UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

RWE Clean Energy, LLC,	)	
Complainant,	)	
	)	
v.	)	Docket No. EL26-7-000
	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

ANSWER OF PJM INTERCONNECTION, L.L.C.

Pursuant to Rule 213 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure,[1] PJM Interconnection, L.L.C. ("PJM"), submits this answer to the Complaint filed by RWE Clean Energy, LLC ("RWE" or "Complainant").[2] RWE has not shown that PJM violated its Tariff or acted contrary to the processes contained in its Manual[3] in allocating the costs of Network Upgrades to Maryland Blue Crab Solar & Storage, LLC project ("Project") in PJM's Transition Cycle No. 1 ("TC1") Phase III System Impact Study.

As a complainant under FPA section 206, RWE has the burden of showing that the Tariff or PJM's practices are unjust, unreasonable, unduly discriminatory, or preferential.[4]

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[1] 18 C.F.R. § 385.213.

[2] *RWE Clean Energy, LLC v. PJM Interconnection, L.L.C.*, Complaint Requesting Shortened Comment Period and Fast Track Processing of RWE Clean Energy, LLC, Docket No. EL26-7-000 (Oct. 27, 2025) ("Complaint"). The Complaint was brought pursuant to Federal Power Act ("FPA") sections 206 and 309. 16 U.S.C. §§ 824e & 825h. This answer is supported by the attached Affidavit of Edmund Franks on Behalf of PJM Interconnection, L.L.C. (Attachment A) ("Franks Aff."). Capitalized terms not defined herein have the meaning set forth in the PJM Open Access Transmission Tariff ("Tariff").

[3] Specifically, RWE alleges that PJM misapplied its Generator Deliverability Procedure, set forth in PJM Manual 14B. Complaint at 13-20.

[4] 16 U.S.C. § 824e(b) (stating "the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant").

Moreover, any "replacement" practice must be just and reasonable.[5] RWE fails to meet the first burden because RWE does not demonstrate that PJM misapplied its Generator Deliverability Procedure, because it cannot. Mr. Franks explains in his Affidavit that PJM properly applied direct current ("DC") loadings in the Common Mode Outage Procedure comparison that is part of the legacy Generator Deliverability Procedure, which it has applied consistently in past interconnection studies, and details the consequences if RWE were to prevail and PJM were required to change the analysis for TC1. Further, RWE's proposal to have the Commission require PJM to reinstate the Project without posting Security fails the second burden. It would be unjust and unreasonable to put in place a result that is contrary to the Commission-approved process contained in the Tariff, requires a tacit waiver of the non-discretionary deadline for posting Security, results in harm to other TC1 Project Developers, and violates the filed rate doctrine. The Commission therefore should deny the Complaint.

I. SUMMARY

As demonstrated herein, the Complaint is erroneous, unsupported, and nothing more than an attempt by RWE to re-enter the TC1 queue after its voluntary withdrawal of the Project and circumvent the posting of Security that is required. RWE alleges that PJM misapplied its procedures in its Manual and incorrectly allocated Network Upgrade costs to RWE's Project in the Phase III System Impact Study. Neither of these claims is correct. Rather, RWE fails to understand PJM's legacy Generator Deliverability Procedure, as explained in the Franks Affidavit. Due to the level of Network Upgrade costs correctly

[5] 16 U.SC. § 824e(a) (stating that if the Commission finds the complained about rate or practice to be "unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order").

allocated to the Project, RWE voluntarily withdrew from the queue and PJM has refunded a portion of its Readiness Deposits in accordance with the Tariff.[6] Now, RWE seeks to reinstate its position in the queue and evade unwaivable Security posting requirements, shifting the cost to Project Developers in Transition Cycle No. 2 ("TC2").

RWE fails to satisfy its burden of proof under FPA section 206 because it has not demonstrated that PJM did not act in accordance with its Tariff and Manuals. In addition, RWE's requested relief is contrary to Commission-approved Tariff procedures, demands waiver of the non-discretionary security deposit, and violates the filed rate doctrine. Accordingly, PJM respectfully requests that the Commission deny the Complaint.

II. BACKGROUND

In 2020, RWE submitted New Service Requests for the Project, comprised of a 100-megawatt ("MW") solar generation facility and a 25-MW battery storage facility in Dorchester County, Maryland.[7] The Transition Period Rules in Tariff, Part VII apply to the Project's New Service Requests.[8] PJM assigned the solar facility Project Identifier AF2-358 and the battery storage facility Project Identifier AG1-450. Following the Tariff provisions for TC1,[9] PJM issued the Phase I System Impact Study results on May 20, 2024; the Phase II System Impact Study results on December 20, 2024; and the Phase III System Impact Study results on September 19, 2025.

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[6] Tariff, Part VII, Subpart D, section 313(B)(5)(b).

[7] The Complaint's accompanying affidavit references the ability of the Project to address PJM's resource adequacy challenges, Complaint, Attachment A (Affidavit of Karthik Mekala) ¶ 5 ("Mekala Aff."). However, Mr. Franks demonstrates in his Affidavit that the Project, if completed, would have only 27.5 MW of accredited unforced capacity ("UCAP") in the 2027-28 Delivery Year. Franks Aff. ¶ 18.

[8] *PJM Interconnection, LLC*, 181 FERC 61,162, at PP 37, 69 (2022) (accepting PJM's Transition Period Rules for New Service Requests submitted between April 1, 2018, and September 30, 2021).

[9] Tariff, Part VII, Subpart D, sections 308, 310 & 312.

On May 20, 2024, PJM released the Project's Phase I Study Report. The Phase I Study Reports allocated Network Upgrade costs of $80,192,013 for Project Identifier AF2-358 and $13,217,059 for Project Identifier AG1-450 for a total of $93,409,072 of Network Upgrade cost allocations for the Project.[10] Based on Phase I cost allocation rules at the time,[11] PJM calculated Readiness Deposit No. 2 to be $7,584,201 for Project Identifier AF2-358 and $1,186,706 for Project Identifier AG1-450.[12] Although the contested Network Upgrade, the Edge Moor-Linwood 230-kV facility, appeared in the Project's Phase I Study Reports as a "problem likely to result in operational restrictions to the project under study,"[13] the Project was not included in the list of projects contributing to the loading of overloaded facilities identified in the report. It is important to note, however, that this listing is prefaced with the following statement:

> The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of other

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[10] *AF2-358 Phase I Study Report*, PJM Interconnection, L.L.C., at "Cost Summary" Table (May 20, 2024) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_1/AF2-358/AF2-358_imp_PHASE_1.htm ("AF2-358 Phase I Study Report"); *AG1-450 Phase I Study Report*, PJM Interconnection, L.L.C., at "Cost Summary" Table (May 20, 2024) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_1/AG1-450/AG1-450_imp_PHASE_1.htm ("AG1-450 Phase I Study Report").

[11] Tariff, Part VII, Subpart D, section 309(A)(1)(a)(i). PJM Interconnection Projects Department, *Manual 14H: New Service Requests Cycle Process*, section 6.2 (Rev. 01, July 26, 2023) https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m14h/m14hv01-new-service-requests-cycle-process-07-26-2023.pdf. RWE had already paid Readiness Deposit No. 1 based on the Project components' sizes (MW) when it submitted its applications-- $400,000 for AF2-358 and $100,000 for AG1-450. AF2-358 Phase I Study at "Readiness Deposit" Table & AG1-450 Phase I Study at "Readiness Deposit" Table.

[12] For Readiness Deposits at Decision Point 1, PJM subtracted the amount of Readiness Deposit 1 from 10 percent of the cost allocation for Phase I Network Upgrades; thus at the completion of Phase I, PJM calculated $79,842,013 in costs for Phase I Network Upgrades for AF2-358 and $12,867,059 in costs subject to readiness for AG1-450's Phase I Network Upgrades. AF2-358 Phase I Study Report at "Readiness Deposit" section; AG1-450 Phase I Study Report at "Readiness Deposit" section.

[13] AF2-358 Phase I Study Report at "Summer Potential Congestion due to Local Energy Deliverability" Table; AG1-450 Phase I Study Report at "Summer Potential Congestion due to Local Energy Deliverability" Table.

> projects. . . . This list may change as other projects withdraw or modify their requests. This table is valid for load flow analyses only.[14]

At the end of Phase I, PJM initiated Decision Point I ("DP1") in accordance with the Tariff, which provided RWE 30 days to decide whether to proceed with the Project.[15]

By June 20, 2024, before the DP1 deadline, RWE elected to proceed with the project and paid the Readiness Deposits for Project Identifiers AF2-358 and AG1-450 based on the approximately $93.4 million of Network Upgrade Costs. PJM began the Phase II System Impact Study in accordance with the Tariff, publishing the report on December 20, 2024.[16] The Phase II System Impact Study reports for the Projects allocated Network Upgrade costs of $10,760,156 for AF2-358 and $10,010,156 for AG1-450, for a total of $20,770,312.[17] Pursuant to the Tariff[18] and accounting for the previously paid Readiness Deposits, the Phase II System Impact Study resulted in a $0 Readiness Deposit No. 3 for AF2-358 and a $630,698 Readiness Deposit No. 3 for AG1-450.[19] Once again, at the end of the Phase II System Impact Study, RWE had 30 days to decide whether to proceed with the Project based on the results of the study.[20]

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[14] AF2-358 Phase I Study Report at "New Service Request Dependencies" section; AG1-450 Phase I Study Report at "New Service Request Dependencies" section.

[15] Tariff, Part VII, Subpart D, sections 308 & 309; PJM Interconnection Projects Department, *Manual 14H: New Service Requests Cycle Process*, section 4.3.1 (July 23, 2025) https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf ("PJM Manual 14H").

[16] *See* Phase II SIS Report Announcement.

[17] *AF2-358 Phase II Study Report*, PJM Interconnection, L.L.C., at "Cost Summary" Table (Dec. 20, 2024) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AF2-358/AF2-358_imp_PHASE_2.htm ("AF2-358 Phase II Study Report"); *AG1-450 Phase II Study Report*, PJM Interconnection, L.L.C., at "Cost Summary" Table (Dec. 20, 2024) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AG1-450/AG1-450_imp_PHASE_2.htm ("AG1-450 Phase II Study Report").

[18] Tariff, Part VII, Subpart D, section 311(A)(1)(a).

[19] AF2-358 Phase II Study Report at "Readiness Deposit" Table; AG1-450 Phase II Study Report at "Readiness Deposit" Table.

[20] Tariff, Part VII, Subpart D, section 310.

