August 18 Co-Located Load Order Workshop Stakeholder Feedback Poll: Question 1

Company Name	Based on the information presented at the August 18 Co-Located Load Order Workshop, what feedback would you like to provide to PJM?
Tangibl Group, Inc.	It is extremely important for PJM to provide as much information and consultation as possible to PJM stakeholders and project developers in regard to any proposed changes to the PJM interconnection process. PJM project developers have literally tens of billions of dollars at stake in the PJM interconnection process, and need to clearly understand the ramifications of any proposed changes to the PJM interconnection process so they can make the most appropriate business and project development decisions going forward.
American Clean Power Association	Risking the progress achieved under PJM's interconnection process reform ACP's foremost concern is that this proposal puts at risk the substantial progress PJM has made under its interconnection process reform since the 2022 transition to the first-ready, first-served cluster study process. Those reforms, coupled with further revisions driven by FERC Order No. 2023 compliance, meaningfully reduced PJM's queue backlog and brought study cycle times and cost/timing certainty back into a workable range after years of delay. It succeeded in significant part because clusters were built around a defined, relatively homogeneous population — generation projects competing for the same system capacity, on defined cycles, with cost allocation methods calibrated to that population. Folding named large load into those same cluster studies — potentially non-proximate, with no output cap, and governed by its own forecast uncertainty, readiness milestones, and withdrawal risk — reintroduces exactly the kind of heterogeneity and unpredictability the 2022 reforms were designed to eliminate. Larger, more complex clusters mean longer study cycles, more restudy triggers, and more opportunities for one participant's change in status — a load forecast revision, a withdrawal, a delayed financial commitment — to cascade delays across every generator clustered with it. Before proceeding, PJM should show how it will preserve the queue processing timelines and predictability the interconnection reform achieved, given that large load brings a materially different risk and uncertainty profile than the generation population those reforms were built around. Structural shift out of the Supplemental Project framework The Conceptual Approach would move large-load-driven transmission needs out of the existing Supplemental Project construct under OATT Attachment M-3 — where they are identified by the Transmission Owner and recovered through the TO's zonal revenue requirement — and into a cluster study with generation in the New Services Request process. This is a structural change to planning and cost recovery, not a procedural refinement, and it applies to load regardless of electrical proximity to the generation it is studied alongside. The FERC Show Cause Order ties joint study of load and generation to electrical proximity and enforceable output limits; it does not on its own require a change of this scope. PJM should explain why removing all named large load from the Supplemental framework is necessary to satisfy the Order, versus a narrower, proximity-based joint study limited to the pairs the Order addresses. Put another way, ACP is concerned that PJM's present proposal exceeds the scope of the Show Cause Order and, as described below, requires more time and comprehensive vetting before it should be adopted and implemented. Cost allocation: backbone transmission costs potentially shifting to generation Today, backbone and network transmission projects identified through the RTEP are regionally cost-allocated under Schedule 12 and socialized across load. Under the proposal, it is unclear whether a backbone or network upgrade jointly identified through a cluster study retains that RTEP/Schedule 12 treatment or is instead assigned, in whole or in part, to the generation interconnection customers in the cluster. This is a central concern: without a stated causation methodology separating what the load caused from what the generator

	caused, generators risk new cost exposure for facilities that would otherwise be regionally allocated. PJM should state clearly whether cluster-identified backbone upgrades retain existing cost allocation treatment before this proposal advances further. Financial milestones tied to unproven modeling and computing capability PJM has indicated it will provide greater computing power and updated models so interconnection customers can decide quickly whether to remain in the queue once cost information is available. ACP supports that goal, but the tools described are not yet validated at scale, and the proposal would tie escalating financial milestones to a decision window built around that unproven capability. Binding generators to financial commitments on a clock calibrated to unproven infrastructure is premature. If the tools underperform, the financial exposure still lands on the generator. We recommend PJM pilot the modeling and computing capability and demonstrate its performance before attaching binding financial milestones to it. ACP recognizes there may be genuine value in studying load and generation together in some circumstances, particularly where they are electrically related. Indeed, ACP supported SPP's adoption of the "Consolidated Planning Process" whereby SPP's generator interconnection process is effectively being merged with SPP's integrated transmission planning process. That said, the Show Cause Order's joint-study directive is anchored in proximity and output limits — narrower than the general clustering PJM has proposed. Whether the broader synergy PJM describes will actually materialize, versus simply concentrating cost and timing risk onto generation, is an open question that deserves focused analysis rather than being assumed at the outset. Timeline: November filing is premature for a proposal of this scope ACP is greatly concerned regarding the short vetting and implementation timeline for such a significant proposal. This is a multi-year, structural proposal that touches RTEP cost allocation, introduces new financial milestone obligations, and rests on infrastructure, technology, and methodology that are not yet finalized. Filing in November does not give stakeholders time to resolve the cost allocation question, does not give PJM time to validate the tools its milestone justification depends on, does not allow the scope of cohesive clustering to be tested rather than assumed, and does not allow PJM to demonstrate that the queue processing gains of the 2022 reform will be preserved. We recommend PJM sequence this work — resolve cost allocation, pilot the modeling/computing tools, and treat clustering scope as a stakeholder question — on a timeline that matches the proposal's complexity.	

EDF power solutions	Comments of new services request process - The amount of new security postings throughout the process should be minimized to the extent possible since they are a time consuming administrative process that also frequently involve executive approvals, risk assessments, and other reviews in addition to simply amending the LC. Based on our limited knowledge of the process, proposed points to submit a new LC or amendment are below: At time of application Following the completion of the winnowing process and start of SIS At GIA execution Later adjustment in GIA security (if applicable) - It will be critical to ensure the increase in risk is accompanied by an increase in certainty – i.e. not requiring many millions of $ at risk if NU costs are still very volatile. - Adverse study impact mechanisms similar to those in place today should remain to offer sufficient protection in the event that costs change significantly at a later stage in the process, which can often be due to the actions of other projects. This will be most important for post winnowing to SIS completion, but also important during the winnowing process itself. - We support using automated processes to the extent possible, but the time required to fully vet vendors and implement new software will be challenging to complete and test prior to its formal introduction. Application Period comments - EDFps supports the changes presented at the August 18th workshop but cautions PJM to take the required time to design a workable process with an implementation timeline that is commensurate with the needs of any software and other process deployments - The description provided of incentivizing projects to submit well in advance of the deadline in order to receive more time to deal with deficiencies would be a welcome change - While an automated tool should be able to screen the technical parts of the application, there may be challenges with the site control documentation – PJM should pay special attention to how the tool will review such documents noting the various types of agreements that are utilized across the PJM footprint. Winnowing Mechanism comments - EDFps is potentially supportive but the process details will be incredibly important. - Practically speaking, it would be very difficult to allow enough time to do security increases during this time – an easier approach would be to have increased risk step-ups for the already posted readiness deposit (at time of application).	

