Co-Located Load Order Workshop Stakeholder Feedback Poll

Based on PJM's filings submitted November 16, 2026 in Docket Nos. ER27-522 and ER27-531, what questions do you have?	
Tangibl Group, Inc.	ER27-531 - PJM Questions 1. Can PJM confirm that in order for PJM to formally scrap Cycle 2 under the current process and move to the Fast Energization process, PJM will need final FERC approval on ER27-531 by 9/16/27? 2. Can PJM clarify that the Readiness Deposit at risk at Screening Window DP1 as the Tariff language on page 99 doesn't seem to agree with Tariff language on page 44? 3. Can PJM clarify that the Readiness Deposit requirements and Readiness Deposit at risk at Screening Window DP2 as the Tariff language on page 114 doesn't seem to agree with Tariff language on page 44? 4. Can PJM clarify if there are additional site control requirements for project developers at Screening Window DP2? 5. Can PJM explain why in the proposed Reinforcement Cost Certainty Framework project developers would still only receive 75% of their readiness deposit/security posted at Decision Point 2 in the Screening Window phase? 6. Would PJM accept a Reinforcement Cost Certainty Framework where project developers would receive 90% of their readiness deposit/security posted at Decision Point 2 in the Screening Window phase minus $15,000/MW? 7. Can PJM provide additional clarity in regard to the Tariff language at the end of the paragraph regarding the Reinforcement Cost Certainty Framework? 8. Can PJM/PJM TOs to present an exact timeline in regard to how the security posted by project developers at Screening Window DP2 will eventually be returned to project developers that sign a GIA and reach COD? ER27-520 - PJM Transmission Owner Questions 9. Can PJM TOs to explain the differences between what was presented at the 11/12/26 PJM Special TOA-AC in regard to cost allocation and cost recovery framework to what was filed at FERC under ER27-520? 10. Can PJM TOs provide a specific example as to how cost allocation would work under ER27-520, along with how would it compare to the current cost allocation process? 11. Can PJM TOs provide a specific example as to how the Generator Reliability Reinforcement Fee would be calculated according to ER27-520?
Electranet REP I, LLC	1. Study methodology for non-firm access • Part VIII, Subpart C, §404(B)(3) says PJM will set "distinct operating measures" but doesn't define them. What are they, and how is a non-firm request modeled? • Part VIII, Subpart M, §440(A)(1) says limits are set "through available studies or additional studies as necessary." Which studies will PJM run, and can they be listed in the tariff? • Part XI, Subpart C, §719.4 can tariff language that restricts transmission curtailments to facilities identified through the study process be included to better provide better commercial certainty for estimating curtailment risks? 2. PJM and TO responsibilities • Part VIII, Subpart A, §401(A) has Contract Demand customers finish the TO study process before entering the Fast Energization study. Does the same apply to Interim NITS? Which party determines the as-available non-firm limit: PJM, the TO, or both? 3. Non-firm loads crowding out other non-firm loads for the same as-available access • Can a later Interim NITS customer request reduce the limits of an earlier Interim NITS customer? In other words, is the as-available access to non-firm service protected or can it be crowded out by other non-firm loads sharing the same "pool" of non-firm availability if in the same load pocket? • Part XI, Subpart C, §719.4 prioritizes equal-priority services by "contribution to exceedance" per the manuals. How is that defined, and can it be in the tariff? 4. Congestion and LMP impacts • Has PJM studied the congestion and LMP effects of many non-firm customers vying for the same non-firm hour? 5. Reservation mechanism • Part XI, Subpart A, §703.5 shows a reserved section for penalties for unreserved use of Interim NITS, which suggests that there will be a reservation mechanism to take Interim NITS; will access be first-come, first-served?

	7. 60-90 day study timeline • The June show cause order calls for a study deadline of no more than 60-90 days, but the Fast Energization proposal describes a 12-month process. Can the 60 to 90 day screening commitment be written into the tariff? • Does the TO load-integration study have to finish before the 12 months start? Is there a cap on how long it can take? 8. Control and protection systems • Part XI, Subpart C, §716-717 and §718.1 have the customer, TO and PJM share responsibility for the controls. Who owns, funds, operates and maintains each piece? • Can the dispatch of a controllable grid-parallel (not co-located) onsite generator with telemetry count as an acceptable means to fulfill the necessary controls to prevent withdrawals? 9. Backup generation for flexible loads • Without a definition of Flexible Large Load, can the Eligible Customer's ability to limit withdrawals from the transmission system be enabled by their willingness and capability to run their non-emergency backup generators to displace their load from the load meter?