On January 20, 2025, before the Decision Point II ("DP2") deadline, RWE provided the required information and paid Readiness Deposit No. 3 amount of $630,698 to proceed.[21] Cumulatively, RWE paid $9,901,605 total in Readiness Deposits for the Project.[22] Accordingly, PJM began its Phase III System Impact Study, publishing it on September 19, 2025. The Phase III System Impact Study allocated costs of $60,741,847 for Project Identifier AF2-358 and $17,870,079 for Project Identifier AG1-450 for Network Upgrades for a total of $78,611,927.[23] Based on the Tariff provisions on Security,[24] PJM calculated the net Security due at Decision Point III ("DP3") for Project Identifiers AF2-358 and AG1-450 to be $78,611,927.[25]

On September 19, 2025, RWE and PJM began discussions concerning the Network Upgrade cost allocations and the analyses under PJM Manual 14B[26] that resulted in these cost allocations. In these discussions, RWE disputed $71.6 million in upgrades allocated to the Project.[27]

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[21] AG1-450 Phase II Study Report at "Readiness Deposit" Table; AF2-358 Phase II Study Report at "Readiness Deposit" Table.

[22] *See* Table 1 below.

[23] *AF2-358 Phase III Study Report*, PJM Interconnection, L.L.C., at "Security Requirement" section (Sept. 19, 2025) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AF2-358/AF2-358_imp_PHASE_3.htm ("AF2-358 Phase III Study Report"); *AG1-450 Phase III Study Report*, PJM Interconnection, L.L.C., at "Security Requirement" section (Sept. 19, 2025) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AG1-450/AG1-450_imp_PHASE_3.htm ("AG1-450 Phase III Study Report").

[24] Tariff, Part VII, Subpart D, section 313(A)(1)(a)(i).

[25] AF2-358 Phase III Study Report at "Security Requirement" section; AG1-450 Phase III Study Report at "Security Requirement" section.

[26] PJM Transmission Planning Department, *Manual 14B: PJM Region Transmission Planning Process* (Rev. 57, Sep. 25, 2024), https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf ("PJM Manual 14B, revision 57").

[27] Complaint, Exhibit D at 2 (Email from Feng Li Vice President Global Transmission RWE Clean Energy, LLC, to various PJM Staff) (Oct. 8, 2025, at 10:39 a.m. CT)).

On October 21, 2025, the deadline for Security to be posted and the close of DP3, RWE voluntarily withdrew its New Service Requests for the Project by written notification to PJM.[28] Pursuant to PJM Manual 14H, because RWE notified PJM that it was withdrawing its New Service Requests, PJM removed the Project from the TC1 model and terminated the associated New Service Requests.[29] Under the terms of its Adverse Test Eligibility and its voluntary withdrawal, PJM refunded to RWE $9,901,605 of its Readiness Deposits on October 31, 2025.[30]

On October 27, 2025, RWE submitted the Complaint to which this Answer responds.[31] On October 28, 2025, the Commission issued a notice of the Complaint.[32]

III. ANSWER TO COMPLAINT

A party filing a complaint under FPA section 206 has the burden of showing that the complained-about rates or practices are unjust, unreasonable, unduly discriminatory or preferential.[33] In addition, the replacement rate or practice must be just and reasonable.[34] Despite RWE's assertions to the contrary, PJM's actions in determining the Network Upgrade cost allocation and the resulting required Security amount, and PJM's

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[28] Complaint, Exhibit G (RWE Notice of Withdrawal to PJM).

[29] Tariff, Part VII, Subpart D, section 313(B)(5); PJM Manual 14H, section 4.8.2 (explaining two conditions for withdrawal at Decision Point III as (1) Project Developer decides to withdraw and gives written notice to PJM or (2) PJM deems New Service Request withdrawn for failing to meet Decision Point III requirements, including paying the required security).

[30] Tariff, Part VII, Subpart D, section 313(B)(5)(b) (cross-referencing Tariff, Part VII, Subpart A., section 301(A)(3)); PJM Manual 14H, section 6.2.2 (Treatment of Readiness Deposits due to Adverse Study Results); AF2-358 Phase III Study at "Adverse Test Eligibility" section; AG1-450 Phase III Study at "Adverse Test Eligibility" section.

[31] Complaint.

[32] *RWE Clean Energy, LLC v. PJM Interconnection, L.L.C.*, Combined Notice of Filings #1, Docket No. EL26-7-000 (Oct. 28, 2025).

[33] 16 U.S.C. § 824e(b); *see also supra* n.4.

[34] 16 U.S.C. § 824e(a); *see also supra* n.5.

enforcement of withdrawal procedures, are proper and consistent with the PJM Tariff and Manuals. The Franks Affidavit, attached hereto as Attachment A, demonstrates that RWE misrepresents PJM's Generator Deliverability Procedure and that, when applied correctly, as PJM did, this screening test allocates to the Project Costs associated with the Network Upgrades to the Edge Moor-Linwood 230-kV line needed to mitigate the common mode contingency overload on the line.

Moreover, the relief RWE seeks—(1) a Commission finding that PJM misapplied its TC1 Phase III Study procedures resulting in unjust and unreasonable cost allocation to the Project; and (2) for the Commission to direct PJM to reinstate the Project at its pre-withdrawal TC1 queue positions without posting the required amount of Security[35]—would be contrary to the Commission-approved Tariff; would result in harm to other TC1 Project Developers; would require a waiver of the Security posting deadline; and would violate the filed rate doctrine. The Commission therefore should dismiss the Complaint with prejudice and deny the requested relief.

A. RWE Was Aware of Potential Changes in the Project's Cost Allocations Throughout TC1

RWE portrays the allocation of Costs to upgrade the Edge Moor-Linwood 230-kV line to the Project as an eleventh hour surprise, alleging that RWE did not learn of the Edge Moor-Linwood 230-kV line cost allocations until PJM released the Phase III System Impact Study results in September 2025.[36] RWE then presents this as justification to refuse to post Security for these Network Upgrade Costs.[37] Even though the Network Upgrade

[35] Complaint at 27.

[36] Complaint at 3.

[37] *Id.*

Costs for the Edge Moor-Linwood line were not allocated to the Project until September 2025 (when all TC1 projects were provided their cost allocations), RWE had ample knowledge and warning of possible changes to the Project's cost allocations, including the addition of these Network Upgrade Costs.[38] The TC1 process set forth in PJM's Tariff and Manuals and the disclaimers included in all System Impact Study reports provided RWE with cost allocation estimates, notice that those estimates could change over the course of the Cycle,[39] and withdrawal opportunities throughout TC1. RWE ultimately chose the off-ramp for its Project from TC1 at the end of Decision Point 3 ("DP3")[40] based on the Phase III System Impact Study results.

In the Phase I Study, released in May 2024, PJM studied the Edge Moor-Linwood 230 kV line among other facilities that might be overloaded by projects in TC1 but did not allocate cost estimates for that line work to the Project.[41] However, PJM estimated Network Upgrade Cost Allocations of $92,709,072 for the Project in the Phase I System Impact Study. Additionally, the Phase I Study report included the following statement: "These network upgrade costs are subject to change as a result of a facility study performed by the TO during the Phase II or Phase III System Impact Study."[42] To continue past DP1, RWE paid the Readiness Deposits calculated for the Project based on these cost allocations.

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[38] *See* Table 1 below.

[39] For example, all System Impact Study reports note the following as it relates to New Service Request dependencies: "The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of other projects." *See, e.g.* AF2-358 Phase III Study at "New Service Request Dependencies" section.

[40] Tariff, Part VII, Subpart D, section 313(B)(5).

[41] AF2-358 Phase I Study at "Summer Potential Congestion due to Local Energy Deliverability" Table and "System Reinforcements" section; AG1-450 Phase I Study at "Summer Potential Congestion due to Local Energy Deliverability" Table and "System Reinforcements" section.

[42] AF2-358 Phase I Study at "Cost Summary" section; AG1-450 Phase I Study at "Cost Summary" section.

PJM cannot find any record of RWE contesting the approximately $93 million cost allocation at DP1. In short, PJM provided a cost allocation estimate for the Project at the end of Phase I that was higher than the cost allocation provided at the end of Phase III and RWE paid the Readiness Deposits based on this estimate.

The Phase II System Impact Study also studied the Edge Moor-Linwood 230-kV line as a "flowgate."[43] While the Phase II System Impact Study reports for the Project did not allocate costs for Network Upgrades to the Edge Moor-Linwood 230-kV to the Project, the Phase II System Impact Study reports warned "[t]he System Reliability Network Upgrades shown in the table are planning level cost estimates that are subject to change as a result of a facility study performed by the TO during the Phase III System Impact Study."[44]

Ultimately, the Phase III System Impact Study reports allocated to the Project Network Upgrade costs of $71,680,000 for the Edge Moor-Linwood 230-kV line.[45] Before listing the three potential System Reliability Network Upgrades for which the Project would be responsible, the Phase III System Impact Study reports for the Project state, "[b]ased on the Phase III analysis results, this project is contingent on and may have cost responsibility for": (1) "Rebuild Edge Moor (DPL)-Linwood (PECO) 230 kV line"; (2) "Install 10 MWAR Cap Bank at new AF2-358 69kV Interconnection Swyd"; and (3) "Install OPGW on PECO portion of EDGEMR 5 230.0 kV to Linwood85 230.0 kV

[43] AF2-358 Phase II Study at "Summer Potential Congestion due to Local Energy Deliverability" Table; AG1-450 Phase II Study at "Summer Potential Congestion due to Local Energy Deliverability" table.

[44] AF2-358 Phase II Study at "Cost Summary" section; AG1-450 Phase II Study at "Cost Summary" section.

[45] AF2-358 Phase III Study at "System Reinforcements" section; AG1-450 Phase III Study at "System Reinforcements" section.

ckt 1."[46] Table 1 below summarizes the cost allocations and Readiness Deposit and Security amounts attributed to the Project over the three phases of TC1.

Table 1. Summary of Readiness Deposits by Phase and Total[47]

	AF2-358	AG1-450	
Readiness Deposit No. 1	$ 400,000	$ 100,000	
Readiness Deposit No. 2	$ 7,584,201	$ 1,186,706	
Readiness Deposit No. 3	$ 0	$ 630,698	
Total	**$ 7,984,201**	**$ 1,917,404**	**$ 9,901,605**

[46] AF2-358 Phase III Study at "System Reinforcements" section; AG1-450 Phase III Study at "System Reinforcements" section.

[47] The Readiness Deposits were calculated based on the specifications in the Tariff and PJM Manuals 14B and 14H. Readiness Deposit No. 1 is calculated based on Project's size. Tariff, Part VII, Subpart D, section 307(5); PJM Manual 14H, sections 2.5.2, 6.2; AF2-358 Phase I Study at "Readiness Deposit" section; AG1-450 Phase I Study at "Readiness Deposit" section. Readiness Deposit No. 2 is calculated as 10 percent of cost allocation for required Phase I Network Upgrades minus Readiness Deposit No. 1. Tariff, Part VII, Subpart D, section 309(A)(1)(a)(i); PJM Manual 14H, sections 4.4.2, 6.2; AF2-358 Phase I Study at "Readiness Deposit" section; AG1-450 Phase I Study at "Readiness Deposit" section. Readiness Deposit No. 3 is calculated as 20 percent of the cost allocation for required Phase II Network Upgrades minus Readiness Deposit Nos. 1 and 2. Tariff, Part VII, Subpart D, section 311(A)(1)(b)(i); PJM Manual 14H, sections 4.6.2, 6.2; AF2-358 Phase II Study at "Readiness Deposit" section; & AG1-450 Phase II Study at "Readiness Deposit" section.