	System Impact Study comments - How will Affected System Coordination occur within this outlined approach? Affected System Impacts should be determined for all types of service requests - We're assuming the SIS includes the NU Facility Study that is currently done in phase 3 – can this be confirmed? - When will the facility study for the POI related upgrades be completed? Agreement - We remember the discussion at the August 18th meeting noting that the negotiation will begin during the SIS phase. Much of what goes into the negotiation requires the cost and schedule of NUs. Leaving just one month from SIS completion to GIA execution will create challenges negotiating GIA milestone dates, among other things if the costs and schedule for the upgrades is not complete until the end of the SIS period - Slide 9 of the presentation indicated 'detailed terms negotiated during the preceding 8mo'. That would not be able to include any milestone related dates (since timelines from facility studies are not yet avbl), which is one of the most important and time consuming items to review and negotiate. - Following SIS completion, we assume the GIA security amount would be known. If projects withdraw following the SIS, would the GIA security be revised in a final retool as is done today? Comments on overlap of large load, co-located load, and load w/BTMG General - EDFps requests that PJM confirm a large load may qualify as "Flexible" where its withdrawal limitation capability is supplied by a contracted BESS from an IPP which is delivering under a tolling or capacity agreement. The tariff should credit the demonstrated ability to limit withdrawals with a BESS - Confirm whether a co-located configuration could change categories as commercial arrangements change, and describe the process Definition clarity - "Single electrical site" and the 1-mile radius aggregation of affiliated load facilities creates significant opens new risks, especially for phased campuses. How will PJM treat a campus that is developed in phases across multiple delivery years, and does an incremental phase re-open the classification of earlier phases? - PJM has stated it is still discussing treatment of "electrically proximate" loads. We request that PJM publish a definition of this (like what SPP did with substation count) in this proceeding. And PJM should confirm that a generating or storage facility interconnected within that boundary receives the same treatment as one behind the load's POI - Can PJM confirm whether load served under a third-party (IPP) tolling contract with a co-located generator qualifies as Flexible Load, Eligible Load, or both? Storage - The definitions may not accommodate storage. BTMG excludes capacity designated as a Generation Capacity Resource, yet storage is a valuable co-located asset because it serves multiple roles - Confirm whether a single facility can be split between Capacity Resource and BTMG/co-located designations, and how CIRs could allocate across the split	

1. Aspen Gen Funding, LLC2. Bath County Energy, LLC3. Seneca Generation, LLC4. Cork Oak Solar LLC5. Five Forks Solar, LLC6. Fresh Air Energy XVIII, LLC7. Fresh Air Energy XXXV, LLC8. Hemlock Solar, LLC9. Milford Solar LLC10. North 301 Solar, LLC11. Rockfish Solar LLC12. Sunflower Solar LLC13. Wyandot Solar LLC	We are concerned that PJM is creating a new interconnection process in a short period of time. This condensed schedule may not allow sufficient time to vet all issues to allow for an orderly process with known rules and impacts for all participants. We are not opposed to an interconnection process that studies load and generation together and indeed think there can be benefits of such a process, but are concerned with the lack of details at this point and the quick timeline for finalizing required given the extensive process that was recently done to overhaul the PJM interconnection queue.	
1. Constellation Energy Generation, LLC 2. Champion Energy Marketing LLC 3. Champion Energy Services, LLC 4. Champion Energy, LLC 5. North American Power and Gas, LLC 6. Calvert Cliffs Nuclear Power Plant, LLC 7. Constellation NewEnergy, Inc. 8. Handsome Lake Energy, LLC 9. Calpine Bethlehem, LLC 10. Calpine Energy Services, L.P. 11. Calpine Energy Solutions, LLC 12. Calpine Mid Atlantic Marketing, LLC	Constellation appreciates PJM's continued development of its framework and believes PJM's proposal to study generation and new Large Loads cohesively is an important step in the right direction. The Commission already found that PJM must implement new transmission services (e.g., INITS, etc.) to reflect the operational dynamics of co-located load arrangements so as to avoid unnecessary, costly and inefficient network upgrades (see, e.g., PJM Co-Location Order at P 177), and Constellation appreciates PJM's continued work towards timely complying with that order. The Commission also found that the same unjust and unreasonable result may occur if the connection study process does not consider the limited impacts to the transmission system that may occur where large load is paired with a co-located generator. (PJM Large Load ANOPR Order at P 95 et seq.) As the Commission explained "[w]here a generating facility's output is matched to the demand of the electrically proximate large load or large co-located load or if the generating facility's output is limited to ensure no new net injection, the impacts to the transmission system of interconnecting the generating facility to serve that electrically proximate large load or large co-located load may be limited, thereby potentially reducing the need for Network Upgrades, which can accelerate the generator interconnection process." (Id. at P 95). Commissioner Rosner emphasized that planning and studying generation and load separately can lead to additional infrastructure, cost, and delay, while studying them together can reduce Network Upgrades and accelerate both generation and load interconnection. The Commission recommended several approaches that PJM should consider to ensure unnecessary, costly and inefficient Network Upgrade costs can be avoided, including Constellation's LCEP proposal. (Id. at PP 96-98). While a generic 12-month combined study is a helpful (but not complete) timing improvement, it does not provide a tailored interconnection pathway that recognizes reduced grid impact (which could provide potential cost reductions and additional timing improvements if fewer Network Upgrades are needed) from operationally linked generation and load as the Commission intends. PJM should make sure that the new framework is not simply a faster version of the existing processes, but captures the cost and other efficiencies the Commission asked PJM to recognize. Against that backdrop, Constellation continues to encourage PJM to expressly include Load-Contingent New Capacity at Existing Plants ("LCEP") in its proposed framework to ensure PJM's framework accommodates the type of tailored generator/load interconnection service the Commission directed PJM to address. LCEP provides a concrete way to implement the Commission's broader objective. PJM's proposed approximately 12-month integrated study process is constructive, but it only help expedite the study process and it should not foreclose a more tailored and expedited pathway that could more efficiently reduce the time and cost of Network Upgrades where the facts demonstrate that the generation/load combination presents materially reduced incremental transmission impacts.	