RMI	• Can PJM provide illustrative examples for certain types of requests and how they would be treated in the study process? For example – what studies would resources requesting ERIS have to go through in comparison to NRIS? Or flexible load in comparison to firm load? And co-located load/gen pairs? • For the proposed simplified screening window, which analyses would be excluded relative to the current study process? What information will participants receive at each decision point within the simplified screening window (DP1 and DP2)? • What level of accuracy does PJM expect participants to have in the cost and schedule estimates between the simplified screening window results (at DP2) and execution of a final interconnection agreement, particularly with respect to the potential for material changes between the screening study and the SIS? • How would compliance with the proposed 12-month timeline be monitored and addressed if studies exceed the target schedule? (How likely are study delays, and how would they be minimized?) • For certain interconnection/transmission service options, like energy-only resources, flexible loads or co-located gen/load, would PJM have off-ramps or specific network upgrade allocations that reflect those customers' different service levels? If so, does PJM intend to specify these?
Talen Energy Marketing, LLC	• How can a Large Load verify that it has been included in the 2028 Load Forecast? • Is the retail load study, the current supplemental project process? How does a Large Load know when the studies have been completed? • Can the required agreements vary by TO? Can PJM provide the categories for the required agreements?
RWE Americas, LLC	We are offering these questions in the spirit of gaining greater visibility into the as-filed proposal. We very much appreciate the time and engagement of the PJM team in reviewing them and providing thoughtful consideration. While we recognize that the list is long, we are making a genuine effort to clearly understand both the proposal and PJM's thought process. To the extent a question is asked and answered in materials already supplied, if you could please point us to them, it would be much appreciated. Thank you for the opportunity to ask these questions. 1. Financial Commitments, Deposits and Security 1.1 Please list every payment, deposit, or security a developer must post in the new process (at Application, at Screening Turn 1 and Decision Point I, at Screening Turn 2 and Decision Point II, and through the System Impact Study to agreement execution), with the amount, form, due date, and release conditions. Please include any security required in addition to Readiness Deposits (for example, at Decision Point II). 1.2 To help us understand what is changing, by how much, and when, please provide a side-by-side cash-outlay timeline (current process vs. Fast Energization) for a 200 MW project, including Study Deposit, Readiness Deposits, security, the Generator Reliability Reinforcement Fee, and any other fees. 1.3 Earlier presentations showed $5,000/MW and $8,000/MW at the two decision points. As we read the as-filed tariff, it shows a $10,000/MW initial Readiness Deposit; $1,500/MW plus 35% of the developer's share of Interconnection Reliability Reinforcement (IRR) costs at risk at Decision Point I; and, at Decision Point II, both a "greater of $10,000/MW or 100% of IRR plus Interconnection Facilities costs" requirement and an additional commitment tied to $3,000/MW plus 100% of those costs. Please explain how these charges operate together and the reasons for the changes. 1.4 For the Decision Point II amounts, what cost estimate is used, who prepares it, and what accuracy range applies? Are Readiness Deposit amounts recalculated if cost estimates change after Decision Point II, and in which direction?

