Interconnection Process Enhancements 2021

Issue Paper and Straw Proposal

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1 Introduction

The Interconnection Process Enhancements (IPE) Initiative is the ISO's ongoing commitment to improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve.

The 2021 IPE initiative is being conducted at a particularly critical inflection point in resource development in California, and in the ISO footprint in particular, as current circumstances have led to a confluence of issues that are needing consideration in the ISO's interconnection processes, related transmission and resource planning occurring at the ISO and state agencies, the procurement activities of load serving entities, and state policy development. Meeting the challenges facing timely, effective, reliable and economic resource and transmission development over the next decade and beyond will require enhancements and improved coordination across all fronts, and progress on each front must be considered in the context of improvements occurring in other parallel paths as well.

The impact of the drive towards higher levels of year over year resource development cannot be overstated. The ISO's 2021-2022 transmission planning currently underway is based on resource portfolios developed through CPUC processes that are more than double the previous plan's forecast for additions. The draft forecast requirements to be used in the 2022-2023 cycle indicate potentially a four-fold increase in new resource requirements over the forecast relied upon in the approved 2020-2021 plan[1]. At the same time, the CPUC authorized more midterm procurement in its June 24, 2021 decision that last year's 10 year plan was based on, and which was the largest single procurement authorization by the CPUC. Responding to these signals and previously approved authorizations, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[2] The 605 projects totaling 236,225 MW, 164,153 net MW at the Point of Interconnection (POI), currently in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates distractions and commandeers precious planning, engineering and project management resources from the ISO and Participating TOs. Developing interconnection proposals for 10 to 15 times the volume of resources

[1] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, *http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcess-Sep27-28-2021.pdf*

[2] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-Generator-Interconnection-Queue-Memo-July-2021.pdf

needed in that time frame, challenges the procurement activities being smoothly aligned with transmission planning and state policy needs (including for resource diversity) when procurement responsibility is spread over more than 40 load serving entities.

The ISO's interconnection queue and transmission planning process (TPP) has to this point been very successful in meeting emerging needs and challenges as it evolved over the last ten to fifteen years. The ISO's current processes in fact already incorporate many of the reforms set out for discussion in the recent Advance Notice of Proposed Rulemaking released by the Federal Energy Regulatory Commission[3]. However, the volume of requirements, pace of development and intensity of competition clearly call for additional reforms to current processes designed around more measured pace of planning, procurement and resource development. A broader spectrum of reform considerations is needed than adjustments to any one process in isolation, and reforms and enhancements must be considered holistically. To aid the ISO in its own considerations, the ISO commissioned a review of other practices in the US, looking not only at other ISOs and RTOs but also other FERC-jurisdictional and non-jurisdictional organizations to explore other practices that may prove helpful. This review, conducted by Grid Strategies LLC[4], will be posted to the ISO website by the Stakeholder conference call on this issue paper and straw proposal on December 13, 2021.

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative is therefore focused on the interconnection process and enhancements specifically, and other tracks of process improvement will proceed through other efforts.

Accordingly, the 2021 IPE initiative will discuss and address interconnection-related issues the ISO and stakeholders have identified given current circumstances, and will seek to resolve concerns that have surfaced since the last IPE initiative in 2018.[5] The ISO seeks to consider potential changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

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[3] Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation, Docket No. RM21-17-000: *http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf*

[4] "Resolving Interconnection Queue Logjams - Lessons for CAISO from the US and Abroad" October 2021, Rob Gramlich, Michael Goggin, Jay Caspary, Jesse Schneider.

[5] For more information on the 2018 IPE initiative please refer to the initiative webpage at: California CAISO - Interconnection process enhancements (caiso.com).

This Issue Paper and Straw Proposal is intended to present the scope and initial proposed solutions to near-term and long-term issues based on comments received from stakeholders from the Preliminary Issue Paper.

2 2021 IPE Process Development

During the initial planning for the 2021 IPE initiative, the ISO identified certain issues to address related to the broader need for reforms, both in the short term and longer term, and also a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

This initiative will have two distinct, but simultaneously run, phases. Phase 1 will focus on near-term enhancements to the existing interconnection processes that the ISO can resolve for Cluster 14 and before the summer of 2022. Phase 2 will focus on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities. The ISO will conduct both phases simultaneously with phase 1 targeting the ISO Board of Governors in May 2022, and phase 2 targeting November 2022.

During the Cluster 14 open window, the ISO received 373 interconnection requests, which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[6]. The supercluster initiative focused specifically on addressing the immediate timing issues associated with the unprecedented number of interconnection applications to ensure parties were well informed of the timing impacts and that an effective plan could be put in place to deal with the situation. In the supercluster initiative, the ISO committed to continue to discuss topics that were not resolved in the time available within that initiative that could affect the Cluster 14 supercluster Phase II processes[7]. Topics that would impact Cluster 14 Phase II will be handled in the phase 1 portion of this initiative as described above. Another impact of the Cluster 14 supercluster is that the current GIDAP may need to be modified to be more adept at dealing with the current significant generation expansion and to better accommodate interconnecting significant amounts of new generation expeditiously to meet near-term reliability challenges. These potential changes will need more time to discuss and come to consensus with stakeholders and will be handled in the phase 2 portion of this initiative as described above.

[6] For more information on the Supercluster Interconnection Procedures initiative please refer to the initiative webpage at: FinalProposal-SuperclusterInterconnectionProcedures.pdf (caiso.com)
[7] The supercluster initiative needed to produce a filing to FERC quickly to receive a FERC order in a time frame that would allowed Cluster 14 to move forward as expeditiously as possible under a revised schedule.

The issues being addressed in this initiative fall into one of three categories; topics that would aid in moving resources more efficiently and effectively through the queue, topics that would aid in managing the overheated interconnection queue, and topics addressing other residual issues warranting attention at this time.

3 Moving resources through the interconnection queue more efficiently and potentially more quickly

3.1 Removing downsizing window and simplifying downsizing request requirements

- Background

  The ISO proposed to transition from an annual month-long open window for receiving downsizing requests and allow them to be submitted at any time. The downsizing requests would be held by the ISO for the next reassessment study where the impact of the upgrades associated with the downsized resource would be determined. The ISO also intends to simplify the downsizing request process where appropriate.

- Stakeholder Feedback

  All stakeholder comments supported, supported with further suggestions, did not oppose, or did not comment. CalWEA, LSA/SEIA, REV, and SCE all support an expedited process for downsizing projects that had no impacts on other projects, possibly using the Material Modification Assessment (MMA) process as the process for determining impacts.

- Proposal

  The ISO proposes to simplify the downsizing process, which currently encompasses six pages of Appendix DD. The ISO proposes to remove the downsizing application window, the unique downsizing deposit, and the downsizing agreement (Appendix HH), among other simplifications. Instead, the downsizing process will be modified to allow downsizing requests to be submitted at any time and be processed through an MMA-like process.[8] Once the downsizing request is received by the ISO the project would be deemed downsized to the requested capacity. Those projects that have no network upgrades would be approved through the MMA process and the GIA would be amended. If a project has one or more network upgrades, the project would be included in the annual reassessment to determine if the project's network upgrades are still required along with any potential cost allocation adjustments. Once the reassessment process is completed, then the downsizing MMA response

[8] Appendix DD, Section 6.7.2.3 requires an MMA to be completed within 45 days unless the ISO notifies the Interconnection Customer and provides an estimated completion date and an explanation for the delay.

would be received by the customer. Tariff rules that prevent interconnection customers from downsizing merely to reduce their cost allocations and non-refundable interconnection financial security before withdrawal will remain in place. The ISO believes the simplification of the downsizing process will enable interconnection customers to right-size their projects more easily and with less administrative burden for all parties.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

3.2 Streamline interconnection studies

- Background

  Due to the increased scope and complexity of the interconnection studies, the current tariff timelines for completing studies are insufficient for large clusters. However, due to the cyclical nature of the cluster studies and the coordination with the transmission planning process, significant changes are difficult. The ISO has considered what changes would be feasible for refining the Phase I, Phase II, and annual reassessment study timelines to allow sufficient time to complete the study work and enhance efficiency.

- Stakeholder feedback

  The ISO received comments from eight stakeholders on including the topic of streamlining the interconnection studies due to the increased scope and complexity of the study process in this initiative. Vistra, SCE, PG&E, CESA, REV Renewables, and LSA/SEIA all supported streamlining the study process and CalWEA and Q Cells provided additional input. No stakeholders opposed including this topic in this initiative.

  LSA/SEIA and Vistra support reducing the scope of the Phase I studies but only if the standard two-year cycle is maintained, and LSA/SEIA suggests this may also simplify the IR submittal process since the dynamic model submissions could be delayed. CESA also suggests the ISO explore if specific study criteria can be reserved for the Phase 2 studies as well as modifying deliverability assessments of energy storage resources to recognize the intended operation of the resource.

  CalWEA states that any reduced study scope should not remove the cost protections in the Phase I study process, and not have the unintended consequence of inflating the Phase I cost to cover potentially missed network upgrade requirements.

PG&E requests to have provisions to extend tariff timelines for ISP, Repowering, and post-COD modifications if dependencies exist with ongoing complex clusters. PG&E also suggests that in-service dates associated with PNU's and CANU's be considered for in-service dates. SCE proposes to extend the application review timelines, and increase the response time to the ISO for Cluster, ISP, and MMA applications from 3 to 5 business days.

Q Cells and LSA/SEIA recommended increasing resources to help manage the workload.

- Proposal

After reviewing stakeholder comments, there was some support for looking for ways to streamline the interconnection study process but only if the standard two-year cycle can be maintained and does not impact the Phase I cost protections currently in place. Any significant streamlining of the study process would most likely have impacts on current cost protections. As such, the ISO does not have any substantial proposals at this time, and will remove this specific topic from the initiative, as the excessive queue volume addressed in various other topics. However, based on the comments received on this topic, as well as suggestions made by SCE during the October 19th workshop, and subsequent comments provided by other stakeholders on SCE's presentation, there are some process, study content, and timeline adjustments that can be further explored in this initiative. These items will be further explored in Section 6.1 of this document.

3.3 Should Transmission Plan Deliverability (TPD) Allocation process revisions be considered?

- Background

The TPD Allocation process has worked well since the TPD allocation process was initiated for cluster 5, including instituting allocation groups in the 2018 IPE initiative. With the trend of very large numbers of IRs submitted in recent clusters the ISO requested input on potential revisions or enhancements to the allocation process, including input on a process where TPD is allocated to Load Serving Entities (LSEs) similar to the ISO Distributed Generation Deliverability allocation process.

- Stakeholder Feedback

Of the stakeholders that commented on this topic, there was near universal opposition to a process of allocating TPD to LSEs. There were only a limited number of comments recommending more limited adjustments to the TPD allocation process.

LSA/SEIA proposed two items. (1) Allow all EO capacity to qualify for Allocation Groups 4-5 if they get or are short-listed, respectively, for eligible PPAs without having to have achieved commercial operation prior to seeking an allocation. (2) Merge Groups 1 & 4 into a new Group 1, and Groups 2 & 5 into a new Group 2.

