As the Commission has previously found, transactions that combine electric generation assets with inputs to generating power (such as natural gas, transmission, or fuel) can harm competition if the transaction increases an entity's ability or incentive to exercise vertical market power in wholesale electricity markets. For example, by denying rival entities access to inputs or by raising their input costs, an entity created by a transaction could impede entry of new competitors or inhibit existing competitors' ability to undercut an attempted price increase in the downstream wholesale electricity market.⁷⁰

60. Based on Applicants' representations, we find that the Proposed Transactions will not have an adverse effect on vertical competition. As noted above, none of Applicants or their affiliates owns a 10 percent or greater voting interest in or controls any electric transmission assets, other than those necessary to connect generation to the grid and the limited and discrete transmission facilities owned by Electric Energy and various ECP III affiliates, which are subject to a Commission-approved OATT or have waivers from the requirement to file an OATT. Further, neither Applicants nor their affiliates owns or controls inputs to electricity production or new sites for electric generation that could raise barriers to entry in any of the relevant geographic markets.

⁶⁹ GSENA Application at 33-36; Stock Purchase Application at 39-42.

⁷⁰ *Upstate N.Y. Power Producers, Inc.*, 154 FERC ¶ 61,015, at P 15 (2016); *Exelon Corp.*, 138 FERC ¶ 61,167 at P 112.

c. Effect on Rates

i. Applicants' Analysis

61. Applicants state that the Proposed Transactions will not have an adverse impact on rates. Applicants assert that any transmission service provided to third parties by Applicants or their affiliates is provided under Commission-approved OATTs or transmission service agreements pursuant to fixed cost-based rates rather than formula rates and cannot be changed without Commission review and acceptance of any proposed rate change. In addition, while most of Applicants' public utility affiliates have market-based rate authority and make most of their sales under negotiated rates, certain subsidiaries make sales under cost-based rates or other schedules on file with the Commission. Applicants assert that none of such rates under cost-based contracts can be affected by the Proposed Transactions. Nevertheless, Applicants commit, on behalf of themselves and their public utility subsidiaries and affiliates, to hold their cost-based rate customers harmless from transaction-related costs, absent a filing under section 205 of the FPA demonstrating that transaction-related costs are exceeded by transaction-related savings. Applicants further commit that neither they nor any of their affiliates will seek to recover any transaction or transition costs attributable to the Proposed Transactions through transmission rates.⁷¹

ii. Commission Determination

62. Based on Applicants' representations and hold harmless commitment, we find that the Proposed Transactions will not have an adverse effect on rates. As noted by Applicants, any transmission service provided to third parties by Applicants or their affiliates is provided under Commission-approved OATTs pursuant to fixed cost-based rates that cannot be altered without Commission approval. While most of Applicants and their affiliates make wholesale sales at market-based rates, Applicants assert that the Proposed Transactions cannot affect any of the rates of Applicants' affiliates under their cost-based contracts.

63. We accept Applicants' commitment to hold wholesale power and transmission customers harmless from costs related to the Proposed Transactions. We interpret Applicants' hold harmless commitment to apply to all transaction-related costs, including costs related to consummating the Proposed Transactions, incurred prior to the consummation of the Proposed Transactions, or after the Proposed Transactions' consummation.

⁷¹ GSENA Application at 36-38; Stock Purchase Application at 42-43.

64. The Commission has established that, where applicants make hold harmless commitments in the context of FPA section 203 transactions, in order to recover transaction-related costs, applicants must demonstrate offsetting benefits at the time they apply to recover those costs. The Commission has clarified its procedures for recovery of such costs under FPA sections 203 and 205.⁷² Consistent with those clarifications, and given the commitment by Applicants to hold wholesale power and transmission customers harmless from transaction-related costs, if Applicants seek to recover transaction-related costs incurred prior to the consummation of the Proposed Transaction or after the consummation of the Proposed Transactions, then Applicants must make that filing in a new FPA section 205 docket⁷³ and submit that same filing as a concurrent information filing in this FPA section 203 docket.⁷⁴ The Commission will notice the new FPA section 205 filing for public comment.