	1.5 Please state which Readiness Deposit amounts are refundable, forfeitable, or applied to underfunded upgrades if a project withdraws at each decision point. 1.6 It appears the tariff makes the full Study Deposit non-refundable for requests submitted after the close of Decision Point II of Cycle 01 (10% before that), and states that actual study costs may exceed the deposit with written notice of additional amounts. Is that correct, is there any cap on additional study costs, and what is the timing of the notice? 2. Cost Certainty, Withdrawal and Refunds 2.1 Please explain how the 135% framework works: (a) is it a ceiling on the amount allocated to the developer, or a best-efforts target, given the tariff states PJM will "attempt" the cap; (b) as we read it, the tariff says forfeited Readiness Deposits and non-refundable Study Deposits will be used "if possible" to fund amounts above 135%. If that pool is insufficient, who bears the excess; (c) if PJM can only achieve a higher cap for the cycle, how is that percentage set and communicated; and (d) on withdrawal the tariff provides reimbursement of 75% of at-risk Readiness Deposits. Does this include security, and what happens to the remaining 25%? 2.2 The adverse-study refund tests in (25% and more than $10,000/MW) and (35% and more than $25,000/MW) appear in provisions for requests submitted before the cutover. Does any adverse-study refund test apply to new-process requests? If not, what is the rationale, given cost uncertainty from load and generation withdrawals and System Impact Study results arriving only after Decision Point II commitments? How does PJM intend to protect projects from significant cost or viability changes beyond their control, including withdrawals after Decision Point II? 2.3 After Decision Point II, can a customer withdraw without forfeiting deposits or security if final costs or in-service dates differ materially from the estimates relied on? Please identify the applicable provision and any thresholds. 3. Calibration of At-Risk Amounts and Development Activities 3.1 How were the at-risk amounts calibrated, and what project development assumptions were used in setting them? 3.2 How did PJM account for major pre-construction expenditures, such as environmental permitting, local stakeholder engagement, land acquisition, and commercial offtake efforts? 3.3 Has PJM evaluated whether the at-risk amounts could affect when developers are willing to advance permitting and commercial activities, given that many depend on greater certainty about upgrade costs? Has PJM considered that permitting outcomes and offtake opportunities are influenced by factors outside the developer's control, and how that affects the practicality of the framework? 4. Decision Windows and Letter of Credit Timing 4.1 The tariff provides 10 Business Days at Decision Point I and 20 Business Days at Decision Point II. What is the rationale for these windows, and has PJM assessed whether they allow interconnection customers to evaluate results, obtain internal approvals, and coordinate letter of credit updates? 4.2 Has PJM considered whether letter of credit issuers can reliably process amendments and reissuances within these windows? If so, what assumptions were used? 4.3 Would PJM consider a longer decision period, or an extension mechanism in defined circumstances, to account for financing, credit, and governance processes outside the customer's direct control? 4.4 Will PJM provide a draft study-results review period before each Decision Point deadline, allowing customers to identify apparent errors? If so, will PJM review and respond to those requests before customers must make their commitments? 5. Generator Reliability Reinforcement Fee and Cost Recovery 5.1 What costs does the Generator Reliability Reinforcement Fee recover that generators do not pay today? Please point to the corresponding current-process to help us see the differences. 5.2 The Annual Carrying Charge Component (ACCC) is described as a weighted-average WACC from Attachment H. Does it include only cost of capital, or also depreciation, taxes, or O&M? Is it fixed when calculated or reset when Attachment H rates change, and is it trued up if "final estimated" costs differ from actual costs? 5.3 Please provide a worked example for a 100 MW generator showing GCAP, TRRGP, ACCC, and the resulting annual fee over 15 years, alongside the charges that would be paid under the current process. 5.4 It appears fee payments begin at the earlier of Commercial Operation or three years after the original COD and continue 15 years. Please explain how the "three years after" trigger works, what happens if the generator is delayed, curtailed, or never reaches COD, and whether payment is owed if the associated IRRs are not in service. 6. Cost Allocation 6.1 Does the tariff state the PJM Manual criteria (thresholds, weighting values) used for the MW-impact allocation. Would changes to them require a FERC filing?