In LSA/SEIA's additional proposed issues for consideration, they proposed a provision for provisional TPD allocations or retentions if Reassessment Reports shows significant change, e.g., delays COD by >1 year or high cost increases, with additional time (e.g., another cycle) for compliance demonstrations. The initiative could also consider criteria for a developer to demonstrate that the compliance issue was caused by the revised information. Considering its proposed modifications to the TPD allocation and retention process below and the proposal in 5.3, expanded errors and omissions process, the ISO believes the issues raised by LSA/SEIA are addressed to the extent that is most appropriate. The ISO is concerned that opening the process to such exceptions would compromise the process by opening it to requests for a myriad exceptions, making the process untenable.

NextEra recommended to immediately address ensuring transmission deliverability is allocated to resources capable of achieving commercial operation for summer 2023 through one-time, limit changes to the 2022 Transmission Plan Deliverability Allocation process. The ISO has recently clarified the process for seeking TPD for generation added in a MMA or post COD addition in the GIDAP BPM. The ISO has also committed to doing the 2022-2023 TPD allocation cycle, even though cluster 14 will not be ready until the 2023-2024 cycle. Beyond that, the ISO does not agree that a one-time TPD allocation process is needed, at least at this time. Currently there are a large number of projects situated to be able to obtain a PPA and seek an allocation by summer 2023.

PG&E believes that the way TPD allocation is applied to Wholesale Distribution Tariff projects should be updated to allow those projects to pay for deliverability network upgrades and potentially participate in wholesale markets. The ISO notes that WDAT projects currently have the opportunity to do this along with ISO interconnections as long as the project selects FCDS in its WDAT interconnection request. WDAT projects requesting FCDS are studied in the ISO cluster deliverability studies and are able to participate in funding Deliverability Network Upgrades.

Vistra believes that project readiness criteria for permitting progress, land access, and ability to use underutilized transmission elements are equally as important to the allocation of deliverability as the project's contract status. Ending the practice of providing deliverability allocation priority to projects with contracts and considering the other important readiness factors, may better inform procurement decisions to reflect existing or planned transmission capacity. Vistra proposes that these factors should apply first in addition to the points associated with contract status:

- Project location at a substation/POI with available headroom that the ISO has identified as supporting state procurement portfolios
- Progress on permitting approvals
- Demonstration of site exclusivity

According to Vistra, a more effective process would weigh these factors based on importance and determine a weighted score for each project and then allocate deliverability in order of highest weighted score to lowest weighted score. The ISO will propose adjustments to the allocation groups and will consider adjustments to the weightings for non-PPA related items within its BPM. However, the ISO maintains that having a PPA is the greatest indicator for a both a project's readiness and viability for proceeding to commercial operation.

- Proposal

The ISO proposes to revise the existing allocation process as follows:

- Eliminate allocation group 3 – Proceeding without a PPA. Of all the projects that have used this and the previous similar classification for obtaining TPD, the ISO is only aware of one project that has actually achieved commercial operation without a PPA. Using this designation appears to give a project an advantage for receiving an allocation, which the project uses to obtain a PPA, not proceed without one. The allocation process should reflect the reality that projects require PPAs to be commercially viable. Moreover, deliverability comes from delivery network upgrades, which are built specifically to support resource adequacy obligations, not just any viable project. By removing group 3, the ISO clarifies that generators and their PPAs must directly support resource adequacy obligations going forward.
- Simplify the allocation groups by combining various groups as follows
  - Group 1: Any active IR demonstrating it has an executed PPA requiring FCDS or the interconnection customer is a LSE serving its own load.
  - Group 2: Any active IR demonstrating it is currently shortlisted for PPA or actively negotiating a PPA.
  - Group 3: Any active EO IR that has achieved commercial operation.

Proposed Allocation Groups

Allocation Group	Status of Project	Allocation Requirement	Can Build DNUs for Allocation?	Allocation Rank
1	Any Active IR	Executed PPA requiring FCDS or interconnection customer is a LSE serving its own load	• FCDS: Yes, • PCDS: Yes for the deliverable portion of the project, • EO: No	Allocated 1st
2	Any Active IR	Shortlisted for PPA or actively negotiating a PPA	• FCDS: Yes, • PCDS: Yes for the deliverable portion of the project, • EO: No	Allocated 2nd
3	Any Energy Only project in commercial operation	Commercial operation achieved	No	Allocated 3rd

Projects with Energy Only Deliverability Status, including Partial Capacity Deliverability Status projects that elected to convert any non-allocated portion of their project to Energy Only, requesting Deliverability must be studied to ensure the project is not behind a deliverability constraint and must submit to the ISO a $60,000 study deposit for each Generating Facility seeking TP Deliverability.

By consolidating the groups, the ISO simplifies the process and rewarding the projects certain or most likely to support resource adequacy, regardless of where they are in queue. At the same time, the new group 3 may reward the rare project that is already online without deliverability, allowing an offtaker to immediately add the generator to its portfolio.

- The GIDAP BPM Section 6.2.9.4 defines the process where points are allotted to projects based on the project's maturity in areas such as their PPA, permitting and land acquisition. The points are used to rank the projects for determining the order that they are considered for allocating any available TPD. The ISO proposes that during the process of updating the BPM following the FERC approved tariff changes, the ISO will consider making adjustments to the scoring weights within Section 6.2.9.4.

- Further clarify the requirement related to a PPA requiring deliverability.

  The intent of constructing delivery network upgrades and allocating deliverability is to allow the facility to participate in the Resource Adequacy program (RA). Although the tariff requires the PPA to require deliverability, it is ambiguous the deliverability required by a PPA is ultimately utilized by, or offered to, an entity with an RA obligation. For the December 6, 2021 affidavit/allocation cycle, the ISO will deem eligible any project's affidavit that demonstrates it has an executed or shortlisted PPA that requires deliverability without requiring the offtaker demonstrate they have an RA obligation; however, the ISO proposes to revise the tariff to clarify that in the future, a PPA must be with an offtaker to fulfill its own RA obligation. In other words, the PPAs of offtakers that do not have RA obligations will not be eligible for groups 1 or 2.

In addition to the seeking TPD allocation adjustments above, the ISO proposes to eliminate all TPD retention criteria except that those projects that received an allocation in group to two (as currently shortlisted or negotiating a PPA), must submit an executed PPA by November 30th of the year the allocation was received. No changes will be made for projects that received an allocation by proceeding without a PPA in the original Group 3 (2018 & later) or with balance sheet financing (prior to 2018). Those projects may continue to retain deliverability under this status. The results of such change and limitations mean that projects will no-longer be required to submit retention affidavits for new Group 1 or Group 3, and most interconnection customers that have retained deliverability after one year will not have to submit retention affidavits. Likewise, once Group 2 projects meet the retention criteria of having executed PPA, those projects will no longer be required to submit retention affidavits.

The ISO believes eliminating all of the retention criteria except for the shortlist-to-PPA requirement is reasonable because ultimately any non-viable project attempting to retain deliverability while lingering in queue will face the commercial viability criteria.[9] The commercial viability criteria has been very successful in deterring projects from lingering in queue with unused deliverability. In contrast, the retention criteria—with the exception of the shortlist-to-PPA requirement—has almost never removed TPD from a customer. The ISO believes the retention criteria is thus an administrative burden for both customers and the ISO, and is more likely to result in false positives than meaningful deliverability retention.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

[9] Section 6.7.4 of Appendix DD to the CAISO tariff.

3.4 How can the interconnection process and procurement activity align with transmission system capabilities and renewable generation portfolios developed for planning purposes?

- Background

The ISO's transmission planning process includes a framework for developing policy-driven transmission associated with state (and federal, although that has not yet been relevant) policy needs and direction. However, that policy direction in the transmission planning process is not coordinated with interconnection requests seeking to utilize that capacity as it is being developed, nor with the procurement activities of the large number of load serving entities now having procurement obligations.

- Stakeholder Feedback

PG&E observed both the Tehachapi and CREZ initiatives in California and Texas have been successful in aligning transmission development, renewable generation portfolios, and generation interconnection in the past. It is important to note that simply identifying the locations may lead to another supercluster; it will be important to address speculative projects if this path is chosen by stakeholders. Others (e.g. REV) suggests that for out-of-state wind that are in CPUC renewable generation portfolios, the projects should be evaluated at their points of interconnection in BAs outside ISO rather than at the ISO boundary injection points. SCE notes that recent procurement efforts have necessarily focused on new projects that could come online quickly because procurement authorizations by the CPUC have been issued on an emergency basis (*e.g.,* D.19-11-016 for 2021-2023 procurement and D.21-06-035 for 2024-2026 procurement). As such, projects must be far along in their development before they can realistically be contracted by an LSE. The planning, interconnection, and procurement process could be significantly improved by:

  - Expanding the planning horizon and scope to identify transmission capacity that can either be approved as a policy-driven upgrade or on an expedited basis;
  - Increasing transparency to the planning process, expected timelines, and existing or expected transmission capability;
  - Development of a "first ready" construct in the interconnection process (but with reservations expressed elsewhere herein about how this "ready" concept is to be implemented).

- Proposal

The ISO remains concerned that lack of coordination among the transmission planning process—and policy-driven transmission in particular—the interconnection process, and load serving entities' procurement processes continue to create the opportunity for transmission to be utilized by resources not envisioned in the original policy direction but earlier-positioned in the queue, resulting in challenges in meeting state resource policy goals. The ISO will not advance a specific proposal at this time, but will seek further stakeholder input on this issue given the additional clarifications developed through this paper, and the stakeholder feedback provided in response to the issue paper. Depending on the feedback, this may be an issue more appropriately addressed in changes to the transmission planning process, or in procurement direction to load serving entities. There are two concepts the ISO specifically seeks feedback on here:

The ISO would appreciate feedback on incorporating, through the transmission planning process:

1. The concept of not only developing transmission capacity for planning purposes associated with achieving specific resource development; and,
2. As a further step, withholding that capacity specifically for the policy-driven processes for which it was planned rather than relying on it for any and all interconnection requests received through the request windows.

The above concepts could potentially help where new capacity is created or capacity is currently available and not already allocated to resources in the queue, but would not help where the overheated queue has already resulted in all available and planned capacity being allocated.

A related concept is addressed under the Section 3.6 regarding solicitation models; stakeholders are requested to provide feedback on that item specifically.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

3.5 Should a one-time framework be adopted to allow resources such as storage to be added to existing sites on an expedited basis, despite potential impacts on earlier-queued projects, to meet pressing reliability needs?

- Background

The ISO sought stakeholder input on whether a one-time option should be adopted to allow resources such as storage to be added to existing sites on an expedited basis to meet pressing reliability needs despite the potential impacts on earlier-queued projects. This concept was raised in part to address the concern regarding the large volume of resources that are required to be connected to the grid by 2025 and beyond, to meet pressing reliability needs.

- Stakeholder Feedback

The ISO received stakeholder comments from nineteen stakeholders on including the topic of a one-time framework to allow resources such as storage to be added to existing sites on an expedited basis. Goldman Sachs Renewable Power, Middle River Power, PG&E, and Cal Advocates supported the concept of a one-time storage addition mainly citing the need for additional supply in the near-term. CPUC Energy Division, Arevia Power, SDG&E, NextEra and some of CESA's, PG&E's, Cal Advocates' comments were outside the scope of this question. Hanwha Q Cells, was open to exploring the concept but did not take a position one way, or the other.