65. In the FPA section 205 proceeding, the Commission will determine, first, whether applicants have demonstrated offsetting savings, supported by sufficient evidence, to customers served under Commission jurisdictional rate schedules such that recovery of transaction-related costs is consistent with the hold harmless commitment and, second, whether the resulting new rate is just and reasonable in light of all the other factors underlying the proposed new rate. In the FPA section 205 filing, applicants must: (1) specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the Proposed Transactions. Applicants must show that the proposed rate is just and reasonable in addition to providing appropriate evidentiary support, such as reasonable documentation and estimates of the costs avoided, demonstrating that transaction-related costs have been offset by transaction-related savings in order to recover those transaction-related costs and comply with its hold harmless commitment. Those savings must be realized prior to, or concurrent with, any authorized recovery of transaction-related costs, and cannot be based on estimates or projections of future savings, but must be based on a demonstration

⁷² See *Policy Statement on Hold Harmless Commitments*, 155 FERC ¶ 61,189 (2016); *Exelon Corp.*, 149 FERC ¶ 61,148, at PP 106-09 (2014).

⁷³ The Commission will not authorize the recovery of transaction-related costs in an annual informational filing under existing formula rates.

⁷⁴ Upon receipt, the Commission will not act on or notice the concurrent informational filing.

of actual transaction-related savings realized by jurisdictional customers.⁷⁵ The Commission will consider rates not to be “just and reasonable” if they include recovery of costs subject to a hold harmless commitment made in connection with an FPA section 203 application and if applicants fail to show offsetting savings due to the transaction.⁷⁶

66. The Commission will be able to monitor Applicants’ hold harmless commitment under its authority under section 301(c) of the FPA⁷⁷ and the books and records provision of the Public Utility Holding Company Act of 2005 (PUHCA 2005), if applicable.⁷⁸ Moreover, the commitment is fully enforceable based on the Commission’s authority under section 203 of the FPA.

d. Effect on Regulation

i. Applicants’ Analysis

67. Applicants state that the Proposed Transactions will not have an adverse effect on the effectiveness of federal or state regulation. According to Applicants, the Proposed Transactions will not affect the ability of the Commission or any state public utility commission to regulate Applicants or any of their affiliates or subsidiaries, each of which will remain subject to regulation by the Commission and by state commissions to the same extent each was regulated before consummation of the Proposed Transactions.⁷⁹

ii. Commission Determination

68. The Commission’s review of a transaction’s effect on regulation focuses on ensuring that it does not result in a regulatory gap.⁸⁰ As to whether a proposed transaction will have an effect on state regulation, the Commission explained in the Merger Policy Statement that it ordinarily will not set the issue of the effect of a proposed

⁷⁵ See *Exelon Corp.*, 149 FERC ¶ 61,148 at P 107 (citing *Audit Report of National Grid, USA*, Docket No. FA09-10-000, at 55 (Feb. 11, 2011)); see also *Ameren Corp.*, 140 FERC ¶ 61,034, at PP 36-37 (2012).

⁷⁶ *Exelon Corp.*, 149 FERC ¶ 61,148 at P 107.

⁷⁷ 16 U.S.C. § 825(c) (2012).

⁷⁸ 42 U.S.C. § 16451 *et seq.* (2012).

⁷⁹ GSENA Application at 38-39; Stock Purchase Application at 44.

⁸⁰ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

transaction on state regulatory authority for a trial-type hearing where a state has authority to act on the proposed transaction. However, if the state lacks this authority and raises concerns about the effect on regulation, the Commission may set the issue for hearing and it will address such circumstances on a case-by-case basis.⁸¹ Based on Applicants' representations, we find no evidence that either state or federal regulation will be impaired by the Proposed Transactions. Finally, we note that no party alleges that regulation, state or federal, would be impaired by the Proposed Transactions, and no state commission has requested that the Commission address the issue of the effect on state regulation.

e. **Cross-Subsidization**

i. **Applicants' Analysis**

69. Applicants state that, based on facts and circumstances known to them or that are reasonably foreseeable, the Proposed Transactions will not result in, at the time of the transaction or in the future, cross-subsidization of a non-utility associate company or the pledge or encumbrance of assets of a traditional public utility that has captive customers or that owns or provides transmission service over jurisdictional facilities for the benefit of an associate company.