Table 2. Summary of Cost Allocations in each Study Phase[48]

		AF2-358	AG1-450	Total
Study Phase	I (May 20, 2024)	$ 80,192,013	$ 13,217,059	**$ 93,409,072**
	II (Dec. 20, 2024)	$ 10,760,156	$ 10,010,156	**$ 20,770,312**
	III (Sept. 19, 2025)	$ 60,741,847[49]	$ 17,870,079	**$ 78,611,926**[50]

The Tariff, Manuals and System Impact Study reports warn of potential changes to cost allocations throughout the Cycle study process and the Tariff provides off-ramps for Project Developers to exit the Cycle if the cost allocations exceed earlier estimates by a certain amount or is greater than the amount of cost allocation the Project Developers are willing to pay.[51] At DP1 and DP2, following the release of the Phase I and II System Impact Study results, respectively, the Tariff and Manuals require Project Developers to pay Readiness Deposit Nos. 2 and 3, which will not be "reduced or refunded based upon subsequent New Service Request modifications or cost allocation changes."[52] PJM Manual

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[48] For a detailed breakdown and comparison of cost allocations for each Study, *see* Attachment B (Tables derived from AF2-358 and AG1-450 Phases I-III Study results), attached hereto. For Phase I, the allocated costs were "total planning level cost estimates." AF2-358 Phase I Study at "Cost Summary" section; AG1-450 Phase I Study at "Cost Summary" section. During the Phase II study, PJM completed facility studies for both the Transmission Owner Interconnection Facilities and Physical Interconnection Network Upgrades. AF2-358 Phase II Study at "Cost Summary" section; & AG1-450 Phase II Study at "Cost Summary" section. During the Phase III Study, PJM performed a facilities study for the required System Reliability Network Upgrades. AF2-358 Phase III Study at "Cost Summary" section; & AG1-450 Phase III Study at "Cost Summary" section.

[49] This total of $60,741,847 differs from the $60,741,848 total in the Phase III System Study Report by $1.00, which is attributable to rounding.

[50] This total of $78,611,926 differs from the $78,611,927 total in the Phase III System Study Report by $1.00, which is attributable to rounding.

[51] See Tariff, Part VII, Subpart D, sections 311(B)(3)(c), 313(B)(5)(c) (Adverse Impact Calculation); PJM Manual 14H, sections 4.6.4, 4.8.2, 6.2.2; AF2-358 Phase II Study report at "Cost Summary" section, n.3 ("If this project presents cost allocation to a System Reinforcement indicates $0, then please be aware that as changes to the interconnection process occur, such as other projects withdrawing, reducing in size, etc, the cost responsibilities can change and a cost allocation may be assigned to this project.").

[52] *See* Tariff, Part VII, Subpart D, section 309(A)(1)(a)(i)(a) (Readiness Deposit No. 2); PJM Manual 14H, section 4.4.2 (Readiness Deposit No. 2). *See* Tariff, Part VII, Subpart D, section 311(A)(1)(b)(i) (Readiness Deposit No. 3); PJM Manual 14H, section 4.6.2 (Readiness Deposit No. 3).

14H, Attachment B, reiterates that cost allocations will be "evaluated and modified, if required, as the interconnection process proceeds."[53]

At multiple stages and through multiple means, PJM communicated to RWE that the Network Upgrade cost allocation for its Project could change from phase to phase. RWE—like all Project Developers remaining in the interconnection process—decided to remain past DP2 knowing that the cost allocation could change.

B. Contrary to the Complaint's Central Thesis, PJM Followed Its Generator Deliverability Procedure Correctly

RWE centers its Complaint on claims that PJM misapplied its Generator Deliverability Procedure to the Project, thereby allegedly allocating to the Project Network Upgrade costs for which the Project is not responsible.[54] Specifically, RWE claims that the steps of the Generator Deliverability Procedure require calculating and comparing facilities' loading using alternating current ("AC") loadings instead of DC loadings and that PJM erred in using DC loadings in the comparison, causing a cost allocation of $71.6 million to be solely allocated to a single project.[55] As Mr. Edmund Franks, Principal Engineer, Interconnection Analysis at PJM explains, RWE misunderstands and misrepresents the applicable Legacy Generator Deliverability Procedure, as Mr. Franks calls it, failing to grasp the role of DC loadings in the Common Mode Outage Procedure that is part of the Legacy Generator Deliverability Procedure.[56] As Mr. Franks observes,

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[53] PJM Manual 14H, Attachment B, section B3 (PJM Generation and Transmission Interconnection Cost Allocation Methodologies).

[54] Complaint at 1.

[55] Complaint at 4-5.

[56] Franks Aff. ¶¶ 3-4. As Mr. Franks explains, the appropriate reference point for the Generator Deliverability Procedure applied to TC1 is not the currently effective version of PJM Manual 14B, revision 57, but PJM Manual 14B, revision 51. Franks Aff. ¶ 4. Mr. Franks calls the Generator Deliverability Procedure applied to TC1 the "Legacy Generator Deliverability Procedure" because PJM changed the deliverability test used

the test RWE appears to be applying to its Project is not the actual test set forth in the Manuals, but simply the one that will avoid the allocation of Network Upgrades to a particular line, changing the cost allocation to the Project.[57] RWE's results-driven interpretation of the relevant procedure should not stand and the Commission should deny the Complaint because it fails to show that PJM has violated its Tariff or misapplied its Manuals.

1. Contrary to RWE's claims, PJM correctly applied its Generator Deliverability Procedure to TC1

The Complaint and the accompanying Mekala Affidavit make sweeping assertions about the alleged error in PJM's application of the Generator Deliverability Procedure,[58] i.e., using DC loadings in the contingency loading comparison part of the procedure, but their walk through of the procedure focuses on the six-step test in PJM Manual 14B, revision 51, Attachment C, section C3.1.3, and disregards the Common Mode Outage Procedure spelled out in Addendum 2 to Attachment C.[59] As Mr. Franks explains, Addendum 2 does not specify whether the loadings that are compared in the Common

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for its Regional Transmission Expansion Plan ("RTEP") process in April 2023 to implement block dispatch. *Id.* Because of this change, the 2027 RTEP model was the last model to use the Legacy Generator Deliverability Procedure and, because PJM studied TC1 using Planning models for the 2027-28 Delivery Year, TC1 will be the last Cycle for which PJM uses the Legacy Generator Deliverability Procedure. *Id. See also* Heather Reiter, *Interconnection Analysis Expedited Process & Transition Cycle 1 Status*, PJM Interconnection Process Subcommittee, 17-19 (Jan. 29, 2024), *https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/ips/2024/20240129/20240129-item-04---fast-lane---tc1-status-update-post-meeting.pdf* (explaining the timeline for application of the Legacy and new Generator Deliverability Procedures).

[57] Franks Aff. ¶ 12.

[58] *See* Complaint at 1-3, 14-15, 20; Mekala Aff. ¶¶ 3, 11.

[59] Complaint at 14-17; Mekala Aff. ¶¶ 7-11; *see* PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process*, PJM Interconnection, L.L.C., (Rev. 51, Dec. 15, 2021), https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m14b/m14bv51-pjm-regional-transmission-planning-process-12-15-2021.pdf ("PJM Manual 14B, revision 51").

Mode Outage Procedure are DC loadings or AC loadings and PJM has always used DC loadings for this screening purpose.[60]

Mr. Franks next explains the reasons for PJM's use of DC loadings in the contingency loadings comparison, namely that DC powerflows are more stable (less volatile) than AC loadings, which means that using DC loadings results in less "flip flopping" or swings in overload percentages over the course of the multiple studies in a Cycle.[61] This stability leads to more consistent results across the studies in a Cycle, which improves certainty for Project Developers.[62]

Mr. Franks also describes PJM's consistent application of the Legacy Generator Deliverability Procedure, including the use of DC loadings in the contingency loadings comparison in the Common Mode Outage Procedures pursuant to Attachment C, Addendum 2 of PJM Manual 14B, revision 51, to past interconnection studies and notes that the use of DC loadings in the comparison is hard coded in PJM's TARA software to ensure that consistency.[63] He contrasts this consistent practice to RWE's criticism of PJM's consistency,[64] and its call for PJM engineers to depart from the correct application of the procedure and consistent practice on a case-by-case basis, which would not be appropriate.[65]

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[60] *Compare* Franks Aff. ¶ 9, *with* Mekala Aff. ¶ 11.

[61] Franks Aff. ¶ 10.

[62] *Id.* ¶ 11.

[63] *Id.* ¶ 12.

[64] Complaint at 19-22; Mekala Aff. ¶¶ 16-18.

[65] Mekala Aff. ¶¶ 17-18.

2. Taking RWE's approach to the Legacy Generator Deliverability Procedure would delay completion of TC1 and could result in new cost allocations to TC1 projects

After explaining that PJM correctly applied its Legacy Generator Deliverability Procedure to TC1, Mr. Franks describes the impact on TC1 and TC2 if the Commission were to require PJM to change how it performs the last iteration of the Legacy Generator Deliverability Procedure for RWE's benefit.[66] As he describes, the impact of the change would not be limited to the Edge Moor-Linwood line and the Project, as RWE claims.[67] PJM would have to go back and perform the Legacy Generator Deliverability Procedure again, as modified by RWE to use AC loadings rather than DC loadings in the comparison of operational contingency loadings to common mode outage loadings, for the entire TC1 Phase III cohort throughout the PJM Region.[68] Thus, RWE's mistaken approach would mean effectively re-running the Phase III studies, after PJM has completed TC1. Doing so carries the potential for the modified analysis to change common mode outage loadings on other facilities to be greater than the operational contingency loadings on those other PJM facilities, resulting in the identification of new reliability criteria violations that would require PJM to scope new Network Upgrades to resolve those new reliability criteria violations and assign new cost responsibility to TC1 projects.[69] Such a re-run of TC1 Phase III would take time, delaying the completion of TC1 and its further advancement of Transition Cycle No. 2, and could upset the expectations of the affected Project Developers in TC1 with these new violations and new cost allocations.[70] Further, such a re-run is not necessary as PJM correctly studied this Project as well as the others in TC1 in accordance with the Tariff and Manuals.

