UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
NRG Power Marketing LLC	)	Docket No. ER22-1539-000
	)	

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"), submits this protest to the Reliability Must-Run Rate Schedule submitted by NRG Power Marketing LLC ("NRG") on April 1, 2022 ("Deactivation Filing"). [1] NRG has filed for a rate pursuant to Part V, Section 119, of the OATT to recover the costs of operating its Indian River Unit No. 4 ("Indian River 4") for a defined period after its desired deactivation date.[2] Continuing to operate is voluntary in PJM, assuming that it is demonstrated that the deactivation is not an exercise of market power.[3] The Market Monitor appreciates NRG's willingness to continue to operate, consistent with good utility practice and NRG's and PJM's reliability obligations. NRG has not, however, proposed just and reasonable compensation for operating the unit and its filing should be rejected. NRG should be directed to provide a rate for operating the unit pursuant to and consistent with Part V of the OATT.

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1 18 CFR § 385.211 (2021).

2 The term reliability must run ("RMR") is not defined in the PJM tariff.

3 *See* OATT § 113.1. The voluntary basis for continued operations is limited. The Market Monitor does agree with NRG's assertion (at 4) of an "unconditional right to deactivate units." Generating units are public utilities, and have reliability obligations and other obligations associated with that status. But generating units are not permitted to intentionally exercise market power. *See* 18 CFR § 1c.2.

NRG's filing does not meet the standard Part V establishes for PJM Generation owners seeking recovery of the costs to operate directly from the Commission. Part V provides that Generation owners "may file with the Commission a cost of service rate to recover the entire cost of *operating* the generating unit until such time as the generating unit is deactivated" (emphasis added).[4] Instead, NRG has instead filed what it asserts to be a traditional utility cost of service rate filing, pursuant to Section 205 of the Federal Power Act.[5]

If NRG's filing were accepted, NRG would recover a return on and of an investment that NRG determined to have no value when NRG informed PJM of NRG's decision to retire the unit on June 29, 2021.[6] NRG previously recognized in SEC filings that the value of Indian River 4 was impaired based on market conditions and therefore should be written down. But NRG proposes to reverse those impairments and recover a return on and of capital that NRG explicitly declared to have no value. NRG is not entitled to recovery on and of the sunk costs in Indian River 4. Sunk costs are not part of the cost of operating the unit.

It is not and cannot be just and reasonable to require customers to pay for assets that have zero market value. It is just and reasonable to require customers to pay the costs that NRG actually incurs to continue to operate.

NRG is pursuing a windfall in this filing based on PJM's need for reliability in the area that requires that Indian River 4 remain in service for four years and seven months (55 months) after the May 31, 2022, date which NRG specified on June 29, 2021, as its desired deactivation date ("Defined Period").[7] The PJM requirement for this unit gives the owner monopoly market power because PJM indicates that only this unit can meet PJM's reliability

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4 OATT § 119.

5 *See* Deactivation Filing at 9–12.

6 *See* Deactivation Filing, Attachment B. NRG previously announced the retirement of Indian River 4 on June 17, 2021 in a call with investors. NRG Energy Inc., Investor Day, Corrected Transcript at 19, which can be accessed at: <*https://investors.nrg.com/static-files/5b7e0190-ec30-478a-8890-1a4851ebec09*>.

7 Deactivation Filing at 5.

needs for this period. The purpose of the deactivation tariff provisions is to ensure both that Generation Owners' costs are covered and that customers are protected from the exercise of market power.

No fact finding hearing is required in order for the Commission to reject NRG's filing based on its filed approach. If NRG chooses to file a new proposal following a just and reasonable cost recovery approach, a hearing to review that approach would be appropriate.

I. COMMENTS

A. NRG Should Be Permitted to Recover the Costs of Operating But No More.

PJM ensures reliability at least cost through a regulatory regime based on competitive markets. In a competitive market, suppliers bear the risks associated with their assets and receive market revenues for their assets. This is in contrast to the traditional cost of service regime which was replaced by markets.