70. Specifically, Applicants verify that the Proposed Transactions will not now, or in the future, result in: (1) transfers 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) new issuances of securities by traditional public utility associate companies that have captive customers or that own or provide transmission service over jurisdictional transmission facilities, for the benefit of an associate company; (3) new pledges or encumbrances 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) new affiliate contracts between non-utility associate companies and traditional public utility associate companies that have captive customers or that own or provide transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review pursuant sections 205 and 206 of the FPA.⁸²

⁸¹ *Id.*

⁸² GSENA Application at 39-40; Stock Purchase Application at 45-46.

ii. **Commission Determination**

71. Based on Applicants' representations, we find that the Proposed Transactions will not result in the cross-subsidization of a non-utility associate company by a utility company, or in a pledge or encumbrance of utility assets for the benefit of an associate company. We note that no party has argued otherwise.

3. **Protest**

a. **Public Citizen's Protest**

72. Public Citizen argues that the Commission cannot evaluate whether the GSENA Transaction is consistent with the public interest due to three ongoing Commission investigations into Dynegy's market conduct and market-based rate authority. Public Citizen first references Docket No. IN15-10, in which the Commission began a formal investigation into market manipulation involving the MISO 2015/2016 Planning Resource Auction and Dynegy's participation in that auction. Public Citizen asserts that neither the Commission nor the public can properly evaluate whether a transaction proposing to expand Dynegy affiliates with market-based rate authority is consistent with the public interest so long as a formal investigation into Dynegy's conduct with affiliates with market-based rate authority remains open.⁸³

73. Public Citizen also references Docket No. EL15-70, which involves Public Citizen's section 206 complaint that alleges market manipulation and other concerns relating to Dynegy and the MISO 2015/16 Planning Resource Auction. Public Citizen contends that the disputed facts in Docket No. EL15-70 raise significant concerns about Dynegy's conduct in Commission-jurisdictional markets and directly prevent the ability to determine whether allowing Dynegy to acquire additional facilities with market-based rate authority is consistent with the public interest.⁸⁴

74. Next, Public Citizen argues that the ongoing audit of Dynegy and its subsidiaries with market-based rate authority in Docket No. PA15-3 interferes with the evaluation of the GSENA Transaction for three reasons. First, Public Citizen argues that the discrepancies in Dynegy's Electric Quarterly Reports (EQR) filings render its market-based rate reporting unreliable. Second, Public Citizen states that Applicants requested waiver of the Exhibit F requirement to file description and location information about wholesale sales as that information is already filed with the Commission in the EQRs.

⁸³ Public Citizen Protest at 3.

⁸⁴ *Id.* at 4.

Public Citizen argues that this waiver is unacceptable and that Applicants' formal application must be considered incomplete. Third, Public Citizen argues that elements of the GSENA Application, such as Exhibit J, may rely on the disputed EQRs.⁸⁵

b. Applicants' Answer

75. Applicants argue that Public Citizen's protest should be rejected as procedurally deficient because it does not address the Response to the Data Request, but rather is an untimely general protest of the Proposed Transactions. Applicants contend that Public Citizen makes no attempt to explain why it did not make its arguments based on ongoing proceedings by the May 24, 2016 comment date for the Proposed Transactions.⁸⁶

76. Applicants also assert that Public Citizen's reference to the three proceedings is irrelevant to any of the public interest factors considered by the Commission in its section 203 analysis. First, Applicants state that in Docket Nos. EL15-70 *et al.*, Dynegy fully rebutted the allegations in those complaint dockets involving the MISO Planning Resource Auction for Zone 4. Applicants state that the substance of that response is not relevant here. Applicants assert that what is relevant in this case is that there is no overlap of Applicants' generation in MISO Zone 4 and that the Commission has held that it does not require analysis of the competitive effects of a merger in markets where the applicants' generation does not overlap. With respect to Docket No. IN15-10, Applicants state that they cannot comment on the non-public investigation, but they argue that the investigation is not relevant to the Commission's review of the Proposed Transactions for the same reason that Docket Nos. EL15-70 *et al.* are not relevant, i.e., there is no overlap of Applicants' generation in MISO Zone 4.⁸⁷

77. Lastly, Applicants contend that Docket No. PA15-3 is not an investigation into Dynegy's EQR filings but is a routine audit by the Commission of Dynegy's market-based rate compliance that includes, among other things, Dynegy's compliance with the Commission's EQR filing requirements. Applicants note that this audit has no bearing on the Commission's review of the Proposed Transactions with respect to whether the Proposed Transactions will have an adverse effect on competition, rates, or regulation. With respect to Public Citizen's argument regarding Exhibit F of the Application, Applicants assert that Dynegy accurately listed its cost-based rate schedules in the applications for the Proposed Transactions and that Public Citizen has not identified any

⁸⁵ *Id.* at 4-7.