Mr. Franks also counters Mr. Mekala's inaccurate suggestion that PJM's real reason for continuing its consistent practice of using DC loadings in the Common Outage Mode

Procedure comparison is timing concerns, given that TC1 is almost complete.[71] Mr. Franks confirms that, contrary to Mr. Mekala's characterization of PJM's concerns, the timing outlined in the Complaint is not relevant to PJM's insistence on using DC loadings in the comparison.[72] If PJM were still in Phase I of TC1, rather than being in the Final Agreement Negotiation Phase of TC1, PJM's explanation as to why DC loadings are used in the comparison would be the same, as would the fact that PJM has always applied the Legacy Generator Deliverability Procedure as it did in the Phase III System Impact Study, and the fact that this application to the 2027-28 Delivery Year is consistent with PJM Manual 14B, revision 51.[73]

C. RWE's Proposed Remedies Are Unjust and Unreasonable As They Are Contrary to the Tariff, Would Harm Other Project Developers in Transition Cycle Nos. 1 and 2, Would Require Waiver of a Non-Discretionary Provision, and Would Violate the Filed Rate Doctrine

As discussed above, not only does FPA section 206 require a complainant to show the complained about rates, charges or practices are unjust, unreasonable or unduly discriminatory or that the utility has violated its tariff, but also the proposed "replacement rate" must be just and reasonable.[74]

As explained in section III.B., the Complaint fails to show that PJM violated its Tariff or misapplied the Legacy Generator Deliverability Procedure in the PJM Manuals when allocating costs to the Project. Thus, the Complaint fails the first hurdle of FPA section 206. RWE also fails the second hurdle of FPA section 206 because the Complaint's proposed remedy, or its proposed "replacement rate"—reinstatement of the Project in TC1

[71] Mekala Aff. ¶ 17.

[72] Franks Aff. ¶ 16.

[73] *Id.*

[74] *See supra* nn.5 & 34.

without allocation of the costs of rebuilding the Edge Moor-Linwood 230-kV line[75]—would be contrary to the Tariff, could harm other Project Developers in TC1 and TC2, would require a waiver of the non-discretionary Security posting deadline, and would violate the filed rate doctrine.

1. RWE's request to reinstate its Project to its TC1 Queue Position should be denied because it would be contrary to the Tariff and could harm other Project Developers in TC1 and TC2

The relief RWE requests in its Complaint would be contrary to the Tariff because it would ignore the withdrawal of the Project, which followed the Tariff procedures for withdrawal and worse, would prioritize one project over the rest of the projects in the Cycle and would cause costs allocated to a project in TC1 to be allocated to projects in TC2, in violation of the Tariff.

RWE withdrew the Project from the interconnection process using the proper procedure pursuant to the Tariff. The Tariff states that a Project Developer "shall choose" to either remain in TC1 by submitting the required elements or withdraw its New Service Request "[b]efore the close of Decision Point III … ."[76] The close of DP3 was October 21, 2025, and RWE submitted written notice of its withdrawal of the Project on October 21, 2025.[77] Even if the written withdrawal had not been submitted, PJM would have deemed the Project withdrawn from TC1 pursuant to its Tariff[78] upon RWE's failure to submit the Security and the other required elements by the DP3 deadline.

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[75] Complaint at 27.

[76] Tariff, Part VII, Subpart D, section 313(A).

[77] Complaint, Exhibit G (RWE Notice of Withdrawal to PJM).

[78] Tariff, Part VII, Subpart D, section 313(A).

Moreover, the relief RWE seeks is antithetical to PJM's reformed interconnection process because it singles out one project in TC1 for special treatment, ignoring the clustered nature of PJM's Cycle process and delaying and affecting other projects in TC1 and TC2 for the sole benefit of the Project. The DP3 deadline that the Complaint essentially asks the Commission to ignore applies not just to the Project but to all projects in TC1. This is the essence of the move to a *clustered* Cycle study process from the former serial process.[79] New Service Requests are no longer studied separately, but as a cluster, and this clustering applies not only to the System Impact Studies but also to System Impact retool studies.[80] Therefore, any relief granted to RWE will disrupt PJM's processing of TC1 and TC2, and shift cost allocations from the Project to one or more projects in TC2, thereby affecting the other Project Developers in TC1 and TC2.

The PJM Cycle process the Commission approved[81] includes specific timing for the System Impact Studies and time for Project Developers to make decisions based on the results of those studies and then submit the required documents, deposits, and information during the three decision points to remain in the Cycle.[82] The Tariff then provides for a Final Agreement Negotiation Phase, during which PJM performs a retool study with the final cohort of projects remaining in the Cycle after DP3.[83] This retool study is needed to finalize the Network Upgrade cost allocations, which are then incorporated into the final service agreements for all projects remaining in the Cycle.[84]

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[79] *See PJM Interconnection*, *L.L.C.*, 181 FERC ¶ 61,162, at PP 32-33 (2022) ("Interconnection Process Reform Order").

[80] Tariff, Part VII, Subpart D, section 314(B)(1)(a).

[81] Interconnection Process Reform Order at P 1.

[82] Tariff, Part VII, Subpart D, sections 308-313.

[83] Tariff, Part VII, Subpart D, section 314.

[84] *Id.*; Tariff, Part IX, Subparts B & C.

PJM began building the model for this final TC1 retool study after the close of DP3,[85] and that model is based on the cohort of TC1 projects that advanced. The Project is not part of that cohort because RWE withdrew it. The retool study is currently anticipated to be completed by the end of November 2025, after which time PJM will issue final service agreements with updated cost allocations, as required by Tariff, Part VII, Subpart D, section 314. PJM anticipates completing TC1 within a few weeks. If the Commission later directs PJM to reinstate the Project as the Complaint requests, PJM will have to perform the retool study again, which could further change the cost allocations among TC1 projects and require revisions to all the affected service agreements. Such a disruption of the final allocations and agreements for TC1 also would require PJM to stop its work on TC2 and restart TC2 from the beginning of Phase II. Under the Tariff, Phase II cannot start before TC1 DP3 ends.[86] Furthermore, PJM uses the final list of New Service Requests that have advanced past DP3 of TC1 to build the TC2 case prior to Phase II of TC2 commencing. As such, reinserting the Project would be disruptive and subsequently delay the progress of TC2.

Granting relief to a Project Developer that benefits only its Project, to the detriment of all other projects in the Cycle, would contradict the queue reforms the Commission approved, be contrary to efficient queue administration,[87] and have the undesirable

[85] Decision Point III closed on October 21, 2025.

[86] Tariff, Part VII, Subpart D, section 310(A)(1)(e) ("Phase II shall start on the first Business Day immediately following the end of the Decision Point I unless the Decision Point III of the immediately preceding Cycle is still open. In no event shall Phase II of a Cycle commence before the conclusion of the Decision Point III Phase of the immediately preceding Cycle.")

[87] The Commission has recognized that efficient queue administration is in the public interest. *See PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,075, at P 38 (2021) (denying request for waiver and finding notices of cancellation are in the public interest); *Cf. Midcontinent Indep. Sys. Operator, Inc.*, 176 FERC ¶ 61,161, at P 24 (2021) (granting waiver in part on the basis that no other projects in the interconnection queue will be affected or require restudy as a result).

consequence of establishing negative precedent that could undermine the integrity of PJM's nascent cluster-based Cycle process. The Commission therefore should deny the Complaint.

Further, as noted above, reinstating the Project in TC1 without allocating the costs of the Edge Moor-Linwood 230-kV line upgrades to the Project will simply shift the costs of those upgrades to projects in TC2. Indeed, the TC2 Phase I System Impact Study results released October 31, 2025 show that the Edge Moor-Linwood 230-kV line upgrades that had been attributed to the Project are now part of the Network Upgrades needed for TC2 with the Project withdrawn from TC1.[88] If the Commission requires PJM to reinstate the Project in TC1 without allocation of the costs of the Edge Moor-Linwood 230-kV line upgrades, it would violate Tariff, Part VII, Subpart D, section 307(A)(5)(c), which explicitly prohibits inter-Cycle cost allocation for Network Upgrades.

Because the relief requested in the Complaint would be contrary to the Tariff's clear provisions on withdrawal and inter-Cycle cost allocation and is antithetical to the clustered nature of PJM's reformed interconnection process, it is unjust and unreasonable. The Complaint would undermine PJM's nascent Cycle process by disrupting and delaying both TC1 and TC2 for the benefit of a single project and to the detriment of other projects in those Cycles and therefore should be denied.

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[88] As of October 31, 2025, PJM estimated $71,680,000 to rebuild the Edge Moor (DPL) – Linwood (PECO) 230 kV line associated with RTEP ID n6925 to be contingent upon a TC2 project, Project Identifier AG2-347. The facility violation does not drop away during the TC2 Cycle and applicable TC2 projects were made contingent upon upgrade n6925. *Transition Cycle 2 New Service Requests System Impact Study Executive Summary Report Transition Cycle 2 Phase I*, PJM Interconnection, L.L.C., 51 (Oct. 31, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC2/TC2_PH1_Executive_Summary.htm. *AG2-347 Phase I Study Report*, PJM Interconnection, L.L.C. (Oct. 31, 2025) https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC2/PHASE_1/AG2-347/AG2-347_imp_PHASE_1.htm ("contingent" cost allocation). *See also* Franks Aff. ¶ 11.

2. PJM properly removed the Project from TC1 because RWE did not post the required Security by the close of DP3 and requested that the Project be withdrawn

RWE chose not to post Security for the Project by the close of DP3 and submitted written notification to PJM that it was withdrawing the Project.[89] Regardless of RWE's characterization of its voluntary withdrawal as occurring "under duress,"[90] the fact remains that RWE did not post the required Security for the Project by October 21, 2025, the date of the close of DP3. By requesting reinstatement of the Project to TC1 after the required Security was not posted by the deadline and the Project was withdrawn, the Complaint effectively requests retroactive waiver of the Security posting requirements, which the Commission should deny, consistent with its precedent on failure to post Security by the Tariff deadline.

a. <u>Commission precedent holds that PJM does not violate its Tariff by terminating projects if Security is not posted by the deadline</u>

The Commission denied a similar request for waiver of the required Security at DP3 in October 2025. There, the Commission denied a request by Hexagon Energy, LLC ("Hexagon") for waiver of the Tariff requirement to post Security by the close of DP3; Hexagon sought to postpone posting the required Security past the deadline but to continue in TC1.[91] Hexagon's reason for seeking to postpone its Security posting was the increase between the Phase II and Phase III System Impact Studies of Hexagon's cost allocation by approximately $250 million, due to withdrawals of other TC1 projects at DP2. The Commission found that "Hexagon has not demonstrated that timely posting full financial

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[89] Complaint, Exhibit G (RWE Notice of Withdrawal to PJM).

[90] *Id.*

[91] *Hexagon Energy, LLC*, 193 FERC ¶ 61,074, at PP 1, 43-45 (2025) ("*Hexagon*").

security, consistent with the Tariff, is a concrete problem that warrants waiver of the Tariff" and Hexagon did not show that "PJM performed the Phase III Study or allocated any amount of Security in a manner that is inconsistent with the Tariff."[92]

RWE asks for more than postponement of the required Security posting; instead, RWE requests waiver of the bulk of the required Security amount while maintaining its position in the queue.[93] But the Commission has found that PJM does not violate its Tariff when it removes projects from the interconnection queue for failure to timely post Security.[94] Although the prior caselaw relates to Tariff, section 212.4, the same logic applies here because both Tariff, section 212.4 and section 313 are "clear" in their requirements for posting Security.[95] Section 212.4 requires an Interconnection Customer to post Security at the time it executes and returns or files the Interconnection Service Agreement ("ISA") unexecuted with PJM "to retain the assigned Queue Position," while

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[92] *Hexagon* at PP 44-45.

