UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER26-1300-000**
	)	**ER26-1303-000**
	)	**(NOT CONSOLIDATED)**

MOTION FOR LEAVE TO ANSWER AND ANSWER OF PJM INTERCONNECTION, L.L.C.

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission ("Commission" or "FERC") Rules of Practice and Procedure,[1] PJM Interconnection, L.L.C. ("PJM") hereby submits this Motion for Leave to Answer and Answer ("Answer") to the Amelia Energy Facility, LLC ("Amelia Energy") Motion for Leave to Answer and Answer.[2] For the reasons set forth below and in its initial Answer, PJM respectfully requests that the Commission reject the Amelia Energy Protest and Amelia Energy Answer and accept the Amelia Energy GIA and associated NUCRAs as filed and establish an effective date of April 11, 2026. The

[1] 18 C.F.R. §§ 385.212, 213.

[2] *PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of the Amelia Energy Facility, LLC, Docket Nos. ER26-1300-000 & ER26-1303-000 (Mar. 25, 2026) ("Amelia Energy Answer"). Amelia Energy filed the Amelia Energy Answer in response to PJM's filing of a Motion for Leave to Answer and Answer, filed in response to Amelia Energy's protest to PJM's filing of an unexecuted GIA and eight partially executed NUCRAs. *See PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C., Docket Nos. ER26-1300-000 & ER26-1303-000 (Mar. 18, 2026) ("PJM Answer"); *PJM Interconnection, L.L.C.*, Protest of Amelia Energy Facility, LLC, Docket Nos. ER26-1300-000 & ER26-1303-000 (Mar. 2, 2026) ("Amelia Energy Protest"); *PJM Interconnection, L.L.C.*, Original Generation Interconnection Agreement, Service Agreement No. 7832; Project Identifier No. AF1-294/AF2-115/AG1-021, Docket No. ER26-1300-000 (Feb. 9, 2026) (PJM's unexecuted filing of Amelia Energy's GIA ("Amelia Energy GIA") for PJM Project Identifier No. AF1- 294/AF2-115/AG1-021 ("Amelia Energy Facility"); *PJM Interconnection, L.L.C.*, Eight Original Network Upgrade Cost Responsibility Agreements; Network Upgrade No. n8492, Service Agreement No. 7827 Network Upgrade No. n8492.1, Service Agreement No. 7828 Network Upgrade No. n8492.2, Service Agreement No. 7829 Network Upgrade No. n9267, Service Agreement No. 7830 Network Upgrade No. n9259, Service Agreement No. 7831 Network Upgrade No. n9220, Service Agreement No. 7852 Network Upgrade No. n9217, Service Agreement No. 7856 Network Upgrade No. n9630, Service Agreement No. 7857, Docket No. ER26-1303-000 (Feb. 9, 2026) ("NUCRA Filing") (PJM's filing of 8 unexecuted NUCRAs related to the Amelia Energy Facility, including the 5 Network Upgrades disputed by Amelia Energy: n8492, n8492.1, n8492.2, n9259, and n9267 ("Disputed Network Upgrades" or "Disputed NUCRAs")) (collectively, the "February 9 Filing").

Commission's timely disposition is necessary to enable PJM to satisfy the remaining requirements for Transition Cycle No. 1 ("TC1"), including the performance of a second retool analysis and maintaining the current schedule for Transition Cycle No. 2 ("TC2").[3]

I. MOTION FOR LEAVE TO ANSWER

The Commission's Rules of Practice and Procedure generally do not permit answers to answers, but this prohibition can be waived for good cause.[4] The Commission has done so in circumstances where the answer would ensure a more complete record,[5] lead to a better understanding of the issues in the proceeding,[6] or assist the Commission in its decision-making process.[7] Good cause exists to grant this Motion for Leave to Answer. PJM's Answer ensures a more complete record and understanding of the issues before the Commission which will assist the Commission in its decision-making process.

[3] PJM Answer at 5. Specifically, based on the February 9, 2026, filing dates, PJM respectfully requests the issuance of a Commission order by April 13, 2026.

[4] *See* 18 C.F.R. §§ 385.212, 385.213.

[5] *See, e.g.*, *High Island Offshore Sys., L.L.C.*, 113 FERC ¶ 61,202, at P 8 (2005).

[6] *See, e.g.*, *CenterPoint Energy–Miss. River Transmission, LLC*, 141 FERC ¶ 61,080, at P 4 (2012); *TransColorado Gas Transmission Co.*, 111 FERC ¶ 61,208, at P 4, *order on reh'g*, 112 FERC ¶ 61,135 (2005).

[7] *See, e.g.*, *Hudson River-Black River Regulating Dist.*, 183 FERC ¶ 61,187, at P 9 n.21, *order on reh'g*, 185 FERC ¶ 61,034 (2023); *E. Shore Nat. Gas Co.*, 181 FERC ¶ 61,233, at P 9 n.17 (2022); *Tri-State Generation & Transmission Ass'n*, 179 FERC ¶ 61,118, at P 34, *order addressing arguments raised on reh'g*, 181 FERC ¶ 61,037 (2022); *S. Cal. Edison Co.*, 141 FERC ¶ 61,100, at P 5 (2012).

II. ANSWER

A. Amelia Energy's Requested Relief Would Have the Commission Exceed Its Authority and Subject Both Amelia Energy and Other TC1 Project Developers To Negative Consequences.

Citing to *NRG Power Marketing, LLC v. FERC*,[8] Amelia Energy argues that the "Commission may order that, if the filing party does not make specified changes to a Section 205 filing, the Commission will reject the filing as unjust and unreasonable."[9] Amelia Energy contends that *NRG v. FERC* supports its requested relief, which includes a Commission order rejecting the unexecuted Amelia Energy GIA, unless PJM makes the changes Amelia Energy has requested in this proceeding.[10] Amelia Energy's requested changes include (1) removal of the five Disputed Network Upgrades; (2) removal of the Disputed Contingent Facilities; and (3) imposition of a December 31, 2029, construction completion and in service date for Network Upgrade n9630.0.[11] Amelia Energy misconstrues *NRG v. FERC*. As the court held in that case, under section 205 of the Federal Power Act, the Commission reviews a proposed rate scheme to determine whether it is just and reasonable and FERC *may either accept or reject* the proposal.[12] Section 205, however, "does not authorize FERC to impose a new rate scheme of its own making without the consent of the…Regional Transmission Organization that made the original proposal."[13] Here, Amelia Energy is not asking the Commission to wholly reject PJM's use of regional topology upgrades

[8] *See* Amelia Energy Answer at 19; *see NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114 (D.C. Cir. 2017) (citations omitted) ("NRG v. FERC") (emphasis added).

[9] *See* Amelia Energy Answer at 19.

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

[11] *See* Amelia Energy Answer at n.3; *see id*. at 21; *see* Amelia Energy Protest at 1-2. In Section II.E, *infra*, PJM explains that Amelia Energy's requested modification to advance the construction completion date for required Network Upgrade n9630.0 to December 31, 2029, is not feasible.

[12] *NRG v. FERC* at 114.

[13] *Id.*

for TC1 and related cost allocation.[14] Amelia Energy also does not ask the Commission to uniformly reject the use of regional topology upgrades for its own project, acknowledging that Network Upgrade n9630.0 is a topology upgrade and Amelia Energy does not challenge its classification as such.[15] Amelia Energy's protest is aimed at a subset of upgrades required for its proposed Generating Facility, i.e., the Disputed Contingent Facilities and Network Upgrades.[16] In essence, Amelia Energy appears amenable to PJM's use of regional topology upgrades as a general matter, except as applied to the disputed upgrades PJM has determined are required to accommodate the safe and reliable interconnection of the proposed Amelia Energy Facility. Thus, Amelia Energy's requested relief seeks the Commission's imposition of a new rate scheme based on Amelia Energy's proposed project-specific modifications. Granting this requested relief would exceed the bounds of the Commission's authority.[17] As discussed below, such a Commission disposition also would contradict a recent order in which the Commission upheld TC1 Phase III System Impact Study results that reflected the use of regional topology upgrades at issue here.[18]

Even if the Commission had authority to impose the modifications that Amelia Energy seeks, Amelia Energy would have the Commission believe PJM could maintain the status quo cost allocation for Amelia Energy without negatively impacting other TC1 Project Developers. This is not the case. Implementing Amelia Energy's requested modifications would necessitate

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[14] *See* Amelia Energy Answer at 20 ("To be clear, Amelia Energy does not argue that the new regional topology upgrade standard PJM has applied for cost allocation of Network Upgrades and identification of Contingent Facilities is unjust and unreasonable for other projects in TC1.").

[15] *See* Amelia Energy Protest at 4 ("Twenty of the overloaded flow gates are eliminated by what PJM has called topology changing reinforcements, i.e., *topology upgrades, including n9630, one the Undisputed Cost Allocated Upgrades* that solves both thermal and stability issues." (emphasis added)).

[16] Amelia Energy Protest at n. 2; *Id*. at 2.

[17] PJM Answer at 27-29.

[18] *See RWE Clean Energy, LLC v. PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,212 at P 43 ("[We] find that RWE has not met its burden to show that PJM violated its Tariff when it allocated costs for certain Network Upgrades to RWE's new service requests for its Project in the Phase III System Impact Study.").

restudies to remove regional topology upgrades,[19] which would, in turn, impact cost allocations not only for other TC1 Project Developers but also Amelia Energy.[20] Such changes would negatively impact other TC1 Project Developers, because the discount factor would need to be adjusted accordingly and such an adjustment would increase the costs for all other Project Developers who rely upon this cluster of regional topology upgrades to realize the minimum number of Network Upgrades.[21] As to the Amelia Energy Facility, PJM estimates that implementing Amelia Energy's requested changes would increase its cost allocation by more than $4 million.[22] Thus, Amelia Energy appears to be under the false impression that the Disputed Upgrades could be removed without having a negative cost impact on its project and the projects of other TC1 Project Developers.

In addition to requesting that the Commission modify the terms of its unexecuted GIA (which it should not), Amelia Energy repeats its primary request for relief that the Commission reject both the unexecuted GIA and Disputed NUCRAs.[23] In the event of such disposition, PJM would treat the Commission's rejection of the unexecuted GIA as Amelia Energy's withdrawal from TC1. However, PJM again respectfully requests that the Commission *not* reject the Disputed

[19] Affidavit of Lisa Krizenoskas on behalf of PJM Interconnection, L.L.C. (Apr. 6, 2026) (Attachment A) ("Second Krizenoskas Aff"). Aff. at P 39. *See also* Affidavit of Lisa Krizenoskas on behalf of PJM Interconnection, L.L.C. (filed March 18, 2026) ("Initial Krizenoskas Aff.") Initial Krizenoskas Aff. at PP 16-21 (discussing the Tariff provisions related to the cluster-based Cycle approach and the "least cost analysis," including the requirement to determine the minimum amount of Network Upgrades for a Cycle and PJM's use of regional topology upgrades to do so).

[20] In Section II.E *infra*, PJM explains that Amelia Energy's requested modification to advance the construction completion date for required Network Upgrade n9630.0 to December 31, 2029, is not feasible. *See also* Second Krizenoskas Aff. at PP 37-38 (discussing the cost impact of regional topology upgrades on Amelia Energy); *id.* at P 39 (discussing the negative impact on Amelia Energy and other TC1 Project Developers).

[21] Second Krizenoskas Aff. at P 39.

[22] *See* Section II.A; *infra see* Second Krizenoskas Aff. at P 39.

[23] Amelia Energy Answer at 3 ("Therefore, the Commission should *reject the Disputed NUCRAs and either (1) reject the GIA* or (2) order that it will reject the GIA unless PJM makes the changes that Amelia Energy has requested." (emphasis added)).

NUCRAs. Contrary to Amelia Energy's contention, PJM's request is not intended to "[inject] fear about the potential for delay if NUCRAs must be redone to remove cost allocations to Amelia Energy."[24] The potential impact to the Cycle timeline established by the Tariff is a legitimate concern, as is the potential impact to the Project Developers who have committed to proceed with the development of their TC1 projects. As to this latter point, Amelia Energy's request to "reject the Disputed NUCRAs"[25] effectively seeks the rejection of five multi-lateral agreements impacting nine other TC1 projects.[26] The Project Developers for these projects have fully executed GIAs, posted Security, and signed the NUCRAs that Amelia Energy has not signed.[27] Contrary to Amelia Energy's contention, PJM's intention is not to "inject fear," but rather inform the Commission of the potential negative consequences to other TC1 Project Developers and the Cycle timeline, if Amelia Energy's request to "reject the Disputed NUCRAs" were granted.[28]

As demonstrated in this proceeding, in performing the System Impact Studies and resulting cost allocation for TC1, PJM complied with the Tariff's requirements and acted in accordance with engineering judgment and Good Utility Practice. Moreover, the use of regional topology upgrades to fulfill the Tariff's requirements that PJM determine the "minimum amount of Network Upgrades required to resolve each reliability criteria violation in each Cycle" and identify "the New Service Requests contributing to the need for the required Network Upgrades within the

[24] Amelia Energy Answer at 21.

[25] *Id.* at 3.

[26] PJM Answer at 26-27; *see also* PJM Answer, Exhibit No. PJM-0001 (showing that rejection of these partially executed service agreements would impact proposed Generating Facilities under nine different GIAs, all of which have been fully executed, securitized, and filed with the Commission and five of which has been accepted).

[27] PJM Answer at 26.

[28] PJM Answer at 27 (explaining that if the Commission were to reject the GIA and Amelia Energy were withdrawn from TC1, then PJM would remove Amelia Energy from the partially executed Disputed NUCRAs and file them with, or report them to, the Commission). PJM also would evaluate the impact of the withdrawal on the cost allocations set forth in the NUCRAs and update the cost allocation accordingly.

Cycle" resulted in the elimination of certain Network Upgrades and a cost savings of approximately $731 million to TC1 Project Developers.[29] Therefore, PJM respectfully submits that the unexecuted Amelia Energy GIA and Disputed NUCRAs are just and reasonable and should be accepted and made effective.

For the reasons previously stated, the Commission should not impose Amelia Energy's requested modifications because doing so would exceed the bounds of the Commission's authority under Section 205 of the Federal Power Act, as well as negatively impact both Amelia Energy and other TC1 Project Developers. If the Commission grants Amelia Energy's request to reject the Amelia Energy GIA and the project is withdrawn from TC1, then PJM respectfully requests that the Commission not reject the Disputed NUCRAs.

B. PJM Use of Regional Topology Upgrades is an Exercise of Engineering Judgement Necessary To Conduct Interconnection Studies As Required by the Tariff and Consistent with Commission Precedent.

Amelia Energy plainly states that it does not challenge the justness and reasonableness of the PJM Tariff or the TC1 process.[30] Rather, Amelia Energy challenges PJM's *decision*[31] to use regional topology upgrades[32] to carry out its obligation under the Tariff to determine "the minimum amount of Network Upgrades required to resolve each reliability criteria violation in each Cycle, by studying the impact of the [New Service Requests in] the Cycle in their entirety"[33]

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[29] Initial Krizenoskas Aff. at P 20; Second Krizenoskas Aff. at n. 55.

[30] Amelia Energy Answer at 2 ("Amelia Energy has not argued that the PJM Tariff or the TC1 process is just and unreasonable.").

[31] *See, e.g*., Amelia Energy Answer at 9 ("[C]ost allocation for one Network Upgrade *that PJM somehow decided* is a *regional topology upgrade* makes Amelia Energy cost responsible for all upgrades *that PJM also decides are regional topology upgrades* without the need for any demonstration of a 'New Service Request's contribution to the reliability violation.'" (emphasis added)).

[32] Amelia Energy is selective in its targeting of PJM's use of regional topology upgrades. While it challenges the 23 Disputed Network Upgrades and Disputed Contingent Facilities, it does not challenge Network Upgrade n9630.0, which PJM also has deemed a regional topology upgrade. *See supra* nn. 13-15.

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

and identify "the New Services Requests in the Cycle contributing to the need for the required Network Upgrades within the Cycle."[34] In addition to raising cost causation arguments, Amelia Energy contends that, if the system upgrades it disputes were removed, the Amelia Energy Facility would be permitted to realize an in service date "as early as the end of 2029,"[35] which – as demonstrated in Section II.D – is inaccurate.

In lieu of PJM's reliability-based System Impact Study analyses performed for all of TC1, inclusive of the Amelia Energy Facility, Amelia Energy urges the Commission to accept its witness's study results and find that its proposed Generating Facility is "fully deliverable" without any of the Disputed Network Upgrades or Disputed Contingent Facilities.[36] In other words, Amelia Energy seeks to set aside PJM's System Impact Studies analyses for all TC1 New Services Requests and engineering judgment exercised while performing these interconnection studies to ensure the reliability of the Transmission System in favor of Amelia Energy's study results for its 86 MW Generating Facility. PJM respectfully submits that the Commission dismiss Amelia Energy's arguments. To do otherwise would undermine PJM's exercise of engineering judgement and ability to administer its generation interconnection process in accordance with the Tariff, as well as depart from Commission precedent and upset the expectations of other TC1 Project Developers.

The Commission "generally allows transmission providers to exercise their engineering judgment when conducting interconnection studies, including deferring to transmission providers'

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

[35] Amelia Energy Answer at 19.

[36] Amelia Energy Answer at 14 ("Mr. Agrawal has shown that the Project only needs n9630 to be fully deliverable."); *see also id*. at 6 ("The Project can connect, obtain interconnection service and be fully deliverable without causing or contributing to a reliability impact that necessitates the need for the 23 Disputed Upgrades.).

discretion regarding how to maintain a reliable transmission system."[37] The Commission also has "recognized that it may be appropriate to provide operational and reliability-related discretion to independent system operators, and to not second-guess their decisions in that regard."[38] As previously explained, PJM's new Generation Interconnection Procedures include cost allocation requirements that were introduced as part of, and are unique to, the cluster-based Cycle process, all of which must be given effect when carrying out the Tariff's requirement.[39] These provisions require each Project Developer to pay for all "costs of the minimum amount of Network Upgrades necessary to accommodate its New Service Request that would have not been incurred but for such New Service Requests,"[40] as well as require PJM to "*determine* the *minimum amount of Network Upgrades required to resolve each reliability criteria violation in each Cycle*, by studying the impact of the [New Service Requests in] the Cycle in their entirety…". [41] The Tariff also mandates that PJM "*identify* the New Service Requests in the Cycle *contributing to the need for the required Network Upgrades* within the Cycle"[42] and that "All New Services Requests that contribute to the

[37] *See RWE Clean Energy*, *LLC*, 194 FERC ¶ 61,212, at P 42; *id*. at P 43 ("[We] find that RWE has not met its burden to show that PJM violated its Tariff when it allocated costs for certain Network Upgrades to RWE's new service requests for its Project in the Phase III System Impact Study."). *See Ponderosa Power, LLC v. Nw. Corp.*, 190 FERC ¶ 61,156, at P 52 (2025); *see also* PJM Interconnection, L.L.C., 185 FERC ¶ 61,202, at P 47 (2023) (finding that a transmission owner reasonably exercised its engineering judgment in determining that a large, third-party generator, which could cause a breaker to trip and therefore impact reliability, represented a more significant reliability risk than the addition of a spare transformer, which would serve to increase reliability); *Tenaska Clear Creek Wind, LLC. v. Sw. Power Pool, Inc*., 182 FERC ¶ 61,084, at P 41 (2023) (finding that complainant failed to demonstrate that the mitigation option the transmission provider adopted was an unreasonable exercise of the transmission provider's "discretion to make engineering decisions consistent with Good Utility Practice") (citing *Big Sandy Peaker Plant, LLC v. PJM Interconnection, L.L.C*., 154 FERC ¶ 61,216, at P 50 (2016) (the Commission gives "reliability-related discretion to independent system operators, and [will] not second-guess their decisions in that regard"); *Salt Creek Solar, LLC v. Sw. Power Pool, Inc*., 180 FERC ¶ 61,116, at P 68 (2022) ("Good Utility Practice affords SPP discretion to exercise reasonable judgment in light of facts known at the time" it makes a decision)).

[38] *Big Sandy Peaker Plant, LLC v. PJM Interconnection, L.L.C*., 154 FERC ¶ 61,216, at P 50 (2016).

[39] PJM Answer at 7.

[40] Tariff, Part VII, Subpart D, section 307(A)(5)(a).

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

[42] *Id.*

need for a Network Upgrade will receive cost allocation for that upgrade pursuant to each New Service Request's contribution to the reliability violation identified on the transmission system in accordance with PJM Manuals."[43]

PJM's decision to use regional topology upgrades to identify the "minimum amount of Network Upgrades" falls squarely within PJM's ability to exercise its engineering judgment to administer its interconnection process.[44] As Ms. Krizenoskas explained, regional topology upgrades are a commonly used engineering concept.[45] Regional topology upgrades assist in minimizing Network Upgrades because they "alter power flow patterns by creating alternative routes for electricity to move through the transmission system, which allows flows to be redirected away from overloaded existing facilities."[46] As a result, transmission overloads can be mitigated or eliminated without relying solely in rebuilding or uprating existing circuits.[47] By using regional topology upgrades to change the transmission network topology in a region, PJM can eliminate certain Network Upgrades and therefore comply with the Tariff's requirement to determine "the minimum amount of Network Upgrades required to resolve each reliability criteria violation in

[43] *See* PJM Interconnection, L.L.C., *Manual 14H*: *New Service Requests Cycle Process*, section 4.2 (Overview of System Impact Studies) (rev. 03, Sep. 25, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf ("Manual 14H"); Manual 14H, section 4.2 discusses that the System Impact Studies will provide Project Developers with estimates of cost responsibility. *Id*. at Attachment B, section B.3.1 discusses the load flow cost allocation methodology, including the cost allocation criteria.

[44] *See supra* note 30 and accompanying text. *See also Big Sandy Peaker Plant* at P 50 (determining that, in certain circumstances, in its necessary to afford transmission providers with reliability-related discretion and that including an exclusive list of all specific, reliability-related reasons for exercising that discretion in the tariff was not required); *id*. (describing such circumstances as including those where "innumerable, reliability-related reasons" exist that are "not realistically susceptible for specification" in a tariff).

[45] Initial Krizenoskas Aff. at P 16 (explaining that regional topology upgrades "introduce new electrical connections within a transmission system, thereby changing the transmission network topology in a region").

[46] *Id.*

[47] *Id.*

each Cycle."[48] The record in this proceeding is devoid of evidence that PJM's exercise of engineering judgment conflicts with the Tariff.

Furthermore, rejecting Amelia Energy's requested modifications would be consistent with the Commission's recent order in *RWE Clean Energy, LLC v. PJM*. In that proceeding, a TC1 Project Developer challenged PJM's engineering methodology and cost allocation for Network Upgrades that PJM deemed necessary for the proposed project, as set forth in the Phase III System Impact Study.[49] The Commission rejected the TC1 Project Developer's complaint and upheld the results of PJM's Phase III System Impact Study.[50] In that case, the Phase III System Impact Study results relied upon PJM's use of regional topology upgrades to identify the minimum amount of Network Upgrade costs. Just as the Commission upheld the Phase III System Impact Study results in *RWE Clean Energy v. PJM,* it should do the same here.

C. The System Impact Study Reports Contain a Significant Amount of Analytical Data Regarding the Potential Need for, Impacts of, and Cost Allocation for Regional Topology Upgrades.

According to Amelia Energy, PJM presented "absolutely no analytical data through its study process of TC1" to "factually demonstrate" that the Amelia Energy Facility requires the Disputed Network Upgrades and Disputed Contingent Facilities to obtain interconnection service or that the Amelia Energy Center contributes to a reliability violation that necessitates any of the disputed upgrades.[51] The previously unmatched level of data and analysis that PJM provides to Project Developers under the cluster-based Cycle process, however, belies Amelia Energy's assertions. As detailed below, PJM's various System Impact Study reports contain ample data

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

[49] *See generally RWE Clean Energy, LLC* at PP 8-19.