Invenergy Energy Management LLC	We appreciate the effort PJM is taking to coordinate the Generation and Transmission service studies through the New Services request process. It is understood there will be more information coming on the Winnowing period but it would be very helpful to understand what, if any, financial commitments or deposits will be needed following each iteration. Additionally, we are concerned that PJM suggests requiring 100% of at risk Network Upgrade costs based on an estimate from the Winnowing process, prior to the SIS taking place is very troublesome. Placing unreasonable financial risk on projects prior to entry in the SIS is an unworkable solution without some level of guarantee on a transmission cost cap and timeline.	
1. Calibrant Energy 2. Camus Energy	A. The New Service Request process must provide large load customers with detailed and timely insight into upgrades needed to enable their interconnection. When identifying upgrades for Firm Service during the Winnowing Period and the System Impact Study, PJM should provide granular information on the system conditions that trigger the upgrade need and the amount of flexibility that would be necessary to avoid the upgrade. A customer seeking transmission service that has been assigned cost responsibility for a network upgrade must understand: i. The constraint or constraints driving the identified upgrade; ii. The system conditions that cause the constraint(s) to bind; iii. The assumed operating behavior of the load during the system conditions that lead to the system constraint; iv. The cost and timeline associated with completing the system upgrade; and v. The amount of flexibility or the operating behavior of the load that would resolve the constraint, including the list of specific parameters enumerated in Section B, below. B. The New Service Request process must also provide robust transparency into the parameters of the load flexibility required to elect Interim NITS and Non-Firm Contract Demand (NFCD) Service. A customer seeking new service on behalf of a large load must have insight into the parameters governing these non-firm service options to make a commercially sound decision. At minimum, PJM should provide the following: i. The constraint or constraints driving the flexibility requirement; ii. The conditions in which flexibility would be required, the duration of required curtailment events, and a forecast of how frequently flexibility would be required (i.e., number of hours per year); iii. MW required to be flexible (i.e., the maximum permitted withdrawal during events); iv. Notice for planned events and required response time for emergency events; v. Curtailment priority and ordering relative to other flexible loads, to demand response resources, and to firm load shed; vi. Measurement, verification, and telemetry requirements, including the baseline or envelope against which performance will be assessed; and vii. Expected lifetime of the flexibility requirement: whether and when planned system investment is expected to relieve or could relieve the constraint. The absence of this transparency would exclude most new large loads from taking service under Interim NITS or NFCD Service. For purposes of determining whether a large load customer has the option to elect Interim NITS, PJM should provide transparency behind their decision. In addition to the above, in instances where a large load is ineligible for Interim NITS, PJM should provide a detailed reasoning and any steps/timeline for eligibility. If PJM seeks to require customers seeking NFCD Service to make that election in an initial, Pre-Application Phase, PJM must provide transparency into applicable flexibility parameters upfront. A customer must understand the characteristics of load flexibility that will be considered in the study process and the constraints driving curtailment events (i-vi above) prior to submitting an application. Regarding the former, we urge PJM to adopt a study methodology that recognizes granular proposals for adjustment of withdrawals during a certain number of hours each year rather than limit flexibility to binary “on/off” curtailment.	

	C. The Study Process Should Enable Limited Modification to the Level of "Firm-ness" of New Load Service Requests Based on Results of the Winnowing Turns and after the System Impact Study. The proposed Winnowing mechanism appears to present iterative determinations of upgrade costs and timelines without enabling a project to adjust the service requested. The generator interconnection process offers a useful model for allowing certain limited modification requests at defined Decision Points, e.g., reducing the capacity interconnection rights requested. The New Service Request process should afford a similar opportunity for new large load customers to request to adjust load flexibility based on actual constraints identified in study results (e.g., switching from Firm Contract Demand (FCD) Service to NFCD Service or altering a proposed combination of FCD and NCFD Service). If PJM proceeds with the proposed Winnowing Mechanism, the Decision Points already contemplated in that process would be a suitable point to allow such modification requests. Any change process should include reasonable limitations to uphold efficiency for all participants, as modeled by the prescriptiveness of the current generator interconnection process. Incorporating a prescribed modification request process should avoid unnecessary network upgrades and lower the risk of disruptive project attrition late in the study process.	
RMI	The following feedback on PJM's proposed response to FERC's Large Load Show Cause Order details how the design and implementation of a reformed interconnection processes for generation and load could best achieve desired outcomes of speed to power and cost-efficiency. In short, PJM's approach should minimize network upgrades by avoiding them where possible – via robust ERIS, flexible load, and proximate generation pathways – and proactively planning necessary upgrades to reduce costs. Recommendation Category 1: Process Design PJM's proposal to unify transmission services studies for generation and large loads into a coordinated process has the potential to reduce overall upgrade timelines and costs if it includes the following elements: a viable pathway for generators seeking energy resource interconnection service (ERIS), a defined interconnection pathway options for flexible large loads, integrated studies for electrically proximate large loads and generation, and alignment of large load interconnection and system-wide transmission planning. It is also important to note that Powering Reliability Through Market Design (PRTMD) pathways could significantly change deliverability requirements and cost allocation. Therefore, PJM should design this process to not preclude path A, B, or C's resource adequacy approaches, limiting the need for future process re-designs. A) Provide a viable pathway for generators seeking ERIS PJM's reformed process should provide a viable pathway for ERIS generators that does not slow their interconnection process nor cause them to pay for broader network upgrades. As long as these speed and cost goals are met, we see viable ways for ERIS to be included in the new proposed process or to have their own parallel and expedited track. We suggest these ERIS targets because energy only generation benefits the PJM grid and should play a larger role. Energy only interconnection services (ERIS) do not require firm delivery and therefore should not trigger network upgrades for deliverability. Following ERCOT's precedent, ERIS studies should be limited to the point of interconnection, using realistic dispatch assumptions and managing broader system impacts through curtailment. ERIS resources have the potential to reduce energy costs and provide grid reliability in PJM. In an analysis commissioned by RMI, Aurora Energy Research found that deploying 10 GW of energy-only resources in PJM over the next decade could yield $11 billion in savings for consumers [1]. Improving the viability of low-cost, fast-to-deploy energy-only resources could provide flexible large loads with an additional pathway to come online quickly. Because they can come online faster, ERIS generators can support speed to power, especially if large loads choose connect and manage options or leverage their own flexibility to align power consumption with ERIS resource availability. [1]: https://rmi.org/the-path-to-power-connecting-large-loads/ B) Define interconnection pathway options for flexible large loads PJM should also ensure that flexible large loads have a clear pathway to interconnection unencumbered by delays in the consolidated process and differentiated from firm contracted demand. Loads that are willing and able to limit energy withdrawals have less stringent deliverability requirements. Consistent with the proposed treatment of ERIS generation resources above, large loads should trigger network upgrades correlated to their degree of flexibility. As explained in RMI's article, "Large Loads and Network Upgrades," it is helpful to	

