UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NRG East Generation Holdings LLC	)	Docket No. EC25-102-000
NRG Demand Response Holdings LLC	)	
Lightning Power, LLC, on behalf of its Public Utility Subsidiaries	)	
Enerwise Global Technologies, LLC dba CPower	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments responding to the filing submitted by NRG East Generation Holdings LLC, et al. ("Applicants") on June 12, 2025 ("June 12th Filing"), corrected by filing dated June 13, 2025, requesting approval of a proposed transaction under Section 203 of the Federal Power Acts. The June 12th Filing requests approval of a transaction ("Transaction") whereby NRG East Generation Holdings will acquire all of the membership interests of Lightning Power, LLC from Lightning Power

[1] 18 CFR § 385.211 (2024).

[2] Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

Holdings, LLC ("Lightning Seller") and DR Holdings will acquire indirect interests in CPower from CCS Power Holdings, LLC ("CCS Seller"). Lightning Seller and CCS Seller are wholly controlled subsidiaries of LS Power Development, LLC ("LSP Development"). As a result of the Transaction, generation, emergency and pre-emergency demand response and economic demand response assets located in the PJM region would change ownership from LS Power to NRG. In this filing and the attached report, we refer to these resources as the "LS Assets."

The Market Monitor provides its analysis of the proposed Transaction in a report ("Market Monitor Report"). The Market Monitor files a public version of the Market Monitor Report with redactions as an Attachment, and files separately a nonpublic confidential version.

The Applicants have not asserted that this transaction enhances competition or market efficiency. The Applicants have not explained why the transaction is consistent with the public interest.[3]

The Transaction would increase structural market power in PJM markets. The significant increase in the concentration of ownership of emergency and pre-emergency demand resources is especially noteworthy given the newly pivotal role of these resources and the absence of any applicable market power mitigation rules. Specifically, there is no must offer obligation which allows physical withholding and there are no offer caps which allows economic withholding. This absence of market power mitigation rules is much more significant now than ever before in the history of the PJM Capacity Market as a result of the fact that demand resources are included in the reserve margin for the first time ever in the 2025/2026 Delivery Year. The PJM Capacity Market would have been short of meeting the reliability requirement in the BRA for 2025/2026 but for these demand resources.

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[3] *See* 16 U.S.C. § 824b ("the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction will be consistent with the public interest").

The Market Monitor does not oppose the proposed Transaction, with the condition that any order approving the Transaction requires specific behavioral commitments by the resulting entity, none of which creates a burden on applicants because all are designed to help ensure competitive behavior. Absent the acceptance of the identified conditions, the Market Monitor opposes the Transaction because it would increase structural market power without any mitigating factors and therefore would not be in the public interest. While the Market Monitor's proposed behavioral conditions for emergency and pre-emergency demand resources would impose unique obligations on NRG as owner of these resources if the Transaction is approved, those conditions are warranted by the extreme increase in concentration of emergency and pre-emergency demand resources that would result. Without these conditions related to emergency and pre-emergency demand resources, the Market Monitor recommends rejection of the demand side part of the Transaction.

The broader question for the Commission's merger policy is whether transactions that result in incremental increases in market power in the PJM Capacity Market, or any PJM market, should be approved given the fact that the PJM Capacity Market is already characterized by endemic market power. A related question is whether Commission merger policy should identify, even in broad terms, the worst case end state market structure for PJM's competitive markets that could be used to evaluate specific transactions.

I. COMMENTS

A. The Transaction Increases Market Power in PJM Markets.

The LS Assets in PJM include 7,383 MW of gas fired generation in the AEP, APS, ATSI, ComEd, Dominion, and MetEd Zones of PJM. The LS Assets in PJM also include CPower's pre-emergency and emergency demand response and economic demand response. NRG's existing assets in PJM consist of 2,092 MW of generation, including hydro, coal fired, gas fired, and oil fired resources, in the ComEd, DPL, Penelec, and Pepco Zones. NRG's existing assets in PJM also include pre-emergency and emergency demand response.

The Transaction increases market power in the PJM markets. Both companies have local market power created by binding constraints in the PJM energy and capacity markets before the transaction. The transfer of the LS Assets to NRG increases local market power in the energy market for some constraints and reduces local market power for other constraints. The transfer of the LS Assets to NRG increases locational market power in the capacity market for some LDAs and reduces locational market power for other LDAs. The market power report discusses particular local areas with increased market power. When examining only the energy market, the Transaction reduces average market concentration at the aggregate market level. However, with the demand response resources, the transaction increases overall capacity market concentration at the aggregate level.

B. HHI Is Not a Definitive Test of Market Power.

The Commission's review of transactions under Section 203 of the Federal Power Act relies in part on the Herfindahl-Hirschman Index (HHI) as a measure of the concentration of ownership in a market. The HHI is the sum of the squared market shares of all market participants.

A supplier may have the ability to raise market prices above the competitive level even with an HHI level considered to be unconcentrated. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to reliably meet the PJM system load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The same is true in the capacity market. If the capacity of a single supplier is needed to clear the capacity market either in aggregate or in an LDA, that supplier is pivotal. The HHI is not a definitive measure of structural market power. The capacity market, where the HHI is in the unconcentrated range but almost all suppliers are pivotal in every auction, illustrates the mismatch between the HHI metric and the pivotal supplier metric. The identification of jointly pivotal suppliers as a source of market power

does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[4] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.[5]

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate energy market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the withheld generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct. There are pivotal suppliers in the aggregate energy market at times.[6]

The current market conditions in which this proposed transaction would occur are also important. PJM's Capacity Market is extremely tight. The result is that structural market power is enhanced because all capacity market sellers are pivotal. The relative rates of growth of the demand for capacity and the supply of new capacity mean that the capacity market is likely to remain extremely tight for the foreseeable future. Given the structure of shortage

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4 *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 PP 104–117 (2007), *clarified*, 121 *FERC* ¶ 61,260 (2007), *order on reh'g and clarification*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g and clarification*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g and clarification*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g and clarification,* Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *order on clarification*, 131 FERC ¶ 61,021, *reh'g denied*, 134 FERC ¶ 61,046 (2010), *reh'g denied*, 143 FERC ¶ 61,126 (2013).

5 *See id.*at P 89.