	6.2 When does a generator first receive its GCAP and TRRGP, and when do they become final? Schedule 12 refers to the fee being calculated “after each System Impact Study Phase” and the allocation analysis completing “within 30 days before” agreements are executed. Please clarify how these fit together. 6.3 If other projects in the cycle withdraw, how are GCAP, the fee, and any other charges re-allocated, and can remaining generators be assigned a larger share? 6.4 How are costs divided between generators and Large Load/Eligible Load in a combined portfolio, and how can generators and load verify the result? Please provide a worked allocation example with one generator, one Large Load, and one reliability constraint. 6.5 How will generator criteria (deliverability, short-circuit, stability) and Transmission Owner load-serving criteria (including N-1-1) be applied in one study? When an upgrade is needed under one criterion but not the other, how is its cost split between generators and Large Loads? 7. Siting and Site Control 7.1 It appears the tariff requires continuous site control from submission through the proposed COD, and allows the term to be met by documents “individually or collectively” with a developer certification of cumulative term. Previous drafts also included a unilateral right to extend 15 years beyond COD, which does not appear in the as-filed tariff. Please confirm whether the as-filed requirement ends at COD, describe how PJM will verify the certified cumulative term, and compare the minimum term, conveyance, and exclusivity requirements with the current process. Does PJM expect any post-COD site control for reliability, planning, or operational purposes, including for projects with shorter economic lives or repowering plans? 7.2 It appears the tariff says PJM will not require options to be exercised earlier than needed solely to show continued control where rights are exclusive and not terminable by the landowner absent developer default. Please confirm that options need not be exercised before final cost information or at any decision point, how PJM will determine whether rights are “exclusive” and not terminable, and at what stage, if any, option exercise is required. How did PJM consider the effect of land commitments on financing, development timelines, and landowner negotiations? 7.3 As we read it, the tariff requires site control evidence for the Generating Facility only for New Plant; an earlier draft also covered Interconnection Facilities and the Interconnection Switchyard. Please confirm that this is a change from the earlier version. Has Replacement Generation Interconnection Service been eliminated for requests after the close of Decision Point II of Cycle 01? If not, please confirm how Replacement Generation and CIR transfers are treated under the as-filed tariff after that date. 7.4 As we read the tariff, it requires Interconnection Facilities and Interconnection Switchyard site control at Decision Point II “as applicable,” but it appears to list only the Generating Facility for New Plant. Please explain how these provisions relate and when that evidence is required. 7.5 For non-deed site control, we read the tariff to require a developer-executed attestation. What liability attaches, and what does PJM do when documents lapse? Please define “accurate,” “valid,” and “in full force and effect,” as they are used in Section 402 and explain whether the customer will receive written notice, the reason, and a defined cure period before a request is deemed withdrawn. 7.6 It appears the tariff requires Stand Alone Network Upgrade land not owned by the Transmission Owner to be held by deed or option to purchase. Is that correct? If so, who identifies this land and when, and how does the developer control land for Transmission Owner-designated facilities? 7.7 For projects at existing Transmission Owner substations, only the interconnection route to Transmission Owner land appears to be required. Is that a proper reading, and who determines “existing substation” status when upgrades expand it? 8. Other Non-Financial Requirements 8.1 Please list the non-financial requirements at Decision Point II (for example, air/water permits, affected-system agreements, state-level process evidence, Option to Build election) and identify which are new vs. current. 8.2 As we read the tariff, Option to Build for Interconnection Facilities or Stand-Alone Network Upgrades must be elected at Decision Point II. What cost and design information will be available at that time? 8.3 What modifications are allowed after each decision, and what is the cost of a change, if permitted? 9. Schedule and Study Timelines 9.1 Please provide the total estimated elapsed time, with contingencies, from application to executed agreement, with and without Affected System studies. 9.2 Can PJM please provide more information on how it plans to complete modeling, studies, and cost allocation within the 45-calendar-day first turn and 35-calendar-day second turn of the Screening Phase and the 200-day System Impact Study, given the added complexity of load and generation requests and current challenges meeting study timelines?

	9.3 Transition Cycle 2 and Cycle 1 schedules were recently extended. What caused this, and how does the new design address the cause? Will the new study tools be tested on current-cycle data first, with results shared? 10. Bankability 10.1 Please identify any document PJM or the Transmission Owner will provide that states a cost ceiling and in-service date a lender can rely on at financial close. 10.2 If the Generator Reliability Reinforcement Fee is a 15-year payment starting at or near COD, can it be treated as a fixed obligation for project-finance modeling? What are its seniority and transfer terms on a change of ownership? 10.3 How does the filing interact with PPA delivery dates, tax-credit deadlines, and capacity-market obligations if reinforcements are delayed? 11. Comparison 11.1 For each of Categories 1–10, please help us understand what has changed. If you could identify the corresponding current-process provision and what is changing, that would be very helpful. 11.2 Has PJM assessed how many current-queue projects would meet the Decision Point II commitments, using current data?