	categorize network upgrades associated with large load projects qualitatively as, "incremental", "material," and "transformational." Today, many large loads are triggering material or transformational network upgrades that carry significant costs and lengthy development timelines. By accepting curtailment risk, flexible loads could avoid or defer many of these upgrades, reducing interconnection costs and enabling faster access to power. Accordingly, interconnection studies for flexible loads should follow a clear timeline that is differentiated from and not impacted by delays for loads requesting firm service. C) Adopt integrated studies for electrically proximate large loads and generation PJM should also have a clear method to link associated load and generation projects in its proposed new service request process. As RMI discussed in its article on "Understanding FERC's Large Load Orders", RTOs should clearly define "electrically proximate", explain how proximate generation and load will advance through the interconnection study, and should specify whether they will require agreements between electrically proximate load and generation to study the pair together [2]. SPP's High-Impact Large Load (HILL) policy may serve as an example: the policy specifies that proximate generation and load are studied together, yielding a generator agreement (HILLGA) that is limited by the load (HILL). SPP also indicates a pathway for customers to energize when firm service is not available via Conditional High-Impact Large Load Service (CHILLs). PJM could use this blueprint for reference to explain how it plans to "utilize interim deliverability for flexible and interim NITS loads" as part of its proposed reforms stated on August 18th. Studying linked, electrically proximate load and generation together could reduce system impacts and resulting network upgrades, enabling speed to power. [2]: https://rmi.org/resources/understanding-fercs-large-load-orders/ [3]: https://spp.org/markets-operations/high-impact-large-load-hill-integration/ D) Align large load interconnection and system-wide transmission planning PJM should assume a proactive, regional-first approach in evaluating configurations for both generation and load. Southwestern Power Pool's Consolidated Planning Process (SPP-CPP) provides a useful precedent for portfolio-level planning: SPP incorporates forecasted load needs into an integrated regional planning and generator interconnection process to identify transmission solutions that address multiple system needs [4]. PJM should capitalize on its proposed new service request process as an opportunity to deploy a more effective approach for preparing the grid for large loads, rather than relying on piecemeal network upgrades increasingly identified through the interconnection process. In a proactive, regional-first approach, large loads would submit their interconnection requests to PJM through a streamlined large load interconnection queue improving data visibility and coordination [5]. Then PJM would use the large load requests to inform regional-first transmission planning, identifying system-wide projects as necessary to simultaneously meet all large load requests and broader system needs together. Finally, after identifying system-wide projects, individual transmission owners would propose any remaining transmission projects necessary to meet reliability requirements and complete interconnections. [4]: https://www.spp.org/engineering/consolidated-planning-process/ [5]: https://rmi.org/resources/using-regional-first-planning-to-streamline-large-load-interconnection/ Recommendation Category 2: Implementation	

	Effective implementation of PJM's proposed new services request process hinges on transparency. Relevant stakeholders should have clarity on both how the process will develop, and how it will be monitored once implemented. This should include a technology implementation of roadmap, high-quality information for developers, and published queue results. A) Create a technology implementation roadmap A suite of advanced grid software solutions exist that PJM can leverage to actualize the desired 12-month interconnection study process. Modeling and analysis tools offer the ability for integrated planning approaches; grid monitoring software and analytics can support faster and more integrated decision-making; optimization in planning can identify and automatically implement grid reconfigurations that alleviate grid congestion, and/or address reliability issues; and study automation and workflow enhancements can advance predictable and faster timelines. A technology roadmap with a clear implementation timeline, engineering oversight guidelines, and accuracy validation checks would help assuage concerns on introducing new tools. PJM should also ensure that software solutions enable deployment of hardware that maximizes grid utilization. Advanced grid software should facilitate robust evaluation of advanced transmission technologies (ATTs), a set of technologies that FERC notes in the first reform in its Show Cause Order. Grid-enhancing technologies (GETs), a subset of ATTs, are a near-term solution for grid reliability. As they are significantly cheaper than standard network upgrades, GETs and the enabled new generation could yield approximately $1 billion annually in production cost savings across PJM [6]. [6]: https://rmi.org/resources/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/ B) Provide transparent, decision-quality study information Providing decision-quality information as early in the process and as frequently as feasible will help developers make informed decisions as their financial commitments increase. Greater certainty on costs, timelines, and system impacts can help viable projects advance and encourage earlier withdrawal of projects that are unlikely to proceed. Queue data and summary metrics will help evaluate whether the new process is delivering its intended benefits and identify where further reforms are needed. A consolidated large-load registry, including electrically proximate generation, could track applications, attrition and reasons for withdrawal, and changes in estimated upgrade costs and timelines across study stages. Section 3: Outcomes Effective design and implementation of PJM's proposed process should yield three key outcomes: speed to power, cost-efficiency, and a higher quality, more stable queue. A) Speed to power Taking an active role in ensuring load service is matched by paths that bring generation online quickly would allow PJM to reduce both the timeline from application to agreement and the extensiveness of network upgrades from centralized planning and coordination of generation, transmission, and load projects. B) Lower total system costs PJM should evaluate the success of the new services process based on whether it minimizes total system costs, not simply whether individual requests can be interconnected. This should include avoiding unnecessary network upgrades through flexible transmission service and coordinated study of generation and load, while evaluating lower-cost alternatives to conventional transmission upgrades, including advanced transmission technologies and grid-enhancing technologies. C) A higher-quality, more stable queue PJM should evaluate whether the new process produces a more mature and predictable queue, with fewer disruptive late-stage withdrawals and re-studies. Metrics should include attrition at each stage, the frequency of late-stage withdrawals and retool analyses, and the share of requests that ultimately reach commercial operation. A more stable queue should also improve PJM's ability to plan for future resource adequacy and transmission needs.	