6 Monitoring Analytics, L.L.C., *2025 Quarterly State of the Market Report for PJM: January through March*, Section 3: Energy Market (May 8, 2025) at 236–237.

pricing in the capacity market, these market conditions and PJM's market rules have resulted and will continue to result in very high capacity market prices by PJM capacity market historical standards. The market conditions and structural market power increase the potential impact of market power on customers under the current market structure.[7] The proposed Transaction will increase structural market power in the PJM Capacity Market.

C. Behavioral Conditions Are Necessary to Reduce the Probability that the Transaction Will Result in the Exercise of Market Power.

In order to ensure that market power is not exercised as a result of the Transaction, if the Transaction is approved, the Market Monitor recommends the following behavioral conditions:

1. A commitment, for all resources owned or controlled by NRG, to develop cost-based offers using a fuel cost policy that passes the Market Monitor's review and to limit price-based offers to a markup no greater than $1 per MWh, will prevent the exercise of aggregate and local market power in the energy market.
2. A commitment, for all resources owned or controlled by NRG, to refrain from using crossing price and cost-based energy market offer curves (markup switching) will ensure that a price-based offer curve with a high markup will not be chosen by PJM's least cost offer determination when a resource has local market power as determined by the TPS test.
3. A commitment, for all resources owned or controlled by NRG, to submit only operating parameters based on physical limits, as defined in the PJM tariff, in the energy market will ensure that NRG cannot use market power to operate inflexibly during weather alerts, emergencies, and periods when its units have market power.

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[7] *See* reports analyzing the 2025/2026 PJM Base Residual Auction. Monitoring Analytics, L.L.C., *Analysis of the 2025/2026 Base Residual Auction*, Parts A through G,, <*https://www.monitoringanalytics.com/reports/Reports/2024.shtml*> *and* <*https://www.monitoringanalytics.com/reports/Reports/2025.shtml*>.

4. A commitment, for all resources owned or controlled by NRG, to only give notice of retirement if the unit is expected to be uneconomic, defined to mean that projected avoidable costs exceed projected net revenues, after accounting for identified risks.
5. A commitment, for all supply owned or controlled by NRG, to submit capacity market offers that do not exceed net avoidable costs will help ensure that capacity market offers are competitive, even if the PJM market rules change.
6. A commitment, for all supply owned or controlled by NRG, to offer the full ICAP MW equivalent of all their cleared UCAP capacity MW in the day-ahead and real-time energy markets every day.
7. A commitment, for all demand response resources owned or controlled by NRG, to base energy offers, including the pre-emergency and emergency demand response strike price, on the documented cost of dispatch, and base all capacity market offers for demand response on the documented annual net avoidable cost of the resources' participation in the demand response program.
8. Require the emergency and pre-emergency demand resources to offer in the capacity markets following the Transaction.
9. A commitment to not remove resources from the PJM market to serve co-located load behind the generator's meter until FERC policy on co-location is clearly established and unless explicitly permitted by Commission policy will prevent withholding and will help ensure continued competitive results in PJM markets.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: July 3, 2025

ATTACHMENT

Monitoring Analytics

PUBLIC

Market Power Analysis: NRG / LS Power Transaction

The Independent Market Monitor for PJM

July 3, 2025

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Table of Contents

Introduction

This report was prepared by PJM's Independent Market Monitor (IMM). The report provides an assessment of the impact of NRG's proposed purchase of certain assets in PJM from LS Power ("LS Assets") on the structure of the PJM energy and capacity markets and its implications for local and aggregate market power in both markets. FERC's approach to merger policy applies to acquisitions like this one. In conducting this analysis the IMM used market data including market shares and the results from the PJM test for structural market power, the three pivotal supplier test (TPS). The IMM used market data to define the relevant markets and to examine the effects of the proposed acquisitions on those markets.

The LS Assets in PJM include 7,383 MW of gas fired generation in the AEP, APS, ATSI, ComEd, Dominion, and MetEd Zones of PJM. {**BEGIN CUI//PRIV} REDACTED {END CUI//PRIV}**. NRG's assets in PJM consist of 2,092 MW of generation, including coal fired, gas fired, and oil fired resources in the ComEd, DPL, and Pepco Zones. **{BEGIN CUI//PRIV} REDACTED {END CUI//PRIV}.**

Table 1 shows all generation units included in the LS Assets in PJM, the control zone where they are located, the summer rating, the fuel type and the technology type. Table 1 also shows all emergency/pre-emergency and economic demand response resources included in LS Assets in PJM, the control zone where they are located and the installed capacity.

Table 1 LS Assets

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The NRG acquisition of LS Assets increases NRG's market power in the aggregate energy market and local energy markets as measured by NRG's pre and post acquisition market share and pivotal supplier test scores. The NRG acquisition of LS Assets decreases overall market power in the aggregate energy market as measured by the decrease in the hourly average HHI and the decrease in the frequency of companies, other than NRG, failing the aggregate energy market pivotal supplier test. The NRG acquisition of LS Assets increases NRG's market power in the capacity market as measured by NRG's pivotal supplier score. NRG currently has market power in the PJM energy and capacity markets, and adding the LS Assets increases that market power. In addition, the NRG acquisition of LS Assets increases NRG's market power in the capacity market based solely on the acquisition of the emergency and pre-emergency demand resources which increase NRG's demand side market share very significantly.

The IMM recommends behavioral remedies that would address flaws in PJM's energy local market power mitigation rules and help ensure that NRG cannot exercise market

power as a result of the LS Assets acquisition. The IMM's behavioral remedies would also protect against potential exercises of market power in the capacity market and in the aggregate energy market.

Sufficiency of PJM Market Power Mitigation

In Section 203 applications and market based rate applications, the Commission relies on the sufficiency of the market monitoring and market power mitigation provisions in the RTO's tariff to mitigate local market power within the RTO region.[1] If the market monitoring and market power mitigation provisions in the RTO's tariff are insufficient, detailed analysis of submarkets created by constraints within the RTO is necessary and any market power created or enhanced by the merger or acquisition requires explicit mitigation to ensure market power is not exercised.[2]

As the PJM markets have evolved, the IMM has identified significant flaws in the market power mitigation provisions of the PJM tariff. Some flaws permit market participants to evade the explicit intent of the PJM market power mitigation rules. Other flaws are gaps in the PJM market power mitigation rules. The overstated Market Seller Offer Cap (MSOC) in the capacity market permitted market power to be exercised for a period.[3] The Commission issued an order in Docket EL19-47 to remedy the market power mitigation issues in the capacity market.[4] PJM again filed to weaken the market power mitigation rules and FERC accepted the changes by permitting standalone CPQR offers without net revenue offsets and permitting segmented offer curves.[5] Given that the Commission has just approved these rules, the IMM will challenge specific noncompetitive offers if and when they occur.