EDF-Renewables, LSA/SEIA, REV Renewables, Golden State Clean Energy, CESA, Strata Clean Energy, SCE, CalWEA and Vistra did not support the one-time opportunity because the ISO already has expeditious processes in place to add storage to existing projects and transfer deliverability. Stakeholders encouraged the ISO to focus resources in other areas. CESA, as an example, did express that an opportunity for additional deliverability to be requested versus transferring deliverability within projects at the same point of interconnection would be beneficial.

- Proposal

Because the ISO already has a Material Modification Assessment and Post-COD modification process that allows the addition of storage to existing projects, and the ISO allows the transfer of deliverability through the same process, an additional one-time framework is not considered necessary at this time, and the ISO will remove this topic from the IPE initiative.

3.6 Should a solicitation model be considered for some key locations and constraints not addressed in portfolio development, where commercial interest is the primary driver?

- Background

While the ISO raised this issue somewhat generically, two alternative concepts underpinned the request for stakeholder feedback: (1) a solicitation model to clarify in an overheated area which projects should proceed into the interconnection process; and (2) a solicitation model to assess interest in an area in which transmission capacity may be expanded in the planning process, with commitments from the resources helping support the transmission development.

- Stakeholder Feedback

Vistra asks the ISO to clarify whether it is suggesting the ISO administer its own long-term competitive solicitation process and argues that there is a historical precedent for the ISO administering solicitations through the Local Area Reliability

Services annual solicitation but that was prior to local Resource Adequacy requirements that negated the need for the ISO solicitation. Vistra also supports an open season for interconnection capacity, if developed appropriately. Vistra suggested FERC consider using an open season process to develop transmission to areas of high commercial interest and that such a process could be modeled on the open seasons used by merchant transmission developers such that priority access would be based on criteria similar to those articulated in the Merchant Transmission Policy Statement, including willingness to pay, commercial readiness, and financial strength. REV argues that ISO could consider a solicitation model for transmission solutions to resolve constraints at key generation constraints. ISO could leverage its policy study framework and Order 1000 process to build transmission network upgrades for key renewable energy zones. However, if the ISO is referring to solicitation for generation, then REV does not support because that is the jurisdiction of CPUC and LSEs.

- Proposal

Based stakeholder feedback, there are two concepts the ISO seeks further feedback on: (1) a solicitation model to seek clarity in an overheated area as to which projects should be carried forward into the interconnection process which could be focused solely on transmission capacity or could be conducted in conjunction with load serving entity procurement processes, and (2) a solicitation model to test and confirm interest in an area in which transmission capacity may be expanded in the planning process via mechanisms like the Location Constrained Resource Interconnection Facility, with commitments from the resources helping support the transmission development. The ISO expects these resources would then have a pre-existing right to interconnect ahead of other projects in queue.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

3.7 Should an accelerated process for "Ready" projects be considered?

- Background

The ISO sought stakeholder input on whether a new accelerated process should be considered for projects that can demonstrate an advanced readiness that would allow them to quickly go into operation relative to other projects. Proposals should include the criteria to verify readiness, the study process for ready projects, and any consequences for delays after declaring being ready. This concept was raised to in part address the concern regarding the large volume of resources that are required to be connected to the grid by 2025 and beyond, to meet pressing reliability needs.

The ISO intentionally did not specify if this was meant to be discussed in the context of an overlay of sorts onto the existing interconnection process as opposed to a replacement of the existing processes, but rather left the door open to the broadest range of stakeholder comments.

- Stakeholder Feedback

The ISO received stakeholder comments from seventeen stakeholders on including the topic of developing an accelerated process for “Ready” projects. The CPUC Public Advocates Office, CalWEA, Golden State Clean Energy, Hanwha Q Cells, Heliovaas, LSA/SEIA, SDG&E, and Vistra support creating an expedited path for “Ready” projects to move forward in the interconnection process especially if these projects contribute to the reliability of the system. Vistra specifically proposes adopting an approach similar to the Southwest Power Pool’s “first ready, first served” framework that allows projects closer to development to move forward in the interconnection process on a priority basis.

ACP- California, CESA, Calpine, PG&E, REV Renewables, and SCE urge the ISO to clearly define “readiness” criteria before considering implementing an accelerated process for “Ready” projects. These stakeholders suggest the ISO move this topic to Phase 2 of the 2021 IPE initiative and address this issue through stakeholder workshops or utilize stakeholder working group’s to consider this issue further.

Middle River Power, Strata Clean Energy, and Upstream oppose developing an accelerated process for “Ready” projects. These stakeholders note the ISO tariff currently has two accelerated processes for projects and introducing a third process would be redundant.

- Proposal

Stakeholders are in three equally sized camps. Some stakeholders support this but do not provide specific ideas on how to implement such a process. Some request the ISO clearly define “readiness” criteria for them to consider. The rest, primarily from the resource development community, oppose.

Given the reluctance from the industry to adopt such measures, and the challenges to define and validate “ready” criteria that would be acceptable to the earlier-queued projects being leapfrogged, the ISO is not recommending a proposal for long term access to be based on this approach at this time.

A framework for urgent reliability-driven interconnection service for interim interconnection is being proposed in its place for stakeholder comment. Along the lines of the emergency generation that was put in place this past summer based on the governor’s proclamation, the ISO would propose an emergency process to the extent a potential capacity shortfall is determined by the ISO that requires a proclamation from the governor and a state agency would need to determine the generator(s) required to meet the shortfall. The ISO would then work with the applicable Participating TO, state agency and generator to expedite the interconnection process and the generator would be allowed to interconnect for a maximum of three years or a shorter period of time determined by the state. In addition, the emergency generator can be accommodated using existing interconnection service, does not require Network Upgrades to be built, and cannot impact any other third party.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

3.8 Should there be incentives for load serving entities to procure generation projects at locations where transmission capacity has been built/approved based on the California Public Utilities Commission (CPUC) portfolios?

- Background

The ISO has developed transmission expansion plans to meet the generation capacity, technologies and locations of the CPUC generation expansion portfolios, including the level of deliverability approved by the CPUC. Much of the new transmission facilities have been built with the remaining approved projects in various stages of design, permitting, and construction. There is significant generator capacity in the queue that does not need any network upgrades other than interconnection facilities to move forward. Furthermore, there is an even greater amount of generator capacity in the queue that along with their interconnection facilities only require a remedial action scheme to move forward.

However, based on the limited visibility the ISO has into the procurement activities of the load serving entities (LSEs), many projects obtaining power purchase agreements (PPAs) are projects that are located outside of the portfolio area where they first require various network upgrades to go into operation. This exacerbates the time required for new generation that have a PPA to go into operation and results in transmission capability that was built to accommodate the new generation required to maintain system reliability not being fully utilized, which increases costs to ratepayers.

The ISO sought stakeholder input on methodologies for more closely aligning the generation procurement processes of the LSEs with the generation and transmission expansion processes of the CPUC and other LRAs and the ISO respectively.

- Stakeholder Feedback

The ISO received comments from fifteen stakeholders on including the topic of exploring incentives for load serving entities to procure generation projects at locations where transmission capacity has been built/approved based on the CPUC portfolios.

CESA, CPUC – Energy Division, EDF-Renewables, PG&E, and Six Cities support the inclusion of this item in the scope of Phase 2 of this initiative. However, these stakeholders acknowledge there needs to be more discussion on this item to better understand how this results in specific requirements and/or modifications to the existing interconnection process.

CA Community Choice Association, CPUC – Public Advocates Office, CalWEA, Golden State Clean Energy, LSA/SEIA, Middle River Power, REV Renewables, SDG&E, SCE, and Vistra do not support providing incentives to ensure that LSE procure generation projects in specific areas. CA Community Choice Association, CalWEA, LSA/SEIA, and Vistra note that LSEs already have incentives to procure generation at locations where transmission capacity is available. Further, LSA/SEIA and REV Renewables explain that it would be inappropriate for the ISO to focus on issues that are within the CPUC's procurement jurisdiction. Alternatively, the Public Advocates Office urges the ISO to provide more information to project developers on where the ISO has available transmission capacity.

- Proposal

In response to stakeholder comments, the ISO will remove this topic from the scope of this initiative. The ISO will instead continue to explore means to communicate transmission capacity as an advantage to the development of viable projects through channels outside of the interconnection process itself.

3.9 How can the interconnection process and incoming applications better align with procurement interest?

- Background

The ISO raised this topic to solicit feedback on the overarching issue of alignment between load serving entity procurement processes and the interconnection process, which became a more significant concern as the number of load serving entities with procurement responsibilities grew, and the amount of procurement needed in a relatively short time frame grew significantly – leaving less time for the resources to mature through multiple cycles.

- Stakeholder Feedback

There was no consensus position on how the interconnection process and upcoming applications can better align with the procurement interest. Vistra raised questions on the ISO stakeholder call that this effort sounds like an effort attempting to allow a one-time emergency generation interconnection fast track process to support California's Emergency Reliability procurement directives. PG&E attests that procurement interest should be aligned with the interconnection process, not the other way around. PG&E argues that clear timelines and opportunities for acceleration or project termination that include the required reliability and deliverability studies. SCE similarly states that if developers know their costs and expected online dates, the procurement process should be able to choose those best fitting the need. LSA/SEIA and Gridwell assert the ISO can best help ensure this alignment through clear and accessible information about locations where few or no upgrades are needed. PG&E stated studies should clearly include a summary of all upgrades needed for projects to achieve commercial operation and full deliverability to enable procurement staff to understand the actual likelihoods of achieving the operational dates included in those studies.

- Proposal

Given the expressed views that the established timelines of the ISO interconnection process provide a baseline around which procurement authorizations from regulators and procurement processes established by load serving entities can be planned, no specific proposals will be advanced at this time. Other issues will continue to be explored in the context of maintaining and improving the efficacy of the coordination between different processes, working with the state agencies and state government.

4 Managing the overheated queue

4.1 Should higher fees, deposits, or other criteria be required for submitting an IR?

- Background

The ISO sought stakeholder input on whether the bar for entry into the interconnection process should be raised to discourage numerous IR submissions by a single developer, such as requiring higher fees or deposits for submitting an IR, or imposing other requirements.

- Stakeholder feedback

The ISO received comments from fourteen stakeholders on including the topic of whether higher fees, deposits, or other criteria should be required for submitting an Interconnection Request (IR). No stakeholder objected to further exploring this topic and a number recommended benchmarking other markets.

Heliovaas, Hanwa Q Cells, REV Renewables, ACP California, CESA, Strata Clean Energy, SCE, Calpine, and the CPUC Public Advocates Office support or could support increasing application fees or deposits. Heliovaas and CESA suggest application fees/deposits could be based on requested MW size. Hanhwa Q Cells supports staggering of fees as the process moves along. ACP California and Strata Clean Energy suggests more of the higher fees/deposits should be at risk. The CPUC Public Advocates Office supports increasing IR submittal fees for locations where there is limited or no transmission capacity. Strata Clean Energy suggests considering increasing the deposit in lieu of site control and making it partially non-refundable after certain milestones. Vistra generally supports scope items that are designed to disincentivize speculative interconnection requests absent a separate study process for speculative requests under a “first ready, first served” framework. Vistra further states that even under a “first ready, first served” framework it is possible that additional disincentives might still be needed and suggests that the most effective changes will be refinements to refund policies.