Mount Storm Wind LLC	Clearway appreciates the opportunity to provide feedback on PJM's latest framework for the generator-load study process. We have concerns with the current proposal and approach as presented. Additional details are needed to properly assess the proposal's feasibility, and we raise several open questions below. In the interim, we offer the following feedback: We support PJM's approach to identify and cure application deficiencies during the pre- application phase. This will encourage customers to submit applications early and reduce PJM's time processing requests after the application window has closed. At a minimum, PJM should notify stakeholders at the next IPS meeting that significant changes to Cycle 2 are being developed in this workshop. We encourage PJM to not rush to this proposal to meet the Show Cause Order compliance deadline and, if needed, pursue it as a separate initiative to allow adequate time for stakeholder and PJM review. PJM mentioned during the meeting that it has preliminary ideas to address post-GIA timeline and cost uncertainties. This is another critical issue for developers, and we encourage PJM to share its potential solutions as soon as they're ready.	

Voltus, Inc.	PJM's Co-Located Load Order and the underlying FERC show cause order (EL26-67) are both aimed at the same three things every RTO is being asked to solve for large load interconnection right now: a reliable grid, faster speed to power, and cost allocation that doesn't shift risk onto other customers. The August 18 workshop materials make progress toward those goals, but as presented they leave open a key question: what counts as flexible. 1. Flexible Load should be defined by verified impact, not by method. The workshop presentation defines Flexible Load as a large load willing and able to limit their energy withdrawals from the transmission system under certain conditions, but doesn't say how that ability is demonstrated or verified. As currently framed, the materials read as though the only way to limit withdrawals is for the load itself to curtail. A load can limit its net withdrawal from the transmission system several ways: by curtailing its own consumption, by drawing on co-located or proximate storage instead of the grid (to the extent that storage has sufficient state of charge and duration to cover the relevant withdrawal event, and — for storage that charges from the transmission system rather than from co-located generation — that the transmission service used to charge it is accounted for, so the claimed benefit reflects the net effect across the full charge/discharge cycle rather than the discharge event alone) , or by contracting for DR/DER that offsets the same withdrawal (provided that DR/DER is not simultaneously counted toward a separate market or transmission obligation of its own). We ask PJM to confirm that Flexible Load status can be demonstrated through any of these, provided the mitigating effect on the load's transmission withdrawal is verified — through metering or telemetry sufficient to confirm the reduction occurred at the time and location PJM specifies as triggering the flexibility obligation, not only through self-curtailment. 2. The treatment of electrically proximate loads should extend to proximate storage and DR/DER, not only proximate generation. The workshop pack notes PJM is still working through how to treat electrically proximate loads: loads not co-located with generation but close enough electrically to have the same system impact — a relationship that could reasonably be established using distribution-factor or similar sensitivity analysis, methods already common in transmission planning and cost allocation more broadly. That's the right question to be asking, but it shouldn't stop at generation. A proximate storage asset or a proximate contracted DR/DER resource can reduce a large load's net impact on the transmission system subject to the same non-duplication condition described above. We ask that whatever treatment PJM adopts for electrically proximate loads apply equally across all services that a large load can bring to the system to mitigate their impacts — including the study or verification burden required to demonstrate proximity, so that proximate storage and DR/DER are not held to a higher evidentiary standard than proximate generation simply because the relevant electrical data is not already on hand. 3. If flexibility doesn't shorten the 12-month timeline itself, PJM should explain why not. The workshop material lays out a single New Service Request process, roughly 3 months for Pre-Application and Winnowing, 8 months for the System Impact Study, and 1 month for Agreement Finalization, that applies to Large Loads generally, with interim deliverability offered to flexible and interim NITS loads during that process. As presented, that reads as the same 12-month process for every load, with flexibility affecting what service a load can access while the study runs, not how long the study takes. A load's verified ability to limit its withdrawal should reduce the system impact PJM and the Transmission Owners need to study in the first place — most directly the scope and duration of the System Impact Study, where a smaller modeled net impact should mean fewer facilities and scenarios to analyze. Interim deliverability during the study period addresses when a load can begin taking some service, but it does not answer whether the underlying study itself should be shorter for a load with a smaller net impact; the two are not substitutes for each other. We ask PJM to clarify whether a Flexible Load's verified impact can shorten any part of this timeline — and specifically the System Impact Study phase — , or if not, why the timeline stays fixed regardless of a load's demonstrated impact on the system.	

	4. Where this proceeding intersects with Transmission Owner planning, all solution types should be on the table. The workshop material is clear that this proceeding doesn't alter the Transmission Owner's interconnection process and is strictly about transmission service, and we're not asking PJM to take on planning functions that sit with the TO. We are asking that PJM's Flexible Load classification be adopted by Transmission Owners as an input to their own interconnection and planning studies. This is consistent with the broader direction of FERC's transmission planning reforms, which call for evaluating a wider range of solutions — including alternative technologies and demand-side resources — rather than defaulting to traditional upgrades. But PJM's Flexible Load classification will shape what a TO studies and builds for. That classification should recognize the full range of solutions described above, so a TO isn't left planning around a narrower definition of flexibility than PJM itself intends to apply. Absent that alignment, a TO could plan and build to a narrower definition than PJM's own classification recognizes, resulting in upgrades sized for a system impact that has already been mitigated — a cost that ultimately falls on customers. We ask PJM to clarify when in the RTEP or TO planning cycle a finalized Flexible Load classification would need to be available in order to actually inform that planning, rather than trail it. 5. RBP/IRAS and this Flexible Load framework are separate processes, but the physical assets behind them aren't. Each should be designed with the other in mind. The presentations clearly state that resource adequacy is being handled through RBP and IRAS, not this proceeding, and lists it among the items not impacted here. We understand the processes serve different purposes and that separation makes sense. But in practice, the same physical asset, co-located or proximate storage, or contracted DR/DER in particular, can deliver a resource adequacy benefit under RBP/IRAS and a transmission benefit under this framework at the same time. RBP and IRAS both include bring your own resource elements, where a large load can bring forward its own resource to meet its resource adequacy obligation. The bring your own elements of these new transmission services should be designed with that in mind, recognizing and giving credit for the transmission side benefit that a bring your own resource is already providing (although ensuring no double counting in the event of deployment for both reasons).But designing one without accounting for what the same asset is already contributing under the other risks under-crediting the asset on one side, or double-crediting it across both, which will result in inefficient system design. We ask PJM to clarify how it will reconcile asset designations between RBP/IRAS and the Flexible Load framework — including whether a single registry or verification record will be shared across both processes — and how that reconciliation will be sequenced given that the two processes are proceeding on different timelines.	