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1 *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 P 241 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055 (2008).

2 Order No. 697-A at P 111.

3 *See* "Analysis of the 2022/2023 RPM Base Residual Auction,"<http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022). "Analysis of the 2022/2023 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf> (January 13, 2023).

4 *See Independent Market Monitor for PJM v. PJM*, 176 FERC ¶61,137 (2021), *reh'g denied*, 177 FERC ¶ 62,066 (2021), *further order on reh'g*, 178 FERC ¶61,121 (2022), *aff'd*, Vistra Corp. et al. v. FERC, Case No. 21-1214 et al. (D.C. Cir August 15, 2023), *cert. pending*.

5 *See PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,117 (2025); *reh'g pending*, Docket No. ER25-785-000.

On October 25, 2024, the Commission ordered changes to PJM's market power mitigation process in the energy market that would remedy the flaws identified by the IMM, but PJM has failed to set an implementation date and has no specific deadline for doing so. The IMM recommends immediate implementation of the new rules. The IMM's recommended behavioral remedies for local market power in the energy market in this report resolve the same issue as the rules approved by FERC without an implementation date. But even correction of the flaws in the application of local market power mitigation rules would not address aggregate market power in the energy market, which occurs when a limited number of suppliers are pivotal for meeting daily demand, and the incentives to exercise market power. PJM has no market power mitigation in place for aggregate market power in the energy market.

Summary

The Transaction increases market power in the PJM markets. Both companies have local market power created by binding constraints in the PJM energy and capacity markets before the transaction. The Transaction increases NRG's market power and decreases LS Power's market power. The sale of the LS Assets to NRG increases local market power for some constraints and reduces local market power for other constraints. When examining only the energy market, the transaction slightly reduces overall market concentration at the aggregate market level. However, the transaction increases overall capacity market concentration at the aggregate level. An increase in capacity market concentration also translates into an increase in market power in the energy market on high load days when PJM requires all capacity to be available to serve load. The Transaction substantially increases NRG's market share in the emergency and pre-emergency demand resource market with a corresponding impact on the capacity market.

The IMM analyzed the effect of the NRG purchase of the LS Assets on market power in the PJM aggregate energy market and local energy markets using data from April 2024 through March 2025. The IMM analyzed the effects of the NRG purchase of the LS Assets on market power in the PJM Capacity Market using auction data for the 2024/2025 and 2025/2026 Base Residual Auctions. The transaction increases NRG's market power in all these markets.

The IMM does not oppose the proposed Transaction, with the condition that any order approving the Transaction requires specific behavioral commitments by the resulting entity, none of which creates a burden on applicants because all are designed to help ensure competitive behavior. Absent the acceptance of the identified conditions, the IMM opposes the Transaction.

Aggregate Energy Market

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- There are no rules in the PJM tariff to address aggregate market power in the energy market.

Local Energy Markets

- For the following constraints, with the acquisition of LS Assets, NRG would have an increase of 50 hours or more in which they failed the TPS test in the real-time energy market from April 2024 through March 2025.
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- There are identified issues with PJM's market power mitigation rules for local market power that allow suppliers to exercise market power. The IMM's behavioral recommendations address these issues.

Capacity Market

- The IMM analyzed the 2024/2025 and 2025/2026 BRA results to measure the effect of the acquisition on the PJM Capacity Market, including both generation and emergency and pre-emergency demand resources.
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- **REDACTED.**
- **{END CUI//PRIV}**
- The IMM's behavioral recommendations address the issues of competitive offers in the capacity market.

Behavioral Recommendations

The IMM recommends that behavioral rules apply to NRG's energy and capacity market offers to help ensure that market power mitigation is effective in preventing the exercise of market power. None of the commitments creates a burden on the company because all are designed to ensure competitive behavior.

Summary of Behavioral Recommendations

1. Develop cost-based offers using a fuel cost policy that passes the Market Monitor's review and to limit price-based offers to a markup no greater than $1 per MWh.
2. Refrain from using crossing price and cost-based energy market offer curves (markup switching).
3. Submit only operating parameters based on physical limits, as defined in the PJM tariff, in the energy market.
4. Only give notice of retirement if the unit is expected to be uneconomic, because projected avoidable costs exceed projected net revenues, after accounting for identified risks.
5. Submit capacity market offers that do not exceed the net avoidable cost rate, which is the definition of a competitive offer.
6. Offer the full ICAP MW equivalent of all their cleared UCAP capacity MW in the day-ahead and real-time energy markets every day.

7. Base economic demand response offers and the pre-emergency and emergency demand response strike price on the cost of dispatch, and base all capacity market offers for demand response on the annual net avoidable cost of the resources' participation in the demand response program.
8. Require the emergency and pre-emergency demand resources to offer in the capacity markets.
9. Do not remove resources from the PJM market to serve co-located load behind the generator's meter unless explicitly permitted by Commission policy.