LSA/SEIA, CalWEA and Upstream do not believe increased fees or deposits will be effective. PG&E and CalWEA further believe higher fees will effect smaller developers unjustly. Rev Renewables believe site control deposits should stay fully refundable upon evidence of site control.

Heliovaas, ACP California, Upstream, PG&E, Strata Clean Energy and Vistra are supportive of additional administrative, project milestones, or other project viability metrics (such as site exclusivity, permitting, locational benefits or transmission constraints) to enter and advance in the interconnection process.

ACP Renewables and CPUC Public Advocates Office suggest additional data (regularly updated transmission constraints and number of projects proposing the same POI) provided by the ISO should reduce the number of unviable requests.

- Discussion

ISOs and RTOs all strive to reduce study time and study costs in the interconnection process. Delays and costs generally result from two causes: (1) excessive interconnection requests, which require more study time and result in more churn in the queue as projects withdraw and modify; and (2) projects lingering in queue without progressing toward commercial operation, which causes delays, false results, and more staff time. To mitigate these risks without imposing substantial barriers to entry, ISOs and RTOs generally increase requirements to progress in queue, thereby encouraging non-viable projects to withdraw earlier. The following table provides a very high-level overview of queue progress requirements among several ISO/RTOs:

ISO/RTO	IR Requirements	Phase I Requirements	Phase II Requirements	Phase III Requirements
CAISO	• Technical package • Site exclusivity documents or $250k deposit (100% refundable) • $150k study deposit	• 15% of NU cost allocation (50% refundable)	• 30% of NU cost allocation (50% refundable)	n/a
PJM	Feasibility Study • Deposit based on request timing (based on month), and MW size (max $130k; 10% non-refundable) • Site control documents • Primary and (allowed) secondary POI • Technical package	System Impact Study • Deposit based on MW size (max $300k; 10% held non-refundable) • Customer must select one POI	Facility Study • Deposit based on MW size (Max $100k or estimated amount of Facilities Study cost for the first three months)	n/a
SPP	Interconnection Request / Stage 1 • Executed Generator Interconnection Study Agreement • Demonstration of Site Control or Site Control Attestation • Financial Security ($2k/MW; fully refundable before Stage 2, or before Stage 3 if costs exceed penalty-free threshold) • Study Deposit, based on size ($25k to $90k) • Technical documents	• *IR requirements sufficient for entry to Stage 1*	Stage 2 • 10% allocated network costs or $2k/MW (minimum) (fully refundable before Stage 3, or after, if costs exceed penalty-free threshold) Penalty-free threshold: costs of Stage 2 compared with Stage 1 increase by 25% or greater and $10k/MW or greater	Stage 3 • Additional 10% network costs (only refundable if costs exceed penalty-free threshold) Penalty-free threshold: costs of Stage 3 or any Stage 3 revision compared with Stage 2 increase by 35% or greater and $15k or greater
MISO[10]	• Demonstration of Site Control or posting of deposit in-lieu of site control ($10k/MW, at least $500k, no more than $2m; refundable upon demonstration or withdrawal) • Application fee $5,000 (non-refundable) • DPP Study Funding deposit $50k-$640k depending on size (partially refundable) • Technical package	Definitive Planning Process (DPP) 1 • Demonstration of Site Control at least 90 days prior to DPP 1. • DPP Entry Milestone M2 Deposit ($4k/MW; 100% refundable prior to DPP 1, 50% refundable prior to DPP 2; non-refundable prior to DPP 3) • Additional technical documents	DPP Phase 2 • DPP 2 Milestone M3 Deposit (10% of NU) prior to DPP 2 start date (100% refundable prior to DPP 3; non-refundable after entering DPP 3)	DPP Phase 3 • Additional deposit equal to the difference between the initial and revised cost estimate from MISO's notice, if necessary • All milestone payments at risk once entering DPP 3

Prior to Cluster 12 interconnection request application window in 2019, the highest number of interconnection requests submitted in an annual window was 131. At this peak, the ISO and Participating TOs were able to meet all tariff and business practice manual study timelines. In the 2019 and 2020 IR application windows the number of interconnection requests increased to 153 and 155 respectively. Although mostly successful,[11] it became more difficult for the ISO and Participating TOs to meet the required study timelines. The story of Cluster 14 speaks for itself: the ISO received 373 applications and the ISO found it necessary extend the overall study process timeline by a year, an extension which was recently approved by FERC. Although the cluster 14 tariff revisions were limited to that cluster only, it is critical the ISO address the potential for excessive queue volume in the future.

Although the ISO and the Participating TOs can study 130 interconnection requests annually under the current cluster study timelines, merely reducing the number of applications to that level should not be the goal. As stated above, the goal should be to eliminate, or substantially reduce, the number of excessive projects submitted in an annual window.

To address excessive queue volume, there is considerable stakeholder support for increasing study and other deposits. A few stakeholders commented that raising deposits substantially as a commercial deterrent would likely harm smaller developers and help large developers, not necessarily incentivize viable projects and discourage less viable projects. Still other stakeholders who commented that solely increasing the deposits would be an effective way to deter large number of interconnection requests submitted in a cluster window. The ISO agrees with all of the above stakeholder comments and will seek to find a balance by exploring the idea of a modest study deposit increase for the first couple of projects submitted by a single parent company/entity and substantially increasing study deposits for multiple requests from the same parent company/entity.

Some stakeholders suggested the study deposit amount be based on the MW size of the proposed generator. In the past, the ISO previously implemented an application study deposit structure based on the MW size of the proposed generator, but found it takes a similar amount of effort to study a small project as it does for a larger project, and could no longer justify the cost difference. The per MW fee

[10] MISO milestone payments refundable if costs for Affected Systems or Network Upgrades exceed 25%-50% or $10k-$20k/MW between various studies.

[11] Even with the 155 interconnection requests the ISO received in cluster 13, the ISO had to issue a market notice to delay the publication of Phase I interconnection study results by one month, and will likely have to do so again for Phase II study results.

structure also encouraged interconnection customers to break up larger projects into smaller projects merely to potentially save study costs, which ultimately increased the ISO and Participating TOs' workload and may have deprived offtakers of larger projects to consider. As such, the ISO does not propose to consider a MW-based study deposit.

The ISO agrees with Vistra and others that an effective way to deter excessive interconnection requests would be to refine the refund policies and increase the amount at risk. The ISO believes the current percentages at risk for the study deposit[12] are appropriate, and with increasing the study deposit, this would also have the effect of increasing the amount of the study deposit at risk. The ISO agrees with Strata and other stakeholders that making part of the in-lieu site exclusivity deposit[13] at risk would be an effective way to deter excessive interconnection requests.

The ISO also agrees with stakeholders that providing regularly updated data such as transmission constraints and other data would be beneficial to interconnection customers when selecting viable points of interconnection. This topic is discussed in Section 6.2.

- Proposal

The ISO proposes to increase the study deposit from \$150K to \$250K per interconnection request. The ISO also proposes to further increase the study deposit for a parent company/entity that submits more than two interconnection requests in a cluster window. The following table illustrates the breakdown of the interconnection requests submitted by unique parent companies in Cluster 14.

Parent Companies	IRs Submitted
27	1
9	2
18	3-5
10	6-10
7	11-20
3	21-35

[12] Current study deposit is refundable minus costs up to 30 days following scoping meeting. Up to half of the study deposit is at risk after 30 days following the scoping meeting and up to 30 days following phase I results meeting. After 30 days following Phase I results meeting, the study deposit is non-refundable if project withdrawn. Upon execution of GIA, remaining deposit (minus costs) is refunded to the interconnection customer.

[13] Site Exclusivity deposit is currently \$100K for small generators 20 MW and less, and \$250K for large generators greater than 20 MW.

This table demonstrates that a large percentage of interconnection request comes from only a few parent companies. The ISO and stakeholders are concerned that, rather than target a small number of well-developed, viable projects, large developers can simply submit numerous interconnection requests to see which work out. To discourage this behavior, the ISO proposes that for the first two projects submitted by a parent company/entity the study deposit would be $250K per request, for projects 3-5 the study deposit would be $500K per request, and for any more than 5 projects, the study deposit would be $1M per request. The same percentages will be at risk as currently defined in the tariff.[14]

The ISO also proposes (1) to increase the site exclusivity deposit requirements to $250k for small generators and $500k for large generators; and (2) if a project withdraws after the interconnection request is deemed complete, 50% of the in-lieu site exclusivity deposit becomes nonrefundable, and the ISO will pool those nonrefundable funds with nonrefundable interconnection financial security.[15] If an Interconnection Customer demonstrates site exclusivity at any point, then the site exclusivity deposit will be refunded in full. As discussed in another part of this paper, site exclusivity will be required to enter the Phase II studies.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

4.2 Should site exclusivity be required to progress into the Phase II study process?

- Background

The ISO did not advocate requiring site exclusivity to submit cluster IRs, but sought stakeholder input on requiring site exclusivity to proceed into the Phase II study process. This change was proposed as one of several potential means to address the “overheated” queue with an excessive number of projects applying in a single or successive request windows that actually hinder effective studies and queue management.

[14] Current study deposit is refundable minus costs up to 30 days following scoping meeting. Up to half of the study deposit is at risk after 30 days following the scoping meeting and up to 30 days following phase I results meeting. After 30 days following Phase I results meeting, the study deposit is non-refundable if project withdrawn. Upon execution of GIA, remaining deposit (minus costs) is refunded to the interconnection customer.

[15] If a potential interconnection request withdraws before the interconnection is deemed complete (or fails to be deemed complete), the deposit will be refunded in full.

- Stakeholder Feedback

  The ISO received stakeholder comments from sixteen stakeholders on including the topic of requiring site exclusivity documentation in order to proceed into the Phase II study process. Calpine, Golden State Clean Energy, Heliovaas, Middle River Power, PG&E, SCE, Strata Clean Energy, and Upstream support incorporating stronger screening criteria before moving into the Phase II study process to discourage the number of speculative projects that enter the interconnection queue. Further, Calpine, Golden State Clean Energy, Middle River Power, and Upstream support requiring site exclusivity documentation even earlier on in the interconnection process before the Phase II study process. Upstream notes requiring site exclusivity documentation earlier in the interconnection process is consistent with the current practice in other ISOs and RTOs.

  California Energy Storage Alliance (CESA), CalWEA, EDF Renewables, Hanwha Q Cells USA and REV Renewables do not support requiring site exclusivity documentation specifically for Cluster 14 and earlier clusters because it would be unfair to change to increase the requirements for interconnection requests that have already been submitted. CESA and REV Renewables recommend the ISO consider this issue in Phase 2 of IPE 2021 if stakeholders seek to change site exclusivity requirements for future clusters.

- Proposal

  Based on stakeholder feedback the ISO proposes to require site exclusivity to move into the Phase II study process. This will apply to Cluster 14 and future clusters. The ISO believes this will help mitigate the overheated queue and allow studies to focus on committed projects. The ISO notes that this proposal still provides more flexibility than other ISO/RTOs in obtaining a final site. Both PJM Interconnection and the Southwest Power Pool require site exclusivity to submit IRs, and MISO requires site exclusivity or higher deposits than the ISO. The ISO also notes that it proposes increasing the deposit requirement and making a portion of it non-refundable if the customer withdraws, as explained in Section 4.1, above.