Section 119 provides for filing a cost of service rate to recover the entire cost of operating the generating unit for reliability at PJM's request. NRG conflates cost of service rate with an old fashioned cost of service rate case as if the Indian River 4 unit had always been a cost of service regulated unit rather than a merchant unit operating in the PJM markets. NRG proposes to ignore the actual market results for Indian River 4 and to pretend that the impairments of the asset did not occur and to require customers to pay for the sunk costs of an asset that has no market value. There is no basis in the tariff for the assertion that the entire cost of operating the unit can be defined by a quasi rate case approach, complete with a test year and going forward adjustments. There is no basis in the tariff for asserting that customers should be required to pay for the sunk costs of the asset. There is no basis in the tariff for asserting that customers should pay estimated costs based on a test year. There is no basis in the tariff for asserting that customers should pay for anything more or less than the actual costs of operating the unit to provide reliability to the PJM market.

The goal of payments for continuing to operate is to ensure that the generation owner recovers all the costs incurred to provide the service. Continuing to operate was not designed to permit asset owners to receive a windfall which was not available in the market.

Generation owners should receive just and reasonable compensation for continuing to operate, as provided for under the OATT.

NRG has acted consistent with its responsibilities in agreeing to continue to operate. This is not a reason to overlook NRG's market power in these circumstances. PJM has no alternative to keeping these units in service until it has implemented the transmission upgrades necessary to accommodate the proposed retirements. Any real or perceived ability for a generation owner to decide not to continue to operate does not mean that customers should be forced to pay an unjust and unreasonable rate.

NRG should receive full compensation for all of the costs it incurs to continue to operate, but no more.

Continuing to operate does not reverse NRG's retirement decision. It accommodates it. The payment to NRG comes within the framework of the PJM market rules and under the FERC approved PJM regulatory framework. Continuing to operate does not create a special alternative cost of service regulatory paradigm applicable to Indian River 4. Continuing to operate is not typical electric service (e.g., energy sales). Continuing to operate is not an opportunity to exercise market power, to reverse market based outcomes or a new profit opportunity. Continuing to operate addresses locational reliability issues. NRG proposes to include costs that are not costs to continue operating. The Deactivation Filing should be evaluated solely on the basis of the requirements and purposes of Section 119 and the Part V of the OATT.

Part V of the PJM OATT is designed to retain in service units that want to retire, with minimal operational commitments and with compensation to the owner for all the costs associated with remaining in service, until the retirement can be accommodated consistent with the reliable operation of the system. Section 114 states that deactivation avoidable cost credits support “continued operations” after the desired deactivation date. The design of Section 114 is indicative of the purpose and function of the whole of Part V.

Section 119 of Part V provides for recovery of the “entire cost of service of operating the unit” for the limited need defined by PJM. Section 119 provides an opportunity for a unit to receive a cost of service rate when an owner determines that the formula rate provisions in Section 114 are not adequate for its circumstances. Sections 114 and 119 provide different approaches to recovering the cost of operating the unit during the Defined Period. Section 119 does not allow for an entirely different definition of recoverable costs than is allowed under the parallel and alternative provision in Section 114. Sections 119 and 114 are intended to serve the same purpose, and these provisions should be interpreted and applied consistently.

The costs of operating the unit during the Defined Period do not include reversing an owner’s prior losses in competitive markets or reversing an owner’s decision to write down the value of its assets or failing to recognize that the assets have no market value. The tariff does not provide an option to exploit the need for the unit to operate to extract a windfall.

B. NRG’s Filing Would Impose Excessive Charges on Customers.

NRG explains that it seeks payment for continuing to operate, based on traditional cost of service principles.[8] NRG confuses cost of service principles with a traditional rate case for a regulated utility company with continuing obligations. According to NRG, the appropriate payment for the capacity of Indian River 4, based on NRG’s synthetic rate case approach, is more than three times higher than the PJM capacity market price for which Indian River 4 was eligible.

The requested customer payments consist in part of return on and of the sunk costs of assets with no value. Based on this approach, NRG requests guaranteed payment of $5,828,312.83 per month, or $69,939,753.96 per year, or $320,557,205.65 for the period. NRG

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8 *Id*. at 9–12.

also requests guaranteed payment of ongoing investments plus carrying charges, equal to an estimated $666,158.46 per month, or $7,993,901.56 per year or $36,638,715.50 for the period. The total requested customer payments are $357,195,921.15 for the period.