1. Aspen Generating, LLC 2. Seneca Generation, LLC 3. Rockfish Solar LLC	• When does the interconnection customer get back their upgrade securitization posting? At COD? Over time as credit through transmission rates? Or other? • What information will be provided to the interconnection customer at DP1 and DP2? What level of study results will be provided? • Will load flow models be posted prior to or during the Screening Phase for customers to review? • What studies will be conducted during Screening Phase and System Impact Phase? If new tools are being used to complete these studies in a more accelerated timeframe, please provide that information. • Will TOs be involved in cost estimates and upgrade timing estimates during the Screening Phase? What level of confidence will TOs have in timing of upgrades? • Please provide examples of how cost allocation will work in the new Portfolio Based cost allocation methodology, provide an example to compare based on current methodology of project-specific upgrades for a project that would have low upgrade costs due to minimal upgrades and another with high upgrade costs due to triggering a larger upgrade. Also show example for how this will work on the load side and how interconnection customers are protected from drop outs of load customers. • Provide examples of how the cost cap methodology works, and how PJM would determine a cap adjustment. Include information on whether customers refundable rate would be adjusted if cap is raised. • Please explain how the Generator Reliability Reinforcement Fee total cost would differ (or stay the same) compared to what generators pay today. • Please explain what is included in the TO Annual Carrying Charge Component (ACCC), such as capital costs, taxes, depreciation, and rate of return.
1. Shell Energy North America (US), L.P. 2. MP2 Energy LLC 3. MP2 Energy NE LLC dba Shell Energy Solutions 4. Marion County Solar Project, LLC 5. Martin County Solar Project, LLC 6. Elkhart County Solar Project, LLC 7. Madison Fields Solar Project, LLC	Questions related to ER27-531 are as follows: • Definition of Co-Located Generation Facility and Co-Located Load – Why does a co-located gen interconnecting with load that does not yet have a signed GIA still need an NSA? Also, why would a co-located generation that is already hit commercial operations that wants to serve co-located load need an NSA? Our understanding is an NSA should only be needed after signed GIA but before commercial operations for connecting co-location load. • III. Network Integration Transmission Service – Regarding the NITS requirement to provide written notice for Necessary Study, why can't this just go through transmission service request like it's done today, as NSA seems repetitive of existing efforts. • The definition of Interconnection Reliability Reinforcements seem to be removing the "but for" argument. What is the justification for that? • Part VIII, Subpart A, section 401 D.1 - The first paragraph appears to indicate that the projects remaining in the queue are responsible for other developers' unpaid invoices. Please clarify. • Part VIII, Subpart A, section 401 D.2A(c) - When is the readiness deposit returned, if applicable? • Part VIII, Subpart A, section 401 H.3a - Planned modifications that include a large load must go through fast energization process. If the planned modification remains solely generation, is an NSA required? • Part VIII, Subpart A, section 402 A.2e - Do stand-alone network upgrades still exist? Aren't there new definitions for Network Upgrades outlined in this tariff language? • Part VIII, Subpart A, section 403 E.4 Application Review - Is there no deficiency cure period? How does a developer ensure an administrative error does not result in a withdrawn application?

	• Part VIII, Subpart A, section 406 C.1 – This section does not mention load only requests. What is the amount of readiness deposit at risk for load requests at DP1? • Part VIII, Subpart A, section 408 C.1 - The requirements at DP II appear to be different than those at DP I, as they apply to both load and generator. Is this the intent? Also, in section 408 C.1b, additional $3k/MW appears to contradict what we was in Part VIII, Subpart A, section 401 D.2A(c), which used “greater of’ language. • Part VIII, Subpart C, section 409 B.3 - The 135% cost containment is superfluous if there is not consequence or impact for going above that. What is the process for the PJM determining the percentage cap, and is it possible that the value could be something like 300% or some unknown number much higher than 135%? Why does PJM consider “attempt” to be strong enough language to be legally durable in this paragraph? • Part VIII, Subpart D, section 411 C.1 - How can a developer negotiate in good faith on a GIA when the studies have not yet been completed?
1. Brookfield Power Piney & Deep Creek LLC 2. Brookfield Renewable Energy Marketing US LLC 3. Brookfield Renewable Trading and Marketing LP	I would like to better understand how Interim Deliverability will work in practice. It would be great to see hypothetical examples of zonal cycle-cohorts of connecting generation and load to see how assignments of Interim Deliverability would be determined for each one. The examples should include a range of generator scenarios. It would be great to also see how it compares to the status quo. We also have a question about the reasonableness of retaining 25% of a developer's posted collateral when the upgrade costs after the SIS are greater than 135% of the costs quoted at DP2 if it chooses to pull out of the queue. We need to know how we can track progress toward full deliverability. Please provide examples, or have the TOs provide examples of how the costs would be allocated.