  The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

4.3 Would different requirements for different technologies to advance in the interconnection process be appropriate? Between location-specific resources versus more location-flexible?

- Background

The ISO sought stakeholder input on whether different requirements and potentially different study processes and paths should be considered based on project technology. Technologies that could be considered for different treatment based on meeting specific system needs are battery energy storage systems (BESS), off-shore wind and geothermal systems. Flexibility of project location is another consideration for different treatment where, for example, BESS are more location-flexible and tend to have shorter development timelines. Conversely, off-shore wind and geothermal project developments are more location constrained and may have longer development timelines. These various issues could warrant a somewhat unique process and treatment within the GIDAP. This concept was raised as a potential solution to the overheated resource interconnection queue that can create a roadblock to new and emerging resource types moving forward on a timely basis and also could help ensure that state policy level goals, including the need for resource diversity, could be achieved effectively as discussed in Section 3.9.

- Stakeholder Feedback

The ISO received stakeholder comments from fifteen stakeholders on including the topic of determining if different requirements for different technologies to advance in the interconnection process is appropriate. ACP - California, CPUC – Energy Division, Golden State Clean Energy, Hanwha Q Cells USA, and Heliovaas support including this topic within scope of Phase 1 of this initiative. ACP-California notes that several western transmission providers enforce site control requirements and have different acres per MW requirements for different resource types, to reflect the relevant land use needs each resource. Additionally, Golden State Clean Energy specifically suggests tying this issue to the topic focused on determining an accelerated process for “Ready” projects as well as broadening the locational considerations as these efforts will ensure this initiative is developing a framework that will help meet state policy and long-term planning goals.

CESA, LSA/SEIA, Middle River Power, PG&E, and Strata Clean Energy have no position on this issue at this time and look forward to further discussion as well as seek clarification on the topic definition. LSA/SEIA notes that giving preference to certain technologies would violate ISO open-access rules and should not be allowed.

CalWEA, REV Renewables, SCE, and Upstream oppose this topic from being included in the scope of this initiative because it implies special treatment will be given to certain technologies and the interconnection process should be technology neutral. SCE highlights the concern that this topic would violate open access principles.

- Proposal

In response to stakeholder comments, the ISO does not intend to move forward with different requirements for different technology types as a means to address the overheated queue issues or to address alignment between policy driven planning and procurement activities discussed in Section 3.4. As there could be a relationship between this topic and the issue of advancing "ready" projects, the concept may resurface to some degree in the context of considering "ready" projects for expedited firm service gets revisited. (At this time, the ISO is not intending to move forward on a firm service proposal based on "ready" status, only an emergency interconnection service). Therefore, this topic will be removed from the scope of this initiative.

4.4 Should equipment requirements be introduced?

- Background

The ISO sought stakeholder input on whether the ISO should require the project supplier demonstrate that the developer has a commitment for various key equipment required for the project to timely move forward, either at the IR stage or to enter Phase II. This change was proposed as a means to address the "overheated" queue with an excessive number of projects applying in a single or successive request windows that actually hinder effective studies and queue management.

- Stakeholder Feedback

The ISO received stakeholder comments from thirteen stakeholders on including the topic of introducing equipment requirements. ACP – California, CESA, CalWEA, EDF Renewables, Golden State Clean Energy, Hanwha Q Cells USA, LSA/SEIA, REV Renewables, Strata Clean Energy, and Upstream oppose introducing equipment requirements as criteria to submit an interconnection or enter the Phase II study process. These stakeholders site concerns that developers do not typically order major equipment this early on in the interconnection process. Additionally, Middle River Power, Strata Clean Energy, and Upstream, are concerned that introducing equipment requirements disproportionately favors developers who are also manufacturers or are large enough to enter into master supply agreements rather than procuring equipment on a per-project basis.

- Proposal

  In response to stakeholder comments, the ISO will remove the topic of introducing equipment requirements from the scope of this initiative.

4.5 Should interconnection application requirements differ for resources that are location constrained, versus resources like standalone batteries that can be located elsewhere on the grid?

- Background

  As discussed in Section 4.3, the ISO has received feedback that different types of resources are very geographically constrained, whereas other types of resources have much more flexibility in where they are developed across the ISO footprint. At one end of the spectrum, for example, geothermal resources and offshore wind generation locations are more limited in development and interconnection options, whereas, battery storage is very flexible geographically. This raises the question of whether interconnection requests should receive different treatment based on the type of resource or public policy. This does overlap somewhat with the concept of different requirements for different technology types, discussed in Section 4.3, but put a particular focus on the location-related issues.

- Stakeholder Feedback

  CESA recommends that the ISO revisit the idea of having different Participating TOs move forward at potential different timelines, and/or have “local” cluster study processes be allowed to occur on quicker timelines if processes allow. CESA argues that on a going-forward basis, knowing that quicker study completion and deliverability allocation can position projects for upcoming solicitations, this can be helpful to guide ICs to understand that cluster study processes could advance more expeditiously at locations with fewer IRs, and/or where upgrades may be less/minimal or locations. With battery storage having flexibility to site in different locations, this may support the intent of this idea/proposal and still maintain key principles of fairness, open access, transparency, and proactive rule/requirement changes, while advancing the prospect of new resources like energy storage in meeting near- and mid-term reliability needs. LSA/SEIA generally oppose discrimination by technology type in the interconnection process and note that the ISO wants projects to include solid POI locations in their IRs, and usually the developer has specified a certain location for a good reason. SCE asserts that interconnection application requirements should not differ for resources that are location constrained, versus resources like standalone batteries that can be located elsewhere on the grid. Sufficient land in proximity to transmission is just as much a constraint on battery projects as PV or wind.

- Proposal

  The ISO proposes to remove this topic from the initiative, consistent with the discussion in Section 4.3. The ISO strives to remain technology neutral wherever possible, and different study processes for different resources are likely to run afoul of the Federal Power Act's prohibition on undue preference. The ISO will continue to explore queue efficiency through other topics.

5 Other Issues

5.1 Should the ISO re-consider an alternative cost allocation treatment for network upgrades to local (below 200 KV) systems where the associated generation benefits more than, or other than, the customers within the service area of the Participating TO owning the facilities?

- Background

  The ISO tariff requires Participating TOs to reimburse interconnection customers whose generators are interconnecting to their systems for the costs of reliability and local delivery network upgrades necessary for the interconnection. The Participating TOs then include those network upgrade reimbursement costs in their FERC-approved transmission rate bases, requiring ratepayers to pay those costs through either the local or regional transmission access charges (TAC). Network upgrades for 200 kV systems and above are considered regional, and upgrades below 200 kV are considered local. The regional TAC is a "postage stamp rate" based on the aggregated transmission revenue requirements (TRR) of all Participating TOs for all regional facilities on the ISO system. In contrast, the local TAC is PTO-specific, charged only to customers within the service area of the Participating TO owning the facilities. There is ongoing concern that the current practice for local upgrades could unduly impact local ratepayers who are not the sole beneficiaries of the upgrades, but who solely bear their costs.

  The ISO addressed this issue with stakeholders and filed a narrowly focused proposal to FERC in 2017. FERC ultimately found that the ISO failed to support its proposal as just and reasonable and not unduly discriminatory and rejected the ISO's filing without prejudice, which allows the ISO to refile a proposal.[16]

- Stakeholder Feedback

  The ISO received comments from 15 stakeholders on whether the ISO should re-consider an alternative cost allocation treatment for upgrades to local (below 200

[16] FERC filing ER17-432: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01EE09AD-66E2-5005-8110-C31FAFC91712

KV) systems where the associated generation benefits the ISO system or another Participating TO more than the service area of the Participating TO owning the facilities.

CPUC Energy Division, Hanwha Q Cells, Arevia Power, California Community Choice Association, LSA/SEIA, REV Renewables, BAMx, Coalition for the Optimization of Renewable Development, California Energy Storage Alliance, VEA, Gridliance West and Vistra support including this topic in this initiative.

Six Cities and SCE do not support including this topic in this initiative. SCE does not believe the current cost allocation is flawed and it would be inappropriate to shift costs from a transmission owner to other customers by allocating the costs of network upgrades to systems below 200 kV to the High Voltage TAC. SCE also states the current 200 kV demarcation has been preserved in the Tariff and TAC for two decades and endorsed by FERC.

VEA in their comments provided a detailed discussions including VEA's unique circumstances and provided a number of potential options (1) Include Low-Voltage Interconnection costs in the Regional TAC, (2) Allocate low-voltage NU costs to the interconnection customer, (3) Create a targeted exception for resources developed outside of California, and (4) Create a targeted exception for policy driven resources.

Vistra suggests waiting to explore a potential solution until the federal policy discussions that may help to highlight how the cost-benefit and cost-allocation principles will evolve for transmission upgrades is firmed up to avoid uncertainty with dual policy efforts.

- Proposal

The ISO agrees with SCE that the current cost allocation is not flawed and it would be inappropriate to shift costs from the local transmission owner to other customers by allocating the costs of network upgrades to systems below 200 kV to the High Voltage TAC. The ISO also agrees with VEA that it may be unreasonable for VEA ratepayers to incur such significant rate shocks due to capacity expansions primarily for California policies.

To mitigate the risk that interconnection-related local network upgrades may create disproportionate impacts on a single set of ratepayers, the ISO proposes to cap the percentage of interconnection-related network upgrade costs within each Participating TO's local transmission revenue requirement.[17] Interconnection

[17] High-voltage network upgrades and the regional revenue requirements would be unaffected.

customers would finance any network upgrade costs that exceed the Participating TO's aggregate funding cap without cash reimbursement, or move their generator interconnection to the high voltage (200 KV or greater) system.

The ISO proposes to use a cost limiting model similar to the one the ISO uses for funding location constrained resource interconnection facilities. The ISO proposes that the addition of the capital costs for low voltage (<200kV) network upgrades driven by generation interconnections to the LTRR of a Participating TO will not cause the aggregate of the net investment for all low voltage network upgrades driven by generation interconnections included in the LTRR to exceed fifteen (15) percent of the aggregate of the net investment for all low voltage transmission facilities of that Participating TO reflected in their LTRR in effect at the time of the in-service date of the network upgrade. Any costs for low voltage network upgrades in excess of the 15 percent threshold will be financed by interconnection customers without cash reimbursement.

The ISO believes this proposal protects local ratepayers from the impact of interconnection-related network upgrades, especially where their low-voltage system is relatively more attractive for generator interconnections than neighboring systems. At the same time, this policy would apply to all transmission owners equally, avoiding the cost shifts among ratepayers that would result from relying on the regional TAC.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

5.2 Policy for ISO as an Affected System – how is the base case determined and how are the required upgrades paid for?

- Background

In the last decade, there have been virtually no instances where a generator's interconnection to a neighboring balancing authority area would affect the reliability of the ISO grid. In interconnection terms, the ISO is almost never an "affected system." However, recently the ISO has received a few notices from neighboring BAAs that a proposed interconnection may affect the ISO, and therefore warrants study. The ISO developed a study process and agreement for such studies in the Contract Management Enhancement initiative. However, that initiative deferred the question to IPE of how any network upgrades required to mitigate reliability impacts would be reimbursed.[18] The ISO also needs to determine what base cases would be used for affected system studies.