NRDC	NRDC strongly supports PJM's proposed 12-month New Services Request process. The new process has the potential to drastically reduce interconnection study timelines and properly allocate network upgrade costs among supply and large load customers. We are also optimistic about the potential to reduce the need for backbone transmission upgrades by considering electrically proximate load and supply together. To achieve even faster interconnection, NRDC suggests the following changes to reduce or eliminate the need for network upgrades, which can drive queue dropouts, increase costs, or block development for up to 7 years. Given urgent resource adequacy and cost allocation concerns in the region, NRDC finds it appropriate to propose this new framework at FERC in November, and warns PJM against delaying implementation. 1. Capture benefits of electrically proximate load and supply. PJM should clarify that its New Services Process will model new large loads and new generation or storage resources together and recognize contractual arrangements and electrical proximity. Specifically, PJM should ensure that both co-located load and supply and electrically proximate load and supply are modeled so that the load and supply resources "balance" one another and reduce contingencies that could lead to network upgrades. PJM's models should account for complex arrangements, like multi-module large loads that are multiple buses away from a multi-unit generator or storage resource with separate transformers and grid ties. These arrangements may still provide significant value to the system as the load and supply balance against one another. PJM should set out clear rules for large loads and proximate/co-located supply to document their commercial arrangements. If needed, PJM could include operational restrictions to the load-supply pairs in any GIAs in order to minimize or avoid network upgrades. 2. Model flexible new large loads and storage. Some new large loads and/or battery storage resources may be willing to reduce their demand during specific conditions. PJM should ensure that these anticipated load or supply reductions are appropriately modeled in its New Services Request process to avoid new network upgrades and to provide an incentive (through reduced cost allocation) for such flexibility. In particular, PJM should consider expanding the non-firm CDS model and energy-only interconnections to allow flexible arrangements between electrically proximate load and supply when those parties are willing to take on all operational deliverability risk. 3. Consider DERs. Several states have expressed interest to us in promoting distributed storage to serve data centers or meet other needs, and distributed solar is a well-established and thriving resource category. We are also aware of private sector proposals to use distributed storage capacity to meet data center BYO obligations. We ask PJM to consider how DER plans might be integrated into this process. Some states will be motivated by policy goals to develop distributed resources. For those states, it is vital that those investments be considered in determining future transmission needs. Other states will consider this investment decision to be based on a cost/benefit comparison between transmission and distributed resources. Those states currently receive little guidance or analysis from PJM as to which might be the more cost effective path. We realize that iteration is challenging in the fast process PJM has proposed, but the ideal outcome would be clear signals to state regulators to enable cost/benefit comparisons between DER investments and competing transmission solutions, and to have their decisions reflected in PJM's planning.	

1. Air Products & Chemicals, Inc. 2. Lehigh Portland Cement Company 3. Messer LLC 4. Linde Inc. 5. Kimberly-Clark Corporation 6. Cleveland-Cliffs Steel LLC 7. Trustees of the University of Pennsylvania 8. Gerdau Ameristeel Energy, Inc. 9. Procter & Gamble Paper Products Company (The)	Clarity on the definition of colocation vs. behind-the-meter generation, particularly for PURPA QF facilities that have been required to secure a PJM ISA to sell their excess power to the grid, especially with respect to ISAs that would qualify for grandfathering. Clarity on the treatment of a retail customer with an ISA that has CIRs or energy injection rights only with respect to excess beyond their onsite load requirements.	

August 18 Co-Located Load Order Workshop Stakeholder Feedback Poll: Question 2

Company Name	**Based on the information provided at the August 18 Co-Located Load Order Workshop, what additional questions do you have?**
Tangibl Group, Inc.	What is the timeline for PJM providing additional details regarding proposed changes to the PJM interconnection process, along with a schedule of meetings/calls with interested PJM stakeholders and project developers to review and discuss the proposal with PJM provide PJM with suggested changes and other feedback?
American Clean Power Association	Preserving queue reform gains: What analysis has PJM performed on how adding large load to generation clusters will affect the study cycle times and processing throughput achieved under the 2022 interconnection process reform? What specific safeguards would prevent a large load's forecast revision, withdrawal, or delayed financial commitment from delaying the generation projects clustered with it? Cost allocation methodology: For a Network Upgrade or backbone facility jointly identified through a cluster study involving both large load and generation, does the upgrade retain its existing RTEP/Schedule 12 cost allocation treatment, or would some or all of the cost be assigned to the generation interconnection customer(s) in the cluster? If assignment to generation is contemplated, what causation methodology would PJM use to determine each participant's share? Supplemental Project status: Do large-load-driven upgrades currently in progress or newly identified under the Conceptual Approach retain their Attachment M-3 Supplemental Project designation and zonal cost recovery, or does entering a cohesive cluster study convert their classification and cost treatment? Proximity scope: What is the specific rationale for clustering non-proximate large load with generation, given that the Show Cause Order's joint-study directive is tied to electrical proximity and enforceable output limits? Would PJM consider limiting cohesive clustering to proximate, output-limited pairs, consistent with the Order and with other RTOs' approaches (e.g., SPP's treatment of HILL/HILLGA)? Modeling and computing capability: What is the current status and validated performance of the enhanced computing power and updated models PJM says it will provide to interconnection customers? What testing or pilot data supports using that capability as the basis for a binding financial milestone timeline? Milestone consequences: If PJM's modeling/computing tools do not perform as represented — slower turnaround, lower fidelity, or required rework — does the financial milestone clock adjust, or does the resulting risk and cost fall entirely on the interconnection customer? Contingent facility and restudy exposure: In a cohesive cluster, how are contingent facility costs and restudy triggers allocated when one participant (load or generation) withdraws or changes its request after upgrades have been jointly identified? Filing timeline: Given the open cost allocation, queue-impact, and methodology questions above, what is PJM's basis for targeting a November filing, and would PJM consider a phased approach that resolves cost allocation and pilots the modeling capability before filing the broader structural changes