[93] Complaint at 2, 27. RWE has already tried a similar argument concerning the Readiness Deposit No. 3 at DP2. *See RWE Clean Energy Development, LLC*, Request for Limited Waiver, Shortened Comment Period, and Expedited Consideration of RWE Clean Energy Development, LLC, Docket No. ER25-973-000 (Jan. 17, 2025) ("RWE January 2025 Waiver Request"), and subsequent RWE Clean Energy Development, LLC, Notice of Withdrawal of Limited Waiver Request of RWE Clean Energy Development, LLC, Docket No. ER25-973-000 (Feb. 25, 2025) ("RWE February 2025 Notice of Withdrawal") where RWE decided to withdraw a project from TC1 instead of pursue a waiver request. On January 17, 2025, RWE requested waiver to postpone payment of its DP2 Readiness Deposit No. 3 for its Concord Wind project and allow RWE to maintain that project's queue position in TC1, alleging misallocation of $60 million in Network Upgrade costs. RWE January 2025 Waiver Request. The Commission did not have to decide the merits of this request as RWE withdrew its waiver request on February 25, 2025, and withdrew the Concord Wind project from TC1 (RWE February 2025 Notice of Withdrawal), following PJM's protest filed on February 7, 2025. *RWE Clean Energy Development, LLC*, Protest of PJM Interconnection, L.L.C., Docket No. ER25-973-000 (Feb. 7, 2025).

[94] *Urban Grid Solar Projects, LLC v. PJM Interconnection, L.L.C.*, 189 FERC ¶ 61,208, at P 42 (2024) ("We find that PJM did not violate the PJM Tariff when it removed the Project's queue positions from the interconnection queue for failing to timely post security"); *CE-Shady Farm, LLC v. PJM Interconnection, L.L.C.*, 184 FERC ¶ 61,140, at P 27 (2023) (finding PJM's cancellation of an ISA for failure to provide the required security by the deadline was "permitted" under the PJM Tariff).

[95] *Urban Grid Solar Projects, LLC*, 189 FERC ¶ 61,208, at P 43 (citing to Tariff, section 212.4).

Section 313 requires the posting of Security before the close of DP3 "to remain in the Cycle."[96]

The Commission also differentiated its decision to grant a limited period waiver in *Lookout Solar* from its denial of a similar waiver request in *Hexagon*, noting that in *Lookout Solar*,[97] the Commission granted a limited time period waiver of the security deposit requirement under the SPP Tariff because of "flawed results" in SPP's study and "undisputed allegations in the record of inconsistent communications and actions by SPP."[98] Here, all of PJM's communications to RWE have consistently stated that the study results are correct; PJM will not re-run the study; and that RWE has the option to post the specified Security or withdraw or be deemed to have withdrawn from the TC1. Indeed, RWE itself complains of PJM's consistency in its Complaint and Affidavit, asserting "PJM is of the opinion that consistency matters most, and it does not want to bend its current application of the rules in a way that could harm or favor a project"[99] and "consistency matters most, and it has proven itself to be inflexible when presented with arguments demonstrating it has been incorrectly applying its own rules."[100] Thus, unlike in *Lookout*

[96] *Compare* PJM Tariff, Part IV, Subpart B, section 212.4(a)-(b) ("To retain the assigned Queue Position" the interconnection customer must have executed the tendered Interconnection Service Agreement and "[a]t the time the Interconnection Customer executes and returns . . . the executed Interconnection Service Agreement" the Interconnection Customer "shall . . . provide . . . a letter of credit or other reasonable form of security" based on PJM's "sum of the estimated costs" of Network Upgrades), *with* PJM Tariff, Part VII, Subpart D, section 313(A)(1)(a) (requiring PJM to "receive [Security] from the Project Developer . . . before the close of Decision Point III for a New Service Request to remain in the Cycle").

[97] *Lookout Solar Park I, LLC*, 176 FERC ¶ 61,100, at P 23, *order on reh'g and clarification*, 177 FERC ¶ 61,127 (2021) ("*Lookout Solar*").

[98] *Hexagon* at P 45 (2025).

[99] Complaint at 10.

[100] Mekala Aff. ¶ 16.

Solar,[101] PJM has not communicated that the results of the study are incorrect and even RWE concedes that PJM has been consistent. Also, Lookout Solar Park I, LLC did not formally withdraw from the SPP queue but rather was deemed withdrawn for failure to pay its security deposit by the deadline.[102] Here, RWE submitted a formal written notice of withdrawal before the close of DP3.[103] Last, unlike in *Lookout Solar*,[104] PJM is not rerunning the studies for the Project's cluster.

b. <u>RWE's request for a tacit waiver of the Security posting requirement would violate the filed rate doctrine</u>

The filed rate doctrine, prohibiting retroactive modifications to "rates,"[105] also prohibits RWE's requested remedy of reinstating the Project in TC1. The Commission routinely has rejected requests for waiver of the deadline to post Security and reinstatement

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[101] *Lookout Solar* at P 24 ("Lookout Solar explained that it engaged in discussions with SPP about apparent errors in the DISIS Phase 1 results that overallocated to Lookout Solar costs associated with a major transmission network upgrade, SPP staff acknowledged that the results appeared to over-allocate certain upgrade costs to Lookout Solar and, according to Lookout Solar, agreed via email to accept a substantially reduced FS2, yet did not accordingly revise the reposted DISIS Phase 1 results or issue a revised invoice. SPP does not dispute these assertions or similar assertions regarding DISIS Phase 2.") (citations omitted).

[102] *Lookout Solar* at P 13.

[103] *See* Complaint, Exhibit G (RWE Notice of Withdrawal to PJM).

[104] *Lookout Solar* at P 24 ("SPP is already conducting a restudy of the DISIS Phase 2 results and the Tariff affords interconnection customers in the cluster 15 business days to review the revised results and decide whether to proceed.").

[105] *See Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 824-25 (D.C. Cir. 2021) ("Once a tariff is filed, the Commission has no statutory authority to provide equitable exceptions or retroactive modifications to the tariff."); *Old Dominion Elec. Coop. v. FERC*, 892 F.3d 1223, 1230 (D.C. Cir. 2018) ("The filed rate doctrine and the rule against retroactive ratemaking leave the Commission no discretion to waive the operation of a filed rate or to retroactively change or adjust a rate for good cause or for any other equitable considerations."). The filed rate doctrine also prohibits retroactive changes to non-rate terms and conditions, such as the terms and conditions of the Tariff. *Okla. Gas & Elec. Co.*, 11 F.4th at 830 ("Non-rate terms within the tariff may not be changed retroactively" and "The statute [FPA] provides no grounds for distinguishing rate and non-rate terms, but rather binds parties to the terms in the filed tariff."); *PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 394-95 (3d Cir. 2024) (*Okla. Gas & Elec. Co.* 11 F.4th at 829-30 (quoting *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966-67 & 980 (1986) and 16 U.S.C. § 824d(d))) ("[T]he filed rate doctrine is 'not limited to rates *per se*, but also extends to matters directly affect[ing] . . . rates.' This stems from the text of the FPA, which 'prohibits changes, not just to a rate, but also to "any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto."' In this case, the petitioners and FERC agree that the filed rate is the PJM Open Access Transmission Tariff.").

of projects in the queue when the Interconnection Customer missed the deadline to post Security.[106] The Commission found that reinstating a project after it fails to timely post Security "to its currently assigned PJM interconnection queue is retroactive in nature and is prohibited by the filed rate doctrine."[107] The same logic applies here and therefore the finding should be the same. The Tariff clearly states that due to RWE's written withdrawal of the Project on the deadline for DP3, the Project is withdrawn and has lost its position in TC1. Reinstating the Project after its withdrawal would violate the filed rate doctrine.

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[106] *CE-Shady Farm, LLC*, 184 FERC ¶ 61,140, at P 24 (missed security deposit deadline by one day); *Ridgeview Solar LLC*, 185 FERC ¶ 61,148 (2023) (submitted security in unacceptable format and then corrected it after the deadline).

[107] *CE-Shady Farm, LLC*, 184 FERC ¶ 61,140, at P 24; *see also Ridgeview Solar LLC*, 185 FERC ¶ 61,148 (waiving security deadline "is retroactive in nature and is prohibited by the filed rate doctrine").

IV. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to, and PJM requests the Secretary to include on the official service list, the following:[108]

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V. AFFIRMATIVE DEFENSES PURSUANT TO 18 C.F.R. § 385.213(c)(2)(ii)

PJM's affirmative defenses are set forth above in this answer, and include the following, subject to amendment and supplementation:

1. *RWE, as the Complainant, has failed to satisfy its burden of proof under FPA section 206 (16 U.S.C. § 824e).*

VI. SERVICE

PJM has served a copy of this filing on all PJM Members and on the affected state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[109] PJM will post a copy of this filing to the FERC filings section on its internet site, https://pjm.com/library/filing-order, and will

[108] To the extent necessary, PJM requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3), to permit all of the persons listed to be placed on the official service list for this proceeding.

[109] *See* 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

send an email on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region,[110] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within twenty-four hours of the filing.

VII. CONCLUSION

For the reasons set forth in this answer, the Commission should deny the Complaint.

Respectfully submitted

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November 17, 2025

[110] PJM already maintains, updates, and regularly uses email lists for all PJM Members and affected state commissions.

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 Washington, D.C., this 17th day of November 2025.

/s/ Alyssa Umberger
Attorney for
PJM Interconnection, L.L.C.

Attachment A

Affidavit of Edmund Franks on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

RWE Clean Energy, LLC, Complainant,	)	
v.	)	Docket No. EL26-7-000
PJM Interconnection, L.L.C., Respondent.	)	

AFFIDAVIT OF EDMUND FRANKS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Edmund Franks, and my business address is 2750 Monroe Blvd., Audubon, Pennsylvania 19403. I am employed by PJM Interconnection, L.L.C. ("PJM") and my current title is Principal Engineer, Interconnection Analysis.

2. I am submitting this affidavit on behalf of PJM in support of PJM's answer to the Complaint Requesting Shortened Comment Period and Fast Track Processing of RWE Clean Energy, LLC (the "Complaint" and "RWE") filed by RWE in Docket No. EL26-7. The Complaint and its accompanying Affidavit of Karthik Mekala,[1] materially misrepresent and distort PJM's Generator Deliverability Procedure in an attempt to evade cost responsibility for Network Upgrades to the Edge Moor-Linwood 230-kilovolt ("kV") transmission facility ("Edge Moor-Linwood Line") for RWE's Maryland Blue Crab generation and storage project ("Project").

3. In this Affidavit, I will:

- explain how the Generator Deliverability Procedure actually works;

[1] Complaint, Attachment A (Affidavit of Karthik Mekala) ("Mekala Affidavit").

- explain why PJM uses direct current ("DC") loadings in the common mode outage procedure comparison of operational contingencies and common mode contingencies;
- show that RWE and Mr. Mekala are wrong in claiming that PJM misapplied the procedure to the Project, that PowerGem's TARA software which runs the PJM Generator Deliverability Procedure needs to be changed, and that PJM can easily correct its alleged errors and relieve the Project of any cost allocation for upgrades to the Edge Moor-Linwood Line; and
- rebut RWE's claims that the Project would provide a significant contribution to resource adequacy in the PJM Region.