- Stakeholder Feedback

  The ISO received comments from 17 stakeholders on including the topic of developing certain policy for when the ISO is an Affected System, specifically how base cases are determined and how network upgrades required on the ISO grid are paid for. No stakeholder objected to including this topic in this initiative.

  REV Renewables and CalWEA state that the base case used for generators interconnecting to neighboring BAAs should be the same and latest available base case used within the ISO studies. CalWEA further states that any affected system studies should not have to wait for current cluster studies to be completed. SCE suggest that interconnection customers from other BAAs provide the requisite project data that is already defined in the tariff and with adequate confidentiality provisions.

  EDF Renewables, Hanwha Q Cells, LSA/SEIA, California Community Choice Association and CalWEA support that NUs required on the ISO system that are needed to serve ISO load or provide resource adequacy in California should be eligible for reimbursement.

  Six Cities, LSA/SEIA and PG&E suggest adopting or negotiating a reciprocity refund agreement with neighboring systems for the cost of NUs required for generator interconnections.

  CPUC Public Advocate Office state the cost for new transmission to accommodate new resources outside of the ISO grid should be handled under the inter-regional review mechanism put into place by FERC Order No. 1000.

  BAMx and SCE opposes NU reimbursement on ISO grid if those upgrades are required for generation interconnection in neighboring BAAs.

- Proposal

  The ISO agrees with stakeholders and proposes the base case assumptions for the study to be based on previously queued projects as of the affected system study agreement execution date. There is a possibility that a study timeline could be affected by the status of studies for previously queued projects.

[18] Consistent with FERC policy, as an affected system the ISO would only be able to address reliability impacts on the ISO system; not deliverability or common loopflow.

There was no stakeholder consensus based on how reliability network upgrades identified in an Affected System study should be funded. Some supported repayment from California ratepayers while others did not. Another suggestion was to base the repayment on a reciprocity refund agreement: if ISO projects that affect a neighboring system are eligible for refund of upgrade costs, the same would be afforded their projects that affect the ISO controlled system. Others proposed refunding the upgrades that serve ISO load or support the resource adequacy requirements.

The ISO proposes to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. Under FERC Order No. 2003, the ISO must provide some form of remuneration for the financing of network upgrades, either in the form of cash reimbursement or transmission rights, which would be Merchant Transmission CRRs for the ISO.[19] The ISO believes providing cash reimbursement is preferable for several reasons:

- It is the ISO's existing policy, and is therefore easy to understand and implement for the ISO and Participating TOs.
- The creation, allocation, and tracking of Merchant Transmission CRRs is complex, presenting a burden that would outweigh the few network upgrades the ISO may ever have to construct as an affected system. Stakeholders should remember that, to date, the ISO has *never* had to construct network upgrades as an affected system.
- Cash reimbursement from the Participating TO recognizes that although the generator may be elsewhere, the network upgrades themselves are in the Participating TO's service territory, and therefore benefit its ratepayers. FERC explained the drawbacks of non-reimbursement policies at length in its recent ANOPR, indicating a preference for cash reimbursement (or transmission owner financing) in the future.[20]
- Reciprocity agreements or providing reciprocal treatment based on the neighboring BAA's own policy fails to recognize that most neighboring BAAs are not FERC jurisdictional and can operate in completely different paradigms

[19] *See* Order No. 2003-A at PP 616-17.
[20] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 at PP 112-13 (2021) ("transmission customers, in some instances, can make use of any excess transmission capacity created by a participant funded interconnection-related network upgrade without paying any of the capital costs that are paid for through a participant funding approach. . . . while the interconnection customer may receive well-defined capacity rights associated with the increased transfer capability caused by the interconnection-related network upgrade, these well-defined capacity rights do not compensate the interconnection customer for the broad range of benefits that the interconnection-related network upgrades can provide to the transmission system. . .").

than the ISO. Moreover, most of these affected systems do not only fail to provide cash reimbursement when they are the affected system; they do not provide cash reimbursement to their own interconnection customers as well. Like the affected systems, the ISO merely proposes to apply its own policy for RNU reimbursement consistently.

- Tracking and providing different reimbursement rules depending on the offtaker erroneously focuses on the beneficiaries of the generator; not the network upgrades themselves.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

5.3 Expanded errors and omissions process to provide criteria and options when changes to network upgrade requirements occur after Financial Security (IFS) postings have been made

- Background

This topic combines the following two items from the Preliminary Issue Paper.

- Process for changes to network upgrade requirements after the second Interconnection Financial Security (IFS) posting.

  Appendix DD Section 6.8 deals with errors or omissions to study reports[21]. However, as stated in Section 6.8.3, *"Once the initial and second Interconnection Financial Security posting due dates as described in this section have passed, the error or omission provisions described in this Section 6.8 no longer apply."* The tariff does not expressly describe the issue of cost responsibility related to increased costs for interconnection when an error or omission is discovered after the initial and the second postings have been made. This topic is to address who the cost responsibility falls to when an error or omission is discovered after the initial and the second postings have been made.

- Withdrawal option for projects impacted by new costs and/or delayed in-service date (ISD) after initial posting.

  When projects receive a new required upgrade or significantly modified upgrade after having made either its initial or second IFS posting that significantly increases the cost for the project to interconnect or significantly pushes back its earliest achievable in-service date, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund for its IFS and a refund of any unused study deposit.

[21] Appendix DD of the ISO tariff: AppendixDD-GeneratorInterconnectionDeliverabilityAllocationProcedures-asof-Jun15-2021.pdf (caiso.com)

- Stakeholder Feedback

  - Process for changes to network upgrade requirements after the second IFS posting:

    All stakeholder comments supported, supported with further suggestions, or did not comment or have a position on the issue. CalWEA, EDF, LSA/SEIA, and REV state that the interconnection customer should not be responsible for any cost responsibility increases related to an error or omission discovered after the second Interconnection Financial Security (IFS) posting has been made. CalWEA and REV stated that any increase in costs should not impact an interconnection customer's maximum cost responsibility (MCR) and maximum cost exposure (MCE) as the IC could have already made financial decisions and commitments based on the MCR and MCE previously provided. PG&E and SCE agree that clear tariff direction is needed and SCE suggested that this topic be combined with the next topic on the withdrawal option for similarly impacted projects, and stated that Appendix DD Section 6.8 needs overhauling and more specificity on how the various issues would impact projects in various situations.

    LSA/SEIA requested an explanation for why certain recent issues did not trigger the use of the "significant error/omission" process in Section 6.8. The ISO clarifies that while the current Appendix DD Section 6.8 "Revisions and Addenda to Final Interconnection Study Reports" addresses errors or omissions, it is no longer applicable once the interconnection customer makes its IFS posting.[22] The purpose of that section is to determine the form of report correction that is needed and if the first or second IFS posting due date should be adjusted. Once the first or and second IFS posting date has passed, Section 6.8 is no longer applicable for the applicable report and posting.

    Six Cities stated the proposal is reasonable. In circumstances where errors/omissions are attributable to interconnection customers, transmission ratepayers should not indemnify interconnection customers for such errors/omissions, as could occur if the effects of interconnection customer-originated errors and omissions are not included in the Current Cost Responsibility, Maximum Cost Responsibility and/or Maximum Cost Exposure, as appropriate.

[22] Appendix DD Section 6.8.3 states "Once the initial and second Interconnection Financial Security posting due dates as described in this section have passed, the error or omission provisions described in this Section 6.8 no longer apply."

- Withdrawal option for projects impacted by new costs and/or delayed ISD after initial posting:

  Other than Vistra, all stakeholder comments either supported or did not comment or have a position on the issue. Vistra was uncertain that this is an issue that needs to be addressed in this initiative and suggested the issue weaken the incentives for developers to submit viable projects or if submitting speculative projects to be reasonable in the amount of these submitted. In response, the ISO clarifies that this issue typically occurs after an interconnection customer has made its second IFS posting for a project, and is not expected to have an impact on developers submitting unreasonable amounts of projects. While the number of projects impacted by this issue has increased recently, the number of projects impacted in this manner is a relatively small number, and the conditions for withdrawal will not incentivize excessive interconnection requests.

  LSA/SEIA and SCE recommended including this topic with the prior topic related to an error or omission discovered after the second IFS posting has been made.

- Proposal

  The ISO proposes that any cost responsibility increases associated with an error or omission discovered after a project makes its second IFS posting should be the responsibility of the party that made the error or omission. Specifically, the MCR and MCE cannot be increased due to an error or omission discovered after the second IFS posting due date has passed.

  The ISO maintains that the annual reassessment study process is the quickest and most efficient study process to deal with errors or omissions discovered after the second IFS posting have been made. Errors and omissions frequently impact more than one project and can impact projects in more than one cluster group. The annual reassessment is the best way to quickly and efficiently study and provide study results reports to multiple projects across multiple cluster groups.

  The ISO further proposes that when an error or omission is discovered after a project has made either its first or second IFS posting that increases the aggregate of all costs for the project to interconnect, regardless of whether the cost is refundable, or pushes back its earliest achievable ISD, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund for its IFS and a refund of any unused study deposit.

  A key policy issue is the threshold dollar increase in cost responsibility for upgrades and the increased time in the earliest achievable ISD that would trigger the ability to withdraw and receive a full refund of its IFS and remaining study deposit. The supercluster instituted a 25 percent cost increase and a twelve month delay in the ISD as the threshold for a somewhat related issue. However, for this topic the ISO suggests a lower cost threshold than 25 percent because projects hit with cost increases after having made a posting have made the decision to post based on what is now incorrect information. Delays in the ISD and cost increases, even if not the cost responsibility of the project, can impact the projects ability to obtain a power purchase agreement. Furthermore, the Participating TO would be responsible for any cost increases and the higher the threshold, the greater the impact to the Participating TO when the cost increase is less than the cost increase threshold. The ISO proposes a cost increase threshold of five (5) percent and a minimum of a 12 month delay in the earliest achievable ISD. The ISO believes these figures correctly balance the low probability of a detrimental error or omission with the high impact they can pose to interconnection customers and potential offtakers.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.4 Clarify definition of Reliability Network Upgrade (RNU)

- Background

This proposed issue is to clarify that any remedial action scheme (RAS) or other RNU that is identified in a deliverability study is categorized as an RNU and will therefore be included in the RNU cost calculation for RNU costs that are eligible for cash reimbursements.[23]

- Stakeholder Feedback

All stakeholders either agree that the topic needs clarity with the specific support for clarifying whether a RNU triggered in a deliverability study should be included in the RNU total cost calculation for determining the RNU reimbursement cap, or have no position. However, stakeholders are split on how an RNU identified in a deliverability study should be treated in the RNU reimbursement cap calculation.

Those supporting the *inclusion* of RNUs triggered in a deliverability study being included in the RNU total cost calculation for determining the RNU reimbursement cap are BAMx, Heliovaas, SDG&E, SCE and Vistra.

[23] ISO Tariff Appendix DD Section 14.3.2.1(1). Costs above the cap are eligible to receive Merchant Transmission Congestion Revenue Rights.