[50] *Id.* at P 43 (finding that RWE has not met its burden to show that PJM violated its Tariff when it allocated costs for certain Network Upgrades to RWE's new service requests for its Project in the Phase III System Impact Study).

[51] Amelia Energy Answer at 5.

demonstrating the Amelia Energy Facility's need for the regional topology upgrades and support the associated cost allocation.

PJM prepared System Impact Study reports at each phase of TC1 for each of the three Project Identifiers that comprise the Amelia Energy Facility.[52] In total, PJM prepared 12 System Impact Study reports for the Amelia Energy Facility alone.[53] In addition, PJM prepared a Final System Impact Study (Retool 1) Report after Decision Point III, as well as a System Impact Study Executive Summary Report for the entire cluster at each Phase which details the regional topology upgrades used in each region, the Network Upgrades eliminated by regional topology upgrades, and the discount factor.[54] Finally, PJM shares the analytical case support by posting the models used for each System Impact Study.[55]

In the accompanying affidavit, Ms. Krizenoskas uses the Amelia Energy TC1 Phase II and Phase III System Impact Study reports for Project Identifier No. AG1-021 and the various Cycle reports to explain how these reports "factually demonstrate" Amelia Energy contributes to reliability criteria violations found in TC1 and requires the regional topology upgrades to safely and reliably interconnect its proposed Generating Facility to the PJM Transmission System. According to the AG1-021 Phase II System Impact Study report:

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[52] Second Krizenoskas Aff. at P 21.

[53] All System Impact Study and Cluster reports that PJM prepares under its new Cycle process are posted on PJM.com: https://www.pjm.com/planning/m/cycle-service-request-status. *See also* Exhibit PJM-0001 (including Amelia Energy's Phase II and Phase III SIS reports for each Project Identifier, as well Phase II and Phase III System Impact Study Executive Summary Reports for TC1 and Final System Impact Study (Retool 1) Reports).

[54] Second Krizenoskas Aff. At PP 21 -27.

[55] These models are accessible pursuant to PJM's CEII procedures. *See* PJM Interconnection, L.L.C., Manual 14B *PJM Region Transmission Planning Process*, section 1A (Critical Energy Infrastructure Information (CEII)) (rev. 58, Dec. 17, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf.

- The summer peak analysis results indicated the Amelia Energy Facility contributed to overloaded flowgates and eight overloaded flowgates were eliminated after modeling the regional topology upgrades for TC1 Phase II[56]

- Absent the use of regional topology upgrades, the Amelia Energy Facility could have had exposure to additional Network Upgrades and/or Contingent Facilities for these overloaded flowgates[57]

- Provided information about potential cost responsibility for system reinforcements, listing nine potential reinforcements and estimating a cost allocation of $4.5 million[58]

- Showed 11 of 17 identified Network Upgrades were regional topology upgrades and that Amelia Energy was part of the pool of "potential aggregate contributors"[59]

- Explained AG1-021 contributed to flowgates that required regional topology upgrades that had the potential to receive cost allocation in Phase III after accounting for changes stemming from Decision Point II project withdrawals, even though AG1-021 did not meet the cost allocation criteria to receive cost allocation for these 11 regional topology upgrades in Phase II.[60]

In addition, the TC1 Executive Summary Report for Phase II:

- Described how PJM determined which upgrades were eliminated as a result of modeling the regional topology upgrades and how it computed the discount factor to apply to reinforcements to reduce the cost of all these reinforcements down to the cost of constructing only the topology changing reinforcements[61]

- Explained the discount factor was applied to the cost of the Network Upgrades for all projects that contributed to the need for a regional topology upgrade or had an upgrade eliminated as a result of the regional topology upgrade, and then the cost was redistributed to the regional topology upgrades that will be built, and all projects receiving the discount factor become contingent on the full set of regional topology upgrades that allowed them to realize the discount[62]

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[56] Second Krizenoskas Aff. at P 24.

[57] *Id*.

[58] *Id.* at P 25.

[59] *Id.* at P 26.

[60] Second Krizenoskas Aff. at 26; *see also* Manual 14H, Attachment B, section B.3.1 (Load Flow Cost Allocation Methodology).

[61] *Id.* at P 27.

[62] *Id.*

After Decision Point II, PJM retooled the TC1 model to remove withdrawn projects and reflect any changes to the remaining projects in the TC1 cohort, as well as to account for the then recently approved RTEP Window 1 updates, and reran the System Impact Study analysis in Phase III.[63] As in Phase II, PJM considered the regional topology upgrades in this analysis; however, the set of regional topology reinforcements in Phase III was notably different from the set of regional topology reinforcements in Phase II as a result of incorporating the recently approved baseline upgrades from the RTEP Window 1.[64]

Again, Ms. Krizenoskas describes the analytical information set forth in a Phase III System Impact Study report, using the summer peak analysis section of the AG1-021 Phase III System Impact Study, which:

- Identified 11 overloaded flowgates remaining after considering the regional topology upgrades for TC1[65]
- Showed 35 overloaded flowgates that were eliminated as a result of evaluating the regional topology upgrades and reflected that, absent the regional topology upgrades, the Amelia Energy Facility also could have had exposure to additional Network Upgrades and/or Contingent Facilities for these overloaded flowgates[66]
- Indicated AG1-021 is contingent on and/or has cost responsibility for 57 required reliability upgrades[67]
- Concluded AG1-021 had potential cost responsibility for approximately $2.7 million in required reliability Network Upgrades[68]

[63] Second Krizenoskas Aff. at P 29; *id.* at PP 15-20 (explaining in detail the retool between Phases II and III and the incorporation of the RTEP Window 1 updates).

[64] Second Krizenoskas Aff. at P 29.

[65] *Id.*

[66] *Id.* at P 30.

[67] *Id.* at P 31.

[68] *Id*.

- Described AG1-021's contributions to both regional topology upgrades and eliminated reinforcements, including the discount factor[69]

- Showed that after evaluating the impact of regional topology upgrades, AG1-021 contributed to the need for one required regional topology upgrade, Network Upgrade n9630.0, and four eliminated reinforcements, for a total cost allocation of approximately $1.03 million[70]

- Included a note for each Network Upgrade that was eliminated due to the application of regional topology upgrades, explaining the cost allocation to the project as well as the reason the project is contingent on the full set of regional topology upgrades in the Dominion region[71]

The TC1 Executive Summary Report for Phase III set forth how PJM determined which upgrades were eliminated because of modeling the regional topology upgrades and how it computed the discount factor for TC1.[72]

Finally, Amelia Energy contends that there is no evidence of the "benefits" Amelia Energy received as compared to TC1 as a whole.[73] The Tariff requires PJM to apply the "least cost analysis" to optimize costs and minimize the number of required Network Upgrades for the entirety of the Cycle. Although performing the type of analysis suggested by Amelia Energy is neither required by or consistent with the Tariff, the System Impact Study results for Amelia Energy show that the application of the "least cost analysis" to TC1 produced an outcome that was cost-effective for its project, resulting in several million dollars in reduced costs.[74] However, if Amelia Energy's request were granted, and the Commission were to direct PJM to remove the Disputed Contingent Facilities and Disputed Network Upgrades from the proposed Amelia Energy

[69] *Id.* at P 33.

[70] *Id.* at P 33.

[71] *Id.* at P 34.

[72] *Id.* at P 35.

[73] *Id.* at P 7.

[74] *Id*. at P 38.

GIA, then Amelia Energy Facility would lose the benefit of the discount factor and its costs would increase by more than $4 million.[75]

Thus, the System Impact Study reports set forth a significant amount of data and information addressing, inter alia, how PJM applied its cluster-based Cycle process to determine the proposed Amelia Energy Facility's impact on the PJM Transmission System, and more specifically, how the use of regional topology upgrades impacted each of Amelia Energy Facility's individual New Service Requests by providing detailed information about the eliminated Network Upgrades, the required Network Upgrades and Contingent Facilities, the regional discount factor applied, and cost allocations. Accordingly, Amelia Energy's arguments alleging the lack of factual support regarding the need for the Disputed Network Upgrades and Disputed Contingent Facilities to obtain interconnection service or its contribution of a reliability criteria violation that necessitates any of the disputed upgrades should be dismissed.

D. Amelia Energy Erroneously Conflates the PJM Studies for Provisional Interconnection Service and Interconnection Service.

PJM previously explained that Amelia Energy could request an interim deliverability study to determine if its proposed Generating Facility would be eligible for Provisional Interconnection Service, which is limited interconnection service provided at the discretion of the Transmission Provider prior to the completion of requisite Contingent Facilities.[76] As part of that discussion on Provisional Service, PJM stated that, for purposes of an interim deliverability study, the Network Upgrades for which Amelia Energy Facility was not a direct contributor would not be included.[77]

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[75] Second Krizenoskas Aff. at P 39.

[76] *See* Initial Krizenoskas Aff. at P 34; s*ee also* Tariff, Part IX, Subpart B, Appendix 2, section 1.4A.2 outlines how a Project Developer may request limited Interconnection Service at the discretion of the Transmission Provider; *see* Manual 14H, at section 4.10.01 (Interim Deliverability Studies); *see also id*. at section 4.10.1.1 (explaining Contingent Facilities may include Network Upgrades, baseline upgrades, or Supplemental Project Upgrades).

[77] *See* Initial Krizenoskas Aff. at P 34.

The Amelia Energy Answer, however, takes Ms. Krizenoskas' statement out of the context of Provisional Interconnection Service and erroneously frames it as PJM "conceding" that none of the 23 Disputed Network Upgrades and Disputed Contingent Facilities Upgrades are needed for the "full deliverability" of the Amelia Energy Facility.[78] Amelia Energy then relies on this false premise to erroneously conclude, if the Disputed Network Upgrades and Disputed Contingent Facilities were required for the Amelia Energy Facility to obtain interconnection service, then PJM "could not logically exclude these upgrades from its interim deliverability analysis."[79] Amelia Energy's position conflates PJM's approach for studying Provisional Interconnection Service requests with the studies performed to evaluate New Service Requests. Accordingly, Amelia Energy's arguments should be rejected.

In the cluster-based Cycle process System Impact Study analyses, PJM evaluates New Service Requests against North American Electric Reliability Corporation and each Applicable Regional Entity's reliability and transmission planning criteria as a cluster.[80] The System Impact Study analyses focus on optimizing the costs and minimizing the amount of required Network Upgrades for the entirety of the Cycle.[81] Moreover, the study case for such analyses include all New Service Requests for the Cycle under study, as well as previously studied New Service

[78] Second Krizenoskas Aff. at P 9. *Cf.* Amelia Energy Answer at 12-13.

[79] Amelia Energy Answer at 13. To support this incorrect assertion, Amelia Energy cites to PJM's filing of amended agreements to remove Contingent Facilities that were no longer required for various projects to obtain interconnection service and claims that the same rationale applies to the Amelia Energy GIA, that PJM can simply remove the Disputed Network Upgrades and Disputed Contingent Facilities from the service agreement or remove Amelia Energy as a party to the Disputed NUCRAs. *See* Amelia Energy Answer at n.31. Where PJM has determined that a Contingent Facility is no longer required and submits an amendment to a service agreement to remove the Contingent Facilities is not the same situation as Amelia Energy insisting PJM remove Contingent Facilities because they do not agree with the results of PJM's analysis.

[80] Second Krizenoskas Aff. at P 10.

[81] *Id.; See* Initial Krizenoskas Aff. PP 16-21.

Requests that have rights to the study case used for the Cycle, i.e., TC1 was studied on a 2027 RTEP base case.[82]

By contrast, the interim deliverability analysis is performed to evaluate only the cohort of projects that have rights or are seeking to generate for a specific Delivery Year (i.e., June 1 to May 31).[83] The objective of this analysis is to determine whether a Generating Facility may output energy and capacity at the Point of Interconnection to the Transmission System up to the MFO and CIR levels set forth in its GIA for a particular Delivery Year prior to Contingent Facilities being in service.[84]

Another key difference is that the interim deliverability study uses a different base case model and set of assumptions for the analysis depending on the requested Delivery Year.[85] By way of illustration, if Amelia Energy were to request an interim deliverability analysis for the 2026/2027 Delivery Year, then the study model would reflect the conditions for that Delivery Year, whereas PJM used the 2027 RTEP case as the base case for TC1.[86] Differences in the base case models could indicate there is more available headroom in the 2026/2027 Delivery Year model, which – in turn – could indicate a Generating Facility may be eligible for Provisional Interconnection Service up to the MFO and CIR levels reflected in its GIAs for that Delivery Year.[87]

A Project Developer with a GIA that requests Provisional Interconnection Service and has Contingent Facilities classified as regional topology upgrades would be evaluated against the

[82] Second Krizenoskas Aff. at P 10.

[83] *Id.* at P 11.

[84] *Id.*

[85] *Id.* at P 12.

[86] *Id.*

[87] *Id.*

facilities/flowgates which the regional topology upgrades directly address or that were eliminated in the final System Impact Study.[88] Due to the far-reaching impact of the regional topology upgrades, the eliminated facility that is used for evaluation in the interim deliverable study for Provisional Interconnection Service may differ from the new regional topology upgrade that addresses the violation.[89]

If a Generating Facility is eligible for Provisional Interconnection Service, any rights to inject energy or capacity are limited to the Delivery Year that was studied.[90] Even though an interim deliverability study may find that a Generating Facility is deliverable for the requested Delivery Year, changes to system conditions for a later Delivery Year may produce different and less favorable results.[91] Therefore, the interim deliverability study results are only valid for the duration of the Delivery Year.[92] As a result, a Generating Facility seeking Provisional Interconnection Service for any subsequent Delivery Year must request to be studied for each of those Delivery Years until the required Contingent Facilities identified in the GIA are in service. Once these Contingent Facilities are in place, the Generating Facility will have the right to generate at the MFO and CIR levels identified in the GIA.[93] In the case of the Amelia Energy Facility, which has a proposed commercial operation date of March 1, 2031, this means that multiple requests for Provisional Interconnection Service would be necessary.[94]

[88] Second Krizenoskas Aff. at P 13.

[89] *Id.*

[90] Second Krizenoskas Aff. at P 14.

[91] *Id.*

[92] *Id.*

[93] *Id.*

[94] *Id.*

Thus, there are key differences between how PJM studies New Service Requests seeking Interconnection Service pursuant to the cluster-based Cycle System Impact Study and requests for Provisional Interconnection Service pursuant to an interim deliverability study. Due to an apparent misunderstanding of those differences, Amelia Energy misapplies Ms. Krizenoskas' statement regarding Provisional Interconnection Service to support its erroneous claim that an interim deliverability study would demonstrate the Amelia Energy Facility is "fully deliverable" without the Disputed Network Upgrades and Disputed Contingent Facilities. Accordingly, PJM respectfully requests that the Commission reject this argument.

E. Contrary to Amelia Energy's Assertion, a 2029 In Service Date Is Not Feasible Due to the 55-Month Construction Timeline for Undisputed Network Upgrade n9630.

The Amelia Energy Answer states that its project "may need to be placed in service as early as the end of 2029 to preserve its federal tax credit eligibility."[95] The Amelia Energy Anwer argues that the expected in service dates for the Disputed Network Upgrades and Disputed Contingent Facilities identified in its unexecuted GIA are the reason Amelia Energy Facility's desired 2029 in service date is in jeopardy.[96] In support of its argument, Amelia Energy states the latest in service date for one of the disputed upgrades is approximately September 16, 2030.[97] Amelia Energy's argument is misdirected. According to the most accurate information provided by the Transmission Owner, Network Upgrade n9630.0 has a 55-month construction timeline, resulting in an estimated in service date of November 30, 2030.[98] Thus, Network Upgrade n9630.0, the

[95] Amelia Energy Answer at 19.

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

[97] *Id.* at 19.

[98] Second Krizenoskas Aff. at P 6-8.

need for which Amelia Energy does not dispute, is the Network Upgrade with the longest lead time.[99]

While the in service date for Network Upgrade n9630.0 could be delayed, it will not be advanced to an earlier date. If the Commission were to accept and make effective the Amelia Energy GIA and Disputed NUCRAs in April 2026, the Amelia Energy Facility's construction timeline likely could remain on schedule. However, because the construction timelines for Network Upgrades are based on the expected date of GIA execution and the completion of a construction kick off call among the Project Developer, Transmission Owner, and PJM promptly thereafter, any delay in the GIA's (and related NUCRAs') effectiveness and the scheduling of the construction kick off call would result in a corresponding delay to the in service dates for required Network Upgrades, including Network Upgrade n9630.0. Accordingly, a 2029 in service date for the Amelia Energy Facility is not feasible.

F. QDEST Is an Analysis Processing Tool that Helps PJM Process the Large Volume of New Service Requests Using the "Least Cost" Analysis Required by the Tariff.

The claims related to QDEST in the Amelia Energy Answer lack record support. According to Amelia Energy, "the limitation of QDEST" is the basis for the "disagreement regarding the Disputed Network Upgrades and the Disputed Contingent Facilities."[100] Similarly divorced from the facts of this proceeding are Amelia Energy's allegations that "PJM explains [QDEST] does not allow it to perform Project-level validation"[101] or that PJM purportedly admitted "it cannot validate whether its cost allocations are correct for individual projects because

[99] *Id.* at P 7.

[100] Amelia Energy Answer at 13-14.

[101] Amelia Energy Answer at 14. Notably, the Amelia Energy Answer does not provide a citation for this alleged explanation.

its automated tool does not support this level of granularity."[102] PJM urges the Commission to dismiss each of these arguments, as none of them bears any rational relationship to the facts in the record of this proceeding.

PJM uses QDEST in conjunction with another tool called PowerGem TARA to assist PJM in performing its obligations under the Tariff.[103] In her initial affidavit, Ms. Krizenoskas described PJM's Tariff obligations, and contrasted them with Amelia Energy's apparent study objectives:

> A key difference is that Mr. Agrawal's study focuses on achieving the most favorable outcome for his client's individual project. *He did not take into account the Tariff requirements that I have discussed, such as the cost allocation methodology or the scope of the System Impact Study reports, which are intended to position PJM to identify the least amount of Network Upgrades required to resolve criteria reliability violations in the most effective way for TC1 in its entirety.*
>
> […]
>
> *By contrast, and as required by the Tariff, PJM focused on optimizing the costs and minimizing the number of required Network Upgrades for the entirety of the TC1 cohort*. Optimizing the analysis on a per project basis, as Mr. Agrawal appears to suggest, is not in alignment with PJM's new cluster-based Cycle process under the Tariff.[104]

Ms. Krizenoskas further explained that PJM's use of these two companion technologies has allowed PJM to increase its interconnection processing speed, particularly in light of the substantially larger volume of projects under study, while preserving accuracy, transparency, and consistency.[105] According to Ms. Krizenoskas:

> This systematic [interconnection analysis] approach is based on PJM's implementation of new technology called QDEST, an analysis processing tool that significantly improves the speed and consistency of the System

[102] Amelia Energy Answer at 14. The Amelia Energy Answer also does not include a citation for this alleged admission.

[103] Initial Krizenoskas Aff. at P 11-18.

[104] *Id.* at P 29.

[105] *Id.* at P 15.

> Impact Study workflow. The tool ingests output from PowerGem TARA, PJM's power flow analysis program, and uploads it into a centralized post-processing platform that presents results in a clear, intuitive format. Within this environment, overloaded facilities are identified, Network Upgrades are assigned, and cost allocation is generated. The QDEST platform also produces complete System Impact Study reports and supports automated publication of results to the PJM website.[106]

Whereas PowerGem TARA assists in identifying and evaluating reliability criteria violations, QDEST supports interconnection analysis processing and cost allocation.[107] The actual assignment of Network Upgrades is not automatically generated by QDEST. PJM must perform an evaluation and exercise its engineering judgment to determine the optimal cohort of Network Upgrades, which may be a combination of new regional topology upgrades and direct facility upgrades, to address the Cycle overloads as a whole.[108] These identified upgrades are then linked to address the overloaded flowgates in the QDEST tool for each project.[109]

Contrary to Amelia Energy's contentions, QDEST is not designed or intended to perform "Project-level validations" like the study performed by Amelia Energy's witness. QDEST is being used to support PJM in processing large volumes of proposed generation projects and exercising its engineering judgment in a manner that is consistent with the Tariff's requirements. Using QDEST, PowerGem TARA, and other technology tools, PJM completed TC1 Phase I in 120 days, Phase II in 183 days, and Phase III in 152 days, [110] which demonstrates enhanced efficiency, speed,

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[106] Initial Krizenoskas Aff at P 15; *see also id.* at P 19 (describing how PJM uses QDEST to compute a discount factor for each of the three topology regions and describing such computation).

[107] Second Krizenoskas Aff. at P 43.

[108] *Id.* at P 43.

[109] *Id.* at P 43.

[110] *See* PJM Interconnection, L.L.C., *Planning / Cycle Timeline*, https://www.pjm.com/planning (last visited Apr. 6, 2026).

and consistency of PJM's interconnection process that has steadily increased in momentum.[111] PJM's use of these technologies aligns with the Commission's call for PJM to "deploy automation tools to improve interconnection process efficiency."[112]

[111] PJM Inside Lines, *Successful Interconnection Reforms, Other PJM Initiatives Seek to Maximize Electricity Supplies*, (Mar. 16, 2026), https://insidelines.pjm.com/connected/ (explaining that PJM processed 294 GW of projects since 2020).

[112] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 13 (2025) ("Going forward, we expect—and the circumstances on the ground demand—that PJM transition to its reformed interconnection procedures as soon as possible, fully implement the reforms directed in the Commission's Order No. 2023, continue working with its stakeholders to proactively identify targeted interconnection process reforms, and *deploy automation tools to improve interconnection process efficiency*." (emphasis added and footnotes omitted)), *order on reh'g*, 192 FERC ¶ 61, 085 (2025).

III. CONCLUSION

For the reasons set forth in this answer and PJM's March 18, 2026 answer, PJM respectfully submits that the Commission should reject the Amelia Energy Protest and Amelia Energy Answer and accept and establish an April 11, 2026 effective date for the Amelia Energy GIA and the related NUCRAs, as set forth in the February 9 Filing and grant any additional relief as the Commission deems appropriate consistent with this and PJM's March 18, 2026 answer and the February 9 Filing.

Respectfully submitted,

By: /s/ *Vasiliki Karandrikas*

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April 6, 2026

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties on the official Service List compiled by the Secretary in this proceeding.

Dated at Audubon, Pennsylvania this 6th day of April, 2026.

/s/ *Vasiliki Karandrikas*

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Attachment A

Affidavit of Ms. Lisa Krizenoskas on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER26-1300-000**
	)	**ER26-1303-000**
	)	**(NOT CONSOLIDATED)**

AFFIDAVIT OF LISA KRIZENOSKAS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Lisa Krizenoskas, and my business address is 2750 Monroe Boulevard, Audubon, Pennsylvania 19403. I am employed by PJM Interconnection, L.L.C. ("PJM") and my current title is Manager, Interconnection Planning Analysis. I have more than 30 years of experience in the power systems industry, with extensive technical, analytical, and managerial expertise in transmission system planning and generator interconnection processes.[1]

2. I am submitting this affidavit and two accompanying exhibits identified as PJM-0001 and PJM-0002 on behalf of PJM in support of PJM's Motion for Leave to Answer and Answer to the to the Amelia Energy Facility, LLC ("Amelia Energy") Motion for Leave to Answer and Answer filed by Amelia Energy in Docket Nos. ER26-1300-000 and ER26-1303-000, on March 25, 2026.[2]

[1] *See PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C., Docket Nos. ER26-1300-000 & ER26-1303-000 (Mar. 18, 2026) ("PJM Answer"). PJM submitted an Affidavit of Lisa Krizenoskas on behalf of PJM Interconnection, L.L.C. ("Initial Krizenoskas Affidavit") as part of the PJM Answer. Paragraphs 1 through 4 of Initial Krizenoskas Affidavit detailed Lisa's extensive experience in the power systems industry, with technical, analytical, and managerial expertise in transmission system planning and generator interconnection processes.