EDF power solutions	- Can PJM explain which current processes would be rolled into this new service request process – like CIR retirement/replacement, surplus, etc.? - A year long process without any overlap with later cycle would have several benefits, but there are some questions: - How would implementation for 1st cycle work considering prior cycle (like Cycle 1) is still on 2 year timeline? seems that this new process, once started, would require part of it to overlap with the preceding cycle the first time it is put into practice. - Certain accommodations may be needed if such an overlap with Cycle 1 creates more uncertainty than would be experienced for years in the future when there is no longer any overlap with prior cycles. What is PJM's proposed approach to deal with this transitional period?	
1. Aspen Gen Funding, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Milford Solar LLC 10. North 301 Solar, LLC 11. Rockfish Solar LLC 12. Sunflower Solar LLC 13. Wyandot Solar LLC	Would the proposed new interconnection process replace the standard Interconnection Cycle process or be a new parallel process? What would be the effective date (e.g. replacing starting with Cycle 2, or if parallel is it on rolling basis)? Please detail all interconnection process information, such as - What detailed study information would be available at each decision point and what project documentation requirements are required at each decision point? What would be the deposit requirements, money at risk, and withdrawal opportunities? Would withdrawals trigger restudies? How is PJM able to complete this new process in 12 months instead of the current ~24 months? Thank you	
1. Constellation Energy Generation, LLC 2. Champion Energy Marketing LLC 3. Champion Energy Services, LLC 4. Champion Energy, LLC 5. North American Power and Gas, LLC 6. Calvert Cliffs Nuclear Power Plant, LLC 7. Constellation NewEnergy, Inc. 8. Handsome Lake Energy, LLC 9. Calpine Bethlehem, LLC 10. Calpine Energy Services, L.P. 11. Calpine Energy Solutions, LLC 12. Calpine Mid Atlantic Marketing, LLC	Constellation does not have additional questions at this time. We look forward to continued engagement with PJM regarding how LCEP can be incorporated in PJM's intended framework	

1. Calibrant Energy 2. Camus Energy	A. Definitions Where do the Large Load definitions summarized on Slide 2 (“Overlap of Large Load” Presentation) – namely, “Large Load,” “New Large Load,” and “Eligible New Large Load” specific to the IRAS filing– fit into the “Overlap of Definitions” summary diagram presented on slides 4 and 5 specific to the Co-Located Load Order? - Are Flexible Loads (as referred to in the June 18 LLSC Order) and Eligible Loads (as Referred to in the June 18 Co-Location Order) that elect Non-Firm Contract Demand Service or that take Interim NITS “Eligible New Large Loads” under IRAS? Slide 8 presents: “FERC requires PJM, as the transmission provider, to offer the new transmission services, but does not require LSEs to offer them to their retail customers. In other words, they do not require any LSE to become an Eligible Customer taking one of the new transmission services on behalf of an Eligible Load.” - Does this mean that an LSE could prevent a retail customer from taking one of the new transmission services (FCD, NFCD, or Interim NITS)? B. Interaction of PJM Study and TO-Level Interconnection Process PJM Staff reiterated the expectation that the proposed New Service Request process would consider the study of new large loads exclusively in the context of the “Transmission Service” required to serve those loads (“Conceptual Framework” Slide 4). - How is the study of “Transmission Service” distinct from the study of new load interconnection? I.e., what is PJM’s intended demarcation between the study of “Transmission Service” within the New Service Request process and the study of new load interconnection at the TO level?	

- How does load flexibility identified in a TO interconnection process to avoid local or sub-transmission constraints interact with the flexibility necessary for the new transmission services? How will PJM study load flexibility commitments made for other components of a load's requested interconnection?
- Workshop discussion raised the Attachment M-3 process governing Supplemental Projects as one area where reform is likely needed to avoid duplication. What changes does PJM anticipate would be necessary to enable the coordination of PJM and TO-level review without duplicating efforts?
- What other factors is PJM considering in evaluating the sequencing of TO and PJM-level review? (I.e., sequential vs. parallel process?) How does the information that PJM expects to require as inputs to the New Service Request process inform this sequencing?
- PJM provides helpful clarification on definitions of "Eligible Customer" in the Tariff and FERC Orders. On a practical level, how would PJM expect a New Large Load Customer (e.g., a new data center) to participate in the New Service Request process? What entity is responsible for initiating the process and making the decision of whether to stay in the process? How would participation function in a jurisdiction where the provision of retail service is divided between the LSE and EDC?

C. Treatment of flexible loads within the New Service Request Conceptual Framework

PJM Staff suggested that a customer taking Interim NITS would apply as a firm load and receive an option to elect non-firm service as an output of the study process.
- Where within the proposed New Service Request sequence summarized on Slide 5 ("Show Cause for Large Loads" presentation) does PJM intend the election of Interim NITS to occur?
- Does a customer need to elect Interim NITS, or will the customer automatically receive Interim NITS if eligible?
- What information would be provided about the nature of non-firm service studied as part of this interconnection process? Will PJM specify curtailment parameters and thresholds, duration, MW required to be flexible? How will studied flexibility translate into operational obligations?
- Where, if at all, does PJM contemplate enabling modifications to a new service request (other than the election of Interim NITS), similar to the requests allowed at prescribed decision points for new generators under current interconnection procedures?