Those supporting the *exclusion* of RNUs triggered in a deliverability study being included in the RNU total cost calculation for determining the RNU reimbursement cap are LSA/SEIA and REV.

An additional issue is whether the RNU is required for the project to synchronize to the grid, or only required to achieve Full Capacity Delivery Status (FCDS), raised by CalWEA, REV, and SDG&E.

- Proposal

The only RNUs the ISO's deliverability studies may identify are RASs. This is not to say that the RAS is required for deliverability. It means that the assumptions the ISO uses in the deliverability studies are different than the initial reliability studies. Rather than requiring the Participating TOs to re-run the reliability studies based on the outcome of the deliverability studies, RASs are RNUs are merely included as deliverability study results. If a RAS is determined to be needed in any study, the RAS is required for all projects in the study area, including EO projects. Unlike a DNU, a RAS may be required for a project to synchronize to the grid and a limited operations study is needed to determination if the project can synchronize prior to the RAS being in service.

Because there has been confusion on this issue, the ISO proposes to clarify its existing policy that a RAS is always considered an RNU, regardless of the study that identified the need for the RNU. Because RASs are RNUs, they are included, and will continue to be included, in the RNU reimbursement calculation.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.5 Transferring Participating Transmission Owner (TO) Wholesale Distribution Access Tariff (WDAT) Projects into ISO Queue

- Background

During the cluster interconnection request (IR) submittal process, the Participating TOs frequently receive IRs in their WDAT application process for points of interconnection (POI) that are under ISO control. Likewise, the ISO frequently receives IRs for POIs on the distribution grids. While the ISO and the Participating TOs strive to work together to handle these issues, the tariff could speak to these situations expressly. This topic will explore how to transfer IRs between the WDAT and ISO queues during the IR submittal, validation and scoping meeting processes.

- Stakeholder Feedback

  All stakeholder comments supported, did not oppose, or did not comment. A number of commenters recommended the ISO publish a list of WDAT/ISO POIs to help the stakeholders submit requests to the appropriate entity.

- Proposal

  The ISO proposes to move forward with developing tariff language for allowing the ISO to accept interconnection request transfers from the Participating TO's WDAT queue to the ISO queue. The ISO will work with the Participating TO's to develop any criteria necessary to ensure that the transfer occurs within an appropriate window of time. Once the ISO has amended its tariff, the Participating TOs could revise their WDATs to include reciprocal language about receiving IRs initially submitted to the ISO. Each Participating TO have a unique window for accepting WDAT IRs. The ISO proposes to work directly with the Participating TOs to develop the specific criteria for this process that accommodates the various differences between the Participating TOs and put forth a more detailed proposal in the next IPE paper.

  The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.6 Changing Sites and POIs during IR Validation

- Background

  Specific tariff criteria needs to be developed for changing proposed generating facility locations and their POIs during the cluster IR validation period. Interconnection customers may request a change in site or POI after a scoping meeting, even when the originally requested POI is feasible. Likewise, customers may seek to alter their site location based on an infeasible POI. Either requested change may be due to high cost to interconnect at that POI or the lack of available deliverability. While the ISO has utilized guidelines based on various tariff requirements, more specific criteria needs to be developed to be more transparent.

- Stakeholder Feedback

  All stakeholder comments supported, supported with further suggestions, did not oppose, or did not comment. A number of stakeholders recommended that the ISO provide more information to facilitate interconnection customers in locating viable POIs.

  Criteria needs to be developed for determining what changes in POI would be allowed and what would not be allowed. REV, SDG&E, Strata Clean Energy, Upstream, and Vistra recommend POI changes be within the study area of the original requested POI. MRP cautioned that a limiting changes to within a single study area may incent ICs to submit projects in each study area. CalWEA recommended that the rules should be based on geographic distance or electrical distance, whichever is further. LSA/SEIA recommended that the change be allowed as long as POI (substation and voltage level) stays the same. Upstream added that the timing of the change be no later than five business days after the scoping meeting.

- Proposal

The ISO proposes the timing of the process for changing POIs remain consistent with current ISO practice that the interconnection customer must confirm its POI within five business days of the project's scoping meeting and any change in POI will be limited to within the same transmission study area[24] as the POI originally requested in its Interconnection Request. If an interconnection customer requests a change of its POI consistent with this criteria, it may change its site as well. Site changes will only be permitted in conjunction with a permissible change in POI.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.7 While the tariff currently allows a project to achieve its COD within seven (7) years if a project cannot prove that it is actually moving forward to permitting and construction, should the ISO have the ability to terminate the GIA earlier than the seven year period?

- Background

This issue was also raised on a generic basis to see if there were any opportunities for the ISO to move projects out of the queue that were languishing and taking deliverability that could be allocated to other queued projects that were moving forward with permitting, procurement, and construction.

Once a project executes the GIA, a welcome letter is sent to the project outlining various requirements, including the requirement to provide a status report. These reports provide the ISO with the project's updated status, including the GIA milestones status and various required steps in the project's development. In some instances, the ISO has projects that have received the welcome letter but never

[24] Study areas change infrequently, but are established annually in the ISO's transmission planning process. *See, e.g.* the ISO's proposed TPP study plan for 2020-21 at p. 9, available at http://www.caiso.com/Documents/FinalStudyPlan_2020-2021TPP_Revised.pdf.

provided the required reports, even after numerous attempts by the ISO to find out the project status.[25] A number of these eventually withdraw once they reach the seven year time limit, or when they do not meet a GIA milestone and are in breach of the GIA.

- Stakeholder Feedback

CalWEA argues this is impractical and thus not worth pursuing as projects can always show some progress towards obtaining a PPA or land-use permit and, even after the seven year period, the ISO tariff allows the ISO only to take away the full capacity or partial capacity deliverability status if the project fails the commercial viability test, not to terminate the GIA. EDF-R does not support ISO's suggestion to initiate a new or different method to terminate generation interconnection agreements that have not yet passed the seven year time-in-queue limit as ISO already has the ability to hold projects in breach for failure to perform on Appendix B milestones in the projects executed GIAs. EDF-R argues that it would be more appropriate for the ISO to focus its attention on the 83 projects cluster 11 and prior that are already at or beyond their seven year time-in-queue limit. MRP is open to discussing the possibility of giving the ISO authority to terminate projects that are not materially advancing toward COD. PG&E is generally supportive of the ISO's suggestion of removing inactive generation projects from the queue, but is also interested in the perspective of the generation development community's perspective on this issue, and if they have any specific suggestions on how to address the issue of "queue squatting". PG&E noted that a queue filled with "ready" projects would improve our ability to interconnect generation projects in a timely and cost effective manner. SCE similarly agrees that ISO should consider developing criteria to remove delayed projects from the queue in less than seven years, with an exception if the delay is due to an event not reasonably within the developer's control.

- Proposal

The ISO proposes to continue with this topic and have further discussion with stakeholders. Some issues that would be helpful to have feedback on are 1) should projects that are energy-only be allowed to stay in the queue forever? 2) If a project does not reply to queries for information, should there be a time limit as to when the project must reply before a default of the GIA is declared? Currently, the ISO generally does not invoke the default clause if the project does not reply to inquiries, should the ISO invoke this clause for this reason? 3) If a project needs a MMA (e.g., because it has missed a major milestone or its' COD) but will not initiate the process,

[25] Section 5.7 of the GIA requires the parties to provide information on the project to the other party. This is the provision used to require the status reports.

how long should the ISO wait before invoking the default clause?[26] 4) If the project is not moving to permitting, procurement, and construction of the interconnection facilities or generating facility, should the ISO do anything other than requiring the project to meet the GIA milestones? Stakeholders may offer other suggestions about moving stalled projects through the queue to completion or withdrawal.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

5.8 Should parked projects be allowed to submit MMAs while parked?

- Background

This issue was raised on a generic basis to see if there was an opportunity to reduce workload for the ISO and Participating TO planners, engineers and project management staff. A project parks when the allocated TP Deliverability is less than requested or the project does not desire to accept the amount allocated. The project can go into parking for up to two years thereby waiting for two additional cycles of TP Deliverability allocation before the project either withdraws or moves forward. During this time, it is not efficient to allow projects to modify their project because the modification is speculative since it has not made a decision to continue in the queue.

- Proposal

The ISO proposes to not allow projects to submit a MMA while the project is parked. Since the Interconnection Customer has determined that the project is not ripe for moving forward, the ISO sees no reason for staff spending time on a project that has not yet determine if it is moving forward.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

[26] The ISO is only referring to delays caused by the customer itself. When the Participating TO cannot construct network upgrades per the GIA schedule, the ISO works with the parties to update the milestones automatically.

6 Other Stakeholder Suggested Proposals

6.1 Comments related to SCE Stakeholder presentation

- Background

  SCE's presentation included incorporating the following four additional issues to the scope of 2021 IPE initiative[27]:

  1. Re-examine and remove ambiguity of errors and omissions in the Study reports before the initial and second IFS postings have been made.
  2. Adding due dates for curing deficiencies in Appendix B, to avoid delays in starting Phase II studies.
  3. Seek to have the IR Validation process and "deemed complete" prior to holding Scoping Meetings (regular cluster, not supercluster procedures).
  4. Making it explicit that when ICs agree to share a Generation Tie-Line, PTO Interconnection Facilities, and any related IRNUs at the substation (e.g., line position to terminate the shared gen-tie) across clusters, the shared IRNUs are not subject to GIDAP Section 14.2.2. And such shared IRNUs will be treated as CANUs for later-queued generation and not PNUs. This exclusion does not apply in the case where the shared IRNU is a Stand-Alone Network Upgrade (e.g., Loop-In Substation).

- Stakeholder Feedback

  The ISO received stakeholder comments from nine stakeholders, including SCE, related to the stakeholder presentation SCE gave during the October, 19th stakeholder workshop.

  Stakeholder comments related to SCE's first proposal to re-examine and remove ambiguity of errors and omissions in the Study reports before the initial and second IFS postings have been made are included in Section 5.3 of this proposal.

  With respect to SCE's second proposal, both LSA/SEIA and REV Renewables support adding due dates for curing deficiencies to avoid delays in starting Phase II studies. Middle River Power suggests not only that ISO and PTOs adhere to timelines for identifying deficiencies, but also request the ISO define the point at which the project will be studied "as is" if deficiencies are not cured.

[27] SCE's presented issues and proposals can be found at Microsoft PowerPoint - 2021-1012 SCE suggestions for IPE 2021.pptx (caiso.com) and at California ISO - All comments (caiso.com).

PG&E is supportive SCE's third proposal to have the IR validation process complete prior to holding Scoping Meetings. LSA/SEIA support completing a "basic" validation prior to the Scoping Meeting and remaining validation issues can be addressed during the meeting as suggested in verbal comments by CalWEA during SCE's presentation. Middle River Power recommends Scoping Meetings be held immediately after the IR window closes. REV Renewables is not supportive of implementing a requirement to have the IR validation process "deemed complete" prior to holding Scoping Meetings.

CalWEA, PG&E, and SDG&E support adding SCE's fourth proposed issue to ensure shared IRNU's are not exempted from GIDAP 14.2.2 in Phase 2 of this IPE initiative. LSA/SEIA opposes this proposal because it is a significant policy change that impacts IRNU's that are often very costly.