<u>How the Generator Deliverability Procedure Actually Works</u>

4. To understand how PJM's Generator Deliverability Procedure actually works, it is important to acknowledge that a change to the Generator Deliverability Procedure occurred in April 2023. As a result, the appropriate reference point for the Generator Deliverability Procedure applied to Transition Cycle No. 1 ("TC1") is PJM Manual 14B, revision 51,[2] and *not* the currently effective version of PJM Manual 14B, revision 57. I will call the Generator Deliverability Procedure applied to TC1 the "Legacy Generator Deliverability Procedure" because in April 2023 PJM changed the deliverability procedure used for its Regional Transmission Expansion Plan ("RTEP") process to

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[2] PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process*, PJM Interconnection, L.L.C., at 47 (Rev. 51, Dec. 15, 2021) https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m14b/m14bv51-pjm-regional-transmission-planning-process-12-15-2021.pdf ("PJM Manual 14B, revision 51"). The applicable sections, attachments, and addendums discussed in this affidavit are attached hereto as Exhibit 1.

implement block dispatch.[3] PJM first implemented the changed deliverability procedure looking forward five years, applying it first to the 2028 RTEP model. The post-April 2023 Generator Deliverability Procedure is the Generator Deliverability Procedure found in the currently effective version of PJM Manual 14B, revision 57. For reference, the table below summarizes these key points:

	Applicable PJM Manual	Cycle Applicability	RTEP Applicability	Planning Models Delivery Year
Legacy Generator Deliverability Procedure	Manual 14B, revision 51	TC1	2027 RTEP	2027-2028
Currently Effective Generator Deliverability Procedure	Manual 14B, revision 57	TC2	2028 RTEP	2028-2029

5. As a result, the 2027 RTEP model was the last model to use the Legacy Generator Deliverability Procedure. Moreover, because PJM studied TC1 using Planning models for the 2027-28 Delivery Year, TC1 will be the last Cycle to use the Legacy Generator Deliverability Procedure. Beginning with Transition Cycle No. 2 ("TC2"), which is being studied using Planning models for the 2028-29 Delivery Year, PJM Interconnection Analysis will apply the Generator Deliverability Procedure found in the currently effective revision of PJM Manual 14B, revision 57.[4] This Generator

[3] *See* PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process*, PJM Interconnection, L.L.C., at 173 (Rev. 57, Sept. 25, 2024), https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf (Revision History for revision 52) ("PJM Manual 14B, revision 57").

[4] *See* Heather Reiter, *Interconnection Analysis Expedited Process & Transition Cycle 1 Status*, PJM Interconnection Process Subcommittee, 17-19 (Jan. 29, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/ips/2024/20240129/20240129-item-04---fast-lane---tc1-status-update-post-meeting.pdf.

Deliverability Procedure no longer simulates and determines operational contingency loadings and no longer compares such operational contingency loadings to the common mode contingency loadings to determine whether there is a reliability criteria violation to be mitigated for the common mode contingency overloads. Instead, the current Generator Deliverability Procedure takes a more conservative approach by simply mitigating for all reported common mode contingency overloads.

6. However, because the Project is in TC1, it is important to explain how the Legacy Generator Deliverability Test works and where the relevant provisions are found. At a high level, the Legacy Generator Deliverability Test is used to ensure that generation output is deliverable throughout the PJM Transmission System during certain conditions and contingencies. Section 2.3.10 and Attachment C.3 of PJM's Manual 14B, revision 51, describe PJM's Legacy Generator Deliverability Procedure and the various contingencies simulated during the Legacy Generator Deliverability Procedure to ensure the PJM Transmission System can deliver the aggregate system generating capacity at summer peak load and during light load and winter peak conditions. Manual 14B, revision 51, section 2.3.10 describes the Legacy Generator Deliverability Test as simulating not only single contingencies, but also North American Electric Reliability Corporation ("NERC") P2, P4, and P7 multiple contingencies[5] that PJM refers to as "common mode contingencies." These common mode contingencies represent the loss of multiple system elements that occur simultaneously due to a single external event or shared component failure, such as a vehicle striking a tower that supports more than one transmission line,

[5] NERC TPL-001 Table 1 labels P2, P4, P7 each as a "multiple contingency." This table is copied and included in PJM Manual 14B, Attachment I (Steady State & Stability Performance Planning Events).

causing multiple lines to fail, or a circuit breaker that is stuck closed, which is attempting to clear a fault by opening.

7. Section 2.3.10 of PJM Manual 14B, revision 51, states (emphasis added):

> [T]he same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C. One additional step is applied after generator deliverability is completed. *The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC P2, P4, and P7 common mode outages.* The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.[6]

The referenced additional step for common mode outages, required by system reliability criteria, is found in Addendum 2 of Attachment C to PJM Manual 14B, revision 51,[7] called the "Common Mode Outage Procedure."

8. The relevant steps of the Legacy Generator Deliverability Procedure set forth in Attachment C, section C.3.1.3, of PJM Manual 14B, revision 51 are as follows.

- **Single Contingencies**
  - Steps 3 through 6 describe the procedure for *single contingencies* being simulated and specify that the relevant loadings used are DC loadings. *See* Step 3, first sentence (emphasis added): "PJM uses a linear *(DC) power flow* program to analyze each facility for which PJM is responsible to determine whether any single contingency can overload the facility."[8]

[6] PJM Manual 14B, revision 51 at 47.

[7] *Id.* at 92-93.

[8] *Id.* at 89.

- Step 6 concludes the procedure, for single contingencies, by first determining the final DC loading, then secondly determining the corresponding final alternating current ("AC") loading by determining the 80/20 AC loading and the resultant Final Flowgate Loading.[9]

- **Common Mode Contingencies**
  - The Legacy Generator Deliverability Procedure not only tests single contingencies as described in Attachment C, but also studies common mode contingencies, through the Common Mode Outage Procedure described in Addendum 2 of Attachment C of PJM Manual 14B, revision 51.
  - Attachment C, Addendum 2 of PJM Manual 14B, revision 51 states that "PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages."[10] The generator deliverability procedure referenced here is the procedure for single contingencies outlined in Steps 3 through 6 in Attachment C, section C.3.1.3, previously discussed. The same Steps 3 through 6 apply to the common mode contingencies but with certain technical differences that Addendum 2 describes.
  - For testing common mode contingencies, the last step again is Step 6 in which a final DC loading will be determined followed by a corresponding final AC loading for the common mode contingencies.

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[9] *Id.* at 91.

[10] *Id.* at 93.

However, as described in Attachment C, Addendum 2 of PJM Manual 14B, revision 51, the Legacy Generator Deliverability Procedure includes in the Common Mode Outage Procedure a comparison of single contingency loadings studied under the Common Mode Outage Procedure to common mode contingency loadings. A single contingency studied under the Common Mode Outage Procedure is called an "operational contingency" and the purpose of studying it and comparing it to a common mode contingency is to determine whether system operators would allow the common mode dispatch to occur.

- Once the comparison of the operational contingency loadings and common mode outage contingencies is done, the outcome is evaluated as follows.
  - An operational contingency DC loading that is greater than or equal to the DC loading produced by a common mode outage means the loading caused by the common mode outage can be ignored;
  - However, if the DC loading of the common mode contingency is greater than the DC loading of the operational contingency, then the common mode contingency loading is considered a reliability criteria violation, and PJM will require a system upgrade to resolve the loading that is scoped and sized using the final AC loading of the common mode contingency.

- PJM uses the final AC loadings of both single contingencies and common mode contingencies if those contingencies are deemed reliability criteria violations to size the system upgrades needed to mitigate the reliability criteria violations, in order to keep the system reliable.

9. PJM uses DC loadings for the comparison of operational contingency loadings to common mode contingency loadings in the Legacy Generator Deliverability Procedure for several reasons. First, DC loadings are more stable for purposes of comparison than AC loadings would be. DC power flow loadings are also less sensitive to changing from minor system model changes than AC power flow loadings are; AC power flow loadings account for reactive power flowing and, therefore, are more volatile.

10. Moreover, the point of using DC loadings for the comparison is to minimize the "flip flopping" of the common mode contingency loadings versus the operational contingency loadings since the common mode contingency loadings and the operational contingency loadings can sometimes be identical or very close to one another with differences of only tenths of a loading percent. When the loadings are this close to one another, even minor changes to the loading can change the conclusion as to which loading is greater when comparing the common mode contingency loading and the operational contingency loading.

11. Further, certain changes to the system model can sometimes change the AC loading by tenths of a loading percent, while the DC loading remains relatively stable as PJM performs interconnection retool studies and RTEP studies. PJM, therefore, chose to use DC loadings specifically to try to maintain a more consistent set of results for Project Developers over the course of a Cycle from the initial Phase I System Impact Study to the

subsequent Phases II and III studies and retool studies. Contrary to RWE's claims, PJM did not choose to use DC loadings for the comparison merely for "simplicity."

12. PJM has consistently used DC loadings in this comparison step in past RTEP studies through the 2027 RTEP and in all past interconnection studies that used the Legacy Generator Deliverability Procedure. PJM's use of DC loadings for the comparison is also coded into the PowerGem TARA Generator Deliverability Procedure software to ensure this consistent use. This comparison step of the Generator Deliverability Procedure is not a step a PJM engineer can subjectively apply inconsistently on a case-by-case basis, as the Complaint would have it seem. All of RWE's assertions to the contrary are self-serving claims designed to change a cost allocation result for the Project that RWE sees as unfavorable and pass those costs onto other Project Developers.

Contrary to RWE's Claims, PJM Did Not Misapply the Legacy Generator Deliverability Procedure, Does Not Need to Correct the Application of the Procedure or the PowerGem TARA Software, and Cannot Readily Change How the Legacy Generator Deliverability Procedure Functions

13. The key portion of the Legacy Generator Deliverability Procedure that the Complaint and Mekala Affidavit misrepresent is the part of Attachment C, Addendum 2 of PJM Manual 14B, revision 51 that describes the comparison of operational contingency loadings and common mode outage contingencies, which states:

> If a single contingency under the common mode outage procedure would result in a loading greater than or equal to the loading produced by a common mode outage, then the loading caused by the common mode outage can be ignored. The single contingency studied under the common mode outage procedure is called an "operational contingency" and its purpose is to determine whether system operators would allow the common mode dispatch to occur.[11]

[11] PJM Manual 14B, revision 51 at 93.

14. The Legacy Generator Deliverability Procedure language in Attachment C, Addendum 2 of PJM Manual 14B, revision 51 says "loadings" and does not distinguish whether the loadings being compared are DC loadings or AC loadings. PJM uses DC loadings, not AC loadings, for this very specific step to compare the operational contingency loadings to the common mode contingency loadings. Further, this procedure is hard coded into PowerGem's TARA software, as RWE remarked.[12] Thus, PJM's use of DC loadings at this step of the Common Mode Outage Procedure does not violate PJM Manual 14B, revision 51, as the Complaint and Mekala Affidavit contend. Moreover, the hard coding of DC loadings in the software is deliberate and does not need to be corrected.