⁸⁶ Applicants' Answer at 3-4.

⁸⁷ *Id.* at 4-6.

reason why the Commission cannot adequately assess the Proposed Transactions given the information provided in each application. Applicants likewise rebut Public Citizen's argument about the use of EQRs in Exhibit J of the Application, arguing that it mischaracterizes the analysis. Applicants state that they used locational marginal price data for market prices in their competitive analysis and merely used EQR data to confirm the results. According to Applicants, Public Citizen's arguments would apply equally to any section 203 filing made by any market participant undergoing such an audit, and if the Commission were to hold that it could not rule on a section 203 application due to an audit, it would disrupt the Commission's processing of these filings.⁸⁸

c. Public Citizen's Answer

78. Public Citizen asserts that a deficiency letter renders a filing incomplete, and it contends that there is no requirement for a commenter to reply to an incomplete filing, and that the timing for such a filing only begins when it is complete. Public Citizen emphasizes that the Commission's audit of ongoing discrepancies involving Dynegy's EQR filings renders a public interest analysis of the GSENA Transaction impossible. Public Citizen suggests that as long as such discrepancies exist between Dynegy's EQRs and what the company reports to various RTOs, neither the public nor the Commission can effectively evaluate whether the GSENA Transaction is consistent with the public interest.

d. Commission Determination

79. We conclude that, based on the record before us, Public Citizen's protest raises concerns that are beyond the scope of this proceeding. We agree with Applicants that the issues raised in Public Citizen's protest are not part of the Commission's public interest analysis under section 203 of the FPA. Public Citizen argues that the ongoing investigations into Dynegy's market-based rate authority implicate the Commission's evaluation of the GSENA Transaction, which would expand Dynegy's market-based rate affiliates. However, the Commission's evaluation of a proposed transaction under FPA section 203 examines the proposed transaction's effect on competition, rates, and regulation, as well as whether the proposed transaction will result in cross-subsidization. As such, we find that the concerns in Public Citizen's protest are not properly raised here.

4. Other Considerations

80. Information and/or systems connected to the bulk system involved in this transaction may be subject to reliability and cybersecurity standards approved by the

⁸⁸ *Id.* at 6-9.

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 database, 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, etc., must comply with all applicable reliability and cybersecurity standards. The Commission, North American Electric Reliability Corporation or the relevant regional entity may audit compliance with reliability and cybersecurity standards.

81. Section 301(c) of the FPA 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 the Proposed Transactions is based on such examination ability. In addition, applicants subject to PUHCA 2005 are subject to the record-keeping and books and records requirements of PUHCA 2005.

82. Order No. 652 requires that sellers with market-based rate authority 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.⁸⁹ To the extent that a transaction authorized under FPA section 203 results in a change in status, sellers that have market-based rates are advised that they must comply with the requirements of Order No. 652.

The Commission orders:

(A) The Proposed Transactions are hereby conditionally authorized, subject to mitigation, as discussed in the body of this order.

(B) If Applicants elect to proceed with the Proposed Transactions as authorized in this order, they are directed to submit within 30 days of the date of this order proposed mitigation that would be sufficient to remedy the competitive concerns discussed in the body of this order.

⁸⁹ *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, Order No. 652, FERC Stats. & Regs. ¶ 31,175, order on reh'g, 111 FERC ¶ 61,413 (2005). See 18 C.F.R. § 35.42 (2016).

(C) Applicants must inform the Commission of any material change in circumstances that departs from the facts or representations that the Commission relied upon in authorizing the Proposed Transactions within 30 days from the date of the material change in circumstances.

(D) 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 costs, or any other matter whatsoever not pending or may come before the Commission.

(E) 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.

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

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

(H) Applicants shall notify the Commission within 10 days of the date or dates on which the Proposed Transactions are consummated.

(I) If Applicants seek to recover transaction-related costs through their wholesale power and transmission rates, they must make a new FPA section 205 filing and submit concurrently an informational filing in the instant FPA section 203 docket. In the FPA section 205 filing, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by the savings produced by the Proposed Transactions.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.