For customers seeking Non-firm Contract Demand (NFCD) service or customers seeking a combination of Firm Contract Demand (FCD) and NFCD:
- Can PJM confirm that the process, as proposed, would require the customer to identify non-firm status up front (i.e., in the Pre-Application Phase)?
- If so, what would a customer indicate? MWs of NFCD and FCD? Specific parameters about a large load's flexibility?
- Will a load customer/LSE be able to specify flexibility on a granular basis (for example, to offer ability to curtail for a certain number of hours per year)? Or does PJM propose that a customer would only select between binary "firm" vs. "non-firm" status?
- What information will be made available to the load customer during the Winnowing Period and after the System Impact Study? E.g., necessary upgrades, cost allocation, information on the flexibility allowed and the nature of the curtailment needed for NFCD?
- How does PJM propose to account for the load flexibility identified in the customer's application in the Winnowing process and during the System Impact Study phase?
- Where in the study process does PJM contemplate enabling the eligible customer to modify the FCD and/or NFCD service requested?

In determining the flexibility required of a large load electing NFCD Service or Interim NITS, would PJM isolate the scope of required curtailment to applicable transmission system constraints? Or would the curtailment assigned to NFCD and Interim NITS customers also reflect resource adequacy constraints?
- If the latter, how would a new large load that contracts with off-site accredited capacity under a ""BYONC"" arrangement be treated differently?

RMI	- The critical missing component in the information presented is a discussion on cost allocation methodology; How will cost-allocation methodology be developed? - How will PJM accommodate electrically-proximate load and generation requests? What is PJM's definition of "electrically-proximate"? - Will customers be able to evaluate alternative service configurations, like flexible service or ERIS, during winnowing? - How does the existing interconnection study process map onto the proposed process? Does PJM plan to change anything in the actual system impact studies? - How will energy-only and surplus interconnection pathways be studied in the proposed process? - How will non-firm load be studied in the proposed process? - How will flexible load be studied in the proposed process? - What information will customers receive at each winnowing turn, and what level of accuracy does PJM expect from automated cost/timeline estimates? - What rights does the Provisional Agreement provide for load and for generators? - What steps of the interconnection studies are PJM looking to automate? - What will happen if PJM's automated upgrade estimate from the "winnowing mechanism" changes significantly during the full system impact study? - How will PJM measure whether the process avoids or reduces network upgrades, instead of accelerate identification of required upgrades?	

Mount Storm Wind LLC	Several key elements of this framework remain undefined, and further detail is needed to provide substantive feedback. What readiness requirements does PJM propose at each stage (and turn) of the process? As was noted on the call, customers will still need a month to review results and arrange additional security. What withdrawal penalties or refundability provisions apply at each stage (and turn)? Will the pre-application “cluster” have a cutoff, or will rolling applications be allowed? Will models built on PJM’s automation tools be available for customers to review and run their own analyses, and how far in advance? Will PJM and the TOs complete the equivalent of the Phase 2 facilities study during the winnowing period? If not, when will customers receive facility study costs and timelines, and how will PJM hold TOs accountable for completing that work under the proposed accelerated timeline? Will customers have insight into affected system costs before executing the Provisional Agreement? What feedback mechanisms will connect the interconnection process to the LTRTP and RTEP? Will PJM provide insight into interim energy/deliverability before the Provisional Agreement is executed? Greater visibility here will be needed as we expect this process to result in large contingent upgrades with long lead times. Will PJM allocate time or a process for stakeholders to review preliminary study results and request corrections where needed? In our experience with MISO using SUGAR to run Phase 1 studies, automation is not perfect, and speed can come at the cost of accuracy. Given the significant amount of security customers will be asked to post, appropriate diligence on study results is essential to ensure they are reliable and credible.	

Voltus, Inc.	1. How will PJM verify that a Large Load qualifies as Flexible Load , including what metering, telemetry, or other verification would be required, and at what point in the process it would need to occur ? Specifically, will that verification recognize co-located or proximate storage, proximate generation, and contracted DR/DER as valid ways of limiting energy withdrawals, on the same footing as a load curtailing its own consumption? For storage that charges from the transmission system rather than from co-located generation, how will PJM treat the transmission service used to charge the asset, so that verification reflects the net effect across the full charge/discharge cycle rather than the discharge event alone? 2. Will PJM's treatment of electrically proximate loads extend to proximate storage and DR/DER, or only to proximate generation , and what methodology will PJM use to establish electrical proximity in the first place, applied consistently across all three resource types? 3. Can a Large Load's verified flexibility shorten the 12-month New Service Request timeline itself — specifically, would a smaller net system impact reduce the scope or duration of the System Impact Study — or does flexibility only affect the type of interim service available during an otherwise fixed timeline? 4. Will PJM design the bring your own elements of the new Flexible Load transmission services to recognize the transmission benefit that a bring your own resource is already providing under RBP/IRAS 5. How will PJM reconcile Flexible Load asset designations with RBP/IRAS asset designations — including whether a shared registry or verification record is contemplated — and how will that reconciliation be sequenced given that the two processes are proceeding on different timelines? 6. What threshold or minimum duration of demonstrated impact is sufficient to qualify a load as Flexible — is there a minimum MW reduction or sustained duration required, or is any verified reduction sufficient?	
NRDC	How will the new process decrease total interconnection timelines, including network upgrade construction timelines? How will the new process model GETs or ATTs in compliance with the Show Cause Order? How will the new process model DR and DERs? How will PJM model surplus interconnection or generator replacement (CIR transfer) requests during this new process? How will PJM assign costs for network upgrades? Is there any possibility of negative costs, e.g., if new supply reduces the need for backbone transmission? How will the results of the new process inform future RTEP cases? Does PJM plan to update or change anything about the RTEP inputs or cost allocation process in light of this proposal? What determines if backbone upgrades end up in RTEP/LTRTP vs this process? Is it time dependent? What happens if forecast load that was included in an RTEP/LTRTP plan ends up interconnecting through this process instead? Similarly, what if new supply reduces the need for upgrades already identified in RTEP/LTRTP? Will load or supply customers be able to change their applications during the winnowing process in order to reduce costs or avoid network upgrades? What happens if there is more load than supply in a given interconnection cycle? How does the proposed process interact with the existing TO process for interconnecting large loads? What happens if there are conflicts between the two processes? Will there be any way for developers and regulators to determine locations where supply can be most beneficially added before the process starts? Across the board, it would be very helpful for PJM to provide more concrete examples of how PJM sees the new process working.	