Dynegy Marketing and Trade, LLC	Necessary Studies The filing does not make clear how pending necessary study applications will be treated. We would expect that if applications have already been submitted and are far along in the process, they would not need to restart in the Fast Energization process. Can you confirm our understanding is correct, and how PJM intends to clarify? Will PJM establish a transition mechanism for new necessary study applications that have yet to be submitted, between now and the opening of the first Fast Energization window next year? Why has PJM changed its position on Necessary Studies from its August 2026 compliance filing in Docket No 25-49 in which it argued that a separate necessary study process for co-located load arrangements was justified? Replacement Interconnection Will PJM continue to require CIR transfers for a replacement resource to take place within 12 months of a deactivation request? What happens if a deactivation notice occurs months ahead of the opening of a Fast Energization window? Will PJM count the months prior to the start of the 12-month Fast Energization process toward the 12-month CIR transfer requirement? What happens to a CIR transfer if Fast Energization’s 12-month schedule is delayed? Will the 12-month requirement for a CIR transfer still be applicable? Will replacement resources still be required to COD within four years of a deactivation under Fast Energization? Will CIR transfers at the same POI be treated the same as CIR transfers between other resources? Why does PJM believe that a replacement of one resource with another resource with a similar operating profile at the same POI need to be studied in a comprehensive Fast Energization process, instead of a separate process that uses a prior queue model of the existing system in which the existing deactivation resource already operates using the same CIRs? How will PJM protect the CIRs being transferred between a deactivating resource and a new replacement resource under the Fast Energization process? Fractional NITS PJM’s filing does not make clear the process for receiving fractional NITS. How will fractional NITS be granted?
Constellation Energy Generation, LLC	Schedule of Interim Deliverability / Provisional Service Schedule M, Sections 439 and 440 1. CIR Transfers

	Can PJM clarify how CIR Transfer Requests will be incorporated into Interim Deliverability Studies, including when a pending or approved CIR Transfer will be reflected in the study base case? If a CIR Transfer is approved after an Interim Deliverability Schedule has been established, will PJM reassess the Interim Deliverability available to affected projects? 2. Allocation of Available Headroom Can PJM clarify how available Energy and Capacity headroom will be allocated between projects receiving an Interim Deliverability Schedule under revised Section 440 and existing projects that have not? If Interim Deliverability Studies allocate available headroom when establishing schedules in GIAs, how will PJM ensure that projects remaining under the Provisional Service process retain a meaningful opportunity to obtain Provisional Service in subsequent annual studies? 3. Base Case Treatment of Existing Queue Projects For the initial Interim Deliverability Studies, how will PJM model projects already in the interconnection queue? Specifically, will PJM assume that all projects within the applicable queue population are in service and fully deliverable for Energy and Capacity beginning with the 2029/2030 or 2030/2031 Delivery Year? Alternatively, will PJM include only projects with an executed or tendered GIA that establishes a Commercial Operation Date prior to the applicable Delivery Year? More generally, what specific milestone or date will PJM use to determine whether a queued project is included in the Interim Deliverability study base case? 4. Identification and Tracking of Limiting Violations Can PJM clarify how transmission violations or constraints that limit Interim Deliverability will be identified and documented? Once identified, will those specific violations be tracked throughout the Interim Deliverability period, and will PJM identify the Network Upgrade or Contingent Facility expected to mitigate each limiting violation? 5. Potential Reduction in Previously Established Interim Deliverability Can PJM confirm whether the Interim Deliverability MW values and schedule established in the GIA represent the minimum level of Interim Deliverability that the project is entitled to retain, or whether those values may subsequently be reduced? If an annual re-study identifies a new violation, a worsening of an existing violation, or another material change in system conditions, can PJM reduce the project's previously established Interim Deliverability MW amount for a subsequent Delivery Year? If so, what methodology will PJM use to determine and allocate that reduction and will it differ for Energy vs Capacity Deliverability? 6. Full Deliverability Date Can PJM confirm whether the Full Deliverability Date identified in the New Service Request/Application is fixed, or whether it may be extended if the project, associated Network Upgrades, or Contingent Facilities are subsequently delayed? If the Full Deliverability Date cannot be extended, how will PJM administer Interim Deliverability when the facilities necessary to achieve Full Deliverability are not completed by that date? 7. Initial Interim Deliverability Determination Can PJM clarify how Interim Deliverability will be evaluated under Section 440 when establishing the initial Interim Deliverability Schedule and MW values to be reflected in the GIA and how the models and assumptions will differ from the base study year models and assumptions? 8. Annual Re-Study Methodology For each subsequent Delivery Year, can PJM clarify the methodology that will be used to perform an annual Interim Deliverability Study at the Project Developer's request? Will PJM perform a comprehensive re-evaluation using the then-current RTEP case, system topology, generation assumptions, load forecast, completed upgrades, and applicable contingencies, or will the analysis primarily re-evaluate the violations identified in the initial Interim Deliverability determination? 9. Earliest Delivery Year for Interim Deliverability Based on the proposed implementation schedule, if the first revised GIAs incorporating Interim Deliverability Schedules are expected in August 2029, what is the earliest Delivery Year for which Interim Deliverability may be established? Could Interim Deliverability apply beginning with the 2029/2030 Delivery Year, or would the earliest opportunity be the 2030/2031 Delivery Year?