Cost-based Energy Market Offers

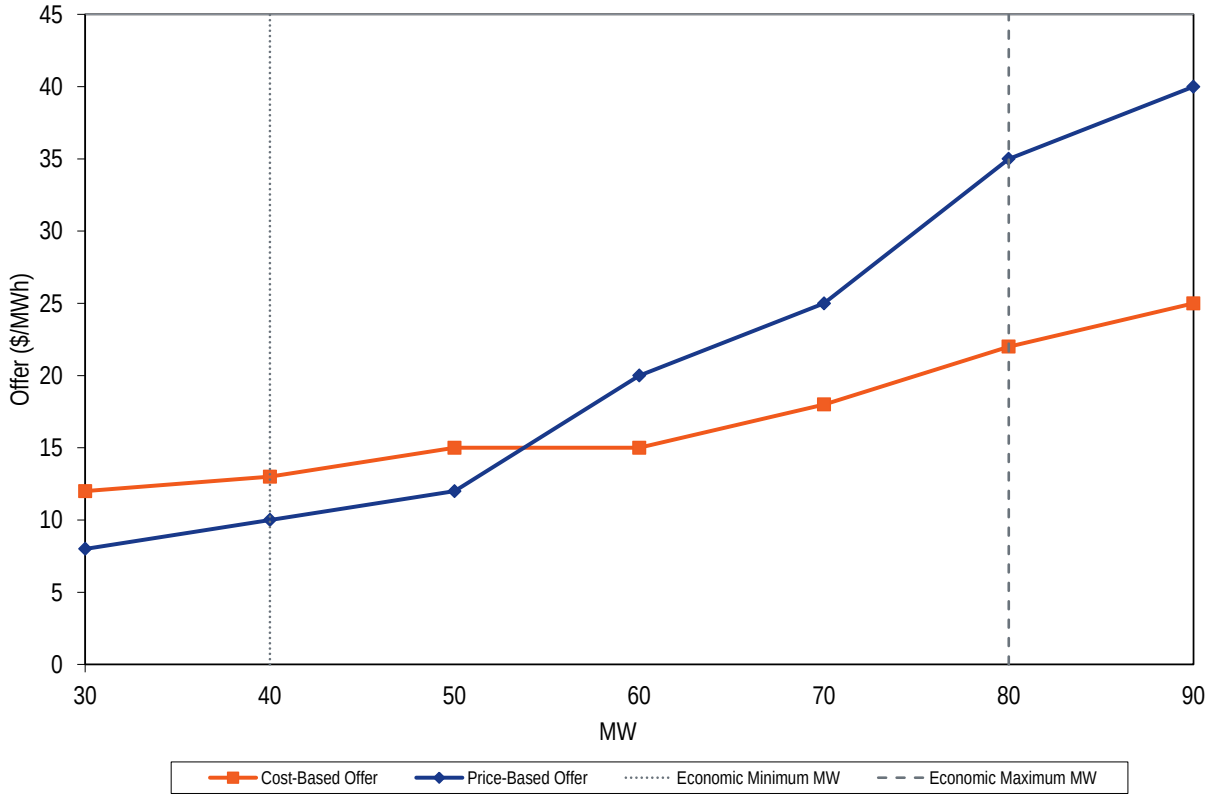
As a result of the transaction, NRG will have market power more frequently in the aggregate energy market. The PJM energy market has no market power mitigation rules for aggregate market power. To ensure competitive energy market offers, the IMM recommends that NRG always develop cost-based offers using a fuel cost policy that passes the IMM's review and limit price-based offers to a markup no greater than $1 per MWh.

No Crossing Curves (No Mark Up Switching)

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, suppliers with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Even when resources fail the TPS test, PJM frequently selects the price-based offer with the high markup based on its negative markup at low output levels. This occurs because PJM chooses between the price-based offer and the cost-based offer considering only the offers at the economic minimum output level in the real-time market and only the offers up to the projected dispatch point in the day-ahead market.[6] Figure 1 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer, even though the price-based offer is higher than the cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation. Frequently, resources with crossing curves committed on the price-based offer are dispatched into the high markup range of the offer curve, allowing the exercise of market power.

[6] On October 25, 2024, in Docket ER24-2905, the Commission approved a new method for selecting among price and cost schedule that would resolve this issue, but PJM has not set an implementation date. The behavioral commitment is needed until implementation.

Figure 1 Offers with varying markups at different MW output levels



Physical Operating Parameters

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, for a defined set of technologies, must include defined unit specific parameters, termed parameter limited schedules.

All resources that choose to make price-based offers are required to make available at least one price-based parameter limited offer with the same parameters as the cost-based offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.[7]

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of

[7] *See* PJM Operating Agreement, Schedule 1, Section 6.6.

the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. [8] Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. This occurs because PJM chooses between the price-based offer and the cost-based offer considering only the offers at the economic minimum output level in the real-time market and only the offers up to the projected dispatch point in the day-ahead market, and does not consider all of the physical operating parameters. The result is that PJM frequently selects price-based offer schedules with inflexible parameters for resources that have market power.

Market Seller Offer Cap

For capacity market offers, NRG should be required to use a market seller offer cap equal to its net Avoidable Cost Rate (ACR).

The net ACR is the marginal cost of capacity and is the competitive offer for a capacity resource.

Generation Retirement

The PJM Capacity Market has become tight in recent auctions, and any generation retirements can have a significant effect on the market. Given the increase in NRG's market power in the capacity market due to the transaction, the IMM recommends that, NRG only give notice of retirement if analysis shows that the resource is expected to be uneconomic, defined to mean that projected avoidable costs exceed projected net revenues, after accounting for identified risks.

Energy Market Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy markets, or report an outage for the difference.[9] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement. PJM's current enforcement of the ICAP must offer requirement is inadequate. The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation. NRG should be required to offer the full ICAP MW equivalent of all their cleared UCAP capacity MW in the day-ahead and real-time energy markets every day.

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[8] On October 25, 2024 in Docket ER24-2905, the Commission approved a new method for selecting among price and cost schedule that would resolve this issue, but PJM has not set an implementation date. The behavioral commitment is needed until implementation.

[9] OA Schedule 1 § 1.10.1A(d).

Demand Response Offers

The PJM tariff has no rules to ensure that demand response offers are competitive. Given the increase in NRG's market power due to the acquisition of demand response resources in the transaction, the IMM recommends that NRG base all demand response energy offers, including the pre-emergency and emergency demand response strike price, on the documented cost of dispatch. The IMM also recommends that NRG base all capacity market offers for demand response on the documented annual net avoidable cost of the resources' participation in the demand response program. The IMM also recommends that the must offer obligation applicable to all other capacity resources also apply to emergency and pre-emergency demand resources.

Co-located Load

Bilateral co-location contracts have the same effect as a retirement on PJM markets, in addition to exacerbating effects associated with back up arrangements and the shifting of the costs of transmission and ancillary services. NRG should agree not to pursue any co-location arrangements where the load is behind the generator's meter until FERC policy on co-location is clearly established and such arrangements are explicitly permitted by Commission policy. Any such proposed co-location agreement should be treated as a retirement and follow the same rules for resources that plan to retire.

Methods of Analysis

In analyzing whether a proposed merger or acquisition is consistent with the public interest, the Commission considers the "effect of the transaction on competition, rates, and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction."[10] In this report, the IMM focuses on the first factor, the effect on competition, measured by the impact on the structure of relevant markets based on actual market data. The IMM evaluates the impact of the merger or acquisition using pivotal supplier analysis and concentration thresholds.