[2] *PJM Interconnection, L.L.C.*, Motion for Leave to Answer and Answer of Amelia Energy Facility, LLC, Docket Nos. ER26-1300-000 & ER26-1303-000 (Mar. 25, 2026) ("Amelia Energy Answer").

I. PURPOSE OF AFFIDAVIT

3. The purpose of my affidavit is to respond to certain arguments raised in the Amelia Energy Answer regarding Amelia Energy's proposed 86 megawatt ("MW") solar generating facility with 46.5 MW of Capacity Interconnection Rights ("CIR") located in Maplewood, Amelia County, Virginia ("Amelia Energy Facility"), that PJM studied as part of Transition Cycle No. 1 ("TC1"). First, I will rebut Amelia Energy's assertion that a 2029 in service date is feasible for undisputed Network Upgrade n9630.0, as well as demonstrate that its estimated November 2030 in service date makes it the longest lead time upgrade for the Amelia Energy Facility, as opposed to the Disputed Network Upgrades and Disputed Contingent Facilities. Next, I will detail how Amelia Energy takes my statement regarding Provisional Interconnection Service out of context to support its erroneous claim that an interim deliverability study would demonstrate the Amelia Energy Facility is "fully deliverable" without the Disputed Network Upgrades and Disputed Contingent Facilities. Third, I respond to Amelia Energy's erroneous suggestion that changes in study results indicate PJM did not conduct its System Impact Studies in accordance with the PJM Open Access Transmission Tariff ("Tariff"). Fourth, I will demonstrate that PJM's various System Impact Study reports contain significant amounts of analytical data on both a project and Cycle basis, and Amelia Energy's assertion that PJM presents "absolutely no analytical data" to demonstrate that the Disputed Network Upgrades[3] and Disputed Contingent Facilities[4] are required for Amelia Energy to obtain

[3] Amelia Energy disputes cost responsibility for Network Upgrades n8492, n8492.1, n8492.2, n9259, and n9267 ("Disputed Network Upgrades"). *See* Amelia Energy GIA, Specifications, section 3.0(b)(ii).

[4] Amelia Energy disputes that the following baseline and supplemental upgrades identified as Contingent Facilities in the Amelia Energy GIA must be completed prior to commercial operation of the Amelia Energy Facility: b3800.312, b3800.313, b3800.354, b3800.356, b3800.357, b4000.325, b4000.326, b4000.327,

interconnection service is disingenuous. Finally, I will provide more detail regarding PJM's use of the QDEST tool and respond to statements reflecting that Amelia Energy misconstrued certain aspects of my initial affidavit.

II. OVERVIEW OF AFFIDAVIT

4. In this affidavit, I will:

- Explain that a 2029 in service date for Network Upgrade n9630.0 is not feasible, notwithstanding the Disputed Network Upgrades and Disputed Contingent Facilities; [5]
- Describe key differences between PJM's cluster-based System Impact Studies used to evaluate requests for Interconnection Service and interim deliverability study used to evaluate Provisional Interconnection Service requests;[6]
- Explain the Tariff's requirements for performing Phase II and Phase III System Impact Studies and how PJM performed these studies in accordance with the Tariff;[7]
- Provide an overview of the extensive analytical data set forth in PJM's various System Impact Study reports;[8] and

b4000.344, b4000.345, b4000.346, b4000.348, b4000.349, b4000.350, b4000.351, b4000.352, b4000.357, and s3047.2. *See* Amelia Energy GIA, Specifications, section 3.0(d).

[5] *See infra* Section III.A.

[6] *See infra* Section III. B.

[7] *See infra* Section III.C.

[8] *See infra* Section III.D.

- Describe in greater detail how PJM uses QDEST and correct the record in light of certain statements made by Amelia Energy.[9]

III. AFFIDAVIT

A. A 2029 In Service Date Is Not Feasible for Network Upgrade n9630.0, Notwithstanding the Disputed Network Upgrades and Disputed Contingent Facilities.

5. The Amelia Energy Answer states that its project "may need to be placed in service as early as the end of 2029 to preserve its federal tax credit eligibility."[10] The Amelia Energy Anwer claims that the construction timelines for the Disputed Network Upgrades and Disputed Contingent Facilities identified in its unexecuted Generation Interconnection Agreement ("GIA") will delay the Amelia Energy Facility's achievement of its desired 2029 in service date.[11] The latest estimated construction completion date for the Disputed Upgrades, as noted in the Amelia Energy Answer, is approximately September 16, 2030.[12]

6. Amelia Energy's delayed in service date argument is based on an expected in service date of December 31, 2029, for Network Upgrade n9630.[13] While PJM acknowledges that the December 2025 Final System Impact Study reflects a date of December 31, 2029, the Facilities Study Report for Network Upgrade n9630.0 represents the most accurate information regarding the construction timeline as provided by the Transmission Owner, which projects a 55-month construction period or an estimated in

[9] *See infra* Section III.E.

[10] Amelia Energy Answer at 19.

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

[12] *Id.*

[13] *Id.*

service date of November 30, 2030.[14] As a result, Amelia Energy misplaces blame on the Disputed Network Upgrades and Disputed Contingent Facilities for allegedly delaying the in service date for the Amelia Energy Facility, as undisputed Network Upgrade n9630.0 has a construction schedule with an estimated completion date of November 30, 2030.

7. Amelia Energy does not dispute the need for Network Upgrade n.9630.0 and has signed the related Network Upgrade Cost Responsibility Agreement. As PJM explained in the PJM Answer, Network Upgrade n9630.0 has an estimated construction timeline of 55 months, the calculation of which is based on the time of GIA execution and construction kick off call.[15] Given this information, and if the Federal Energy Regulatory Commission ("Commission") were to make the Amelia Energy GIA effective in April 2026 and the kick off call were held, Network Upgrade n9630.0's estimated completion date would fall in November 2030, which would render it as the longest lead time Network Upgrade when compared to the Disputed Network Upgrades and Disputed Contingent Facilities.[16, 17]

[14] PJM Interconnection, L.L.C., *PJM Facilities Study Report for Network Upgrade N9630 Transition Cycle #1*, (July 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Facility_Studies/TC1/PHASE_3/n9630_0_TC1_PH3_fac.pdf. A copy of this report is also included as Exhibit No. PJM-0002.

[15] *Id.*; *see* Initial Krizenoskas Aff. ¶ 33 n.44. The construction timelines for all Network Upgrades use the GIA execution date and kick off call as a starting point. Therefore, the construction timelines for all Network Upgrades required for the Amelia Energy Facility may be subject to adjustment based on the GIA's effective date and the construction kick off call date.

[16] Initial Krizenoskas Aff. ¶ 33.

[17] The table below represents a concise summary of estimated completion timelines for the Disputed Network Upgrades. *See* PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle #1 Phase III*, at Stability Reinforcements, (Sep. 18, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH3_Executive_Summary.htm#exec-sum-analysis-stability. A copy of this report is also included as Exhibit No. PJM-0001.

Upgrade	In-Service
n8492	26 to 27 months
n9267	45 to 46 months
n9259	38 to 39 months
n8492.1	30 to 36 months
n8492.2	15 to 16 months

Furthermore, the Disputed Contingent Facilities that constitute baseline and supplemental upgrades that are Regional Transmission Expansion Plan ("RTEP") project have dates ranging from February 24, 2029, to September 16, 2030.[18] As a result, even the estimated completion timelines for these Disputed Contingent Facilities are *before* the established completion date for Network Upgrade n9630.0 (i.e., November 2030).

8. If Amelia Energy proceeds with this project, a 2029 in service date would not be possible because certain of the Disputed Network Upgrades and Disputed Contingent Facilities for the Amelia Energy Facility have in service dates beyond 2029, including undisputed Network Upgrade n9630.0, which is projected to have the longest lead time.

B. PJM's Approach for Studying a Generating Facility's Request for Provisional Interconnection Service Differs from the Approach Used to Study New Service Requests for Interconnection Service.

9. The Amelia Energy Answer references a section in my initial affidavit where I discuss the option of requesting Provisional Interconnection Service, which is a process available to a Project Developer, like Amelia Energy, who seeks to have its Generating Facility come into service prior to the construction of required Contingent Facilities, which may include Network Upgrades reflected in its GIA. As part of that

[18] *See id*. at System Reinforcements (setting forth the in service dates for the Disputed Contingent Facilities).

Provisional Interconnection Service discussion, I stated that PJM's study approach would not consider regional topology upgrades to which Amelia Energy Facility is not a direct contributor when evaluating a Provisional Interconnection Service request. The Amelia Energy Answer, however, takes my statement out of the context of Provisional Interconnection Service and erroneously frames it as PJM "conceding" that none of the 23 Disputed Network Upgrades and Disputed Contingent Facilities Upgrades are needed for the "full deliverability" of the Amelia Energy Facility.[19] To ensure an accurate record, I will explain the key differences between how PJM studies New Service Requests seeking Interconnection Service pursuant to the cluster-based Cycle System Impact Study and requests for Provisional Interconnection Service pursuant to an interim deliverability study.[20]

10. In the cluster-based Cycle process System Impact Study analyses, PJM's studies include evaluating New Service Requests against North American Electric Reliability Corporation and each Applicable Regional Entity's reliability and transmission planning criteria as a cluster.[21] As detailed in my initial affidavit, the System Impact Study analyses focus on optimizing the costs and minimizing the amount of required Network Upgrades for the entirety of a Cycle.[22] The study case for such analyses include all New Service Requests for the Cycle under study, as well as previously studied New Service Requests that have rights to the study case used for the Cycle, i.e., TC1 was studied on a 2027 RTEP base case. For example, for TC1, PJM modeled all TC1 New Service Requests

[19] Amelia Energy Answer at 12-13.

[20] *Id.* at 12.

[21] Tariff, Part VII, Subpart D, section 307(A)(2)(a)(iv).

[22] Initial Krizenoskas Aff. ¶¶ 16-21.

and previously studied New Service Requests that resulted in a signed and effective GIA, because such Project Developers have rights to generate at the Maximum Facility Output ("MFO") and CIR, as applicable, which are documented in the Specifications section of the GIA.[23] If there are any Contingent Facilities, which may include Network Upgrades, that must be completed prior to the Generating Facility under a GIA receiving Interconnection Service (which Amelia Energy appears to call being "fully deliverable"), those Contingent Facilities also would be stated in the GIA Specifications section.[24]

11. If a Generating Facility seeks to connect to the Transmission System prior to Contingent Facilities being in service, a Project Developer may request that its individual Generating Facility be studied for Provisional Interconnection Service.[25] PJM evaluates Provisional Interconnection Service requests by performing an interim deliverability study which evaluates whether a Generating Facility may output energy and capacity at the Point of Interconnection to the Transmission System up to the MFO and CIR levels set forth in its GIA for a particular Delivery Year (i.e., June 1 to May 31). Unlike the cluster-based Cycle perspective of the System Impact Studies, the interim deliverability study examines only the cohort of projects that have rights to or are seeking to generate for a particular Delivery Year.

[23] *See* Tariff, Part IX, Subpart B, Form of Generation Interconnection Agreement Combined with Construction Service Agreement, Specifications, sections 1.0-2.0.

[24] *See id.*, Specifications, section 3.0.

[25] Tariff, Part IX, Subpart B, Appendix 2, section 1.4A.2 outlines how a Project Developer may request limited Interconnection Service at the discretion of the Transmission Provider prior to the completion of requisite Interconnection Facilities or Network Upgrades.; *see* PJM Interconnection, L.L.C., *Manual 14H: New Service Requests Cycle Process*, section 4.10.01 (Interim Deliverability Studies) (rev. 03, Sep. 25, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf ("Manual 14H").

12. Another key difference is that the interim deliverability study uses a different base case model and set of assumptions for the analysis depending on the requested Delivery Year. For example, if a TC1 Project Developer submitted a request to be studied for Provisional Interconnection Service for the upcoming 2026/2027 Delivery Year, then PJM would use a study model reflecting the conditions for that Delivery Year. The interim deliverability study model would contain the latest topology, including only the generation, New Service Requests and Contingent Facilities that are expected to be in service by the start of the requested Delivery Year and load forecast. Because TC1 was studied on a 2027 RTEP case, the base case model assumptions for a 2026/2027 Delivery Year interim deliverability study will be different from the 2027 study model, as there will be less generation modeled in a 2026/2027 Delivery Year model compared to the 2027 RTEP case used for TC1. Due to the difference in the base case models, the results of the interim deliverable study could indicate there is more available headroom in the 2026/2027 Delivery Year model, which–in turn–could indicate a Generating Facility may be eligible for Provisional Interconnection Service up to the MFO and CIR levels reflected in its GIAs during the 2026/2027 Delivery Year.

13. Moreover, for the Amelia Energy Facility, an interim deliverability study would consist of a power flow study (e.g., Generation Deliverability Test). For example, if a Contingent Facility was deemed necessary to alleviate reliability and/or transmission planning criteria violations identified in the final System Impact Study report for the requested Delivery Year, but such Contingent Facility was not scheduled to be placed in service prior to that Delivery Year, then the interim deliverability study would evaluate the impact of that Generating Facility's connection to the Transmission System without the

Contingent Facility. Typically, Contingent Facilities are facility rating increases of the facility with the reliability criteria violation(s). For these facility-style upgrades, the interim deliverability study evaluates whether that same facility/flowgate produces a reliability criteria violation in the interim deliverability study. A Project Developer with a GIA that requests Provisional Interconnection Service and has Contingent Facilities classified as regional topology upgrades would be evaluated against the facilities/flowgates which the regional topology upgrades directly address or that were eliminated in the final System Impact Study. Due to the far-reaching impact of the regional topology upgrades, the eliminated facility that is used for evaluation in the interim deliverable study for Provisional Interconnection Service may differ from the new regional topology upgrade that addresses the violation.

14. Finally, to the extent a Generating Facility is eligible for Provisional Interconnection Service, any rights to inject energy or capacity are limited to the Delivery Year that was studied. Even though an interim delivery study may find that a Generating Facility is deliverable for the requested Delivery Year, changes to system conditions for the following Delivery Year may produce different and less favorable results. Therefore, the interim deliverability study results are only valid for the duration of the Delivery Year. As a result, a Generating Facility seeking Provisional Interconnection Service for any subsequent Delivery Year must request to be studied for each of those Delivery Years until the required Network Upgrades and Contingent Facilities identified in the GIA are in service. Once these Network Upgrades and Contingent Facilities are in place, the project will have the right to generate at the MFO and CIR levels identified in the GIA. In the case of the Amelia Energy Facility, which has a proposed commercial operation date of

March 1, 2031, this means that multiple requests for Provisional Interconnection Service would be necessary.

C. PJM Conducted Phase II and Phase III System Impact Studies in Accordance with the Tariff.

15. The Amelia Energy Answer appears to imply that the changes in study results reflected between the Phase II System Impact Study and Phase III System Impact Study indicate that PJM did not conduct its studies in accordance with the Tariff's requirements. Specifically, Amelia Energy points to "what transpired from Phase 2 to Phase 3 in TC1"[26] as support for its position that the Disputed Network Upgrades and Disputed Contingent Facilities were improperly identified during Phase III because they were not included in the Phase II System Impact Study for Amelia Energy Facility.[27]

16. Amelia Energy's position suggests a potential lack of familiarity with the Tariff's three-phased System Impact Study requirements. In my initial affidavit, I provided a detailed explanation of PJM's three-phased Cycle process, which includes a System Impact Study followed by a Decision Point during which a Project Developer must make certain demonstrations and financial commitments required by the Tariff to advance or to "exit" from the interconnection study process.[28] Now, I will discuss the Tariff's timing considerations when performing System Impact Studies and the potential impact on study results.

[26] Amelia Energy Answer at 6.

[27] *Id.* at 6-7.

[28] Initial Krizenoskas Aff. ¶ 10.

17. The Tariff defines the terms for Phase II and Phase III and requires PJM to conduct the System Impact Studies during those time periods.[29] After a System Impact Study phase, a Decision Point follows and Project Developers may elect to demonstrate that they meet the requirements to advance to the next phase or withdraw.[30] After a Decision Point, the System Impact Study is retooled to account for changes to the Cycle's cohort, including removal of those that have withdrawn, as well as any other withdrawals outside of TC1 that may have occurred since the start of the phase.[31]

18. For TC1 Phase II began on June 21, 2024, and ended on December 20, 2024. Decision Point 2 followed, beginning on December 23, 2024, and concluding on January 21, 2025. TC1 Phase III began on April 21, 2025, and ended on September 19, 2025. Decision Point 3 started on September 22, 2025, and ended on October 21, 2025.[32] Consistent with the Tariff, PJM developed study models for the Phase II and Phase III System Impact Study that were based on the information known at the start of each phase, i.e., June 21, 2024, for Phase II and April 21, 2025, for Phase III.

19. On February 26, 2025, the PJM Board of Managers approved the 2024 RTEP Window 1 projects, which included the baseline regional topology upgrades that are among the Disputed Contingent Facilities at issue in this case. The Board's approval occurred well after TC1 Phase II had ended and the Phase II System Impact Study reports and Phase II models had been posted. Therefore, the 2024 RTEP Window 1 projects were not reflected in the Phase II System Impact Study model.

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[29] Tariff, Part VII, Subpart A, Definitions P (Definitions of Phase II and Phase III).

[30] Initial Krizenoskas Aff. ¶ 10.

[31] *Id*.

[32] *See* PJM Interconnection, L.L.C., *Planning / Cycle Timeline*, https://www.pjm.com/planning (last visited Apr. 6, 2026).

20. Although PJM was unable to consider the 2024 RTEP Window 1 projects as part of Phase II due to timing, during the Phase III retool PJM incorporated this information as part of the Phase III System Impact Study when identifying the minimum amount of Network Upgrades required to resolve reliability criteria violations for TC1. Contrary to Amelia Energy's allegation, any changes in study results, including classification changes, which may have occurred between the Phase II and Phase III System Impact Study phases, are due to the phased nature of the cluster-based Cycle process, the impacts of changes to the Cycle cohort's composition between phases, and the further refinement of the study results based on the incorporation of changes to the Transmission System reflected in a subsequent phase of the Cycle. Simply stated, PJM's Cycle process is designed to update study models at each phase to provide Project Developers with accurate information about project development costs and timelines considering the constantly evolving nature of the Transmission System.

D. The System Impact Study Reports Contain a Significant Amount of Analytical Data Regarding the Potential Need for, Impacts of, and Cost Allocation for Regional Topology Upgrades.

21. Amelia Energy suggests that it had no indication that the Amelia Energy Facility had the potential for cost allocation or additional Network Upgrades based on its Phase II System Impact Study reports. According to Amelia Energy, "[t]his type of uncertainty is not just and reasonable and cannot be allowed to exist."[33] Amelia Energy further argues that PJM presented "absolutely no analytical data through its study process of TC1" to "factually demonstrate"[34] that the Amelia Energy Facility requires the Disputed Network Upgrades and Disputed Contingent Facilities to obtain interconnection service or

[33] Amelia Answer at 7.

[34] *Id.* at 5.

that the Amelia Energy Center contributes to a reliability violation that necessitates any of the disputed upgrades.[35] In this section, I demonstrate why these statements are entirely inaccurate. With the implementation of QDEST,[36] PJM has provided Project Developers with a previously unmatched level of data, as evidenced by the robustness of not only the three System Impact Study reports generated for every New Service Request in a Cycle, but also the System Impact Study Executive Summary Reports prepared for each phase of a Cycle and the Final System Impact Study (Retool 1) Reports. To help illustrate this point, I have prepared Exhibit No. PJM-0001 containing hyperlinks to the Phase II and Phase III System Impact Study reports for each of the three Project Identifiers associated with the Amelia Energy Facility, as well Phase II and Phase III System Impact Study Executive Summary Reports for Transition Cycle No. 1 and the Final System Impact Study (Retool 1) Reports. All reports are also posted on PJM's website.

1. Phase II System Impact Study

22. In the following paragraphs, I will use the TC1 Phase II and Phase III System Impact Study reports for Project Identifier No. AG1-021[37] to illustrate some of the analytical data PJM provided to Amelia Energy and other TC1 Project Developers. This data demonstrates that the Phase II System Impact Study report included sufficient information to alert Amelia Energy of the potential for cost allocation for, or contingencies on, certain regional topology upgrades in Phase III, depending on changes occurring at

[35] *Id.* at 6-7.

[36] Initial Krizenoskas Aff. ¶¶ 15, 19 & n.29.

[37] Amelia Energy has three separate Project Identifiers in TC1, AF1-294, AF2-115, and AG1-021, which collectively represent the Amelia Energy Facility.

Decision Point II, since the Project Developer met the "aggregate contributor pool."[38] The data also demonstrates that, *without* the use of regional topology upgrades in PJM's regional System Impact Study analyses, Amelia Energy Facility could have had exposure to additional Network Upgrades and Contingent Facilities and subsequently, additional cost allocation of more than $4 million to Amelia Energy, as discussed later in my affidavit.

23. The main page of the Phase II System Impact Study report for all projects contains a preface that explains "[t]he Phase II System Impact Study is conducted on an *aggregate basis* within a New Service[] Request's Cycle, and results are provided in both (i) a single Cycle executive summary format and (ii) an individual project-level basis."[39]

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[38] Manual 14H, section B.3.1 describes the aggregate contributor pool for the load flow cost allocation method as follows:

> If no New Service Request(s) in a Cycle meet the prior cost allocation thresholds, all non-zero contributors to the facility overload in question who do not receive cost allocation via the prior rules shall be pooled into an aggregate contributor. If the cumulative impact of this aggregate contributor pool exceeds 1% of the applicable line rating, projects with an individual contribution of greater than 0.25% of the applicable line rating will have some cost allocation. If no projects in the aggregate contributor pool contribute greater than 0.25%, the 5 highest contributors in the pool will receive some cost allocation.
>
> […]
>
> Allocation of costs to New Service Requests for a required Network Upgrade will be based on the full MW impact on the facility requiring a Network Upgrade as determined in each phase of System Impact Study. Cost allocation will be based on the highest loading of all test procedures performed (e.g., if Summer Peak overload is more significant than Light Load for the same flowgate, Summer Peak loading will determine cost allocation) [.]
>
> Analysis to determine cost allocation for the engineering design of Network Upgrades will continue to be refined as needed after the Phase III System Impact Study and throughout the Final Agreement Negotiation Phase. Final resolution of cost allocation will occur using as-built costs upon construction completion.
>
> A complete list of Distribution Factors for all PJM modeled substations will be maintained during System Impact Studies for each identified Network Upgrade. This Distribution Factor list will be used for all cost allocation pertaining to the identified Network Upgrade.

[39] PJM Interconnection, L.L.C., *AG1-021 Phase II Study Report*, at Preface (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AG1-021/AG1-021_imp_PHASE_2.htm (emphasis added). *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AG1-021 Phase II System Impact Study Report).

While there are many sections to each System Impact Study, I will focus on the summer peak analysis and system reinforcements sections for purposes of my affidavit.

24. Included in PJM's System Impact Study report is a summer peak analysis where PJM tests potential summer peak network impacts. In the Phase II System Impact Study report for AG1-021, the summer peak analysis shows overloaded flowgates.[40] Below is an excerpt from the AG1-021 Phase II System Impact Study report which shows the overloaded flowgates in the Summer Peak analysis that remain after evaluating the regional topology upgrades for TC1 Phase II.

Summer Peak Analysis

The New Service Request was evaluated as a 20.0 MW (12.0 MW Capacity) injection in the Dominion area. Project was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Potential summer peak period network impacts were as follows:

Note: The capacity portion of Generation Interconnection Requests are evaluated for single or N-1 contingencies. The full energy output of Generation Interconnection Requests are evaluated for multiple facility contingencies (double circuit tower line, fault with a stuck breaker, and bus fault).

The following flowgates remain after considering the topology reinforcements required by the cycle.