	GIA Identification and Treatment of Associated Upgrades 1. Identification of IRRs and Network Upgrades Can PJM clarify how Network Upgrades and Interconnection Reliability Reinforcements (IRRs) associated with a project's Interim Deliverability and Full Deliverability will be identified and incorporated into the GIA? Should Project Developers expect the revised GIA to identify these facilities with a similar level of specificity as current GIAs, or does PJM anticipate changing how these facilities and associated obligations are documented? 2. Relationship Between IRRs and Incremental Deliverability Will the GIA establish a clear relationship between completion of specific IRRs and the corresponding increases in Capacity deliverability reflected in the Interim Deliverability Schedule? For example, will the GIA identify which specific upgrade or facility must be completed before a project may progress from one level of Interim Deliverability to the next? 3. Subsequent Changes to Identified IRRs If PJM subsequently determines that an IRR identified in the GIA is no longer required, is modified, or is replaced by another system improvement, how will that change be documented? Additionally, how will PJM determine the resulting impact, if any, on the project's Interim Deliverability and Full Deliverability dates and associated MW values? 4. Relationship Between Violations and IRRs Will Project Developers receive information to identify the specific transmission limitation or violation associated with each IRR identified in the GIA? Reinforcement Cost Certainty Framework & Payments 1. Maximum Financial Commitment/Cost Certainty Cap Would PJM consider establishing the cap on the Project Developer's financial commitment based on the lesser of: (i) a defined percentage of the identified or estimated upgrade costs, or (ii) a specified dollar amount? This approach could provide an appropriate demonstration of project readiness while limiting disproportionate financial exposure when preliminary screening identifies significant upgrade costs. 2. Refundability of Financial Commitment Would PJM consider modifying the proposed framework such that 90% of the required financial commitment remains refundable if identified costs exceed the established cost certainty framework cap, thereby limiting the Project Developer's non-refundable or at-risk amount to 10%? This approach would more closely align with the existing readiness framework following Phase I and may be more commensurate with the level of cost certainty available to a Project Developer following completion of the screening process. 3. Security, Invoicing, Cost Responsibility, and Reimbursement Please clarify how PJM and the Transmission Owners intend to administer security, invoicing, cost responsibility, and reimbursement from execution of the applicable agreement through Commercial Operation and the conclusion of the proposed 15-year payment period. Specifically: a. Timing of Invoicing When will PJM and/or the Transmission Owner begin invoicing the Project Developer for engineering, procurement, construction, construction management, or other costs associated with the applicable transmission upgrades? b. Pre-Commercial Operation Costs If costs are incurred or invoiced prior to Commercial Operation, but the applicable transmission cost allocation does not become effective until Commercial Operation, how will those costs be funded, tracked, and accounted for during the interim period? c. Final True-Up and Reconciliation How and when will PJM and/or the Transmission Owner reconcile amounts previously secured or paid by the Project Developer against the Project Developer's ultimate cost responsibility? d. Timing of Refunds or Additional Payments What timeframe should the Project Developer expect for completion of the final reconciliation and issuance of any resulting refund, credit, or additional amount due? 4. Request for Cost Allocation Examples

	Would PJM and the Transmission Owners consider dedicating time during one of the next two workshops to walk stakeholders through representative cost allocation and carrying-cost examples?