Any analysis of market structure depends on an accurate definition of the relevant markets. Market definitions depend on properly identifying and evaluating potential substitutes for a given product. Within organized markets data are available, and should be used, to define markets based on how the units are evaluated and dispatched to meet demand, based on network relationships between resources and load, relative costs, availability and operational parameters. Such an approach provides definitions of the relevant markets based on actual operational data related to the participants and the markets in which they operate.

In the IMM analysis, the definition of the relevant local markets for the time period of the analysis is based on the actual substitutability among available, relevant resources which

[10] 18 CFR § 33.2(g) (2024).

in turn is based on the physical facts of the system and how the PJM markets defined the substitutability among available resources in the relevant markets over the analysis period. Rather than limit the analysis to a predefined range of load and price levels, the IMM has analyzed the actual relevant markets defined by constraints in the real-time look ahead tool used by PJM to identify structural market power, known as Intermediate Term Security Constrained Economic Dispatch (IT SCED). The relevant PJM submarkets defined in this analysis are those local energy markets created by transmission constraints within the broader PJM market that occurred for one hundred or more hours from April 2024 through March 2025. The relevant capacity markets in this analysis are those that resulted from the actual operation of the markets for the 2024/2025 and 2025/2026 Delivery Years, the last two Base Residual Auctions run by PJM.

The IMM analysis of the relevant markets reflects the information available based on the actual operation of the PJM wholesale power markets, rather than static market definitions that ignore dynamic changes in constraints. For different resources and different time periods, market conditions would change, and the relevant identified local markets would change. The information used to prepare the analysis included in this report is highly confidential and market sensitive as it relates to specific market participants.[11]

While analysis of actual markets is limited by available data and actual market dynamics, the nature of PJM markets means that those market dynamics will change, in unpredictable ways. Consideration of the impacts of mergers and acquisitions must also consider changing market structures. Consolidating ownership of assets in smaller numbers of owners will always increase structural market power. Structural remedies based on the recent history of market structures cannot remedy that fact. If further concentration of ownership is accepted, strong behavioral remedies are the only way to help mitigate the impacts of increased concentration on competitive outcomes. The Commission's merger policy does not address longer term trends in concentration or define a maximum level of concentration that is consistent with competitive outcomes.

Merger Standards

For the evaluation of the impact of a merger or acquisition on competition, FERC adopted the 1992 Horizontal Merger Guidelines ("1992 Guidelines") as the analytical framework as described in the Competitive Analysis Screen relied on by the Commission.[12]

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11 *See* OATT Attachment M–Appendix § I.

12 *See Order Adopting Guidelines for the Submission of Documents in Electronic Form*, Order No. 642, 93 FERC ¶ 61,177 *mimeo* at 4–*5* (November 15, 2000) ("Order No. 642"); U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (1992, revised April 8, 1997). DOJ and FTC modified their guidelines in 2010, increasing their HHI and market share thresholds and expanding the criteria used to define the relevant market. U.S. Dept. of Justice & Federal

The Commission reserves the opportunity to consider alternative approaches for analyzing the impact of proposed mergers and acquisitions, including pivotal supplier analyses similar to the analysis included in this report, when evaluating proposed mergers and acquisitions in PJM.[13]

The 1992 Guidelines presented the enforcement policy of the Department of Justice and the Federal Trade Commission concerning horizontal mergers subject to section 7 of the Clayton Act, Section 1 of the Sherman Act, and Section 5 of the Federal Trade Commission Act. As noted in the 1992 Guidelines, "[t]he unifying theme of the Guidelines is that mergers should not be permitted to create or enhance market power or facilitate its exercise."[14]

The Commissions' Competitive Analysis Screen, based on the 1992 Guidelines, uses market concentration, measured by the HHI, as a basic metric of the structural competitiveness of a market. The 1992 Guidelines define three basic levels of market concentration while recognizing that "[o]ther things being equal, cases falling just above and just below a threshold present comparable competitive issues."[15] A market with an HHI of less than 1000 is considered to be unconcentrated. Mergers and acquisitions resulting in HHI level less than a 1000 are not considered to have adverse competitive effects. A market with an HHI between 1000 and 1800 is considered to be moderately concentrated. A merger or acquisition resulting in a moderately concentrated market is not considered to have an adverse effect on competition if it increases the market's HHI by less than 100 points. A merger or acquisition resulting in a moderately concentrated market is considered to "potentially raise significant competitive concerns" if it increases the market's HHI by 100 points or more.[16] A market with an HHI of 1800 or above is considered to be highly concentrated. A merger or acquisition resulting in a highly concentrated market is not considered to have an adverse effect on competition if it

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Trade Commission, "Horizontal Merger Guidelines" (August 19, 2010). FERC considered whether to revise its policies to follow the DOJ and FTC 2010 modifications, but decided, after notice and inquiry, to retain the 1992 Guidelines. *See Analysis of Horizontal Market Power*, 138 FERC ¶61,109 (2012).

13 *See Id*. at P 38 ("We reiterate, however, that the Commission may consider arguments that a proposed transaction raises competitive concerns that have not been captured by the Competitive Analysis Screen. Likewise, while applicants must continue to provide a Competitive Analysis Screen, we will also consider any alternative methods or factors, if adequately supported."); *Exelon Corporation, NRG Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012).

14 1992 Guidelines at 2.

15 1992 Guidelines at 15.

16 *Id*. at 16.

increases the market's HHI by less than 50 points. A merger or acquisition producing an increase in the market HHI of 50 points or more in a highly concentrated market "potentially raises significant competitive concerns."[17]

In a market with an inelastic demand curve, the existence of two, or three, jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[18]

Higher concentration ratios indicate that comparatively small numbers of sellers dominate a market while lower concentration ratios mean larger numbers of sellers split market sales more equally. Lower aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. Higher concentration ratios do, however, indicate an increased potential for participants to exercise market power and an increased incentive to exercise market power. Despite their significant limitations, concentration ratios provide some useful information on market structure.