15. If the Commission were to grant the Complaint and require PJM to change how it performs the last iteration of the Legacy Generator Deliverability Procedure for RWE's benefit, the impact of the change would not be limited to the Edge Moor-Linwood Line and the Project, as RWE claims. To consistently and fairly apply the changed rule to all TC1 projects, PJM would need to go back and again perform the Legacy Generator Deliverability Procedure, as modified by RWE to use AC loadings rather than DC loadings in the comparison of operational contingency loadings to common mode outage loadings, thereby effectively re-running the Phase III System Impact Study. There certainly is the potential for the modified analysis in the re-run to change common mode contingency loadings on other facilities to be greater than the operational contingency loadings on those other PJM facilities if the AC loadings were used in the comparison as opposed to the DC loadings. This would result in the identification of new reliability criteria violations, requiring PJM to scope new Network Upgrades to resolve those new reliability criteria

[12] Complaint at 10; Mekala Affidavit ¶ 10.

violations and assign new cost responsibility to TC1 projects. Not only would this re-run take time and delay the completion of TC1 and further advancement of Transition Cycle No. 2, but the new violations and new cost allocations would upset the expectations of the affected Project Developers in TC1 just as they are moving to execute their final interconnection agreements.

16. To the extent the Mekala Affidavit suggests that PJM wishes to continue its consistent practice of using DC loadings in the Common Mode Outage Procedure comparison because of timing concerns at the end of TC1, I can confirm that the timing of the Complaint is not relevant to PJM's insistence on using DC loadings in the comparison. Even if PJM were in Phase I of TC1, rather than being in the Final Agreement Negotiation Phase of TC1, PJM's explanation as to why DC loadings are used in the comparison would be the same, as would the fact that PJM has always applied the Legacy Generator Deliverability Procedure that way in the past, and the fact that the application is consistent with PJM Manual 14B, revision 51.

17. Finally, I note that the results of the Transition Cycle No. 2 Phase I System Impact Study, which PJM released on October 31, 2025, show that the Edge Moor-Linwood Line is overloaded and that Transition Cycle No. 2 projects contribute to the overloads. If Queue Nos. AF2-358 and AG1-450 were required to remain active and the Project were to advance in the interconnection process without funding the required upgrades to the Edge Moor-Linwood Line, the cost responsibility for the required upgrades would shift to Transition Cycle No. 2 Project Developers, in violation of the Tariff's prohibition on inter-Cycle cost allocation.[13]

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[13] Tariff, Part VII, Subpart D, section 307(A)(5)(c).

Rebutting Claims the Project Would Provide A Significant Contribution to Resource Adequacy in the PJM Region

18. The Complaint and the Mekala Affidavit both reference the value of the Project to the PJM Transmission System to help alleviate system-wide resource adequacy shortfalls. I provide some details on the two Interconnection Requests that make up the Project to show that, while PJM values all generation coming onto the system at this critical time, RWE exaggerates the Project's impact from a resource adequacy or Capacity accreditation perspective:

- Queue No. AF2-358 is a tracking solar project and its 2027-28 Delivery Year Effective Load Carrying Capability ("ELCC") class rating is 8 percent. With a 100 MW Maximum Facility Output and 60 MW of Capacity Interconnection Rights ("CIRs"), Queue No. AF2-358 will have 8 MW of accredited unforced capacity ("UCAP"); and
- Queue No. AG1-450 is a 10-hour battery storage project and its 2027-28 Delivery Year ELCC class rating is 78 percent. With a 25 MW Maximum Facility Output and 25 MW of CIRs, Queue No. AG1-450 will have 19.5 MW of accredited UCAP.

The two Interconnection Requests that make up the Project, assuming they operate and participate in the PJM Markets as Co-Located resources (as opposed to a Hybrid configuration), would comprise a combined total of approximately 27.5 MWs of Accredited UCAP (8 MW UCAP + 19.5 MW UCAP).

19. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

RWE Clean Energy, LLC, Complainant,	)	
	)	
v.	)	Docket No. EL26-7-000
	)	
PJM Interconnection, L.L.C., Respondent.	)	

VERIFICATION

I, Edmund Franks, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Edmund Franks referred to in the foregoing "Affidavit of Edmund Franks on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Signed by:
Edmund Franks
03815747F7D6480...
Edmund Franks

Executed on: 11/17/2025

Exhibit 1

Excerpts from PJM Manual 14B: PJM Region Transmission Planning Process, Revision 51 (Dec. 15, 2021)

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 51

Effective Date: December 15, 2021

Prepared by
Transmission Planning Department

2.3.9 Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer and winter load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC P0 and P1 criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

2.3.10 Generator Deliverability Analysis

The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified Capacity Resources in each "area". Areas, as referred to in the generator deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of Capacity Resources. For generator deliverability, areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the "area" for that element. The starting point power flow is the same power flow case set up for the baseline analysis. Thus the same baseline load and ratings criteria apply. The flowgates ultimately used in the reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. As already mentioned the same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

One additional step is applied after generator deliverability is completed. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC P2, P4, and P7 common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

2.3.11 Light Load Reliability Analysis

The light load reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at light load. The 50% of 50/50 summer peak demand level was chosen as being representative of an average light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted as well as areas surrounding PJM that impact loadings on facilities in PJM. Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. Thus the same baseline network model and criteria apply. The flow gates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5 and P7. NERC TPL P0, normal system conditions will also be studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques also apply. Details of the light load reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.2. The resulting system enhancements from all Light Load reliability analysis are expected to be in-service prior to November 1 of the Delivery Year under study.

2.3.12 Spare Equipment Strategy Review

PJM will annually evaluate the spare equipment strategy that could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer) and assess the impact of this possible unavailability on system performance using NERC category P0, P1 and P2 contingency categories identified in Table 1 of NERC TPL-001-4. This assessment will consider the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

2.3.13 Winter Peak Reliability Analysis

The winter peak reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at winter peak. The PJM 50/50 winter peak demand

PJM OATT (Tariff) in Section 15 of Attachment DD. Criteria needed to be met to include an easily resolved constraint as a transmission upgrade in the RTEP include

- The transmission upgrade(s) will result in a Capacity Emergency Transfer Limit that exceeds 1.15 times the Capacity Emergency Transfer Objective for the LDA; and
- The transmission upgrade(s) is/are expected to be in-service prior to June 1 of the Delivery Year for which the Base Residual Auction is being conducted; and
- The transmission upgrade cost is expected to be less than $5 million; and
- There are no Merchant Network Upgrades that have or are expected to have an executed Facilities Study Agreement by 45 days prior to the Base Residual Auction that are designed to resolve the same constraint for which the RTEP upgrade is designed to resolve.

The annual costs of such upgrade shall be allocated as specified in Schedule 12 of the tariff.

C.3 Deliverability of Generation

The second deliverability test examines the ability of an electrical area to export Capacity Resources to the remainder of PJM. This test is applied to ensure that capacity is not "bottled" from a reliability perspective. This requires that each electrical area be able to export its capacity, at a minimum, during the summer peak load period as this represents the condition where PJM reserve margins have historically been at their lowest levels. Export capabilities under winter and light load conditions are also examined using their own unique deliverability criteria described in Appendix D. All three generator deliverability tests are required to be passed in order for a generator to become certified as a PJM Capacity Resource. Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if Capacity Resources are available and called on, their ability to provide energy to the system will not be limited by the dispatch of other certified Capacity Resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, and that the excess energy above load in that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In short, the test attempts to ensure that bottled capacity conditions that limit the availability and usefulness of certified Capacity Resources to system operators will not exist. In actual operating conditions, energy-only resources may displace Capacity Resources in the economic dispatch that serves load. This test demonstrates that resources equal to or greater than the installed capacity in any given electrical area could simultaneously deliver energy to the remainder of PJM. The premise of the generator deliverability test is that all PJM Capacity Resources within an electrical region within PJM are required; hence the remainder of the system outside this electrical region is experiencing a significant reduction in available capacity. The dispatch pattern in the remainder of the system is modeled based on a uniformly distributed outage pattern.

C.3.1 Generator Deliverability Procedure

C.3.1.1 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability within the PJM Control Area in two ways. First, energy must be deliverable, from the aggregate of resources available to the PJM Control Area to load in portions of the applicable PJM areas experiencing a localized capacity emergency. PJM utilizes the Load Deliverability procedure to ensure this requirement. Second, Capacity Resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM when required. PJM utilizes the Generator Deliverability procedure to ensure the deliverability of individual generation resources. The following sections describe the Generator Deliverability procedure.

C.3.1.2 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be deliverable in order to be a PJM installed Capacity Resource.

C.3.1.3 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All identified RTEP Baseline and Supplemental Projects projected to be in service by June 1 of the reference year are included in the system model. Load is modeled at a non-diversified forecasted 50/50 summer peak load level. All long-term firm transmission service confirmed for the reference year and service with rollover rights that has been coordinated with the applicable PJM neighboring region is included in the model. Generation and Merchant Transmission Facilities that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a uniform reduction of generation in place of discrete forced outages for this test due to the significant bias any one specific outage pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

Place all in-service Capacity Resources (those that have procured Capacity Interconnection Rights) and all Capacity Resources with an executed Interconnection Service Agreement (ISA) on-line at a generation value equal to their installed capacity x (1 – PJM average EEFORd). Wind units with capacity delivery rights are derated to their granted capacity rights (13% beginning with the “U” queue, 20% for prior queues, or higher values when justified by meteorological data) representing the combined effects of wind variation and outage characteristics. The target generation value is the projected load + losses + firm interchange. (See Addendum 1 for treatment of Firm Transmission Withdrawal and Injection Rights). If all in-service and ISA Capacity Resources are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. If all in-service and ISA Capacity Resources are less than the target generation value, then place all Capacity Resources with an executed Facility Study Agreement on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service, ISA and Facility Study Capacity Resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. This represents the starting dispatch in the RTEP baseline generator deliverability studies. During the generator deliverability evaluation of a New Service Request additional dispatch procedures are employed. More specifically, all resource requests in the study queue ahead of the unit under study are set at 0 MW but available to be turned on. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a single contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any single contingency can overload the facility. These results are utilized to determine which flowgates will be used in the generator deliverability analysis, i.e., the program examines each PJM flowgate (contingency / monitored element pair) in the entire PJM footprint as well flowgates near the border of PJM. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. This result will be referred to the ramping impact of a particular generator on a particular flowgate. For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping of internal generation is 10,000 MW (20,000 MW for studies examining the impacts of external generators as well) but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine 80/20 DC loading

The number of generators having greater than a 1% distribution factor in Step 3 is often large enough that having them all simultaneously outputting their full installed capacity would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Units modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's lowest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. The availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 20%. This resulting "80/20" cumulative ramping impact is then added to the initial DC loading on the flowgate. This resulting loading is the 80/20 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 80/20 generators.