In terms comparable to the PJM capacity market clearing prices, NRG requests a guaranteed payment of $170,584.77 per MW-year or $467.36 per MW-day. That guarantee does not include the requested guaranteed payment of the additional costs of the investments that NRG states are required in order to maintain the unit. The investment costs would be paid in real time as incurred, plus carrying charges. The revenue required to pay for NRG's estimated investment costs of $36,215,000 plus associated carrying charges at the requested rate is an additional $19,497.32 per MW-year or $53.42 per MW-day. The estimated total revenue that NRG wants customers to pay for the capacity from Indian River 4 is $190,082.09 per MW-year, or $520.77 per MW-day for 55 months. This is a total payment by customers of $357,195,921.15 over the period.

To put the request in perspective, NRG's requested payment from customers of $520.77 per MW-day for capacity from Indian River 4 is more than three (3.30) times the cost of capacity in the PJM Capacity Market that would apply to this unit and therefore much more than this unit would ever have received in the PJM Capacity Market if it had cleared all its MW. The average capacity market clearing price in base auctions relevant to Indian River 4 for the last three base auctions was $157.79 per MW-day. NRG requests payment equal to 3.30 times the capacity market price. Actual payments could exceed this level if the actual investments in the unit exceed the estimate.

C. NRG Would Require Customers to Pay for Failed Investment.

NRG includes in the requested fixed monthly payment a return on and a return of the investment in Indian River 4 that has zero market value. Customers should not be required to make investors whole for their losses. Customer payments for the return on and of the sunk costs in Indian River 4 should be set to zero. Indian River 4 participated in PJM markets and made a decision to deactivate.

The guaranteed annual revenue that NRG wants customers to pay just for the failed investment is $42,256,853.00 per year, or a total of $193,677,242.92 for the period. The requested guaranteed payments by customers just for the failed investment equal $282.37 per MW-day or 1.79 times the price of capacity in the PJM Capacity Market.

In addition to the guaranteed revenue from the failed investment, the guaranteed annual revenue that NRG wants customers to pay for estimated O&M costs plus allocated and estimated overhead costs is $27,682,900.96 per year, or a total of $126,879,962.73 for the period. The requested guaranteed payments by customers for the estimated O&M costs plus allocated and estimated overhead costs equal $184.98 per MW-day or 1.17 times the price of capacity in the PJM Capacity Market.

D. Issues with Claimed Estimated Costs.

The Market Monitor supports full recovery for NRG of all costs spent to continue to operate during the Defined Period.

But all of the costs recoverable for continued operation for reliability should be subject to review and true up, regardless of whether they are higher or lower than the initial estimates. That is the only way to ensure that both NRG and the customers are treated fairly. There should be no payment for sunk costs. The O&M costs should be paid as incurred and not based on estimates using a rate case model with a test year and adjustments.

NRG has proposed to collect costs, in addition to sunk costs, through a fixed monthly payment despite the fact that these costs are estimates not subject to true up. The most significant of these costs are estimated fixed operating and maintenance expenses. Estimated fixed operation and maintenance expenses plus allocated and estimated overhead costs make up 39.6 percent of the guaranteed total fixed monthly payments in NRG's proposal.

These costs are inflated through adjustments proposed by NRG. There should be no guaranteed fixed payment. All the costs should be subject to review and true up. There should be no payment for an allocated share of corporate overheads. NRG is proposing that customers pay $5,868,704 per year in allocated corporate overheads for a total of $26,898,227 over the period.

The estimated capacity costs of operating Indian River 4 for the Defined Period, excluding the costs of the failed investment, and excluding overheads, are $136,620,456.33, or $199.19 per MW-day, or 1.26 times the price of capacity in the PJM Capacity Market. This is the estimated cost of fixed O&M from the NRG filing plus the estimated cost of project investment over the period with NRG's proposed recovery method. Both the O&M and the project investment plus carrying charges are overstated, but this is the maximum estimate of the actual costs of operating the unit, apart from the short run marginal costs including fuel, based on the incomplete data provided by NRG to date.