Summer Peak Analysis									
Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contributic
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-6: CHASE C T342_SRT-A	Breaker	DC	293.6	208.7	C	612.74	11.07
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-2: 4012_SRT-A	Breaker	DC	222.39	208.7	C	464.12	6.48
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-2: 17112_SRT-A	Breaker	DC	222.31	208.7	C	463.95	6.48
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-2: 102712_SRT-A	Breaker	DC	222.31	208.7	C	463.95	6.48

Additionally, the same section of the AG1-021 Phase II System Impact Study report shows the eight overloaded flowgates identified in the summer peak analysis that were eliminated as a result of evaluating regional topology upgrades, and I have included this information below.

[40] *Id.* at Summer Peak Analysis.

The following flowgates were eliminated after considering the topology reinforcements required by the cycle.

Summer Peak Analysis - Eliminated Flowgates										
Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contribution	Details
DVP	AE1-173 TP-8SUFFOLK 500.0 kV Ckt 1 line	DVP_P4-2: 562T563_SRT-S	Breaker	AC	100.59	3144.0	C	3162.54	2.16	
DVP	AE2-313 TP-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 585_SRT-A-2	Single	AC	110.33	4070.2	B	4490.83	2.46	
DVP	8ROGERS RD-AE2-094 TP 500.0 kV Ckt 1 line	DVP_P1-2: LN 511_SRT-S-A	Single	AC	106.47	4070.2	B	4333.62	2.17	
DVP	AE2-313 TP-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 585_SRT-A-1	Single	AC	114.58	4070.2	B	4663.68	2.46	
DVP	6CARSON-6CHAPARRAL T 230.0 kV Ckt 1 line	DVP_P4-2: 562T563_SRT-S	Breaker	AC	134.78	1204.0	C	1622.78	1.32	
DVP	8RAWLINGS-AE2-313 TP 500.0 kV Ckt 1 line	DVP_P1-2: LN 585_SRT-A-1	Single	AC	109.86	4070.2	B	4471.55	2.46	
DVP	AE2-094 TP-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 511_SRT-S-A	Single	AC	111.55	4070.2	B	4540.37	2.17	
DVP	6MTEAGLE-6CHARLVL 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-1	Single	AC	107.37	661.76	B	710.55	3.08	

If the regional topology upgrades had not been considered in PJM's Phase II analysis, Amelia Energy Facility could have had exposure to additional Network Upgrades and/or Contingent Facilities for these overloaded flowgates.

25. As I mentioned above, PJM's System Impact Study report also includes a "System Reinforcements" section which states, "[b]ased on the Phase II analysis results, this project has potential cost responsibility"[41] for certain system reinforcement and a list of such potential system reinforcements is provided, as illustrated below. In Amelia Energy's case, nine system reinforcements were identified in the Phase II System Impact Study report for AG1-021, with a total cost of approximately $4.5 million.[42] Accordingly, based on the detailed information provided in the Phase II System Impact Study, Amelia Energy's New Service Request with Project Identifier AG1-021 had notice of a potential $4.5 million in cost responsibility for required reliability Network Upgrades. Below is a table showing the nine system reinforcements.

[41] PJM Interconnection, L.L.C., *AG1-021 Phase II Study Report*, at System Reinforcements, (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AG1-021/AG1-021_imp_PHASE_2.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AG1-021 Phase II System Impact Study Report).

[42] AF1-294 and AF2-115 are larger projects and had a cost responsibility of $9.3 million and $5.7 million, respectively, in the Phase II System Impact Study reports.

AG1-021 System Reinforcements Cost Breakdown:						
Type	TO	RTEP ID / TO ID	Title	MW Impact	Percent Allocation	Allocated Cost ($USD)
Stability	Dominion	n9141 / TC1-PH1-DOM-075	Farmville to Chase City upgrades: wreck and rebuild 115kV as DCT 115kV and 230kV	35.1 MW	0.7%	$2,357,792
Load Flow	Dominion	n9220 / TC1-PH2-DOM-033	Wreck and rebuild 15.41 miles of 230 kV Line 298 from Buckingham to Bremo with (2) 768.2 ACSS/TW (20/7) "Maumee" conductor @ 250 degrees C. Replace line lead at Bremo.	8.8 MW	1.4%	$632,255
Load Flow	Dominion	n9217 / TC1-PH2-DOM-028	Rebuild 12.73 miles of 230 kV Line 298 from Buckingham to Farmville with (2) 768 ACSS/TW (20/7) "Maumee" conductor @ 250 degrees C and replace line lead at Farmville.	8.8 MW	1.4%	$522,314
Load Flow	Dominion	n9203 / TC1-PH2-DOM-008	Wreck and rebuild 10.86 miles of line 2028 between Fork Union and Cunningham (Grape Vine) with (2) 768.2 ACSS/TW (20/7) "Maumee" @ 250C	3.0 MW	1.3%	$392,671
Load Flow	Dominion	n7569 / dom-490	Reconductor 6.51 miles of line between Mt. Eagle and Cunningham with (2) 768.2 ACSS/TW (20/7) "MAUMEE" conductor @250 degrees C	3.0 MW	1.3%	$235,386
Load Flow	Dominion	n7568 / dom-369	Wreck and rebuild 6.47 miles of line 2028 between Charlottesville and Mt. Eagle with (2) 768.2 ACSS/TW (20/7) "Maumee" @ 250C and replace line lead at Mt. Eagle	3.1 MW	1.3%	$234,849
Load Flow	Dominion	n7687 / dom-046	Add a 3rd 230/115 kV transformer at Sedge Hill substation and associated breakers (230 kV and 115 kV)	3.0 MW	0.7%	$95,561
Load Flow	Dominion	n9199 / TC1-PH2-DOM-004	Wreck and rebuild 1.63 miles of line 2193 between Fork Union and Bremo replace line lead at Bremo	6.7 MW	1.3%	$61,838
Load Flow	Dominion	n9221 / TC1-PH2-DOM-035	Replace Wave Trap at Buckingham 230 kV (Buckingham - Bremo).	8.8 MW	1.5%	$2,993
Grand Total:						$4,535,659

26. Within the "System Reinforcements" section of the Phase II System Impact Study report, 17 Network Upgrades were identified (11 of which were categorized as regional topology upgrades), for which AG1-021 is part of the pool of "potential aggregate contributors." As explained in the Phase II System Impact Study report, "[a]s changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-021 could receive cost allocation. Although AG1-021 may not presently have cost responsibility for this upgrade, AG1-021 is a potential Aggregate Pool Contributor."[43] This means that AG1-021 contributed to flowgates that required regional topology upgrades that had the potential to receive cost allocation in Phase III after accounting for changes stemming from Decision Point II project withdrawals, even though AG1-021 did not meet the cost allocation criteria to receive cost allocation for these 11 regional topology

[43] PJM Interconnection, L.L.C., *AG1-021 Phase II Study Report*, at System Reinforcements, (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AG1-021/AG1-021_imp_PHASE_2.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AG1-021 Phase II System Impact Study Report). To clarify, the preface is intended to reference changes occurring within the study process as *inputs* change (e.g., withdrawals) and not change to the process itself. *See also supra* note 37 (describing the aggregate contributor pool).

upgrades in Phase II. The table below illustrates how PJM shared this information in the AG1-021 Phase II System Impact Study report, using Network Upgrade n9250 as an example.

System Reinforcement						
Type	TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Load Flow	Dominion	n9250 / TC1-PH2-DOM-044	Construct new 22.59 mile line between Carson and Rawlings with (3) 1351.5 ACSR (45/7) "Dipper" at 110 degrees C. Station upgrades at Carson and Rawlings to accommodate new line.	$140,058,000	$0	48 to 60 Months

Potential Aggregate Contributor | Topology Changing

Note 1: Based on PJM cost allocation criteria, AG1-021 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-021 could receive cost allocation. Although AG1-021 may not presently have cost responsibility for this upgrade, AG1-021 is a potential Aggregate Pool Contributor.

Note 2: This topology changing reinforcement was developed by the transmission owner and modeled in PJM analysis to address cycle overload(s). A flowgate that this project contributed to was identified as requiring this topology reinforcement.

Description: Construct new 22.59 mile line between Carson and Rawlings with (3) 1351.5 ACSR (45/7) "Dipper" at 110 degrees C. Station upgrades at Carson and Rawlings to accommodate new line. New Rating = 4356/4356/5009 MVA

Notably, the blue label below the Network Upgrade information identifies that this is a regional topology upgrade with the label of "Topology Changing" and explains "[a]s changes to the PJM process occur . . . AG1-021 could receive cost allocation" for the upgrade. The other 10 potential aggregate contributors to topology upgrades contain the same labels and explanations, again signaling to Amelia Energy that regional topology upgrades were used in the Phase II System Impact Study reports and that, depending upon other projects in TC1 withdrawing or reducing in size, Amelia Energy Facility's cost allocation could increase based on these required system reinforcements to which Amelia Energy was a potential aggregate contributor.

27. As I previously stated, in addition to the individual System Impact Studies, PJM prepares a single Cycle executive summary report for each phase of the Cycle. In the

system reinforcements section of the TC1 executive summary report,[44] PJM explains how it determined which upgrades were eliminated as a result of modeling the regional topology upgrades and how it computed the discount factor. The report states, "[a]s part of Transition Cycle 1 Phase II, PJM evaluated the impact of topology changing reinforcements to mitigate the impacts driven by New Service Requests. PJM determined which reinforcements were eliminated as a result of modeling the topology changing reinforcements. PJM then grouped the topology changing and eliminated reinforcements by region [(i.e., "regional topology upgrades")] and computed a discount factor to apply to reinforcements to reduce the cost of all these reinforcements down to the cost of constructing only the topology changing reinforcements."[45] This discount factor[46] was applied to the cost of the Network Upgrades for all projects that contributed to the need for a regional topology upgrade or had an upgrade eliminated as a result of the regional topology upgrade, then the cost was redistributed to the regional topology upgrades that will be built. With this approach, all projects receiving the discount factor are contingent on the full set of regional topology upgrades that allowed them to realize the discount.

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[44] PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle #1 Phase II*, (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH2_Executive_Summary.htm. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase II System Impact Study Cluster Report).

[45] PJM Interconnection. L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle #1 Phase II*, (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH2_Executive_Summary.htm#exec-sum-analysis-header. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase II System Impact Study Cluster Report).

[46] A discount factor of .8435697 was multiplied by the cost of the Network Upgrade (both regional topology upgrades and eliminated Network Upgrades) to compute the reduced cost and was applied to all projects which contributed to a topology changing upgrade or eliminated Network Upgrade in the Dominion region. *See* PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle #1 Phase II*, (Dec. 18, 2024), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH2_Executive_Summary.htm. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase II System Impact Study Cluster Report).

2. Phase III System Impact Study

28. The Phase III System Impact Study reports for all projects, as well as the executive summary report, contain the same Preface and introductory language as the Phase II reports explained in the preceding paragraphs.[47] Therefore, I will focus on a few of the key differences between the Phase II and Phase III reports for Amelia Energy Facility by, again, using Project Identifier No. AG1-021, as an example.

29. After Decision Point II, PJM retooled the TC1 model to remove withdrawn projects and reflect any changes to the remaining projects in the TC1 cohort, as well as to account for the then recently approved RTEP Window 1 updates,[48] and reran the System Impact Study analysis in Phase III. Just like in Phase II, PJM considered the regional topology upgrades in this analysis; however, the set of regional topology reinforcements in Phase III was notably different from the set of regional topology reinforcements in Phase II as a result of incorporating the recently approved baseline upgrades from the RTEP Window 1. The summer peak analysis section of the AG1-021 Phase III System Impact

[47] *See supra* paragraphs 30-34. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase III SIS Cluster Report).

[48] *See supra* Section III.C.

Study report reflects 11 overloaded flowgates remaining after considering the regional topology upgrades for TC1. Below is a table reflecting these results.

Summer Peak Analysis										
Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contribution	Details
DVP	6FARMVIL-6BUCKING 230.0 kV Ckt 1 line	DVP_P4-2: 511T556_SRT-S-1	Breaker	AC	133.47 %	684.0	C	912.91	8.66	
DVP	6BUCKING-6BREMO 230.0 kV Ckt 1 line	DVP_P4-2: 511T556_SRT-S-1	Breaker	AC	132.6 %	699.0	C	926.86	8.66	
DVP	6CARSON-6CHAPARRAL T 230.0 kV Ckt 1 line	DVP_P4-2: 562T563_SRT-S	Breaker	AC	115.93 %	1204.0	C	1395.79	1.58	
DVP	6CHAPARRAL T-6LOCKS 230.0 kV Ckt 1 line	DVP_P4-2: 562T563_SRT-S	Breaker	AC	114.15 %	1204.0	C	1374.4	1.58	
DVP	8CARSON-6CARSON 500.0/230.0 kV Ckt 2 transformer	DVP_P4-2: 56372_SRT-S	Breaker	AC	118.17 %	1056.8	C	1248.84	1.14	
DVP	6FARMVIL-6BUCKING 230.0 kV Ckt 1 line	DVP_P1-2: LN 556_SRT-S-3	Single	AC	126.69 %	559.3	B	708.6	4.68	
DVP	6BUCKING-6BREMO 230.0 kV Ckt 1 line	DVP_P1-2: LN 556_SRT-S-3	Single	AC	125.44 %	571.52	B	716.93	4.68	
DVP	6SAPONY-6CARSON 230.0 kV Ckt 1 line	DVP_P1-2: LN 556_SRT-S-3	Single	AC	118.96 %	678.68	B	807.34	0.91	
DVP	AE2-033 TP-6SAPONY 230.0 kV Ckt 1 line	DVP_P1-2: LN 556_SRT-S-3	Single	AC	116.16 %	678.68	B	788.36	0.91	
DVP	6CLUBHSE-AE2-033 TP 230.0 kV Ckt 1 line	DVP_P1-2: LN 556_SRT-S-3	Single	AC	107.24 %	678.68	B	727.84	0.91	
DVP	8MDLTHAN-8NO ANNA 500.0 kV Ckt 1 line	DVP_P1-2: LN 574_SRT-S_SENS	Single	AC	104.61 %	3220.44	B	3368.83	2.39	

30. Additionally, the summer peak analysis section of the Phase III System Impact Study report for AG1-021 shows 35 overloaded flowgates that were eliminated as a result of evaluating the regional topology upgrades. If the regional topology upgrades had not been considered, the Amelia Energy Facility also could have had exposure to additional Network Upgrades and/or Contingent Facilities for these overloaded flowgates. I have included the table of summer peak analysis eliminated flowgates below.

Summer Peak Analysis - Eliminated Flowgates

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contribution	Details
DVP	8SPOTSYL-8MORRSVL 500.0 kV Ckt 1 line	DVP_P1-2: LN 575_SRT-S	Single	AC	122.94 %	3220.44	B	3959.17	1.58	
DVP	8SPOTSYL-8MORRSVL 500.0 kV Ckt 1 line	DVP_P1-2: LN 552_SRT-S	Single	AC	122.77 %	3220.44	B	3953.87	1.7	
DVP	8MDLTHAN-8NO ANNA 500.0 kV Ckt 1 line	DVP_P1-2: LN 574_SRT-S	Single	AC	120.01 %	3220.44	B	3864.83	2.41	
DVP	8NO ANNA-8SPOTSYL 500.0 kV Ckt 1 line	DVP_P1-2: LN 575_SRT-S	Single	AC	118.84 %	3220.44	B	3827.26	1.61	
DVP	8NO ANNA-8SPOTSYL 500.0 kV Ckt 1 line	DVP_P1-2: LN 581_SRT-S	Single	AC	117.57 %	3220.44	B	3786.34	1.72	
DVP	8NO ANNA-8LADYSMITH 500.0 kV Ckt 1 line	DVP_P1-2: LN 594_SRT-S	Single	AC	113.06 %	3220.44	B	3640.94	1.44	
DVP	8NO ANNA-8LADYSMITH 500.0 kV Ckt 1 line	DVP_P1-2: LN 573_SRT-A	Single	AC	111.16 %	3220.44	B	3579.93	1.5	
DVP	8RAWLINGS-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 585_SRT-A-1	Single	AC	109.08 %	4070.2	B	4439.64	2.64	
DVP	6SAPONY-6CARSON 230.0 kV Ckt 1 line	Base Case	Single	AC	108.58 %	678.68	A	736.88	0.59	
DVP	6FARMVIL-6BUCKING 230.0 kV Ckt 1 line	DVP_P1-2: LN 563_SRT-S-1	Single	AC	107.79 %	959.3	B	902.85	3.55	
DVP	6BUCKING-6BREMO 230.0 kV Ckt 1 line	DVP_P1-2: LN 563_SRT-S-1	Single	AC	106.88 %	571.52	B	610.86	3.55	
DVP	AE2-094 TP-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 511_SRT-S	Single	AC	106.03 %	4070.2	B	4315.65	2.31	
DVP	AE2-011 TP-6SAPONY 230.0 kV Ckt 1 line	Base Case	Single	AC	105.77 %	678.68	A	717.82	0.59	
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 2 transformer	DVP_P1-2: LN 235_SRT-A-3	Single	AC	105.45 %	182.64	B	192.59	4.75	
DVP	8RAWLINGS-8CARSON 500.0 kV Ckt 1 line	DVP_P1-2: LN 585_SRT-A-2	Single	AC	104.91 %	4070.2	B	4270.21	2.64	
DVP	6CARSON-6CHAPARRAL T 230.0 kV Ckt 1 line	DVP_P1-2: LN 563_SRT-S-1	Single	AC	104.68 %	984.18	B	1030.28	0.64	
DVP	6BRENO-6BREMODIST 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-2	Single	AC	104.65 %	678.68	B	710.22	2.68	
DVP	6BREMODIST-6FORK UNION 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-2	Single	AC	103.58 %	678.68	B	703.0	2.68	
DVP	8CARSON-8MDLTHAN 500.0 kV Ckt 1 line	DVP_P1-2: LN 574_SRT-S	Single	AC	103.22 %	3220.44	B	3324.19	1.83	
DVP	6FORK UNION-6CUNNING 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-2	Single	AC	103.11 %	661.76	B	682.37	2.4	
DVP	6CHAPARRAL T-6LOCKS 230.0 kV Ckt 1 line	DVP_P1-2: LN 563_SRT-S-1	Single	AC	102.52 %	984.18	B	1008.98	0.64	
DVP	8ROGERS RD-AE2-094 TP 500.0 kV Ckt 1 line	DVP_P1-2: LN 511_SRT-S	Single	AC	101.17 %	4070.2	B	4117.87	2.31	
DVP	6BRENO-6BREMODIST 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-1	Single	AC	100.93 %	678.68	B	684.99	2.68	
DVP	6CUNNING-6MTEAGLE 230.0 kV Ckt 1 line	DVP_P1-2: LN 2027_SRT-A-2	Single	AC	100.45 %	661.76	B	664.72	2.4	
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 1 transformer	DVP_P4-6: CHASE C T342_SRT-A	Breaker	AC	149.46 %	221.4	C	330.91	8.92	
DVP	8SPOTSYL-8MORRSVL 500.0 kV Ckt 1 line	DVP_P4-2: 568T575_SRT-A	Breaker	AC	117.71 %	3940.0	C	4637.69	3.08	
DVP	3FARMVIL-6FARMVIL 115.0/230.0 kV Ckt 1 transformer	DVP_P4-2: 29822_SRT-A	Breaker	AC	116.81 %	221.4	C	258.62	8.18	
DVP	8NO ANNA-8LADYSMITH 500.0 kV Ckt 1 line	DVP_P4-2: SPOTS HIT594_SRT-S	Breaker	AC	112.93 %	3940.0	C	4449.5	2.77	
DVP	8NO ANNA-8SPOTSYL 500.0 kV Ckt 1 line	DVP_P4-2: 568T575_SRT-A	Breaker	AC	112.18 %	3940.0	C	4419.9	3.12	
DVP	3SEDGE HILL-6SEDGE HILL 115.0/230.0 kV Ckt 1 transformer	DVP_P4-2: H2T296_SRT-A	Breaker	AC	108.73 %	264.5	C	287.59	1.28	
DVP	8NO ANNA-8LADYSMITH 500.0 kV Ckt 1 line	DVP_P4-2: HIT594_SRT-S	Breaker	AC	108.64 %	3940.0	C	4280.5	2.68	
DVP	3SEDGE HILL-6SEDGE HILL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-2: 2202_SRT-A	Breaker	AC	102.93 %	279.1	C	287.26	1.67	
DVP	3SEDGE HILL-6SEDGE HILL 115.0/230.0 kV Ckt 2 transformer	DVP_P4-2: H1T296_SRT-A	Breaker	AC	102.75 %	279.1	C	286.78	1.28	
DVP	AG1-285 TP-3CHASCTY 115.0 kV Ckt 1 line	DVP_P4-2: 235T298_SRT-A-1	Breaker	AC	102.22 %	349.0	C	356.75	4.93	
DVP	6CARSON-6POE 230.0 kV Ckt 1 line	DVP_P4-2: 562T563_SRT-S	Breaker	AC	102.1 %	830.0	C	847.45	1.02	

31. The "System Reinforcements" tab of the Phase III System Impact Study report for AG1-021 shows that AG1-021 is contingent on and/or has cost responsibility for 57 required reliability upgrades. Below is a table showing these results from the Phase III

System Impact Study report, which indicates that AG1-021 had potential cost responsibility for approximately $2.7 million in required reliability Network Upgrades.