Notwithstanding the HHI level, a supplier may have the ability to raise market prices. If reliably meeting demand requires a single supplier, that supplier is pivotal and has monopoly power. If a small number of suppliers are jointly required to meet demand, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market. A single generation owner is pivotal if the output of the owner's generation facilities is needed to meet demand. Multiple generation owners are jointly pivotal when the output of the owners' generation facilities, taken together, is needed to meet demand. When a generation owner is pivotal, it has the ability to affect market price. For a given level of market demand, the RSI compares the market supply, net of the supply controlled by one or more generation owners, to the market demand. The RSI value is calculated as a ratio, where total supply minus the supply of the tested

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17 *Id.*

18 For detailed examples, see Joseph E. Bowring, PJM Market Monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006). <http://www.monitoringanalytics.com/reports/Presentations/2006/20061220-combined-regulation-market-mic.pdf>.

suppliers is divided by the market demand. If the RSI is greater than 1.00, the supply of the specific generation owner(s) is not needed to meet market demand and that generation owner(s) has a reduced ability to influence market price. If the RSI is less than 1.00, the supply owned by the specific generation owner(s) is needed to meet market demand and the generation owner(s) is a pivotal supplier with an ability to influence price. When the RSI is reported for a market, the reported RSI is for the largest supplier or identified number of the largest suppliers.

FERC indicates that a single supplier RSI of less than 1.0 is an indicator of market power.[19] In the PJM markets a three pivotal supplier RSI of less than 1.0 defines the existence of local market power. The three pivotal supplier test (TPS) defines market power even in the presence of market share and concentration levels that fall below 1992 Guidelines for a competitive market structure.[20] The TPS test uses a broader definition of competitors than FERC's single pivotal supplier approach.

Three Pivotal Supplier Test

In the IMM analysis, the basic metrics used for each market include market share, the Herfindahl-Hirschman Index (HHI), and the three pivotal supplier test (TPS), a residual supplier index used in the PJM markets to define locational market power. Market share measures the proportion of market output contributed by a supplier. Market share is calculated by dividing the output of a supplier by total market output. Concentration ratios are a summary measure of market share. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market.

The IMM uses the three pivotal supplier test as the key measure of market structure and structural market power. The three pivotal supplier test is used in PJM markets to define the existence of local market power and as a trigger for market power mitigation. A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate.

The three pivotal supplier test, as implemented in PJM markets, is consistent with the Commission's market power tests, encompassed in the Delivered Price Test, which is the central calculation of the Competitive Analysis Screen required by the Commission. The three pivotal supplier test is used by PJM for market power mitigation in the real-time energy market, the day-ahead energy market, the regulation market, and the capacity market. Like the Delivered Price Test, the three pivotal supplier test considers the

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19 *See Midwest Independent Transmission System Operator, Inc.*, 121 FERC ¶ 61,190 at P 6 n.5 (2007).

20 *See AEP Power Marketing, Inc., et al.*, 107 FERC ¶ 61,018 at P 111 (2004) ("AEP Order").

interaction between individual participant attributes and features of the relevant market structure. Unlike the Delivered Price Test, the three pivotal supplier test takes into account the incremental ability of resources to affect prices in a constrained area from both the loading and relief sides of the constraint. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action which accounts for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 or less than 1800. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. An HHI in excess of 2500 does not indicate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not indicate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[21]

The three pivotal supplier test was designed in light of actual elasticity conditions in constrained areas in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[22] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very

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[21] For detailed examples, see Joseph E. Bowring, PJM Market Monitor, "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006) <http://www.monitoringanalytics.com/reports/Presentations/2006/20061220-combined-regulation-market-mic.pdf> .

[22] AEP Order at P 72.

> responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response. [23]

TPS Test: Defining the Relevant Market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the producer to raise price while continuing to sell its output. A producer cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The Commission definition of the relevant market includes all suppliers with cost-based offers less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with cost-based offers less than, or equal to, $210 per MWh are defined to have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The TPS definition of the relevant market includes all suppliers with cost-based offers less than or equal to 1.50 times the clearing price. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh are defined to have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier test incorporates a definition of meaningful competitors that is at the extreme high end of inclusive. It is questionable whether a unit with a competitive offer price of $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to

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[23] *Id*. at P 103.

relieve a constraint, as defined by PJM's market solution software. The market demand is the amount of incremental, effective MW required to relieve the constraint.[24] The market demand is calculated as the difference between the defined MW limit on flow across the constraint and the flow in an economic dispatch solution if the limit did not exist (unconstrained flow). The market supply consists of the incremental, effective MW of supply available to relieve the constraint. This includes resources that can ramp up or start up to provide relief for the constraint as well as resources that can ramp down to provide relief for the constraint. The sign of the distribution factor (dfax) of a resource with respect to the defined constraint indicates whether a resource would relieve the constraint by increasing or decreasing output. A resource with a positive dfax with respect to a constraint provides relief by reducing its output, and a resource with a negative dfax with respect to the same constraint provides relief by increasing its output. For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

Unlike structural tests that define markets by geographic proximity, the TPS test makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor greater than, or equal to, the dfax used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network, as measured by unit characteristics and distribution factors is included in the three pivotal supplier test. That supply is included only to the extent that it is incremental, effective MW of supply available at a price less than, or equal to, 1.5 times the clearing price that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

Constraints: Defining the Relevant Market

In its Order Reaffirming the 1992 Guidelines, the Commission stated:

> The Commission will remain flexible in its approach and will reevaluate whether a previously recognized submarket continues to exist if the evidence shows that the persistent

[24] A unit's contribution toward effective, incrementally available supply is based on the distribution factor (dfax) of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within the period that the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a dfax of -0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a dfax of -0.5 to the constraint would be 25 MW.

> transmission constraints that led to the recognition of that submarket are no longer present. We clarify that we will not require applicants to submit a DPT 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.[25]

NRG's Delivered Price Test considers the PJM RTO market, the submarkets recognized in previous 203 and Market Based Rates proceedings, and the West of Central Interface submarket which captures some constraints that bind more frequently in PJM in recent years. In addition, patterns of congestion and constraints will continue to be dynamic in PJM. It is important to analyze existing submarkets but also to address the fact that market power is persistent and may be actionable in submarkets that do not yet exist. While the NRG analysis extended to more submarkets than some recent 203 filings related to PJM, the IMM analyzed all submarkets based on historic market data, not only the subset of markets analyzed in the Applicants' Delivered Price Test analysis. The IMM analysis shows that NRG has local market power in PJM and that local market power will increase with the LS Assets acquisition.

The Commission's guidelines do not accurate reflect the ability to exercise market power in an LMP market, like PJM. Mergers and acquisitions can affect submarkets created by transmission constraints whether or not there is overlapping generation on the high price side of the constraint. The IMM analysis considers all available supply that can relieve a constraint regardless of its location.