E. NRG Misunderstands the *GenOn* Case.

NRG cites the order approving a settlement in the *GenOn* deactivation case as precedent for its position that it is not limited to going forward costs.[9] But the case actually means exactly the opposite of NRG's assertion. The rate was approved in *GenOn* based on a determination that the approved rate was approximately equal to going forward costs.[10] The Commission accepted a rate excluding net plant and based on going forward costs as the standard of reasonableness.[11] NRG's filing includes a very significant level of claimed revenue based on net plant and does not meet the standard of reasonableness accepted by the Commission in *GenOn.* NRG's filing requests that customers pay revenues very significantly in excess of that standard. The Market Monitor did not argue in the *GenOn* case

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[9] Deactivation Filing at 6, citing *GenOn Power Midwest, LP*, 149 FERC ¶ 61,218 at P 34 (2014). NRG also cites to the order approving a deactivation filing for RC Cape May, LLC, but this matter was resolved in an order approving the settlement that does not establish precedent, and so is not properly relied upon to resolve any issue raised here. *See RC Cape May Holdings, LLC*, 162 FERC ¶ 61,194 (2018).

[10] *See* 149 FERC ¶ 61,218 at P 33. The settlement was approved as a just and reasonable package under *Trailblazer*, and did not include findings on the merits for individual issues.

[11] *Id*. at P 34.

and does not argue here that a unit owner must use the formula rates under Section 114 and cannot file a rate under Section 119. Part V offers a choice between Section 114 and Section 119. But Part V is not properly interpreted to offer a choice of entirely different regulatory paradigms. It should not be a matter in dispute that Section 119 is properly interpreted consistent with the nature and purpose of Part V of the OATT.

As the Deactivation Filing makes clear, Indian River 4's ordinary service life has ended and the Deactivation Filing does not provide for extending it. Costs incurred by Indian River 4 to provide full electric service before the decision to deactivate it do not properly belong in a rate to recover the costs of continuing to operate.

F. NRG Misunderstands the *Mystic* Case.

NRG asserts that its filing should be evaluated based on recent orders issued in the *Constellation Mystic Power* case.[12] NRG's reliance on the *Mystic* case is misplaced. The *Mystic* case was not decided within the framework of the PJM market rules. The case was not initiated under the ISO-NE market rules. The function of the *Mystic* units in ISO-NE is not the function of Indian River 4 in PJM.

The *Mystic* case involved whether certain units located in New England should receive subsidies in order to address winter fuel supply conditions unique to New England.[13] As a result of flawed capacity market rules, the *Mystic* units, which were proposed to be "de-listed" under the ISO-NE capacity market rules, were determined to be needed to ensure resource adequacy.[14] The units filed for cost of service rates under Section 205 of the Federal

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12 *See* Deactivation Filing at 10, citing *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (2018) ("*Mystic*"), *order on clarification*, 172 FERC ¶ 61,044 (2020).

13 *See* Deactivation Filing at 10, citing *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (2018) ("*Mystic*"), *order on clarification*, 172 FERC ¶ 61,044 (2020).

14 *See id.* at PP 7–8.

Power Act, outside of the then existing ISO-NE market rules.[15] Interim rules for ISO-NE were filed and subsequently applied.[16]

In approving interim rules in connection with the *Mystic* case, the Commission noted: "…fuel security resources may not necessarily need to be treated the same way in the FCM as reliability resources due to potentially 'material differences' between cost-of-service agreements for local reliability needs and regional fuel security concerns."[17] The Commission noted that it had addressed the differences between fuel security and transmission reliability resources in a prior order and recognized that there are material differences between cost of service agreements for local reliability needs and regional fuel security concerns.[18] In his dissent, Commission Chatterjee emphasized that "RMR resources are distinguishable from resources retained for fuel security."[19] RMR resources are needed "to address local reliability needs" while transmission upgrades are made.[20] Resources retained for fuel security "are intended to address regional fuel security issues that may be more difficult to solve."[21]

The issue in *Mystic* was whether the precedent providing that RMR generators could offer as price takers in the ISO-NE capacity market should be extended to the *Mystic* fuel

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15 *See id.* at P 10.

16 *See ISO New England, Inc.*, 165 FERC ¶ 61,202 (2018).

17 *See id.* at P 86.

18 *Id.*, citing *ISO New England Inc.*, 164 FERC ¶ 61,003 at P 57 (2018).

19 *Id*.

20 *Id*.