System Reinforcements

Based on the Phase III analysis results, this project is contingent on and may have cost responsibility for the following System Reinforcements:

AG1-021 System Reinforcements:					
TO	RTEP ID	Title	Category	Allocated Cost ($USD)	Facilities Study
Dominion	n9220.0	Wreck and rebuild 15.42 miles of 230 kV Line #298 from Buckingham to Bremo Substations with twin bundled (2) 768.2 ACSS/TW (20/7) "MAUMEE" conductor.	Cost Allocated	$830,039	
Dominion	n9217.0	Wreck and rebuild 12.73 miles of 230 kV Line 298 from Buckingham to Farmville Substations with twin bundled (2) 768 ACSS/TW (20/7) "MAUMEE" conductor.	Cost Allocated	$754,345	
Dominion	n9138.0	Wreck and rebuild 22.59 miles of Line #511 between Carson and Rawlings Substations with three (3) 1351 ACSS/TW and associated substation work.	Cost Allocated	$221,202	
Dominion	n9250.0	Construct a new 22.59 mile line between Carson and Rawlings Substations.	Cost Allocated	$216,420	
Dominion	n9630.0	Construct a new 230 kV line from the AG1-285 substation to the Finneywood 230 kV Substation. Expand AG1-285 substation and add two (2) new 230/115 kV transformers.	Cost Allocated	$178,085	
Dominion	n8492	Wreck and rebuild the existing Yadkin to Fentress 500 kV Line #588 to share the right of way with the new Yadkin to Fentress #5005 line.	Cost Allocated	$159,581	
Dominion	n9199.0	Wreck and rebuild 1.63 miles of line 2193 between Fork Union and Bremo with (2) 768.2 ACSS/TW (20/7) "MAUMEE" @ 250C and replace line lead at Bremo.	Cost Allocated	$115,793	
Dominion	n9267.0	Construct new 10.21 mile 115 kV line between Northern Neck and Moon Corner.	Cost Allocated	$91,024	
Dominion	n9259.0	Install two 230 kV gas insulated switchgear ("GIS") bus ties for the Coastal Virginia Offshore Wind ("CVOW") project.	Cost Allocated	$50,369	
Dominion	n7541	Add a third 224 MVA 230/115 kV transformer at Earleys Substation and supporting equipment.	Cost Allocated	$45,342	
Dominion	n8492.1	Two Breaker Additions at Fentress Substation.	Cost Allocated	$39,702	
Dominion	n8492.2	Expand Yadkin Substation to accommodate the new 500 kV line.	Cost Allocated	$32,260	
Dominion	n6588	Replace 230 kV breaker 210512 at Yadkin 230 kV with a 63 kA breaker.	Cost Allocated	$3,433	
Dominion	b4000.357	Build a new 765/500/230 kV substation called Yeat. Install (2) 765/500 kV transformers. Cut in 500 kV line Bristers-Ox and 500 kV line Meadowbrook-Vint Hill into Yeat.	Contingent	$0	N/A
Dominion	b4000.356	Build a new 156 mile 765kV line from Joshua Falls - Yeat. (Roughly 86.7 miles in Dominion section).	Contingent	$0	N/A
Dominion	b4000.355	Build a new 156 mile 765kV line from Joshua Falls - Yeat. (Roughly 69.3 miles in AEP section).	Contingent	$0	N/A
Dominion	b4000.352	Cut in Line #568 Ladysmith - Possum Point into Kraken, creating new Line #568 Kraken to Possum Point.	Contingent	$0	N/A
Dominion	b4000.351	Cut in Line #568 Ladysmith - Possum Point into Kraken, creating Line #9517 Ladysmith to Kraken.	Contingent	$0	N/A
Dominion	b4000.350	Update relay settings at Possum Point to change the destination of 500kV line #568 from Ladysmith to Kraken.	Contingent	$0	N/A
Dominion	b4000.349	Update relay settings at Ladysmith to change the destination of 500kV line #568 from Possum Point to Kraken.	Contingent	$0	N/A
Dominion	b4000.348	Build a new 500/230kV substation called Kraken. The 500kV, 5000A ring bus will be set up for a redundant breaker configuration. Install (2) 1400MVA 500/230 kV transformers.	Contingent	$0	N/A
Dominion	b4000.346	Cut-in 500kV line from Kraken substation into Yeat substation	Contingent	$0	N/A
Dominion	b4000.345	Build a 500kV line from a new substation called Kraken to a new substation called Yeat. New conductor to have a minimum summer normal rating of 4357MVA.	Contingent	$0	N/A
Dominion	b4000.344	Build a 500kV line from North Anna substation (bypassing Ladysmith Substation) to a new substation called Kraken. New conductor to have a minimum summer normal rating of 4357MVA.	Contingent	$0	N/A
Dominion	b4000.342	Remove the terminal equipment and substation work required for the termination of the Morrisville-Wishing Star 500 kV line into Vint Hill.	Contingent	$0	N/A
Dominion	b4000.341	Remove the 500 kV conductor previously planned to terminate into the Vint Hill 500 kV Substation and extend approximately 0.2 miles of conductor to fly-over the site.	Contingent	$0	N/A
Dominion	b4000.325	Build a new 26.38mi 230kV Line from Elmont - Ladysmith on the existing 5-2 structures between the two stations. New conductor has a summer rating of 1573 MVA.	Contingent	$0	N/A
Dominion	b3689.2	Replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 80 kA	Contingent	$0	N/A
Dominion	b4000.103	Brambleton Sub 230kV - replace 63kA breakers 217202, 2172T2183, L102, L202 with 80kA	Contingent	$0	N/A
Dominion	b3800.405	Replace Brambleton 230 kV breakers 20102, 20602, 204502, 209402, 201T2045, 206T2094 with breakers rated 80 kA.	Contingent	$0	N/A
Dominion	b3854.1	Replace over duty Carson 230kV circuit breakers 200272 and 24972-3 with an interrupting rating of 63 kA	Contingent	$0	N/A
Dominion	b4000.108	Carson Sub 230kV - replace 40kA breaker 23872 with 63kA	Contingent	$0	N/A
Dominion	b4000.326	At Elmont substation, install/upgrade associated equipment to accommodate a 4000A line rating for the new 230kV line between Elmont - Ladysmith.	Contingent	$0	N/A
Dominion	b4000.327	Upgrade/install equipment at Ladysmith Substation to 4000A. Expansion will be required to accommodate a total of three (3) new 230 kV strings of breaker and a half scheme.	Contingent	$0	N/A
Dominion	b3800.406	Replace Gainesville 230 kV breaker 216192 with a breaker rated 80 kA.	Contingent	$0	N/A
Dominion	b4000.115	Ladysmith Sub 500kV - replace 40kA breaker 574T581 with 63kA	Contingent	$0	N/A
Dominion	b4000.354	Ladysmith substation breakers replacement: 574T575 and 568T581	Contingent	$0	N/A
Dominion	b3853.1	Replace over duty Ladysmith CT 230kV circuit breakers SX1272 and SX3472 with an interrupting rating of 63 kA	Contingent	$0	N/A
Dominion	b4000.114	Ladysmith S1 Sub 230kV - replace 40kA breakers 25672, 209072, 256T2090, GT172, GT272, GT372, GT472, GT572 with 63kA	Contingent	$0	N/A
Dominion	b3800.235	Replace 5 overdutied 230kV breakers at Loudoun substation with 80kA breakers	Contingent	$0	N/A
Dominion	b3800.334	Replace four (4) overdutied 230 kV breakers at Loudoun Substation with 80 kA breakers.	Contingent	$0	N/A

Dominion	b3800.407	Replace Loudoun 230 kV breakers 204552 and 217352 with breakers rated 80 kA.	Contingent	$0	N/A
Dominion	b4000.119	Loudoun Cap Substation 230kV - replace 50 kA breaker SC352 with 63 kA.	Contingent	$0	N/A
Dominion	b4000.128	North Anna Substation 500 kV - replace 40 kA breakers 57502, G102-1, G102-2, G202, G2T575, and XT573 with 63 kA.	Contingent	$0	N/A
Dominion	b3800.408	Replace Ox 230 kV breakers 22042, 24342, 24842, 220T2063, 243T2097, 248T2013, and H342 with breakers rated 80 kA.	Contingent	$0	N/A
Dominion	s2609.6	Upgrade two (2) 230 kV breakers 201342 and L142 from 50 kA to 63 kA at Ox Substation due to an insufficient breaker duty rating with the expansion in place.	Contingent	$0	N/A
Dominion	s2609.9	Upgrade 230 kV Pleasant View breakers L3T203 and L3T2180 from 50 kA to 80 kA.	Contingent	$0	N/A
Dominion	b4000.134	Remington Substation 230 kV - replace 40 kA and 50 kA breakers 211462, GT162, GT262, GT362, GT462, 2077T2086, 208662, H962, and H9T299 with 63 kA.	Contingent	$0	N/A
Dominion	b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV: 20212 and 20712	Contingent	$0	N/A
Dominion	b3800.236	Replace 2 overdutied 500kV breakers at Ox Substation with 63kA breakers.	Contingent	$0	N/A
Dominion	s3047.2	Install two (2) 1400 MVA 500-230 kV transformers at Vint Hill Substation and loop 500 kV line #535 and #569 into the proposed 500 kV ring bus at Vint Hill Substation.	Contingent	$0	N/A
Dominion	b3800.312	Rebuild 500 kV Line #569 Loudoun - Morrisville to accommodate the new 500 kV line in the existing right-of-way.	Contingent	$0	N/A
Dominion	b3800.313	Rebuild approximately 10.29 miles line segment of Line #535 (Meadow Brook to Loudoun) to accommodate the new 500 kV line in the existing ROW.	Contingent	$0	N/A
Dominion	b3800.356	Build a new 500 kV line from Vint Hill to Wishing Star.	Contingent	$0	N/A
Dominion	b3800.357	Build a new 500 kV line from Morrisville to Vint Hill.	Contingent	$0	N/A
Dominion	b3800.354	Install terminal equipment at Wishing Star Substation to support a 5000A line to Vint Hill. Update relay settings for 500 kV Lines #546 and #590.	Contingent	$0	N/A
Dominion	b3800.335	Replace 1 overdutied 500kV breaker at Ox Substation with a 63kA breaker	Contingent	$0	N/A
Grand Total:				$2,737,595	

32. To mitigate the impacts driven by New Service Requests, just like in Phase II, PJM evaluated the impact of regional topology upgrades and determined which reinforcements were eliminated as a result of modeling the regional topology upgrades. As I explained in paragraph 27, PJM then grouped the topology changing reinforcements and eliminated reinforcements by region and computed a discount factor[49] to reduce the cost of all reinforcements down to the cost of constructing only the topology changing reinforcements.

33. In the AG1-021 Phase III System Impact Study report additional details regarding AG1-021's contributions to both regional topology upgrades and eliminated reinforcements, including the discount factor, are found by selecting "Regional Topology Upgrade Conversion" in the report. Unlike in Phase II, AG1-021 had eliminated Network

[49] A discount factor of 0.408652 was multiplied by the cost of the Network Upgrade (both regional topology upgrades and eliminated Network Upgrades) to compute the reduced cost and was applied to all projects which contributed to a topology changing upgrade or eliminated Network Upgrade in the Dominion region. *See* PJM Interconnection. L.L.C., *New Service Requests System Impact Study Executive Summary Report, Transition Cycle 1 Phase III*, (Sep. 18, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH3_Executive_Summary.htm. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase III System Impact Study Cluster Report).

Upgrades due to the evaluation of regional topology upgrades in Phase III.[50] The table below, pulled from the Regional Topology Upgrade Conversion view in the AG1-021 Phase III System Impact Study report, shows that after evaluating the impact of regional topology upgrades, AG1-021 contributed to the need for one required regional topology upgrade, Network Upgrade n9630.0, and four eliminated reinforcements, for a total cost allocation of approximately $1.03 million.[51]

AG1-021 Contributions into Topology or Eliminated Reinforcements:								
Type	TO	RTEP ID / TO ID	Title	Topo or Elim	MW Impact	Percent Allocation	Category	Allocated Cost ($USD)
Stability	Dominion	n9630.0 / TC1-PH3-DOM-013	Construct a new 230 kV line from the AG1-285 substation to the Finneywood 230 kV Substation. Expand AG1-285 substation and add two (2) new 230/115 kV transformers.	Topology	18.6 MW	2.0%	Cost Allocated	$745,909
Load Flow	Dominion	n9203.0 / TC1-PH2-DOM-008	Wreck and rebuild 10.74 miles of line 2028 between Fork Union and Cunningham (Grape Vine) with (2) 768.2 ACSS/TW (20/7) "MAUMEE" @ 250C.	Eliminated	2.4 MW	1.4%	Cost Allocated	$163,149
Load Flow	Dominion	n7569 / dom-490	Upgrade a 3.78 mile segment of 230kV transmission line 2028 between Mt. Eagle and Grape Vine Substations at structure 2080/73.	Eliminated	2.4 MW	1.4%	Cost Allocated	$73,788
Load Flow	Dominion	n7687 / dom-046	Add a 3rd 230/115 kV transformer at Sedge Hill Substation and associated breakers (230 kV and 115 kV).	Eliminated	2.9 MW	0.8%	Cost Allocated	$35,089
Load Flow	Dominion	n9221.0 / TC1-PH3-DOM-015	Replace 230 kV Breaker 29822 at Bremo with a higher-rated device (Buckingham - Bremo).	Eliminated	8.7 MW	1.9%	Cost Allocated	$16,049
Contributions into Topology or Eliminated Reinforcement Total:								$1,033,984

34. The cost for the regional topology upgrades and eliminated upgrades is converted into a distribution for the regional topology upgrades as shown below, and in the Regional Topology Upgrade Conversion view of the AG1-021 Phase III System Impact Study report.

[50] The same is true for all Project Identifiers associated with Amelia Energy Facility in Phase III.

[51] This result is based on the Phase III System Impact Study report. The Final System Impact Study reports for Amelia Energy Facility do not contain eliminated Network Upgrades. PJM Interconnection, L.L.C., *AF1-294 Final System Impact Study (Retool 1) Report*, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF1-294/AF1-294_imp_FINAL.htm; PJM Interconnection, L.L.C., *AF2-115 Final System Impact Study (Retool 1) Report*, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF2-115/AF2-115_imp_FINAL.htm; PJM Interconnection, L.L.C., *AG1-021 Final System Impact Study (Retool 1) Report*, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AG1-021/AG1-021_imp_FINAL.htm. *See also* Exhibit No. PJM-0001 (providing the hyperlinks to the Final System Impact Study Reports).

AG1-021 Contingent Region Topology Upgrades:				
TO	**RTEP ID**	**Title**	**Category**	**Allocated Cost ($USD)**
Dominion	n9138.0	Wreck and rebuild 22.59 miles of Line #511 between Carson and Rawlings Substations with three (3) 1351 ACSS/TW and associated substation work.	Cost Allocated	$221,202
Dominion	n9250.0	Construct a new 22.59 mile line between Carson and Rawlings Substations.	Cost Allocated	$216,420
Dominion	n9630.0	Construct a new 230 kV line from the AG1-285 substation to the Finneywood 230 kV Substation. Expand AG1-285 substation and add two (2) new 230/115 kV transformers.	Cost Allocated	$178,085
Dominion	n8492	Wreck and rebuild the existing Yadkin to Fentress 500 kV Line #588 to share the right of way with the new Yadkin to Fentress #5005 line.	Cost Allocated	$159,581
Dominion	n9267.0	Construct new 10.21 mile 115 kV line between Northern Neck and Moon Corner.	Cost Allocated	$91,024
Dominion	n9259.0	Install two 230 kV gas insulated switchgear ("GIS") bus ties for the Coastal Virginia Offshore Wind ("CVOW") project.	Cost Allocated	$50,369
Dominion	n7541	Add a third 224 MVA 230/115 kV transformer at Earleys Substation and supporting equipment.	Cost Allocated	$45,342
Dominion	n8492.1	Two Breaker Additions at Fentress Substation.	Cost Allocated	$39,702
Dominion	n8492.2	Expand Yadkin Substation to accommodate the new 500 kV line.	Cost Allocated	$32,260
Dominion	b4000.357	Build a new 765/500/230 kV substation called Yeat. Install (2) 765/500 kV transformers. Cut in 500 kV line Bristers-Ox and 500 kV line Meadowbrook-Vint Hill into Yeat.	Contingent	$0
Dominion	b4000.356	Build a new 156 mile 765kV line from Joshua Falls - Yeat. (Roughly 86.7 miles in Dominion section).	Contingent	$0
Dominion	b4000.355	Build a new 156 mile 765kV line from Joshua Falls - Yeat. (Roughly 69.3 miles in AEP section).	Contingent	$0
Dominion	b4000.352	Cut in Line #568 Ladysmith - Possum Point into Kraken, creating new Line #568 Kraken to Possum Point.	Contingent	$0
Dominion	b4000.351	Cut in Line #568 Ladysmith - Possum Point into Kraken, creating Line #9517 Ladysmith to Kraken.	Contingent	$0
Dominion	b4000.350	Update relay settings at Possum Point to change the destination of 500kV line #568 from Ladysmith to Kraken.	Contingent	$0
Dominion	b4000.349	Update relay settings at Ladysmith to change the destination of 500kV line #568 from Possum Point to Kraken.	Contingent	$0
Dominion	b4000.348	Build a new 500/230kV substation called Kraken. The 500kV, 5000A ring bus will be set up for a redundant breaker configuration. Install (2) 1400MVA 500/230 kV transformers.	Contingent	$0
Dominion	b4000.346	Cut-in 500kV line from Kraken substation into Yeat substation	Contingent	$0
Dominion	b4000.345	Build a 500kV line from a new substation called Kraken to a new substation called Yeat. New conductor to have a minimum summer normal rating of 4357MVA.	Contingent	$0
Dominion	b4000.344	Build a 500kV line from North Anna substation (bypassing Ladysmith Substation) to a new substation called Kraken. New conductor to have a minimum summer normal rating of 4357MVA.	Contingent	$0
Dominion	b4000.342	Remove the terminal equipment and substation work required for the termination of the Morrisville-Wishing Star 500 kV line into Vint Hill.	Contingent	$0
Dominion	b4000.341	Remove the 500 kV conductor previously planned to terminate into the Vint Hill 500 kV Substation and extend approximately 0.2 miles of conductor to fly-over the site.	Contingent	$0
Dominion	b4000.325	Build a new 26.38mi 230kV Line from Elmont - Ladysmith on the existing 5-2 structures between the two stations. New conductor has a summer rating of 1573 MVA.	Contingent	$0
Dominion	b3689.2	Replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 80 kA	Contingent	$0
Dominion	b4000.103	Brambleton Sub 230kV - replace 63kA breakers 217202, 2172T2183, L102, L202 with 80kA	Contingent	$0
Dominion	b3800.405	Replace Brambleton 230 kV breakers 20102, 20602, 204502, 209402, 201T2045, 206T2094 with breakers rated 80 kA.	Contingent	$0
Dominion	b3854.1	Replace over duty Carson 230kV circuit breakers 200272 and 24972-3 with an interrupting rating of 63 kA	Contingent	$0
Dominion	b4000.108	Carson Sub 230kV - replace 40kA breaker 23872 with 63kA	Contingent	$0
Dominion	b3800.235	Replace 5 overdutied 230kV breakers at Loudoun substation with 80kA breakers	Contingent	$0
Dominion	b3800.334	Replace four (4) overdutied 230 kV breakers at Loudoun Substation with 80 kA breakers.	Contingent	$0
Dominion	b3800.407	Replace Loudoun 230 kV breakers 204552 and 217352 with breakers rated 80 kA.	Contingent	$0
Dominion	b4000.119	Loudoun Cap Substation 230kV - replace 50 kA breaker SC352 with 63 kA.	Contingent	$0
Dominion	b4000.128	North Anna Substation 500 kV - replace 40 kA breakers 57502, G102-1, G102-2, G202, G2T575, and XT573 with 63 kA.	Contingent	$0
Dominion	b3800.408	Replace Ox 230 kV breakers 22042, 24342, 24842, 220T2063, 243T2097, 248T2013, and H342 with breakers rated 80 kA.	Contingent	$0
Dominion	s2609.6	Upgrade two (2) 230 kV breakers 201342 and L142 from 50 kA to 63 kA at Ox Substation due to an insufficient breaker duty rating with the expansion in place.	Contingent	$0
Dominion	s2609.9	Upgrade 230 kV Pleasant View breakers L3T203 and L3T2180 from 50 kA to 80 kA.	Contingent	$0
Dominion	b4000.134	Remington Substation 230 kV - replace 40 kA and 50 kA breakers 211462, GT162, GT262, GT362, GT462, 2077T2086, 208662, H962, and H9T299 with 63 kA.	Contingent	$0
Dominion	b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV: 20212 and 20712	Contingent	$0
Dominion	b3800.236	Replace 2 overdutied 500kV breakers at Ox Substation with 63kA breakers.	Contingent	$0
Dominion	s3047.2	Install two (2) 1400 MVA 500-230 kV transformers at Vint Hill Substation and loop 500 kV line #535 and #569 into the proposed 500 kV ring bus at Vint Hill Substation.	Contingent	$0
Dominion	b3800.312	Rebuild 500 kV Line #569 Loudoun - Morrisville to accommodate the new 500 kV line in the existing right-of-way.	Contingent	$0
Dominion	b3800.313	Rebuild approximately 10.29 miles line segment of Line #535 (Meadow Brook to Loudoun) to accommodate the new 500 kV line in the existing ROW.	Contingent	$0
Dominion	b3800.356	Build a new 500 kV line from Vint Hill to Wishing Star.	Contingent	$0
Dominion	b3800.357	Build a new 500 kV line from Morrisville to Vint Hill.	Contingent	$0
Dominion	b3800.354	Install terminal equipment at Wishing Star Substation to support a 5000A line to Vint Hill. Update relay settings for 500 kV Lines #546 and #590.	Contingent	$0
Dominion	b3800.335	Replace 1 overdutied 500kV breaker at Ox Substation with a 63kA breaker	Contingent	$0
Region Topology Upgrade Total:				**$1,033,985**

For each Network Upgrade that was eliminated due to the application of regional topology upgrades, the following note was included in the System Impact Study report to explain the cost allocation to the project as well as why the project is contingent on the full set of regional topology upgrades in the Dominion region:

> Note: The topology changing reinforcements listed in the Cycle executive summary report eliminated the need for this reinforcement and it is no longer required by the Cycle. However, this project is

> receiving cost allocation based on its MW contribution to this eliminated reinforcement to fund the topology reinforcements which together alleviated the need for this reinforcement. This project's cost allocation is based on the pro rata share of the MW impacts from all cost allocated contributors multiplied by the relevant regional discount factor listed in the executive summary report.
>
> Since this project contributed to a violation with a reinforcement that was eliminated by the topology changing reinforcements, this project is contingent on all of the topology changing reinforcements within the region in which the eliminated reinforcement belongs.[52]

35. As I previously explained, in addition to the individual project-level Phase III System Impact Study, PJM prepares a single executive summary report for each phase of the Cycle. Just like in the Phase II System Impact Study report, in the system reinforcements section of the TC1 Phase III executive summary report,[53] PJM explains how it determined which upgrades were eliminated as a result of modeling the regional topology upgrades and how it computed the discount factor for TC1. Contrary to Amelia Energy's claim that PJM provided no evidence about how much of this savings came from other projects that withdrew from TC1 or from RTEP projects which "would be constructed in any event,"[54] PJM provided analytical data in the Phase III System Impact Study

[52] PJM Interconnection, L.L.C., *AG1-021 Phase III Study Report*, at System Reinforcements, (Sep 18, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AG1-021/AG1-021_imp_PHASE_3.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AG1-021 Phase III System Impact Study Report).

[53] *See* PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle #1 Phase III*, (Sep. 18, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH3_Executive_Summary.htm ("As part of Phase III, PJM evaluated the impact of topology changing reinforcements to mitigate the impacts driven by New Service Requests. PJM determined which reinforcements were eliminated as a result of modeling the topology changing reinforcements. PJM then grouped the topology changing and eliminated reinforcements by region and computed a discount factor to apply to reinforcements to reduce the cost of all these reinforcements down to the cost of constructing [sic] only the topology changing reinforcements."). *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase III System Impact Study Cluster Report).

[54] Amelia Energy Answer at 7.

executive summary report that the approximate $751 million in savings came from eliminated Network Upgrades from applying the regional topology upgrades in the Dominion region.[55] Below is a screenshot of the system reinforcements section of the Phase III executive summary report, indicating that there were approximately $751 million of Network Upgrades eliminated in the Dominion region by using regional topology upgrades.[56]

System Reinforcements

As part of Phase III, PJM evaluated the impact of topology changing reinforcements to mitigate the impacts driven by New Service Requests. PJM determined which reinforcements were eliminated as a result of modeling the topology changing reinforcements. PJM then grouped the topology changing and eliminated reinforcements by region and computed a discount factor to apply to reinforcements to reduce the cost of all these reinforcements down to the cost of contstructing only the topology changing reinforcements.

Regional Discount Factors for Topology Changing Upgrades				
Region	Topology Upgrades	Eliminated Upgrades	Discount Factor	Details
Dominion	$519,466,645	$751,704,547	40.865200%	
Mid-Atlantic Area Council	$0	$0	100.000000%	
PJM West	$203,595,627	$6,125,000	97.079448%	

36. For the AG1-021 project specifically, instead of needing to build and assume cost responsibility for all four of the eliminated upgrades shown in paragraph 33 *without* the discount factor, the project is now responsible for the regional topology upgrades at the *reduced* cost. However, as the regional topology upgrades are considered beneficial to their respective topology region as a whole due their elimination of Network

[55] PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle 1 Phase III*, at System Reinforcements, (Sep 18, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH3_Executive_Summary.htm#exec-sum-analysis-header. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the TC1 Phase III System Impact Study Cluster Report).

[56] *Id.* Note that my previous affidavit discussed $731 million in cost savings to the TC1 cohort as a result of modeling the regional topology upgrades, which is the amount from the Final System Impact Study executive summary report. PJM Interconnection, L.L.C., *New Service Requests System Impact Study Executive Summary Report Transition Cycle 1 – Final (Retool 1)*, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_FINAL_Executive_Summary.htm. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the Final System Impact Study Report).