Step 5: Determine Facility Loading Adder

This Step 5 addresses off-line generators which are not included in the 80/20 list. Existing generators pending retirement, active queued generators and merchant transmission projects that do not yet have a signed ISA or have a suspended ISA may be modeled offline, and, if so, are available to be turned on to contribute to but not back off flowgate loadings. The ramping impact of this set of generators determines the Facility Loading Adder. First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the lowest terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

The summation of 85% (100% for a merchant transmission project) of the ramping impact on a flowgate from each off-line resource that meets the above conditions is calculated. The resulting impact defines the Facility Loading Adder. The Facility Loading Adder is added to the 80/20 DC loading to obtain the final DC loading on the facility.

Facility Loading Adder Restrictions

1) For each potential flowgate, an approximated Capacity Emergency Transfer Objective (CETO) will be calculated for the flowgate's receiving end area. The CETO is used to ensure the transfers over the flowgate are not exceeding those that would occur under more severe capacity emergency conditions than are examined under the PJM Load Deliverability test described in the first part of this Attachment C. The receiving end area will include all PJM

- Load buses with a positive impact on flowgate loading
- Generators with negative impact on flowgate loading

The estimated CETO will be calculated using the following function

Estimated CETO = 1.08 * (Bus Loads + Losses - Diversity – Demand Response) – (1 – Avg. EEFORD) * ICAP + Largest Unit

In order to account for generation assistance from outside PJM, each receiving end area will be assigned a portion of the PJM Capacity Benefit Margin (CBM) based the receiving end area's share of the PJM load. CBM is the amount of imports that PJM assumes will be available from neighboring regions during a RTO-wide capacity deficiency.

The CETO and CBM will be used to provide an upper limit to the Facility Loading Adder by limiting its contribution to the import level for a of the receiving end area of the flowgate such that the

- Receiving end area imports < Receiving end area estimated CETO - Receiving end area CBM allocation)

In order to ensure that offline generators within small clusters of the electrically closest generation to a flowgate will not be restricted by this Facility Loading Adder limit, an exception to the application of the CETO and CBM will be made. Generators which contribute to the Facility Loading Adder and have distribution factors that are greater than two standard deviations plus the mean of all PJM generator distribution factors, or less than the negative of this value, will be available to contribute to the Facility Loading Adder. For example, if the mean distribution factor is 3% and the standard deviation is 2%, then offline generators having a DFAX greater than 7% or less than -7% will not be restricted by this Facility Loading Adder limit.

2) The amount of generation change from the initial load flow due to changes in 80/20 and Facility Loading Adder generation shall not be any more than the online installed capacity exclusive of the 80/20 generators × PJM average EEFord. This rule is enforced by curtailing generators that contribute to the Facility Loading Adder. In order to always maintain a critical system condition for this deliverability test, the 80/20 or 50/50 generation, as applicable, will not be curtailed to enforce this rule.

3) The ramping impact of active queued generators at the feasibility study stage of the interconnection process considers the commercial probability. For generators at the feasibility study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the impact study stage of the interconnection process. To be conservative, the values developed during the feasibility study stage are then multiplied by 150% to determine the ramping impact of generation at the feasibility study of the interconnection process.

Step 6: Determine Final Flowgate Loading

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 80/20 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 80/20 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will sometimes create a localized capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, which is a DC value as determined in Step 5, is added to the 80/20 AC loading to result in the Final Flowgate Loading.

Addendum 1: Modeling Merchant Transmission Facilities (MTFs)

Controllable MTFs, i.e. HVDC which interconnects PJM to another system, may have some combination of firm rights (Transmission Withdrawal Rights, Transmission Injection Rights or long-term firm transmission service). Existing MTFs with firm rights and MTFs with an executed ISA with firm rights are modeled as a transmission facility carrying the firm rights. Refer to Exhibit 4.

In the case of a bi-directional MTF, the rights associated with the injection into PJM are modeled as an offline generator at the PJM MTF terminal. A net injection from the terminal into PJM equal to the firm injection rights is simulated, consistent with the 80/20 and Facility Loading Adder rules, when such injection contributes to a flowgate’s loading.

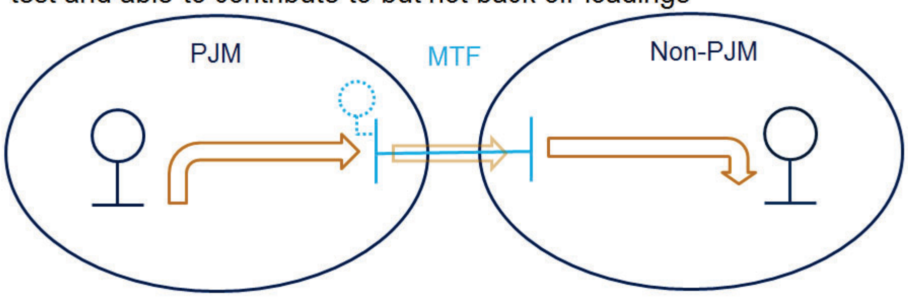
If the MTF request does not have an executed ISA it will be modeled offline but be allowed to contribute to flowgate loadings consistent with the 80/20 and Facility Loading Adder rules.

Scenario	LTF TS?	Firm TWRs?
1	No	No
2	No	Yes
3	Yes	No
4	Yes	Yes

*LTF TS = Long-term Firm Transmission Service; Firm TWRs = Firm Transmission Withdrawal Rights

Load & Generator Deliverability

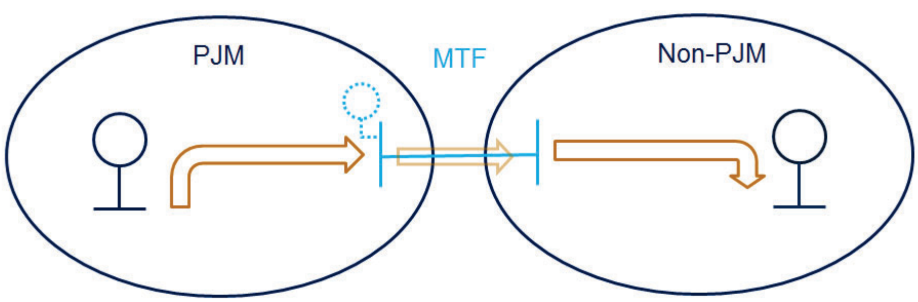
- Scenario 1 not considered
- Scenarios 2, 3 & 4 modeled at greater of LTF TS or Firm TWRs
- Firm TIRs modeled as offline generator at MTF PJM terminal in generator deliverability test and able to contribute to but not back off loadings



*Arrows represent firm flows

Common Mode Outage Deliverability

- Scenarios 1 through 4 modeled at FTWRs + NFTWRs
- FTIRs + NFTIRs modeled as offline generator at MTF PJM terminal able to contribute to but not back off loadings



*Arrows represent firm + non-firm flows

Exhibit 4: Modeling Rights for Merchant Transmission Facilities

Addendum 2: Common Mode Outage Procedure

In addition to single contingencies, PJM planning criteria requires that the PJM system withstand certain common mode outages. These outages include line faults coupled with a stuck breaker, double circuit towerline outages, faulted circuit breakers and bus faults. PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages. The list below highlights the other details of the common mode outage procedure that differ from the generator deliverability procedure.

In addition to the modeling of Capacity Resource requests, all existing energy resources (including MTFs with non-firm rights), the energy resource request under study and all energy resource requests queued ahead of the unit under study are set at 0 MW but available to be turned on. Energy resource requests queued after the unit under study are not modeled.

A 50/50 DC loading is used instead of an 80/20 DC loading, i.e., the expected availability of the selected units is close to but not less than 50%.

If a single contingency under the common mode outage procedure would result in a loading greater than or equal to the loading produced by a common mode outage, then the loading caused by the common mode outage can be ignored. The single contingency studied under the common mode outage procedure is called an “operational contingency” and its purpose is to determine whether system operators would allow the common mode dispatch to occur.

The offline resources can contribute to the flowgate loading as a Facility Loading Adder. However, only non-intermittent energy resources that exist or have an ISA can contribute as a Facility Loading Adder in such a manner that they back off the loading on the flowgate under study.

For all voltage levels, a 10% distribution factor is used instead of a 5% distribution factor to select the 50/50 generators; however, the thresholds used to restrict the Facility Loading Adder are the same as those in the generator deliverability procedure.

Addendum 3: Transmission Service Study Procedures

During the conduct of New Service Request studies, for the evaluation of Transmission Service impacts during generator deliverability testing and common mode outage testing, contribution thresholds have been developed to account for the proximity of the source of the service in relation to the PJM footprint. During testing of transmission service seeking to import energy into PJM, PJM shall use a 3% distribution factor or 3% rating cutoff to select the service which shall be allowed to contribute to flowgates under study. During testing of transmission service seeking to export energy from PJM, PJM shall use these same distribution factor and rating cutoffs to select the service which shall be allowed to contribute to flowgates under study when that flowgate involves a facility outside of PJM’s footprint; however, PJM shall maintain all thresholds for impacts to flowgates that involve PJM facilities consistent with the requirements listed outside this Addendum 3.

In both baseline and New Service Request studies, constraints identified in the PJM Capacity Import Limit procedure (Section G.11 PJM Capacity Import Limit Calculation Procedure) are studied in the same manner as internal PJM constraints. . With regard to transmission service, in baseline studies any transmission service which impacts a constraint identified in the CIL study shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading. In New Service Request studies any transmission service which impacts a constraint identified in the CIL study at greater than the thresholds identified above in this section shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading.

Attachment B

Tables derived from AF2-358 and AG1-450 Phases I-III Study results

Attachment B: Tables Derived from AF2-358 and AG1-450 Phases I-III Study Results

	AF2-358			AG1-450		
	Phase I	Phase II	Phase III	Phase I	Phase II	Phase III
Transmission Owner Interconnection Facilities	$ 350,000	$ 417,314	$ -	$ 350,000	$ 417,314	$ -
Other Scope		$ 5,822	$ -		$ 5,822	$ -
Option to Build Oversight			$ 1,500,000			$ 1,500,000
Physical Interconnection Network Upgrades						
Stand Alone Network Upgrades	$ 6,775,000	$ 8,727,020	$ -	$ 6,775,000	$ 8,727,000	$ -
Network Upgrades	$ 1,000,000	$ 610,000	$ 610,000	$ 1,000,000	$ 610,000	$ 610,000
System Reliability Network Upgrades			This amount is disputed.			This amount is disputed.
Steady State Thermal & Voltage (SP & LL)	$ 72,067,013	$ 1,000,000	$ 57,529,731	$ 5,092,059	$ 250,000	$ 14,382,433
Transient Stability	$ -	$ -	$ 1,102,116	$ -	$ -	$ 1,377,646
Short Circuit	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Owner Analysis						
SubRegional	$ -	$ -	$ -	$ -	$ -	$ -
Distribution	$ -	$ -	$ -	$ -	$ -	$ -
Affected System Study Reinforcements	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 80,192,013	$ 10,760,156	$ 60,741,847	$13,217,059	$ 10,010,136	$ 17,870,079