21 *Id*.

security generators.[22] On that limited issue, the Commission approved the inclusion of fuel security generators in the ISO-NE capacity market as price takers.[23]

The issue of allowing the fuel security units to participate as price takers in the ISO-NE capacity market is not relevant to Indian River 4. Under the Deactivation Filing, Indian River 4 will not participate in the PJM Capacity Market and will not provide capacity to PJM.[24] Indian River 4 is fully distinguishable in law and fact from the *Mystic* case, and *Mystic* is not properly relied upon to support any aspect of the Deactivation Filing.

One aspect of the *Mystic* case relied on by NRG Witness Lovinger is a finding in *Mystic* on the treatment of impairments. Witness Lovinger cites a statement by the Commission excusing the *Mystic* units from taking into account previously recognized GAAP impairments because "the claimed impairments do not represent a write-off that was previously authorized by the Commission."[25] Indian River 4 is an Exempt Wholesale Generator ("EWG"), not subject to the Commission's regulation of books and records under Part 366.[26] NRG has market based rates authorization, including waivers from the Commission's accounting rules.[27] The rationale relied on in *Mystic* does not apply to Indian River 4, and does not excuse the improper treatment of impairments in the Deactivation Filing. Regardless, the rationale in *Mystic* could not be applied to this case because the Commission did not have authority over the treatment of impairments on the books of NRG.

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22 *See id*. at P 85, citing *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 (2015), *order on reh'g & compliance*, 155 FERC ¶ 61,076 (2016), *order on reh'g & compliance*, 161 FERC P 61,189 (2017).

23 *See id.*

24 Deactivation Filing at 7 ("NRG-PML is not obligated to offer Unit 4 into the PJM capacity market.").

25 *Id.*, Attachment E at 17:1–12.

26 *Id*. at 4; 18 CFR Part 366.

27 *Id*. at 3, citing *NRG Power Mktg. Inc.*, 81 FERC ¶ 61,185 (1997).

G. Additional Issues.

1. Tracking Inventories.

The Deactivation Filing does not address how inventories will be tracked during the Defined Period. A monthly accounting including volumes and values should be required and provided to PJM and the Market Monitor for review and verification and subject to challenge.

2. Starting Inventories.

Any inventories that exist prior to the start of the Defined Period are the responsibility of NRG to dispose of because they resulted from operation in the PJM market.[28] NRG does not distinguish removal costs of inventory that resulted from market operations that NRG would have had to address without this process, and the removal costs of inventory that result from operations during the Defined Period.

3. Termination Notice.

The Deactivation Filing requires PJM to provide one hundred twenty (120) day's written notice to NRG to terminate operations. NRG has not provided support for the 120 day period. PJM should be required to provide thirty (30) days' notice.

4. Review of Costs.

The Deactivation Filing should include provisions that require PJM and the Market Monitor to review all costs submitted to PJM for payment and have the authority to challenge all such costs as needed.

5. Restatement of Price of Existing Coal Inventory.

NRG proposes to restate the value of the existing coal inventory at current (April and May 2022) coal prices plus transport and a low volume adder. The restatement is not appropriate as it would result in customers being charged a carrying charge for coal already purchased at a price greater than actually paid. In addition, NRG proposes to increase the

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28 Deactivation Filing, Attachment A, at 11.

coal inventory to a 21 day supply (81,417 tons) valued at current (April and May 2022) coal prices plus transport and a $10.00 adder for being a low volume purchaser. NRG includes this entire estimated amount in the rate base in their rate case approach. NRG's approach would require customers to pay a carrying charge for coal which has not yet been acquired, at estimated prices and a higher cost to customers as the coal is consumed.[29] NRG's weighted cost of existing inventory should be used for all the calculations and adjusted at least monthly to account for changes in inventory value. There is no rate base. This is not a utility rate case. Customers should pay for the actual cost of additional coal purchased to operate during the Defined Period and appropriate carrying charges.

6. Allocation of the Oil Inventory Between Unit 4 and Unit 10.

The allocation of the oil inventory between Unit 4 and Unit 10 is based on oil consumption for the 13 month period ended December 31, 2021. This calculation assumes that the relative usage of the two units will remain constant during the Defined Period. Customers should pay for the actual oil usage by Indian River 4.

7. Oil Inventory Balance

NRG includes the estimated value of the oil inventory in the rate base in the NRG rate case approach. NRG includes a 13 month average for the oil inventory value. Customers should pay for the actual cost of additional coal purchased to operate during the Defined Period and appropriate carrying charges.