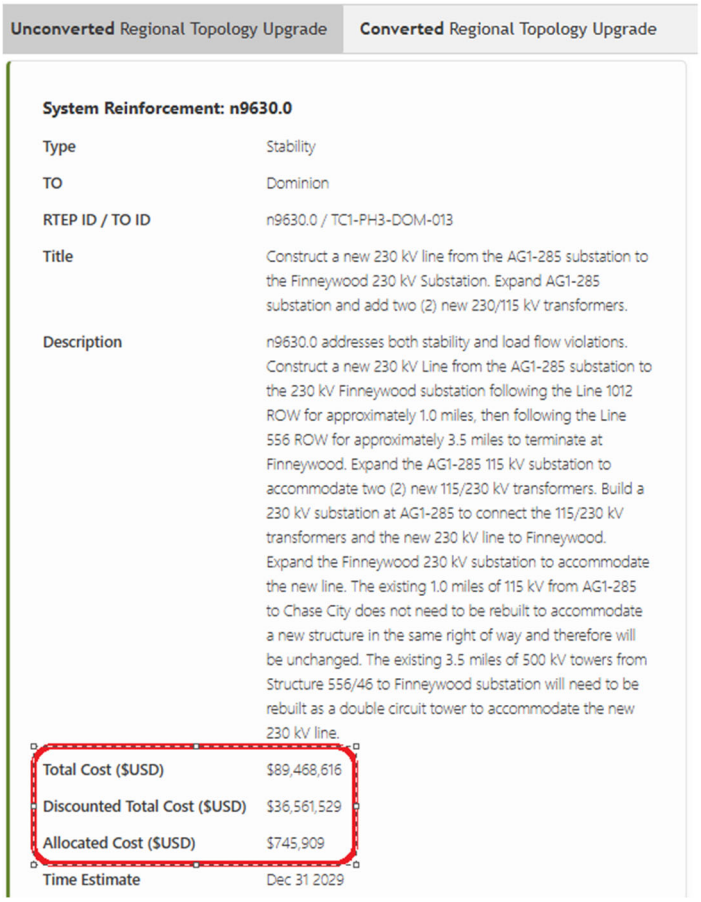
Upgrades, the AG1-021 project has cost responsibility for all regional topology upgrades in the Dominion region and is held contingent on those upgrades as are all other TC1 projects that rely on the regional topology upgrades. With the use of regional topology upgrades, AG1-021's cost responsibility for the topology and eliminated reinforcements is $1,033,984 instead of $2,530,231, *without* the discount through the use of regional topology upgrades.[57]

37. The table below is a summary of the eliminated Network Upgrade cost allocations for all three of Amelia Energy's TC1 New Service Requests that I prepared. If PJM had not used regional topology upgrades to carry out its obligations under the Tariff, these Amelia Energy's New Service Requests would not have received the discount factor. Instead, they would have been responsible for the "allocated cost *without* discount" amount of approximately $10.9 million shown below for all of the eliminated Network Upgrades, rather than the "allocated cost *with* discount" amount of $4.4 million. The table shows the savings to Amelia Energy, on a combined basis for its TC1 New Service Requests, is over $6.4 million through the use of regional topology upgrades in the Phase III System Impact Study analysis. Below the table is a screenshot from the Phase III System Impact Study report for AG1-021 of the converted regional topology upgrade cost for Network Upgrade n9630.0 to illustrate where these numbers can be found in the report.[58]

		Allocated Cost with Discount				Allocated Cost without Discount				Savings due to Discount			
Reinforcement	Type	AF1-294	AF2-115	AG1-021	Total	AF1-294	AF2-115	AG1-021	Total	AF1-294	AF2-115	AG1-021	Total
n9630.0	Topology	$1,530,154	$932,376	$745,909	$3,208,439	$3,744,394	$2,281,589	$1,825,291	$7,851,274	$2,214,240	$1,349,213	$1,079,382	$4,642,835
n9203.0	Eliminated	$335,331	$203,902	$163,149	$702,382	$820,578	$498,962	$399,237	$1,718,778	$485,247	$295,060	$236,088	$1,016,396
n7569	Eliminated	$151,662	$92,220	$73,788	$317,670	$371,128	$225,669	$180,564	$777,361	$219,466	$133,449	$106,776	$459,691
n7687	Eliminated	$71,940	$43,867	$35,089	$150,896	$176,042	$107,346	$85,865	$369,253	$104,102	$63,479	$50,776	$218,357
n9221.0	Eliminated	$32,898	$20,061	$16,049	$69,008	$80,504	$49,091	$39,273	$168,867	$47,606	$29,030	$23,224	$99,859
	Total	$2,121,985	$1,292,426	$1,033,984	**$4,448,395**	$5,192,646	$3,162,657	$2,530,231	**$10,885,533**	$3,070,661	$1,870,231	$1,496,247	**$6,437,138**

[57] *Compare supra* paragraph 33 *with infra* paragraph 37.

[58] As noted in section III.A above, please recall that "estimated time" of December 31, 2029, reflected here is not accurate.

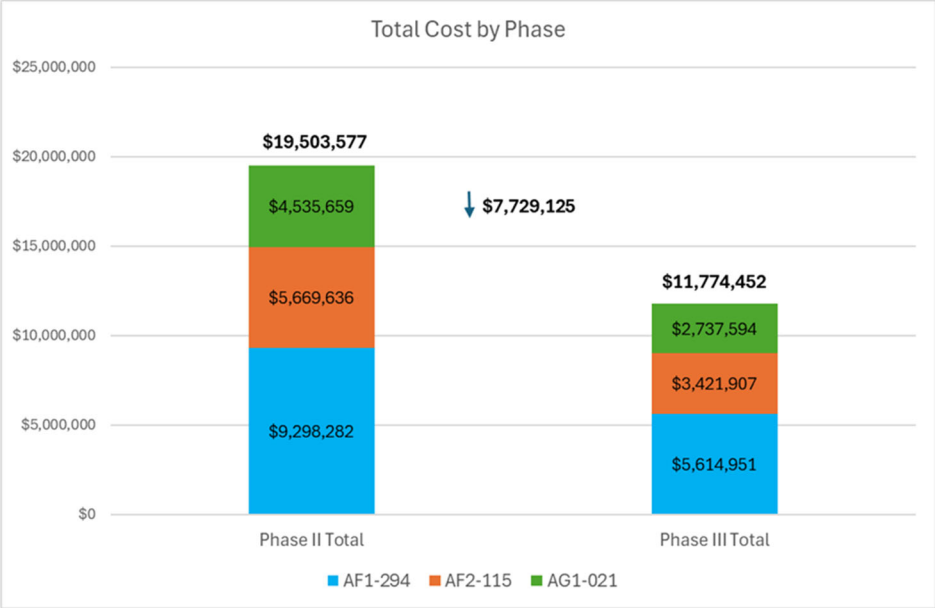


Unconverted Regional Topology Upgrade | **Converted** Regional Topology Upgrade

System Reinforcement: n9630.0

Type	Stability
TO	Dominion
RTEP ID / TO ID	n9630.0 / TC1-PH3-DOM-013
Title	Construct a new 230 kV line from the AG1-285 substation to the Finneywood 230 kV Substation. Expand AG1-285 substation and add two (2) new 230/115 kV transformers.
Description	n9630.0 addresses both stability and load flow violations. Construct a new 230 kV Line from the AG1-285 substation to the 230 kV Finneywood substation following the Line 1012 ROW for approximately 1.0 miles, then following the Line 556 ROW for approximately 3.5 miles to terminate at Finneywood. Expand the AG1-285 115 kV substation to accommodate two (2) new 115/230 kV transformers. Build a 230 kV substation at AG1-285 to connect the 115/230 kV transformers and the new 230 kV line to Finneywood. Expand the Finneywood 230 kV substation to accommodate the new line. The existing 1.0 miles of 115 kV from AG1-285 to Chase City does not need to be rebuilt to accommodate a new structure in the same right of way and therefore will be unchanged. The existing 3.5 miles of 500 kV towers from Structure 556/46 to Finneywood substation will need to be rebuilt as a double circuit tower to accommodate the new 230 kV line.
Total Cost ($USD)	$89,468,616
Discounted Total Cost ($USD)	$36,561,529
Allocated Cost ($USD)	$745,909
Time Estimate	Dec 31 2029

38. The graph below shows the total cost allocated to Amelia Energy Facility for required system reliability Network Upgrades in Phase II and Phase III for all Project Identifiers, with Phase III reflecting the discount factor for regional topology upgrades.



Without the use of the regional topology upgrades and, therefore, without the discount factor, Amelia Energy's Phase III cost allocation for Network Upgrades could have been much higher. Finally, the Final System Impact Study (Retool 1) reports, which reflect changes following the withdrawal of TC1 Project Developers during TC1, Decision Point 3, reflect further reductions in system reinforcements costs, with AG1- 021 dropping from approximately $2.7 million to approximately $2.5 million;[59] AF2-115 from approximately $3.4 million to $3.1 million;[60] and AF1-294 from $5.6 million to $5.1 million.[61] In the Final System Impact Study (Retool 1) reports, there were no more

[59] PJM Interconnection, L.L.C., *AG1-021 Final System Impact Study (Retool 1) Report*, at System Reinforcements, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AG1-021/AG1-021_imp_FINAL.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AG1-021 Final System Impact Study Report).

[60] PJM Interconnection, L.L.C., *AF2-115 Final System Impact Study (Retool 1) Report*, at System Reinforcements, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF2-115/AF2-115_imp_FINAL.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AF2-115 Final System Impact Study Report).

[61] PJM Interconnection, L.L.C., *AF1-294 Final System Impact Study (Retool 1) Report*, at System Reinforcements, (Dec. 8, 2025), https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF1-294/AF1-294_imp_FINAL.htm#system-reinforcements. *See also* Exhibit No. PJM-0001 (providing the hyperlink to the AF1-294 Final System Impact Study Report).

eliminated Network Upgrades, but Network Upgrade n9630 remains, as does the applicability of the discount factor and the project's contingency on the Dominion the regional topology upgrades.

39. Although the Tariff requires PJM to apply the "least cost analysis" to optimize costs and minimize the number of required Network Upgrades for the *entirety of the Cycle*, in this instance, the PJM System Impact Study process for TC1, including its use of regional topology upgrades, produced an outcome that was cost-effective for Amelia Energy. However, if Amelia Energy's request is granted, and the Commission directs PJM to remove the Disputed Contingent Facilities and Disputed Network Upgrades from the proposed Amelia Energy GIA, then Amelia Energy Facility would lose the benefit of the discount factor and its costs would increase by more than $4.7 million. Moreover, such changes would negatively impact other TC1 Project Developers, because the discount factor would need to be adjusted accordingly and such an adjustment would increase the costs for all other Project Developers who rely upon this cluster of regional topology upgrades to realize the minimum amount of Network Upgrades.

40. Finally, and as discussed above, removing the Disputed Contingent Facilities and Disputed Network Upgrades would not advance the scheduled 2030 in service date for undisputed Network Upgrade n9630.0.

E. QDEST Is an Analysis Processing Tool that Helps PJM Process the Large Volume of New Service Requests Using the Least Cost Analysis Required by the Tariff.

41. With respect to my discussion of QDEST, the Amelia Energy Answer misrepresents what I stated, alleging that I made an "admission" that PJM "cannot validate whether its cost allocations are correct for individual projects because its automated tool

does not support this level of granularity."[62] Amelia Energy also asserts that PJM "explains [QDEST] does not allow it to perform Project-level validation."[63]

42. Contrary to Amelia Energy's assertions, in my initial affidavit I explained how PJM uses QDEST in conjunction with another tool called PowerGem TARA to assist PJM in performing its obligations under the Tariff.[64] I also described PJM's Tariff obligations and contrasted them with Amelia Energy's apparent objectives.[65] Furthermore, I explained that PJM's use of these two companion technologies has allowed PJM to increase its interconnection processing speed, particularly in light of the substantially larger volume of projects under study, while preserving accuracy, transparency, and consistency.[66] However, I did not make any statements that would support Amelia Energy's erroneous conclusions.

43. PowerGem TARA assists PJM in identifying and evaluating reliability criteria violations. QDEST supports interconnection analysis processing and cost allocation, but it does not automatically generate assignments of Network Upgrades. PJM must perform an evaluation to determine the optimal cohort of Network Upgrades, which may be a combination of new regional topology upgrades and direct facility upgrades, to address the Cycle overloads as a whole. These identified upgrades are then linked to address the overloaded flowgates in the QDEST tool for each project.

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[62] Amelia Energy Answer at 14.

[63] *Id*.

[64] Initial Krizenoskas Aff. ¶¶ 11-18.

[65] *Id*. ¶ 29.

[66] *Id.* ¶ 15.

44. QDEST is not designed or intended to perform "Project-level validations" like the study performed by Amelia Energy's witness. QDEST is being used to assist PJM in processing the large volumes of proposed generation projects and exercising its engineering judgment in manner that is consistent with the Tariff's requirements. Using QDEST, PowerGem TARA, and other technology tools, PJM completed TC1 Phase I in 120 days, Phase II in 183 days, and Phase III in 152 days, which demonstrates the enhanced efficiency, speed, and consistency of PJM's interconnection process.

IV. CONCLUSION

45. PJM prepared the unexecuted Amelia Energy GIA and the partially executed Disputed NUCRAs according to the Commission-approved TC1 cluster-based Cycle process set forth in the Tariff and provided a significant amount of analytical data in the System Impact Studies to describe this process

46. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER26-1300-000**
	)	**ER26-1303-000**
	)	**(NOT CONSOLIDATED)**
	)	

VERIFICATION

I, Lisa Krizenoskas, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Lisa Krizenoskas referred to in the foregoing "Affidavit of Lisa Krizenoskas 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.

Lisa Krizenoskas

Executed on: 4/6/26

State of Pennsylvania **County of** Montgomery

Signed and sworn to (or affirmed) before me on April 6th, 2026 **(date)**

by Lisa Krizenoskas **(name(s) of individual(s) making statement).**

(Signature of notarial officer)

(Seal)

Commonwealth of Pennsylvania - Notary Seal
Notary Public
KATRINA ELAINE ZARCZYNSKI-MAGEE
Montgomery County
My Commission Expires April 26, 2029
Commission Number 1311503

Notary Public **(Title of office)**

My commission expires: April 26, 2029

Exhibit No. PJM-0001

Phase II System Impact Study Reports:

AG1-021 Phase II System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AG1-021/AG1-021_imp_PHASE_2.htm

AF1-294 Phase II System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AF1-294/AF1-294_imp_PHASE_2.htm

AF2-115 Phase II System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_2/AF2-115/AF2-115_imp_PHASE_2.htm

Phase III System Impact Study Reports:

AG1-021 Phase III System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AG1-021/AG1-021_imp_PHASE_3.htm

AF1-294 Phase III System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AF1-294/AF1-294_imp_PHASE_3.htm

AF2-115 Phase III System Impact Study Report:
https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/PHASE_3/AF2-115/AF2-115_imp_PHASE_3.htm

TC1 Phase II SIS Cluster Report:

https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH2_Executive_Summary.htm

TC1 Phase III SIS Cluster Report:

https://www.pjm.com/pjmfiles/pub/planning/project-queues/Cluster-Reports/TC1/TC1_PH3_Executive_Summary.htm

Final System Impact Study (Retool 1) Reports:

AG1-021 Final System Impact Study (Retool 1) Report:

https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AG1-021/AG1-021_imp_FINAL.htm

AF2-115 Final System Impact Study (Retool 1) Report:

https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF2-115/AF2-115_imp_FINAL.htm

AF1-294 Final System Impact Study (Retool 1) Report:

https://www.pjm.com/pjmfiles/pub/planning/project-queues/TC1/FINAL/AF1-294/AF1-294_imp_FINAL.htm

Exhibit No. PJM-0002

PJM Facilities Study Report

For

Network Upgrade N9630

Transition Cycle #1

July 2025

Introduction

This Facilities Study has been prepared in accordance with the PJM Open Access Transmission Tariff and PJM Manuals. The Transmission Owner (TO) is Virginia Electric and Power Company (VEPCO or Dominion).

A. Project Description

The System Impact Study for PJM Interconnection Transition Cycle #1 has identified the need for PJM Network Upgrade N9630. The scope of this Network Upgrade includes the following:

- Construct a new 230kV line from AG1-285 subsation to Finneywood 230kV substation
- Expand the proposed 115kV AG1-285 substation to include a 230kV substation with 2 230/115kV transformers.
- Add 230kV line position at Finneywood substation.

B. Transmission Owner Facilities Study Results

1. Detailed Scope of work for Network Upgrade N9630:

The following is a detailed description of Transmission Owner Upgrades for Network Upgrade N9630. These facilities shall be designed according to the Transmission Owner's Applicable Technical Requirements and Standards. Once built the Transmission Owner will own, operate, and maintain these facilities.

See Preliminary Scoping Summaries located in the Appendices, Attachment #1, #2 and #3.

2. MILESTONE SCHEDULE FOR COMPLETION OF DOMINION WORK

Facilities outlined in this report are estimated to take 55 months to construct, from the time of full execution of the Generation Interconnection Agreement and completion of a construction kickoff call. This schedule may be impacted by the timeline for procurement and installation of long lead items and the ability to obtain outages to construct and test the proposed facilities.

Description	Start month	Finish month
Engineering	1	30
Permitting/Procurement	3	45
Construction	43	55

Due to outage congestion, Network Upgrades and/or internal Dominion projects have been identified as having possible outage conflicts with this network upgrade that may affect the estimated milestones listed above. Additional outage sequencing may be required that includes, but not limited to the following projects:

3. ASSUMPTIONS IN DEVELOPING SCOPE/COST/SCHEDULE

- The preliminary construction schedule is dependent on outage availability.
- See Attachment 1 and 2– Preliminary Scoping Summary – Substation for additional assumptions
- See Attachment 3 – Preliminary Scoping Summary – Transmission line for additional assumptions

4. LAND REQUIREMENTS

Dominion will be responsible for the following expectations in the area of Real Estate:

- Any additional land needed for Storm Water Management, Landscaping, and Wetlands/Wetlands Mitigation.
- Any other Land/Permitting requirements required by the Network Upgrade

5. ENVIRONMENTAL AND PERMITING

The Dominion will be responsible for the following expectations in the area of Environmental and Permitting:

- Assessment of environmental impacts related to the Network Upgrade including:
    - Environmental Impact Study requirements
    - Environmental Permitting
- A stormwater easement and/or specific stormwater design BMP's to allow access to and use of the facilities, including a maintenance agreement for said stormwater facilities.
- Conditional Use Permit for Substation
- Any additional land needed for Storm Water Management, Landscaping, and Wetlands/Wetlands Mitigation
- Any other Permitting requirements required by the Network Upgrade

C. APPENDICES

Attachment #1: Preliminary Scoping Summary – Substation AG1-285

Attachment #2: Preliminary Scoping Summary – Substation Earleys

Attachment #3: Preliminary Scoping Summary – Transmission

Attachment #4: Preliminary General Arrangement Plan

Attachment #5: N9630 Single Line Diagram

Attachment #1

Dominion Energy

Project Number: N9630 – AG1-285

Project Description: New 115/230kV Substation and New 230kV Line to Finneywood Substation

SUBSTATION SCOPE OF WORK

Date: 7/1/2025

Revision Number: 1

Project Summary

Project number N9630 provides for the new 115kV/230kV breaker and a half station in Charlotte County, Virginia.

Transmission Line Engineering is to provide a new number for the lines to Finneywood, Central, Chase City, and the 115kV generator interconnect.

Assumptions & Clarifications:

1. *The scope of work depicted on the drawings assumes that there is no overlap with other designs and construction activities, except if mentioned in this Project Summary.*
2. *Relay Settings and P&C design will be revised as part of the SPE Scope of Work.*
3. *4-hole pad connections must be replaced with 6-hole and 8-hole pad connections to maintain 5000A ratings.*
4. *It is assumed that level 3 fence security will be used. If level 1 is necessary, the station will require an estimate update.*

Purchase & install substation material – Network Upgrade:

1. Approximate station fence line dimensions of 430’ x 430’. At a minimum, site preparation and grading will be required to extend 15’ beyond these dimensions for station grounding. Additional property and site prep may be required for proper grading and stormwater management, etc.

2. Approximately 1,720 linear ft of 5/8" chain link, 12 ft tall, perimeter fence around the station along with the security cameras and integrators as per design 3 fence standards
3. Two (2), 230-115kV, 224MVA, three phase transmission transformer
4. Two (2), Transformer oil containment
5. Eight (8), 115kV, 3000A, 40kAIC, SF-6 circuit breaker
6. Four (4), 230kV, 4000A, 63kAIC, SF-6 circuit breaker
7. Sixteen (16), 115kV, 3000A, 3-phase center break gang operated switch
8. Eight (8), 230kV, 4000A, 3-phase double-end break switch
9. Eight (8), 115kV, relay accuracy CCVT
10. Five (5), 230kV, relay accuracy CCVT
11. Two (2), 115kV, 2000A wave trap
12. Two (2), line tuner
13. Fifteen (15), 90kV, 74kV MCOV surge arrester
14. Nine (9) 180kV, 144kV MCOV surge arrester
15. Six (6) 18kV, 15.3kV MCOV surge arrester
16. Four (4), 167kVA, 13.2kV-120/240V, station service transformer
17. Two (2), 13.2kV, 25A-E, SMD-20 fuse link
18. Two (2), 13.2kV, 25A-K, SMD-20 fuse link
19. Four (4), 8.3kV, 40A-K, BCL fuse
20. Two (2), 115kV, heavy duty steel backbone (by Transmission)
21. One (1), 230kV, heavy duty steel backbone (by Transmission)
22. Four (4), shield wire poles and three spans of shield wire (by Transmission)
23. One (1), 24' x 70' control enclosure
24. One (1), 125 VDC, 495 Ah station battery and 2-50 Amp charger (size to be verified during detail engineering)
25. Two (2), 38" x 38" x 42" precast yard pull box
26. Approximately 370 ft of cable trough with a 40 ft road crossing section
27. Station stone as required
28. Station lighting as required
29. Steel structures as required including switch stands, bus supports, station service transformers, CCVT and wave trap supports
30. Foundations as required including control house, equipment, and bus support stands
31. Conductors, connectors, conduits, control cables, cable trough, and grounding materials as per engineering standards

Purchase & install relay material – Network Upgrade:

1. Two (2), SPR Relay/Aux Package
2. Two (2), 4510 – SEL-2411 transformer annunciator
3. Two (2), 1217 – dual SEL-487E transmission transformer diff panel
4. Seven (7), 1110 – SEL-587/351 bus panel
5. Twelve (12), 4510 – SEL-2411 breaker annunciator
6. Eight (8), 1510 – dual SEL-351 transmission breaker panel w/ reclosing
7. Four (4), 1511 – dual SEL-351 transmission breaker panel w/o reclosing
8. One (1), 1340 – dual SEL-411L CD/Fiber line panel
9. Two (2), 1340 – dual SEL-411L DCB/PLC line panel

10. Three (3), 4506 – 3-phase CCVT potential make-up box
11. Four (4), 4507 – 1-phase CCVT potential make-up box
12. Twelve (12), 4526_A – Circuit breaker fiber optic make-up box
13. Two (2), 4526_C - >=84MVA transformer fiber make-up box
14. Seven (7), 4200 – Bus differential CT make-up box
15. Two (2), 4000 – station service potential make-up box
16. Two (2), 4018 – 500A station service AC distribution panel
17. Two (2), 4007 – 225A outdoor transmission yard AC NQOD
18. Two (2), 4019 – 225A 3-phase throw over switch
19. Two (2), 4016 – 600A PVT disconnect switch
20. One (1), 4153c – wall mount station battery monitor
21. One (1), 5618 – SEL-3555 communications panel
22. One (1), 1255 – station annunciator panel
23. One (1), 5021 – SEL-2411 RTU panel
24. One (1), 5609 – fiber optic management panel
25. One (1), 5202 – 26" APP 601 digital fault recorder
26. Ten (10), 4040 – security fiber/power make-up box
27. One (1), 5603 – station network panel no. 1
28. One (1), 5603 – station network panel no. 2
29. One (1), 4051 – power block
30. One (1), 4042_D1B – security utility – utility ATS
31. One (1), 4044 – 225A 1Ø outdoor main security AC NQOD
32. Two (2), 4040 – 100A 1Ø outdoor security AC NQOD
33. One (1), 5616 – station security panel
34. One (1), 5616 – station security fence panel
35. Two (2), 4018 – 225A station service AC distribution panel branch breaker
36. One (1), high voltage protection (HVP) box (provided by IT) (to be verified during detail engineering)
37. One (1), telephone interface box (to be verified during detail engineering

The Transmission Owner Interconnection Facilities include the portion of the interconnecting switching station which is associated solely with the single feed to the generating facilities collector station. The equipment associated with the Transmission Owner Interconnection Facilities include the metering accuracy CCVT's, metering accuracy CT's, disconnect switch, conductors and connectors.