The broader point about congestion is that it is dynamic and unpredictable. Submarkets in one period may not be submarkets in subsequent periods. The analysis of market power and of mergers should reflect these basic facts. Local market power may not exist in one period and may exist in the next. Local market power may exist in one period and not exist in the next. It is essential that merger reviews recognize that increased concentration of ownership creates the potential for market power beyond the specific facts of a specific period. It is essential for that reason to have clear, workable and enforceable rules for market power mitigation that can address the dynamic reality of PJM markets.

Energy Market Results

Aggregate Market Power

The IMM analyzed the impact of the proposed transaction on aggregate energy market concentration using actual generation data for April 2024 through March 2025.

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[25] *See Analysis of Horizontal Market Power*, 138 FERC ¶ 61,109 at P 43 (2012).

The concentration metrics are the market share for energy and the HHI for energy in the aggregate PJM market. The IMM also uses a pivotal supplier screen for the day-ahead energy market.

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Table 2 NRG's average hourly market share of PJM generation: April 2024 through March 2025

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Table 3 Energy market HHI: April 2024 through March 2025

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To assess the number of aggregate pivotal suppliers in the day-ahead energy market, the IMM determines, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable locational marginal price. Generating units, import transactions, economic demand response, and virtual supply ("INCs"), are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and virtual demand ("DECs"). A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

When NRG is a pivotal supplier in the energy market, it has the ability to raise prices in the energy market which benefits the inframarginal energy that it owns. There are no market power mitigation rules to address aggregate market power in the PJM energy market. Acquiring LS Assets would increase NRG's aggregate market power, increasing its incentive and ability to raise prices.

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Table 4 PJM Day-ahead aggregate energy market pivotal supplier frequency: April 2024 through March 2025

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Local Market Power

The IMM also analyzed the energy market results for the relevant submarkets defined by actual binding constraints for April 2024 through March 2025. The analysis identifies constraints for which NRG has market power, as shown by failures of the TPS test.

The TPS test considers incremental, effective MW available to provide relief to binding constraints in the energy market. LS Power and NRG's fleets frequently have incremental, effective MW available to provide constraint relief in PJM's energy market meaning that NRG has local market power as measured by TPS test failures both before and after the transaction.

Table 5 identifies the constraints on the PJM system that were binding for more than 100 hours during April 2024 through March 2025. It provides the number of hours for which NRG failed the TPS Test and the number of hours for which NRG would have failed the TPS Test with the acquisition.

Table 5 Constraints where NRG had market power as determined by the real-time energy market TPS test: April 2024 through March 2025

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Table 6 identifies the constraints on the PJM system that were binding for more than 100 hours during April 2024 through March 2025. It provides the average TPS score for NRG and the average TPS score NRG would have had with the acquisition.

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Table 6 Preaquisition and Postaquisition TPS scores for constraints where NRG had market power as determined by the real-time energy market TPS test: April 2024 through March 2025

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Demand Response Market Results

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market. Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.

Emergency and pre-emergency demand response are pivotal in the aggregate energy market on high load days. They have also been pivotal in the recent capacity market auctions. When PJM calls on the emergency and pre-emergency demand response in the energy market, all identified resources are expected to respond, and they enter the supply curve for energy at a strike price of up to $1,849 per MWh.[26] Emergency and pre-emergency demand resources are not subject to market power mitigation rules of any kind. There is no must offer obligation which allows physical withholding and there are no offer caps which allows economic withholding. This absence of market power mitigation rules is much more significant now than ever before in the history of the PJM Capacity Market as a result of the fact that demand resources are included in the reserve margin for the first time ever in the 2025/2026 Delivery Year. The PJM Capacity Market would have been short of meeting the reliability requirement in the BRA for 2025/2026 but for these demand resources. In addition, the rules governing the actual calling of these demand resources by PJM are not clear and are inconsistent with the rules governing other capacity resources. Finally, the rules governing the required response by demand resources when called are weak and do not actually require a defined level of reduction.

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Table 7 NRG Demand Response Market Share

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[26] For more details on the distribution of the DR strike price, see Monitoring Analytics, L.L.C., *2025 Quarterly State of the Market Report for PJM: January through March*, Section 6: Demand Response at Table 6-21.

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The HHI for emergency and pre-emergency demand resources shows that ownership is highly concentrated both prior to and following the proposed acquisition. Table 10 shows the HHI value for committed UCAP MW by LDA for demand resources. The proposed acquisition results in significant increases in HHI in a market that is already highly concentrated. Pre-acquisition HHI values range from 2251 to 4581. **{BEGIN CUI//PRIV} REDACTED {END CUI//PRIV}**

Table 8 HHI value for committed UCAP MW by LDA

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Capacity Market Results

Market Design

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007. The RPM Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources. Recent changes to the market power mitigation rules include ending the categorical exemption from the must offer requirement for intermittent and storage resources.[27] Capacity storage resources include hydroelectric, flywheel and battery storage. Intermittent resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. Demand resources remain exempt from the must offer requirement. In addition, the Commission recently approved the inclusion of standalone CPQR offers with no net revenue offset and segmented offers based on CPQR, both of which were opposed by the Market Monitor as undermining market power mitigation.[28]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future, although recent events have resulted in shorter lead times for BRAs. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year if there is time available.[29]

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27 *See* 190 FERC ¶ 61,117.

28 *See id*.

29 *See* 126 FERC ¶ 61,275 at P 86 (2009).

RPM prices are locational by LDA and may vary depending on transmission constraints between LDAs and local supply and demand conditions within LDAs.[30] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation on the demand side by LSEs is mandatory, except for those entities that elect the FRR option. Load must buy all cleared capacity. There is an administratively determined demand curve that defines shortage pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power using the three pivotal supplier test, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources may be offered directly into RPM auctions and receive the clearing price without mitigation. Demand resources may exercise market power under the existing rules.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand.[31] The capacity market, following the implementation of

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30 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

31 Recent reports by the Market Monitor explain many of the current issues in the capacity market design. See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) ("IMM BRA Report Part A"). <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>; "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) ("IMM BRA Report Part B") <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf> ; "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (November 6, 2025) ("IMM BRA Report Part C") <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>; "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) ("IMM BRA Report Part D") <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>; "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025) ("IMM BRA Report Part E") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>; "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) ("IMM BRA Report Part F") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>; "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) ("IMM BRA Report Part G")

PJM's approach to the ELCC definition of capacity, is much tighter. Local LDA markets may have different supply demand balances than the aggregate market. Demand is inelastic because the market rules require loads to purchase the system capacity requirement. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. Given the basic features of the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the potential for the exercise of market power is high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market.