8. Carrying Charges on Project Investment.

The Deactivation Filing states that "Actual PI Costs for Project Investment shall accrue carrying charges at 9.49% per annum from the first of the month in which the cost is accrued until paid."[30] The 9.49 percent has not been adequately supported. The proposed carrying

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[29] Deactivation Filing, Attachment A at 10

[30] Deactivation Filing, Attachment A at 8.

charge approach would result in paying carrying charges on investments before they are made. Carrying charges should reflect the timing of NRG's actual investment spending to ensure that customers pay the costs of continued operation but not more.

9. Depreciation.

NRG fails to account for increases in depreciation over the Defined Period. The result is inappropriately higher costs to customers.

10. Impairments.

Impairments are a reduction in the value of assets carried on a company's books. NRG does not explain in detail how NRG calculated impairment values. NRG's SEC filings do not explain how the defined impairment amounts are assigned to Indian River 4 and other NRG generating assets. NRG should provide this information.

NRG added the impairments back to the value of the Indian River 4 plant.[31] NRG proposes that customers pay for plant that NRG has explicitly recognized in its SEC filings as having zero value. While the rate case approach is not appropriate, if that approach is to be followed, the impairments should not be added to the value of the plant and thus the rate base.

NRG's 2013 10-K/A Amendment (filed September 10, 2014) explained that Indian River recorded impairment charges in the fourth quarter of 2013 of $459 million. That filing stated: "As a result, the assets are considered to be impaired, and the Company measured the impairment loss as the difference between the carrying amount and the fair value of the assets."[32] The filing did not define or state the impairment related to Indian River 4.

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31 Deactivation Filing, Attachment E at 41

32 NRG SEC Filings 2013 10-K/A (September 10, 2014) at a41, <https://investors.nrg.com/sec-filings/sec-filing/10-ka/0001013871-14-000019>.

NRG's 2017 10-K (filed March 1, 2018) stated: "The Company recognized an impairment loss of $36 million for Indian River as a result of the decrease in the Company's view of long-term power prices in PJM."[33] The filing did not define or state the impairment related to Indian River 4.

NRGs 2021 10-K (filed February 24, 2022) stated: "Company recorded impairment losses of $544 million, of which $306 million was recorded in the second quarter related to the decline in capacity prices and the planned retirement of a significant portion of the PJM coal fleet."[34] The filing did not define the impairment related to Indian River 4. In an NRG meeting with investors on June 17, 2021, an NRG representative stated: "Given the recent PJM auction results, I'm announcing the expected retirement of Indian River 4, Waukegan 7, Waukegan 8 and Will County 4 in June of 2022."[35]

11. Capacity Interconnection Rights

All capacity resources must have capacity interconnection rights (CIRs) which define the deliverability of the resource to the PJM grid.[36] NRG appears to take the position that Indian River 4 will remain a capacity resource in PJM but that Indian River 4 will not have the obligations of a capacity resource, including the requirement to offer the capacity in the PJM capacity auctions.

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33 NRG SEC Filings 2017 10-K (March 1, 2018) at 108, <https://investors.nrg.com/sec-filings/sec-filing/10-k/0001013871-18-000011>.

34 NRG SEC Filings 2021 10-K (February 24, 2022) at 56, <https://investors.nrg.com/sec-filings/sec-filing/10-k/0001013871-22-000010> >.

35 NRG Energy Inc., Investor Day, Corrected Transcript at 19, <*https://investors.nrg.com/events/event-details/nrg-energy-inc-2021-investor-day*>.

36 *See* OATT § 230.

NRG did not address the disposition of Indian River 4's CIRs. CIRs have market value and if NRG proceeds with its rate case approach, the value of the CIRs must be included as an offset to the obligations of customers to pay the costs of Indian River 4.

12. Fuel Cost Policy

NRG does not reference its current fuel cost policy. NRG should be required to follow its current fuel cost policy for purposes of defining its cost-based offers in the energy market.

13. Rate of Return

NRG proposes to use the rate of return on equity of the transmission owner to which Indian River 4 is interconnected.[37] NRG does not explain whether that rate of return on equity includes the RTO incentive adder and whether such an adder is appropriate for Indian River 4.

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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37 Deactivation Filing, Attachment E at 28:15–22.

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Dated: May 6, 2022

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 6th day of May, 2022.

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