Purchase and install substation material – Transmission Owner Interconnection Facilities Upgrade:

1. One (1), 115kV, 2000A, 3-phase vertical mounted switch (by Transmission)
2. Three (3), 115kV, metering accuracy CCVT
3. Three (3), 115kV, 500:5 metering accuracy CT
4. Conductor, connectors, conduits, control cables, foundations, steel structures and grounding material as per engineering standards

Purchase and install relay material – Transmission Owner Interconnection Facilities Upgrade:

1. One (1), 1340 – 24” dual SEL-411L CD/Fiber line panel
2. One (1), 1425 – 24” dual SEL-735 transmission and generator interconnect metering panel
3. One (1), 4524 – revenue metering CT make-up box
4. One (1), 4506 – 3-phase CCVT potential make-up box with metering (P4)
5. One (1), 1323 – 24” SEL-487E/735 PMU and PQ monitoring panel

Attachment #2

Dominion Energy

Project Number: N9630 – Finneywood Substation

Project Description: Install one new 230kV Line Position

SUBSTATION SCOPE OF WORK

Date: 07/01/2025

Revision Number: 0

Project Summary

Network Upgrade N9630 provides for the addition of a new 230kV line position at Finneywood Substation in Mecklenburg County, Virginia.

Transmission line engineering is to provide a new number for the new line between Finneywood and AG1-285.

Assumption:

Currently, the scope and estimate assume Dominion standard spread footer foundations. Once the soil information is available and it is prudent to change the design to “helical pile foundations” the Dominion team should be informed to adjust the project estimate at the earliest possible opportunity.

Purchase and install substation material – Network Upgrade:

1. Two (2), 230kV, 4000A, 63kAIC, SF-6 circuit breaker
2. Two (2), 230kV, 4000A, 3-phase double end break switch
3. Three (3), 180kV, 144kV MCOV surge arrester
4. Three (3), 230kV relay accuracy CCVT
5. One (1), 230kV, heavy duty steel backbone (by Transmission)
6. Station stone as required
7. Station lighting as required
8. Steel structures as required including switch stands, bus supports, and CCVT supports
9. Foundations as required including equipment and bus support stands

10. Conductors, connectors, conduits, control cables, and grounding materials as per engineering standards

Purchase and install relay material – Network Upgrade:

1. One (1), 1340 – 24” dual SEL-411L CD/Fiber line panel
2. Two (2), 1510 – 24” dual SEL-351-7 transmission breaker with reclosing panel
3. Two (2), 4510 – SEL-2411 breaker annunciator
4. Two (2), 4526_A – circuit breaker fiber optic make-up box
5. One (1), 4506 – 3-phase CCVT potential make-up box

Attachment #3

230 kV LINE #2XXX

500 kV LINE #556

AG1-285 - Finneywood

PROJECT N9630

PRELIMINARY SCOPING SUMMARY

This project serves to construct a new 230 kV line from AG1-285 substation to Finneywood substation following Line #1012's ROW for approximately 1 mile and then Line #556's ROW for approximately 3.5 miles, located in Charlotte and Mecklenburg County, VA. See **Figure 1** for the project location. The new line will be named 2XXX. Line #1012 will remain as is and Line #2XXX will be on separate structures for that section. The existing 3.5-mile span of Line #556 from Structure 556/46 to Finneywood substation will be rebuilt with double circuit 500/230 kV towers and 3-poles to include Line #2XXX. The proposed work will require a right of way of 170' for the span following Line #1012, however the span including Line #556 will all be completed within the existing 150'-250' right of way. A new 120' right of way will be required for Line #2XXX near Finneywood substation. This project will install a total of 28 new structures. CPCN filing is expected.

The existing relevant span of Line #556 consists of single circuit steel 500 kV towers. The proposed structures to be installed are 500 kV - 230 kV double circuit steel towers, 500 kV – 230 kV double circuit double dead-end 3-poles, 230 kV single circuit direct embed H-frames, and 230 kV single circuit double dead-end 3-poles. The conductor wires for Lines #556 & 2XXX will be triple bundled (3) 1351.5 ACSR (45/7) "Dipper" and twin bundled (2) 768.2 ACSS/TW/HS "Maumee", respectively. While Line #2XXX is adjacent to Line #1012, two (2) DNO-11410 OPGW will be used. Two (2) DNO-10100 OPGW will be used starting from when Line #2XXX & 556 are on shared double circuit structures to Finneywood. Single (1) 7#7 Alumoweld shield wire will be used for additional shielding in the substations.

This project assumes that the AG1-285 substation cut-in for Line #1012 and Finneywood substation cut-in and structure addition for Line #556 (992959V1 & 992959V8) have been completed. There will be anticipated outages for Lines #556, 235, 1012, & 2258.

Design Considerations:

EXISTING FACILITIES TO BE REMOVED:

1. Remove twelve (12) existing single circuit steel 500 kV suspension towers as follows:
    a. Structures 556/46-556/48, 556/50-556/57, & 556/59.
2. Remove two (2) existing single circuit steel 500 kV running angle towers as follows:
    a. Structure 556/49 & 556/58.
3. Remove approximately 3.27 miles of triple bundled (3) 1351.5 ACSR (45/7) "Dipper" conductor wire from existing structures 556/46 through 556/59.
4. Remove approximately 3.27 miles of two (2) 7#7 Alumoweld shield wire from existing structures 556/46 through 556/59.

EXISTING FACILITIES TO BE MODIFIED:

1. Cut and transfer the existing triple bundled (3) 1351.5 ACSR (45/7) "Dipper" conductor wire

for Line #556 from the back side of existing structure 556/46 to the back side of proposed structure 2XXX/8A (556/45A).

2. Cut and transfer the existing triple bundled (3) 1351.5 ACSR (45/7) “Dipper” conductor wire for Line #556 from the ahead side of existing structure 556/59 to the ahead side of proposed structure 2XXX/23 (556/59A).
3. Cut and transfer the existing two (2) 7#7 Alumoweld shield wire for Line #556 from the back side of existing structure 556/46 to the back side of proposed structure 2XXX/8A (556/45A).
4. Cut and transfer the existing two (2) 7#7 Alumoweld shield wire for Line #556 from the ahead side of existing structure 556/59 to the ahead side of proposed structure 2XXX/23 (556/59A).

PERMANENT FACILITIES TO BE INSTALLED:

1. Install five (5) 230 kV single circuit direct embed suspension “DOM” steel H-frames [Reference Drawing 12.555] as follows:
    a. Structures 2XXX/4-2XXX/8.
    b. See **Figure 2** for proposed structure configuration.

2. Install two (2) 500 kV - 230 kV engineered steel double circuit double dead-end heavy angle 3-poles [Reference Drawing 15.226] on foundations as follows:
    a. Structures 2XXX/8A (556/45A) & 2XXX/23 (556/59A).
    b. See **Figure 3** for proposed structure configuration.

3. Install two (2) 500 kV – 230 kV engineered steel double circuit double dead-end light angle 3-poles [Reference Drawing 15.225] on foundations as follows:
    a. Structures 2XXX/12 (556/49) & 2XXX/21 (556/58).
    b. See **Figure 4** for proposed structure configuration.

4. Install twelve (12) 500 kV - 230 kV steel 5-2 LT Towers [Reference Drawing 15.800] on foundations as follows:
    a. Structures 2XXX/9 (556/46)-2XXX/11 (556/48), 2XXX/13 (556/50)- 2XXX/20 (556/57), & 2XXX/22 (556/59).
    b. See **Figure 5** for proposed structure configuration.

5. Install one (1) 230 kV single circuit steel backbone [Reference Drawing 12.901] on foundations as follows:
    a. Structure 2XXX/1 in AG1-285 substation.
    b. See **Figure 6** for proposed structure configuration.

6. Install three (3) 230 kV engineered steel single circuit double dead-end 3-poles [Reference Drawing 12.158] on foundations as follows:
    a. Structures 2XXX/2, 2XXX/3, & 2XXX/24.
    b. See **Figure 7** for proposed structure configuration.

7. Install three (3) steel static poles [Reference Drawing 9.008] on foundations as follows:

a. Structure 2XXX/1A, 2XXX/1B, & 2XXX/1C.
b. See **Figure 8** for proposed structure configuration.

8. Install approximately 4.52 miles of twin bundled (2) 768.2 ACSS/TW/HS "Maumee" conductor wire from proposed backbone 2XXX/1 in AG1-285 substation to existing backbone 2XXX/25 in Finneywood substation.

9. Install approximately 1.0 mile of two (2) DNO-11410 OPGW from proposed backbone 2XXX/1 in AG1-285 substation to proposed structure 2XXX/8A (556/45A).

10. Install approximately 3.52 miles of two (2) DNO-10100 from proposed structure 2XXX/8A (556/45A) to existing backbone 2XXX/25 in Finneywood substation.

11. Install approximately 3.5 miles of triple bundled (3) 1351.5 ACSR (45/7) "Dipper" conductor wire from proposed structure 2XXX/8A (556/45A) to proposed structure 2XXX/23 (556/59A).

12. Install one (1) 7#7 Alumoweld shield wire as follows:
    a. Approximately 0.02 miles from proposed backbone 2XXX/1 in AG1-285 substation to proposed static pole 2XXX/1A.
    b. Approximately 0.02 miles from proposed static pole 2XXX/1B to proposed static pole 2XXX/1C.

13. Install two (2) OPGW splices on structures as follows:
    a. Proposed backbone 2XXX/1.
    b. Existing backbone 2XXX/25.
    c. Proposed structures 2XXX/2, 2XXX/3, 2XXX/8A (556/45A), 2XXX/12 (556/49), 2XXX/21 (556/58), 2XXX/23 (556/59A), & 2XXX/24.

CONCEPTUAL SCOPE NOTES:

1. No PLS-CADD modeling was done for this project. Structures were designed like for like using Lines #1012 & 556's existing structures and estimated using typical transmission right of way characteristics.

2. Substation arrangement and proposed structure locations are subject to change. This design is based on conceptual substation arrangements for AG1-285 and Finneywood substations provided on 6/19/25. This scope may need to be revised if there are any changes to the conceptual substation designs.

3. Structures are designed based off the following NESC code parameters: NESC Heavy, 90 mph wind, ¾" Ice & 30 mph wind regardless of project location.

4. It is assumed for detailed engineering that a LiDAR survey will be required.

5. The nearest airport is Chase City Municipal airport approximately 4.5 miles away.

6. Lines #2XXX & 556 cross over Highway 47 (in between structures 556/47 and 556/48) and a railway (in between 556/51 and 556/52).

7. Lines #1012, 235, 2258, & 556 will require outages.
    a. Lines #2XXX & 556 will cross Line #1012.
    b. Line #2XXX will cross over 230 kV Lines #235 & 2258.

8. An existing right of way width of 100' for Line #1012 and 150' for Line #556 is assumed based on map viewer.
    a. For approximately 1.0 mile starting at AG1-285 substation and following Line #1012's span, an additional ROW width of 70-ft is needed to accommodate the installation of Line #2XXX for that span, resulting in a ROW width of 170-ft.
    b. Line #556's existing 150-ft ROW width from Line #1012's intersection to Finneywood will not need to change.
    c. A new 120-ft ROW is needed for approximately 0.09 miles between proposed structure 2XXX/23 and Finneywood substation.

9. A wetland delineation has not been completed as part of this conceptual package.

10. This scope is assuming that the existing 3-1351 ACSR is being removed and replaced with a new 3-1351 ACSR conductor. It may be determined in detailed engineering that the existing 500 kV conductor can be transferred to the new structures instead.

11. Wire reel lengths were not accounted for this line design. The assumed pull pad locations to avoid tension splices will be determined during detailed design. 15,000-ft reels may be required in detailed engineering.

CONCEPTUAL ESTIMATE NOTES:

1. Engineered steel pole costs were determined based off typical wind and weight spans, line angles, and average structure heights in the typical right of way associated with the structure type.

2. Steel pole foundation costs were based off the projects' location and structure type in the regional soil profile map. The regional soil profile map used for this project is Piedmont.

3. The conceptual estimate assumes that a laydown yard is required for this project.

4. Prior to detailed engineering, a full land rights review would be required. A desktop review was completed to estimate the project cost.

5. Forestry estimate cost inputs include the following assumptions:
    a. Work pad totals based on provided SOW and assumptions from KMZ file. Assume 15 mats for tangents and 30 mats for angles at each work pad for reconductor work and 50 mats per pull pad.
    b. DDE structures assumed based off wire reel lengths-based off pull pad location.
    c. Pull pad locations based on location of major road/water crossings and line mileage.
    d. Assuming that existing stone in substations will be used for access per SOW and that access is existing or will be built by others before the start of construction. Assuming that the substations will be constructed with access roads built to and from substations and work from inside the substations for backbone installation.
    e. Assumes no delays due to permitting or real estate issues after work begins. Assume no schedule compressions from SOC/PJM.
    f. Assumes all clearing and forestry costs have been captured by others. No access costs for forestry activities included in this pricing.
    g. Stream crossing based on estimates from aerial imagery.
    h. Assuming that all existing roads may be dressed in stone that can remain at the end of the project. Assuming two track roads exist in many locations will be impermeable. No costs for stone road removal are included.

6. Due to the time allotted to create an estimate, stakeholders were not consulted for their respective costs. Stakeholder costs were derived as follows:
    a. DEES Permitting costs were based on a cost per mile based off comparable projects in the TC#1 Phase 3 Cycle. Project N9217, which is rebuilding 230 kV line 298 from Buckingham Sub to Farmville Sub for approximately 12.73 miles, was used to develop the DEES cost per mile due to similar project scope and location.
    b. Siting and Permitting costs were derived using the permitting spreadsheet but not verified by the permitting team.
    c. Real Estate acquisition costs are based on typical cost per acre in the West region of Virginia as provided by the real estate team in 2025.
    d. Right of Way Management (Encroachment) costs were based on a cost per mile based off comparable projects in the TC#1 Phase 3 Cycle. Project N9217 was used to develop the ROW Management cost per mile due to similar project scope and location.
    e. Forestry, Rehab, and Access costs were based on a cost per mile based off comparable projects in the TC#1 Phase 3 Cycle. Project N9217 was used to develop the Forestry and Access cost per mile due to similar project scope and location.

f. Surveying costs were based on the typical cost to acquire approximately ten miles of survey and acquire new right of way. These costs were provided by the surveying team as part of the TC#1 Phase 3 process.
g. Communications (Marketing Manager) costs are assumed to be Tier 4 - $300K due to similar scope of work for project N9217.
h. Telecommunications costs were based on a cost per mile based off comparable projects in the TC#1 Phase 3 Cycle. Project N9217 was used to develop the Telecommunications cost per mile due to similar length of the lines.