Nonetheless, a competitive outcome can be ensured by appropriate market power mitigation rules. Attenuation of those rules would mean that market participants would not be able to rely on the competitiveness of the market outcomes. The market power rules are not perfect and, as a result, competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. One of the key gaps in current market power mitigation rules in the capacity market is the entire absence of any rules that apply to emergency and pre-emergency demand resources. Specifically, there is no must offer obligation which allows physical withholding and there are no offer caps which allows economic withholding. This absence of market power mitigation rules is much more significant now than ever before in the history of the PJM Capacity Market as a result of the fact that demand resources are included in the reserve margin for the first time ever in the 2025/2026 Delivery Year. The PJM Capacity Market would have been short of meeting the reliability requirement in the BRA for 2025/2026 but for these demand resources. In addition, the rules governing the actual calling of these demand resources by PJM are not clear and are inconsistent with the rules governing other capacity resources. Finally, the rules governing the required response by demand resources when called are weak and do not actually require a defined level of reduction.

The capacity market currently has explicit market power mitigation rules designed to permit competitive, locational capacity prices based on limiting the exercise of market power. The capacity market construct has been consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions based on explicitly limiting market power. The capacity market design provides that

<https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.

competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test and the resultant offer capping. The efficacy of the market power mitigation rules under recent rule changes remains to be seen and cannot be assumed. The modifications to the nature of the demand curve by PJM also create significant issues and have resulted in market prices above the competitive level.[32]

On February 20, 2025, FERC issued an order accepting proposed rules in Docket No. ER25-785-000 which became effective February 21, 2025, beginning with the 2026/2027 Delivery Year. The rule changes include elimination of the categorical RPM must offer exemption for Intermittent Resources, Capacity Storage Resources, and Hybrid Resources; modifying the Market Seller Offer Cap definition to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR); and modifying the Market Seller Offer Cap definition to include segmented unit specific offer caps. The filing highlights the fact that market power mitigation rules are uncertain. The inclusion of offers based on standalone CPQR and segmented offers both undermine market power mitigation.[33]

Market Analysis

The analysis of the impact of the NRG acquisition of LS Assets on the capacity market examines the locational markets defined by the underlying economics of the market including supply and demand curves and transmission constraints. Each transmission zone is a Locational Deliverability Area (LDA) which can be a separate submarket if PJM models the zone as an LDA and market conditions result in binding transmission constraints and associated price separation in an auction. There are, in addition, several defined subzonal LDAs, including PSEG North, DPL South, and ATSI Cleveland.

For the defined submarkets, market concentration and HHI levels were calculated on a preacquisition and a postacquisition basis for each market.

As in the energy market, to the extent that total RTO demand for capacity can be met without any constraints binding, the optimal solution is defined by the intersection of the aggregate supply and demand curves. However, if the next increment of demand for capacity in an LDA cannot be met by the next economic increment of total supply and must be met by higher cost supply within the LDA, then the transmission constraint is binding and there is a separate market created. That separate market is defined by the

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32 *See* IMM BRA Report Part A, IMM BRA Report Part B and IMM BRA Report Part C.

33 *See* Comments of the Independent Market Monitor for PJM, Docket No. ER25-785-000 (January 10, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-785-000 (February 18, 2025); Request for Rehearing of the Independent Market Monitor for PJM, Docket No. ER25-785-000 (March 19, 2025).

incremental demand that must be met by capacity within the LDA and the higher cost incremental supply within the LDA available to meet that demand.

The ability to exercise market power in the LDA is determined by the ownership structure of the incremental supply and the relationship between incremental supply and incremental demand. The incentive to exercise market power in the LDA is a function of the ownership structure of all capacity in the LDA. Regardless of offer price and regardless of whether the capacity was incremental, all capacity in a constrained LDA receives the higher constrained clearing price. The ability to exercise market power can be measured most accurately by the TPS test while the HHI provides a measure of the incentive to exercise market power.

When the capacity market clears as a single market, total RTO supply and demand determine the clearing price and all resources receive the single market clearing price. When an LDA within the RTO clears as a separate market, the incremental locational supply available to meet the locational demand determines the clearing price for the LDA. All capacity resources in the LDA receive the single locational market clearing price, regardless of whether the capacity resources are incremental.

When there are multiple LDAs that clear as separate markets and the LDAs are not overlapping, the logic is exactly the same for each LDA separately and its relationship to the rest of RTO.[34] [35] When the LDAs are nested, the analysis becomes more complex.

For this analysis, the actual sell offer prices and offered MW quantities in the 2024/2025 and 2025/2026 RPM BRAs were used.[36]

Aggregate Market: HHI

Table 9 shows pre and post NRG LS Assets acquisition HHIs for the 2024/2025 and 2025/2026 RPM Base Residual Auctions, including all modeled LDAs for each BRA. The HHIs in Table 9 measure concentration of ownership for all cleared capacity in the identified LDAs.

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[34] *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

[35] *See* the "Analysis of the 2024/2025 RPM Base Residual Auction," (October 30, 2023) <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf>.

[36] If the ownership of assets changed between the conduct of the BRA and the present, the current parent company ownership was used in both the preacquisition and postacquisition cases.

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Table 9 Preacquisition and postacquisition HHI

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Locational Capacity Markets: TPS

The pivotal supplier analysis uses the pre and postacquisition Three Pivotal Supplier test scores to measure the change in market power for the RTO and LDAs. Table 10 shows the preacquisition and postacquisition TPS scores for NRG and LS Power.

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The market for a constrained LDA is defined by the incremental supply available to meet the incremental demand when locational incremental demand must be met by capacity resources within the LDA. The RTO market is defined to include all supply that is not incremental supply in a constrained LDA. The RTO market includes all MW that resulted in the clearing price for the rest of RTO.

The three pivotal supplier (TPS) test measures the degree to which the incremental supply from three suppliers of capacity is required in order to meet the incremental demand in an LDA. In applying the TPS test in the capacity market, the relevant demand consists of the incremental MW of capacity required to relieve a constraint or clear a market. The relevant supply consists of the incremental MW of supply from generation resources available to relieve the constraint or clear the market. The supply does not include demand response resources.

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Table 10 Preacquisition and postacquisition TPS results for NRG and ECP

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 3rd day of July, 2025.

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