Figure 1 – Project Location

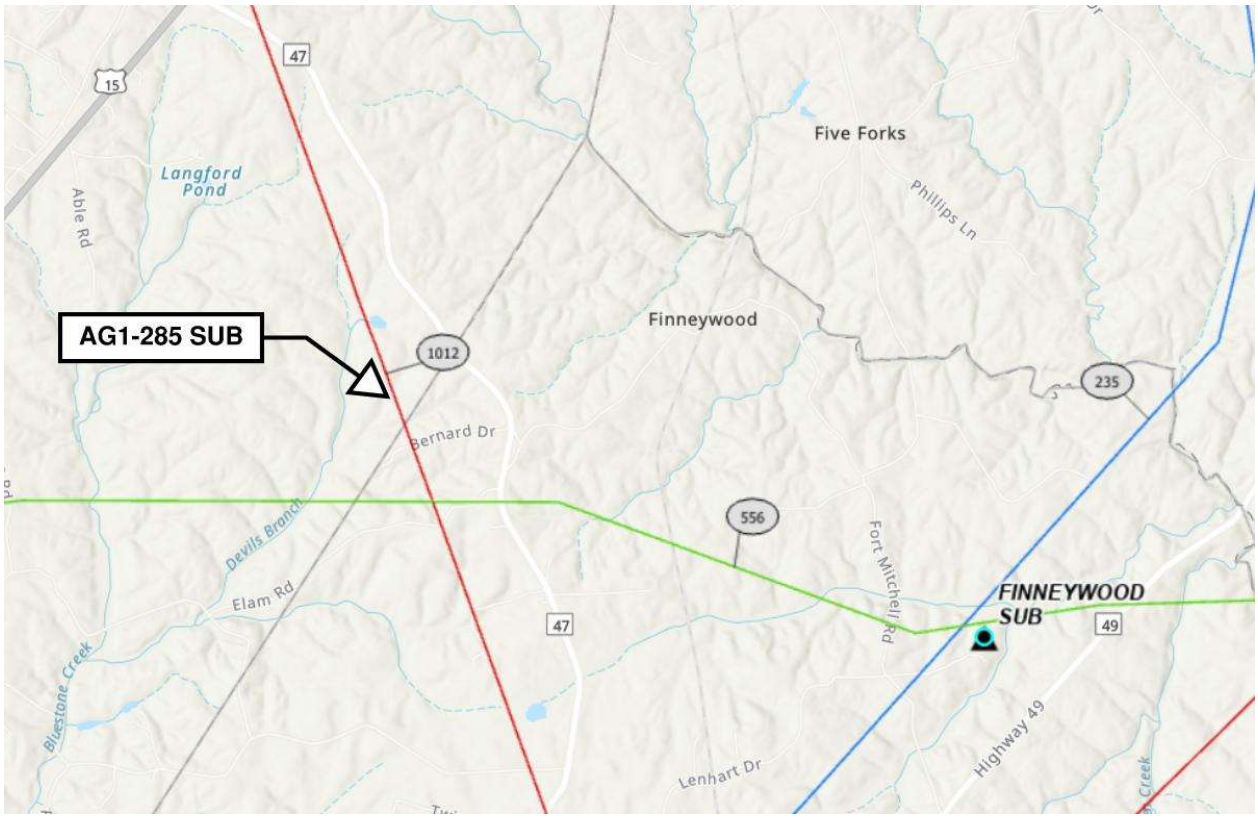


Figure 2 – Proposed Structure Configuration

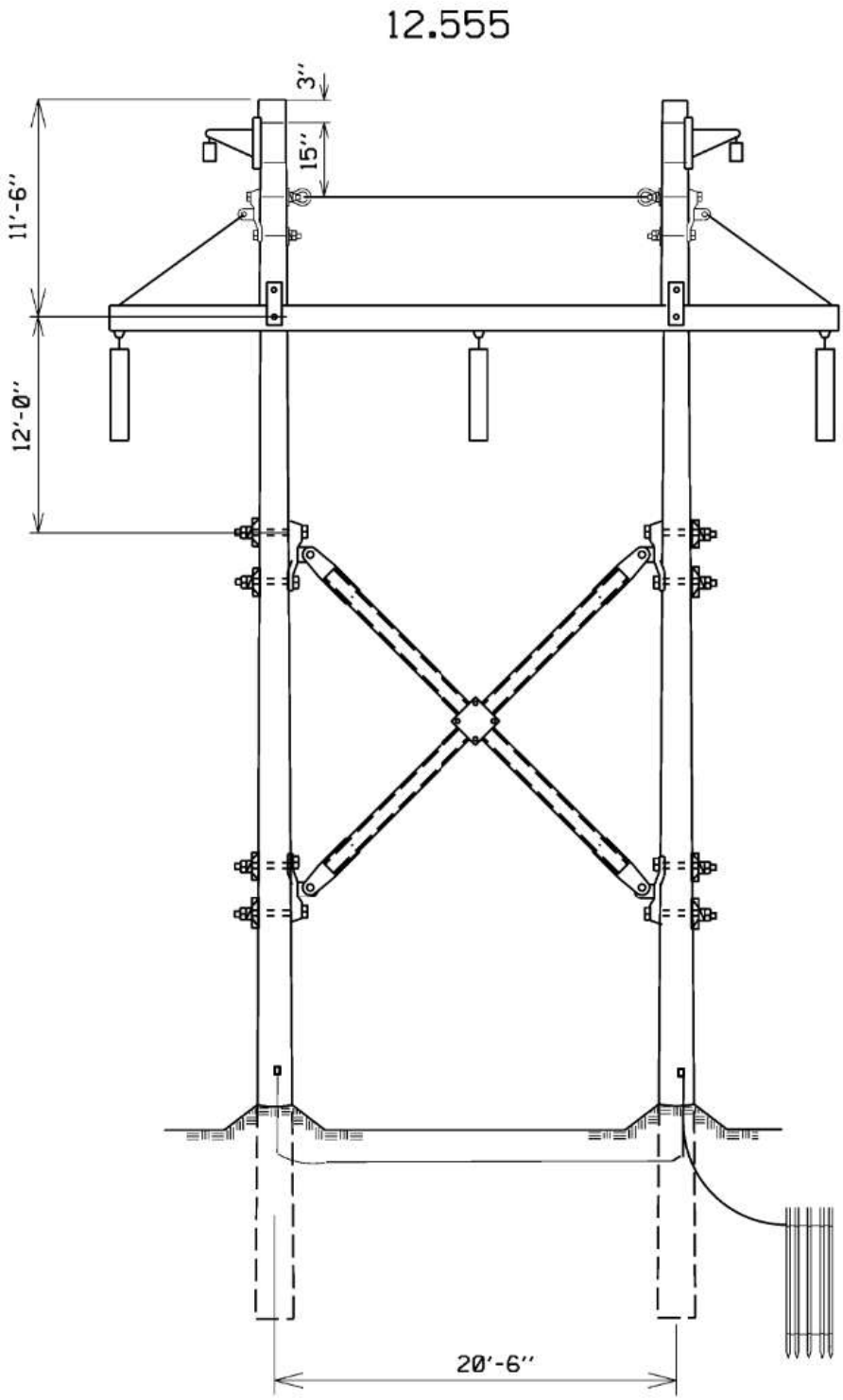


Figure 3 – Proposed Structure Configuration

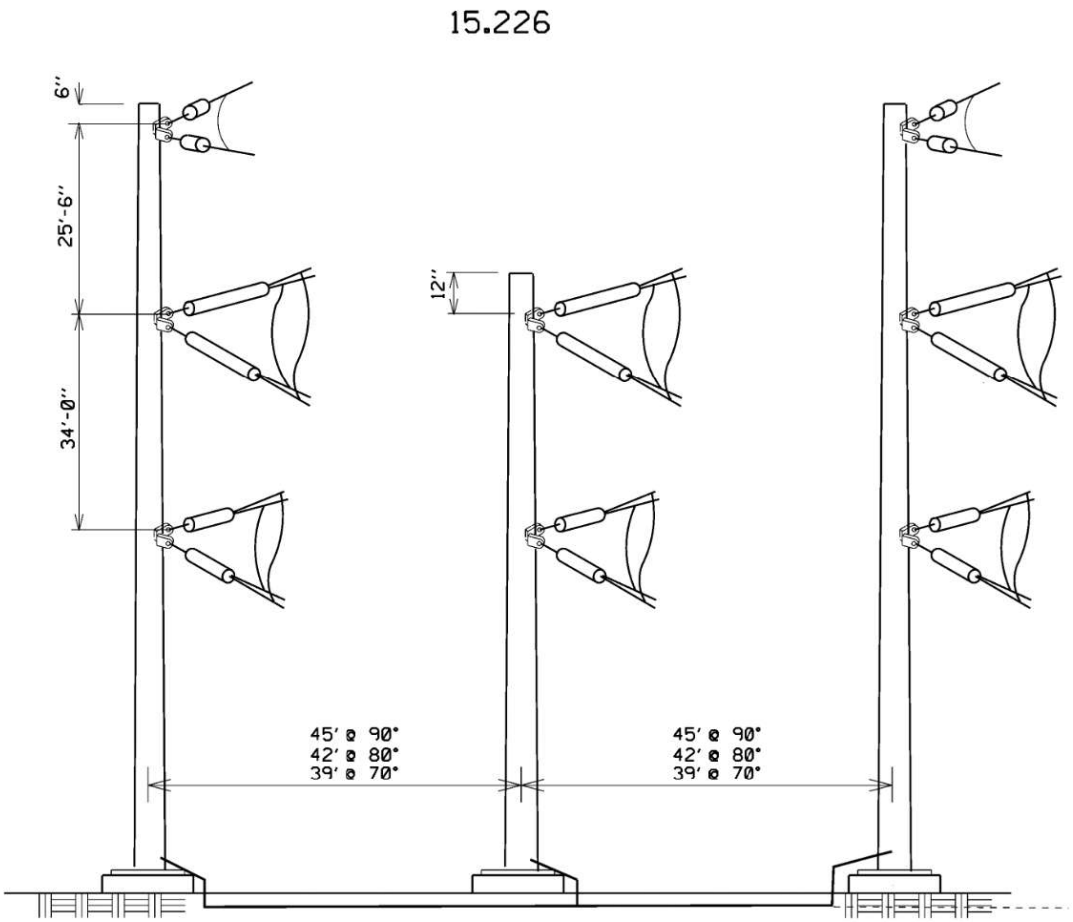


Figure 4 – Proposed Structure Configuration

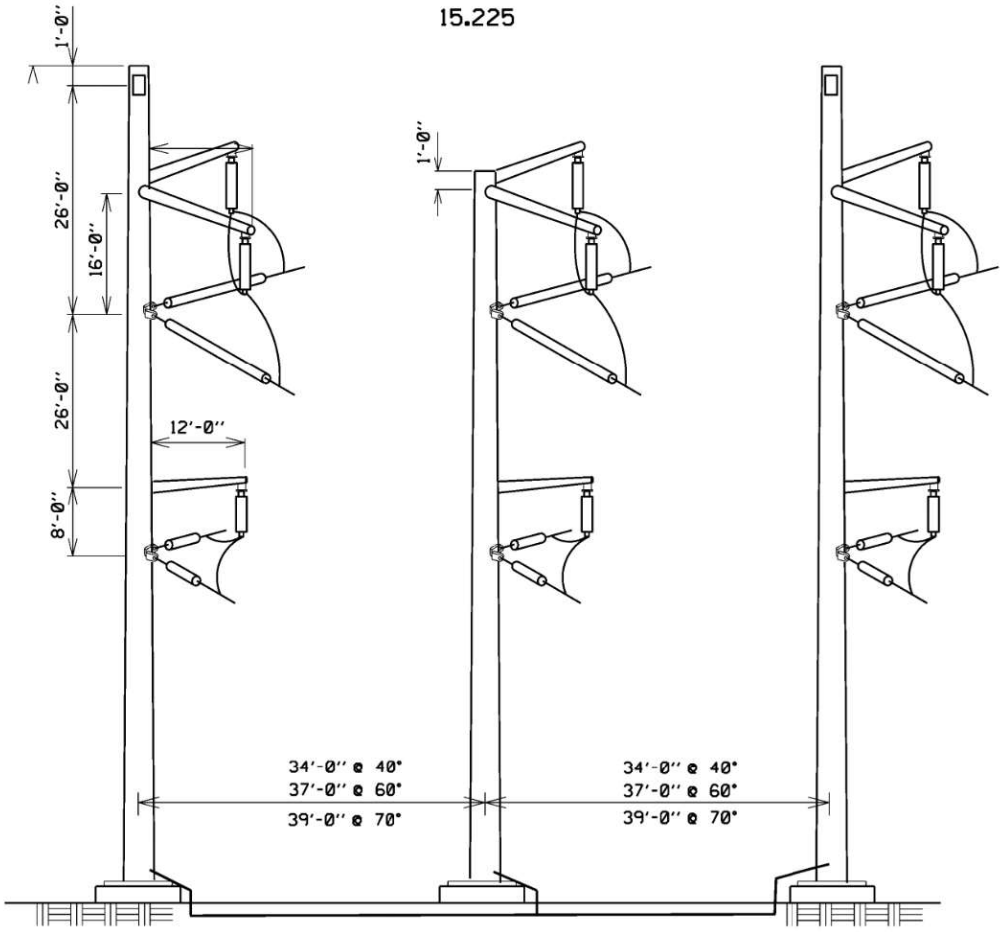


Figure 5 – Proposed Structure Configuration

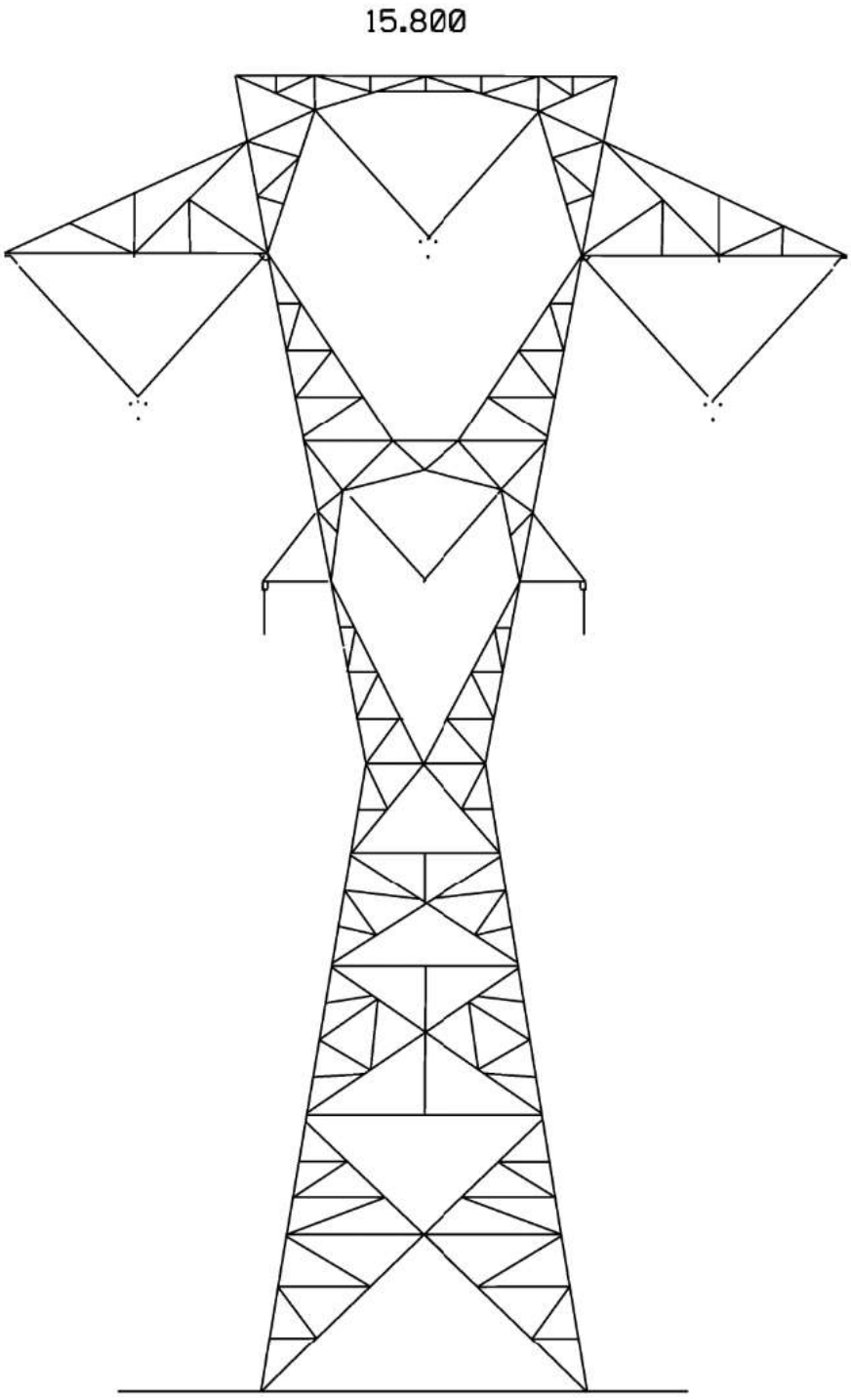


Figure 6 – Proposed Structure Configuration

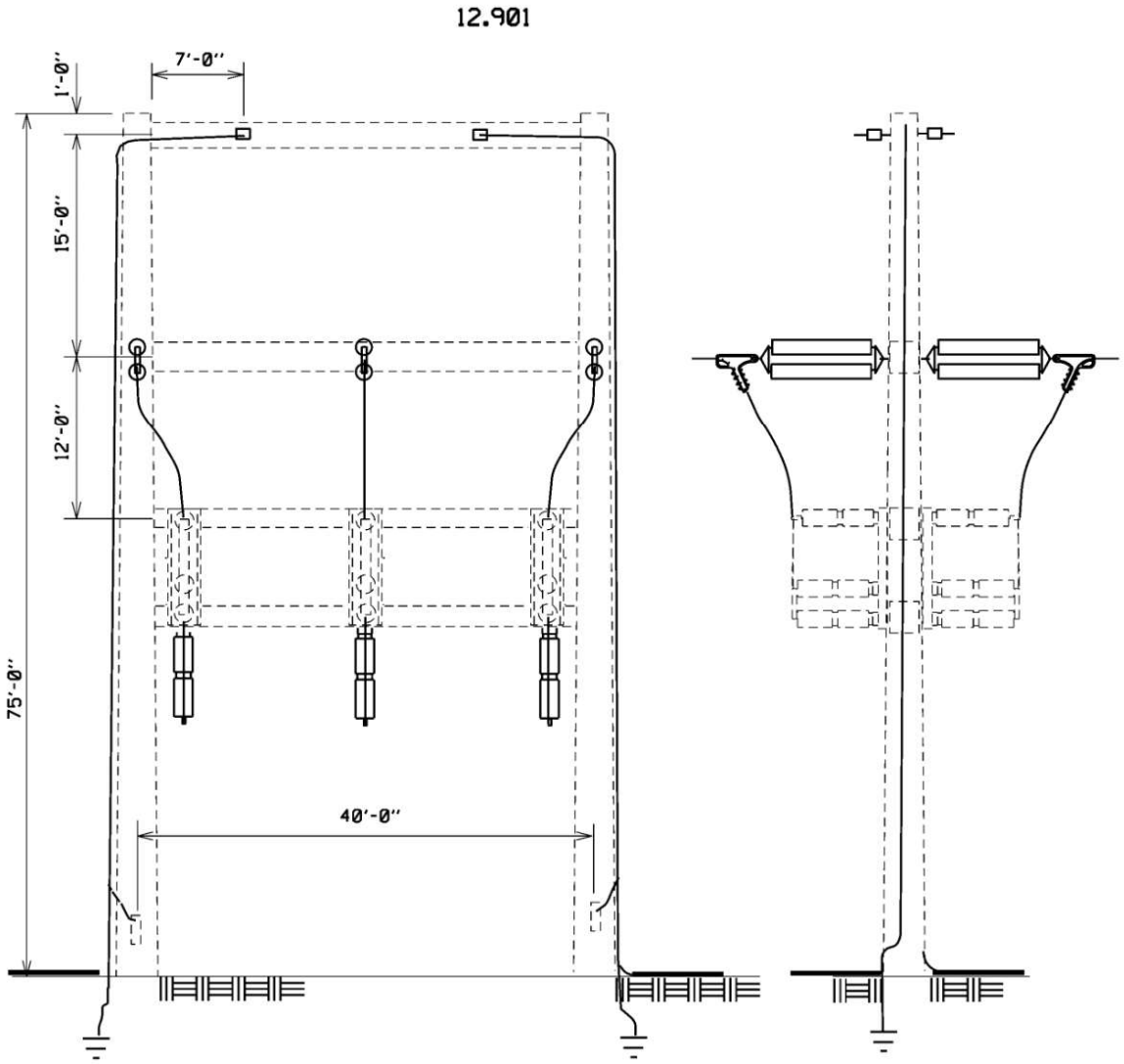


Figure 7 – Proposed Structure Configuration

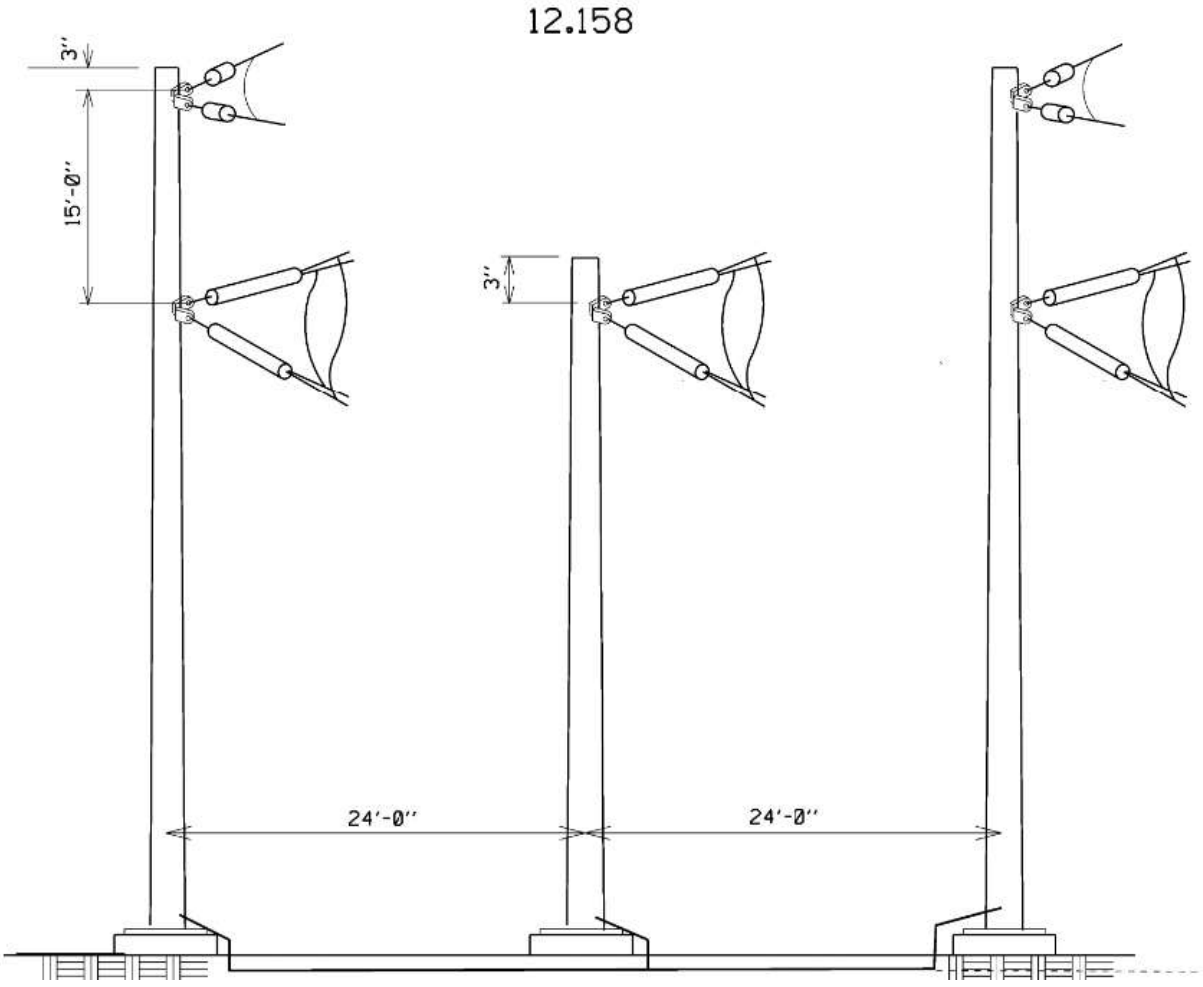
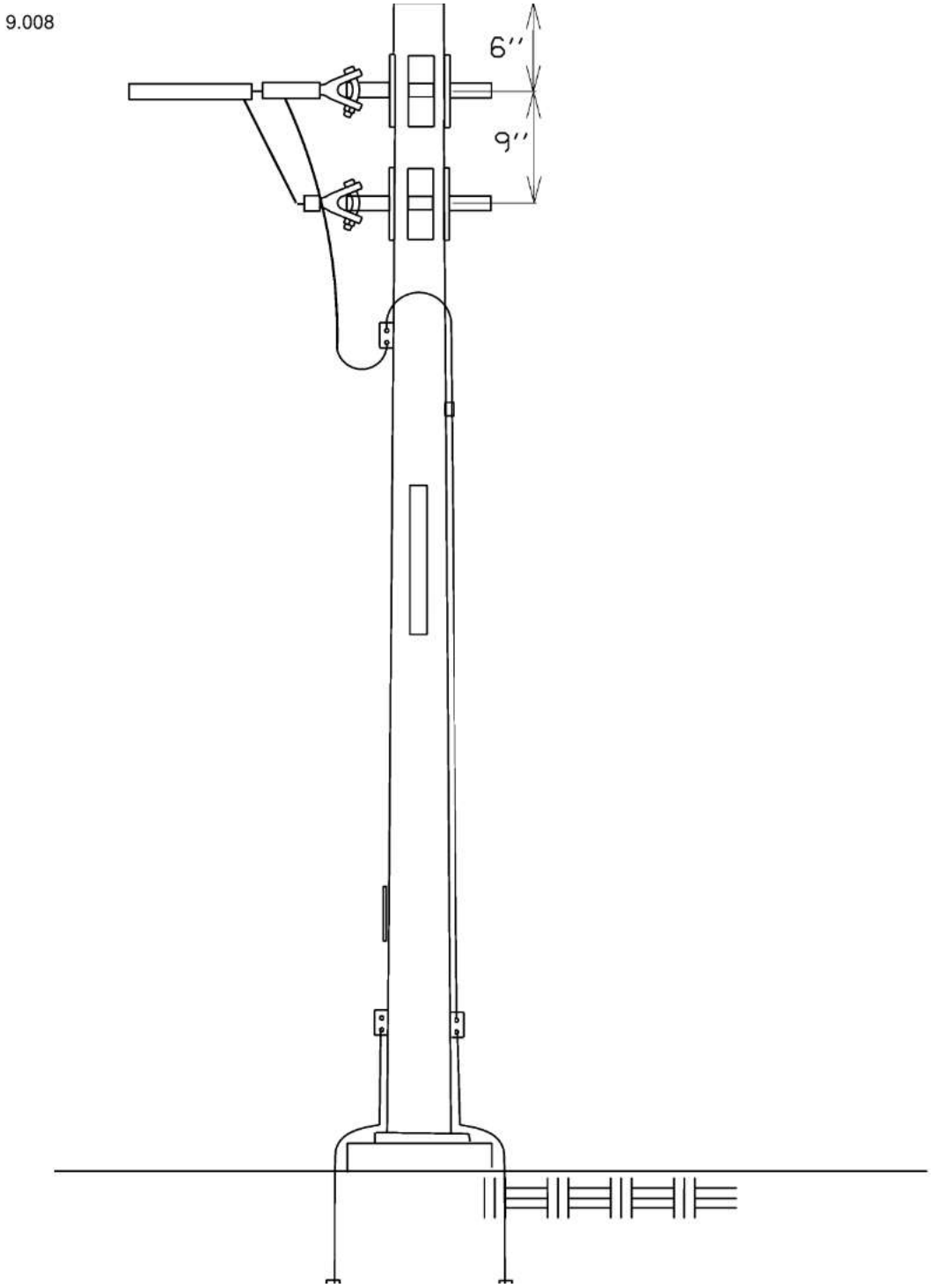


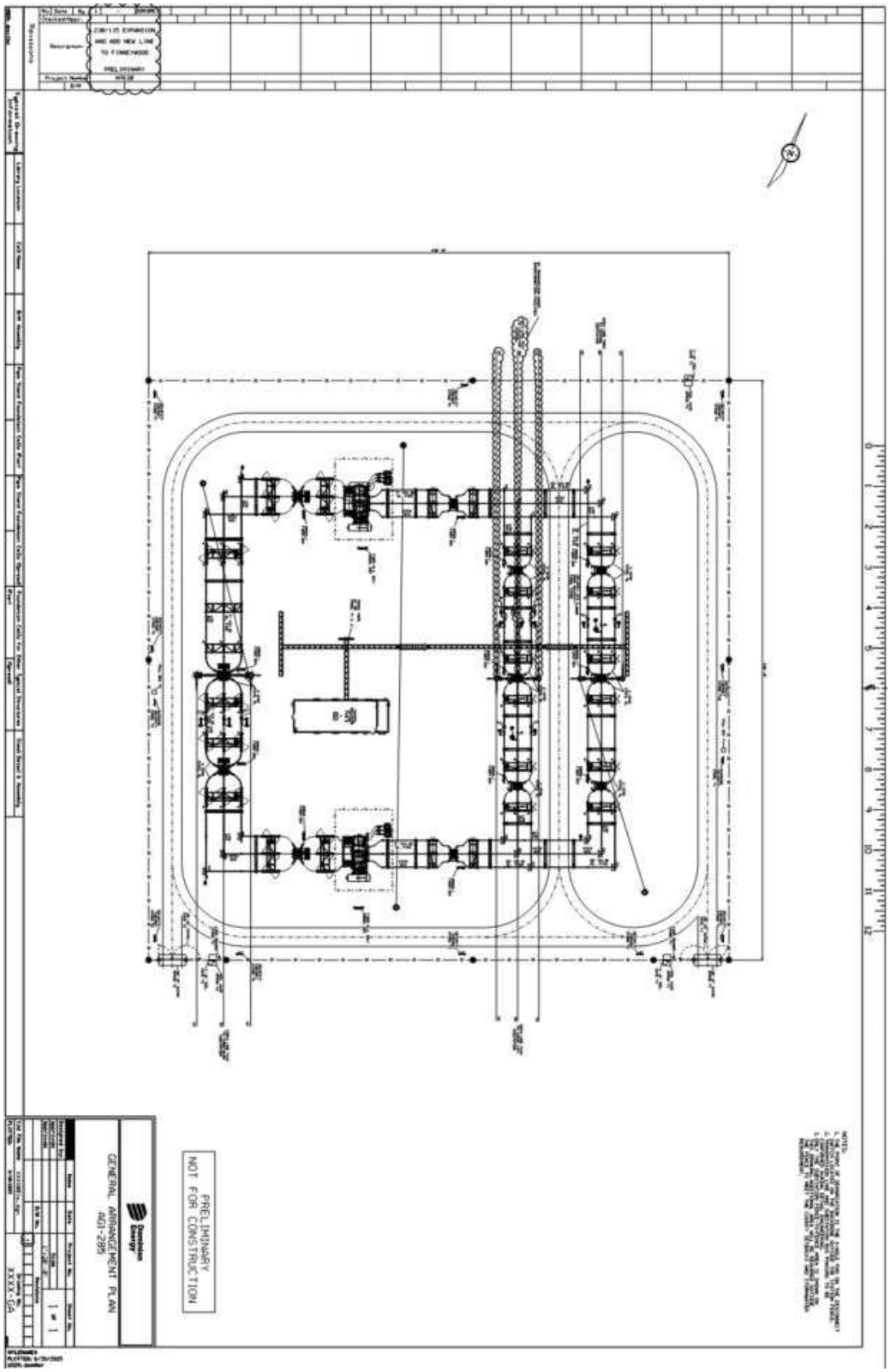
Figure 8 - Proposed Structure Configuration



Required Material Summary

Item	Qty
Backbones	1
Static Poles	3
Engineered Structures	7
Lattice Towers	12
DOM Poles	5
7,100-Ft Static Reels	1
12,000-Ft DNO-11410 OPGW	2
12,000-Ft DNO-10100 OPGW	4
12,000-Ft 768.2 ACSS/TW/HS “Maumee”	14
12,000-Ft 1351.5 ACSR (45/7) “Dipper”	18

Attachment #4



Attachment #5