- Proposal

The following are the ISO's proposals to address SCE's four additional issues listed above:

1. This issue is addressed in Section 5.3 Expanded errors and omissions.
2. Appendix DD Section 7 states "Within ten (10) Business Days following the Phase I Interconnection Study Results Meeting, the Interconnection Customer shall submit to the ISO the completed form of Appendix B". The ISO proposes to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. Those not valid would be withdrawn with five business days to cure.
3. This proposal would be going back to the validation timeline prior to C12. In the 2018 IPE the ISO moved the IR validation due date from May 31 to June 30 to allow for more time to validate IRs and to allow for discussion of validation issues during the scoping meetings. There hasn't been an opportunity to test the change on a "normal" sized cluster. Both C13 and C14 have been too large of a sample to really see how the June 30^{th} validation date works, and in the case of C13, the extra time to validate all IRs was needed. The ISO does not agree that the process should be changed in this IPE initiative.
4. The ISO proposes to include this topic in the initiative and we seeks stakeholder input for the development of a specific proposal in the next paper. The ISO has combined SCE's proposal and a somewhat similar proposal from SDG&E. Both the SCE and SDG&E proposals are provided below.

- **SCE:** Make it explicit that when ICs agree to share a Generation Tie-Line, PTO Interconnection Facilities, and any related IRNUs at the substation (e.g., line position to terminate the shared gen-tie) across clusters, the shared IRNUs are not subject to GIDAP Section 14.2.2 and such shared IRNUs will be treated as CANUs for later-queued generation and not PNUs. This exclusion does not apply in the case where the shared IRNU is a Stand-Alone Network Upgrade (e.g., Loop-In Substation).
- **SDG&E:** Stranded Cost Responsibility for IRNU Switchyards (Phase I): If an IC proposes to connect to a switchyard of an earlier queued project(s) that has executed a LGIA, the new IC does not have any cost responsibility or cost exposure related to the switchyard. If the earlier queued project(s) terminates the LGIA, then the PTO is responsible for funding the switchyard. There should be a mechanism for IRNU reallocations with associated cost responsibility and cost exposure assigned to later queued project(s).

6.2 Comments related to Gridwell Stakeholder presentation

- Background

Gridwell's presentation focused on data transparency and the ability to obtain data in a usable format for analysis. While acknowledging that the ISO has information on its website in various reports and applications, the information needed for interconnection customers to make informed decisions are not easily accessible. Gridwell suggested a data transparency issue be added to the scope of the 2021 IPE initiative[28].

- Stakeholder Feedback

The ISO received comments from twelve stakeholders, all supporting the concepts put forth by Gridwell and commented that the additional data transparency may reduce the queue size and avoid a waste of resources. Heliovaas, EDF-Renewables. Middle River Power, LSA/SEIA, Six Cities, ACP – California, CESA, PG&E, SCE, Cal Advocates, CalWEA and Vistra would like the additional data to improve decision making including:

- Implement online maps for the transmission system that details where capacity is available, similar to existing distribution information;
- Define what MW level could move forward without upgrades;
- Information on resource curtailments by specific planning sub-areas;
- Project transmission upgrade tracking/status information;

[28] Gridwell's presented issues and proposals can be found at PowerPoint Presentation (caiso.com).

- Data on constraints, TPD allocation remaining and areas; percentage of PCDS; project in service dates; and % of projects that reach completion;
- Ensure the additional data is accessible;
- A data dictionary should be provided; and
- Primary key be adopted in the long-term across all state agencies – ISO, CPUC and CEC – for all transmission and interconnection data tables.

- Proposal

The ISO agrees that additional data, in a usable format, should be made available to the interconnection customers. The ISO is already working with the Participating TOs to develop transmission reports that outline the status of major transmission upgrades for interconnection customers. During this initiative, the ISO will work with stakeholders to further define the data that can become public, accessible, and usable. Also, the ISO recognizes that a consequence of the overheated queue is that the generation interconnection process related studies have resulted in examination of potential generation development areas that far surpass generation portfolios developed for planning purposes – including even the significantly increased expectations for the upcoming 2022-2023 planning cycle. Accordingly, rather than explore where there may be available capacity in areas not already tested by those studies, the ISO has begun providing additional summary information about interconnection applications that can move forward without requiring additional area network upgrades. This work will also be refined moving forward, and sees it as valuable in helping guide procurement activities to where transmission capacity is available and interconnection requests are already in place to move forward on a timely basis.

The ISO proposes this issue be renamed to Transmission Grid Data Transparency and will move into the scope of Phase 1: Near-Term Enhancements.

6.3 Comments related to LSA/SEIA Stakeholder presentation

- Background

LSA/SEIA's presentation included incorporating the following additional issues and associated proposals to the scope of 2021 IPE initiative[29]:

1. Delays caused by new PTO standards (CRAS, BAAH/substation upgrades, etc.): Implementation of new standards by PTOs (including

[29] LSA/SEIA's presented issues and proposals can be found at 2021 Interconnection Process Enhancements (caiso.com) and at California ISO - All comments (caiso.com).

CRAS, substation upgrades, BAAH conversions, new automation standards, new telecom requirements, etc.) can create significant delays, even though existing projects have been operating under the prior standards.

i. LSA/SEIA Proposal: The ISO should allow temporary operation using existing equipment/standards and implement improvements later, and/or work with the PTOs to find ways to accelerate PTO implementation of the new standards (e.g., CRAS implementation in less than 2-4 years).

   (The Limited Operation Study (LOS) tool is not effective in this situation because it cannot be applied until 5-months prior to a project's In-Service Date due to changes in the system topology; by then, a project would likely have already delayed its COD based on information in the studies.)

ii. The ISO should also re-align the commercial viability criteria timeline if the COD is adjusted due to PTO delays and is beyond the seven (7) year maximum time in the queue. The interconnection customer should not lose their deliverability before the PTO delayed COD.

2. Better differentiation within clusters: Recent discussions about the SDG&E circuit-breaker situation at Imperial Valley (IV) substation have highlighted the flaws in the current approach. Nearly all the SDG&E Cluster 12 projects can safely reach COD without these upgrades, but the "feasible" CODs of all are impacted in the study because all the generation in the cluster cannot, and no information has been provided to indicate how the ISO or SDG&E will determine which projects can reach COD without the upgrades.
   - LSA/SEIA Proposal: The ISO should consider: (1) Providing information in Interconnection Studies (especially Phase II Studies) on how much of the cluster could achieve COD without all the RNUs triggered, and how much of the cluster could achieve full deliverability without all the DNUs triggered; and (2) consider reflecting that information in GIAs, to allow projects to come on-line (and potentially receive FCDS) before all the upgrades for the cluster are complete. This could enable more rapid deployment of many resources where, for example, a cluster triggers RNUs that will take 5 years to complete, but some projects with earlier requested CODs can be accommodated without them.

Similarly, DNUs may only be needed for some projects in a cluster group, i.e., while they are needed for the cluster as a whole, some or many projects may be able to achieve deliverability without them. In this case, the ISO grants projects Interim Deliverability ("ID") on an annual basis that then allows projects to sell RA. The ISO should consider granting FCDS to projects that reach COD even if all the DNUs are not built, e.g., if all the DNUs are not needed to serve the first few projects in the cluster.

3. Interim Deliverability Status transparency: Long-duration DNUs impede PPA contracting and incents COD delays, even though many or most projects in a cluster may be able to achieve full deliverability without those upgrades.
    - LSA/SEIA Proposal: The ISO should provide IDS information in the Phase II Study process, with regular annual updates in Reassessments, would allow developers to rationally decide whether to continue or delay development of their projects and greatly aid their PPA contracting. For example, this information help developers determine whether to:
        - Retain requested CODs or delay them to match the in-service date of the longest-duration DNU; or
        - Contract with offtakers despite the risk of "RA Shortfall" provisions.
4. Network Upgrade re-stack: Some later-queued projects may be assigned NUs with longer durations preventing them from reaching their desired CODs or FCDS, while some earlier-queued projects with later CODs may be assigned shorter-duration upgrades they don't need right away.
    - LSA/SEIA Proposal: The ISO should consider "re-stacking" NUs, to better match NU in-service dates to project CODs, assigning faster NUs to projects with earlier CODs (to speed COD and/or FCDS for those projects) without delaying COD/FCDS for projects with earlier CODs. (No changes to cost allocation are suggested here.)
5. Use existing TPD: Currently, the applicable tariff language (GIDAP Section 8.9.9) could be interpreted to allow only deliverability transfers between Generating Units within a single Generating Facility (i.e., under a single GIA). However, the deliverability impact to the system of different projects connecting to the same substation and voltage level should be the same; moreover, in at least some situations, developers are contemplating attempting to combine projects under a single GIA for this

purpose alone, a cumbersome and burdensome course of action for the ISO, PTOs, and Interconnection Customers.

- LSA/SEIA Proposal: Expand TPD transferability to allow transfers between Generating Facilities interconnecting at the same substation (or other location, e.g., line tap) and voltage level, particularly if the "transfer from" capacity withdraws from queue. This would allow TPD to be assigned to projects that can better use it, and allow less-viable projects to monetize their valuable TPD and then exit the queue. (The ISO could also pay projects to exit, if that would be cheaper than adding deliverability in the area.) more efficiently

6. Reassessment accommodation for TPD acquisition or retention: Several recent Reassessment Reports have contained significant new information – some examples: (1) Circuit breaker upgrades delaying CODs by up to 2-5 years; and (2) Precursor DNUs previously shown with "TBD" in-service date now shown with ISD in 5 years. This situation has been exacerbated by timing issues – Reassessment Reports are usually issued around July 31st, but several recent reports were not issued until August 31st or September 15th.

   New information that close to the TPD Acquisition or Retention affidavit deadlines confounds compliance with allocation and/or retention requirements. This can jeopardize PPA acquisition and retention, e.g.: (1) projects with already executed PPAs could lose them; and/or (2) projects about to execute PPAs could be prevented from doing so because modifications are needed to reflect the new information (or the project could lose the PPA entirely due to the new information and have to find and negotiate a different PPA to retain the allocation).
   - LSA/SEIA Proposal: This initiative should include a provision for provisional TPD allocations or retentions if Reassessment Reports shows significant change, e.g., delays COD by >1 year or high cost increases, with additional time (e.g., another cycle) for compliance demonstrations. The initiative could also consider criteria for a developer to demonstrate that the compliance issue was caused by the revised information.
7. Improve TPD allocation processes Energy-Only project qualifications for new TPD allocations, Part 1: TPD allocation rules for Energy Only capacity currently require that the capacity be built before receiving a TPD allocation, even if the developer meets the same qualifications as a project that started out requesting deliverability. This prevents quicker and more

cost-effective project additions through the MMA process, because the added capacity can't get PPAs without TPD allocations but can't get TPD allocations without PPAs.

- LSA/SEIA Proposal: The ISO should allow EO capacity to qualify for Allocation Groups 4-5 if they get or are short-listed, respectively, for eligible PPAs. There is no apparent reason why they should be considered in a lower priority group if they are equally qualified to other projects that requested FCDS but were converted to Energy Only.

8. Energy-Only project qualifications for new TPD allocations, Part 2: Existing projects that lost FCDS are ranked below new ones for TPD allocation. However, there is no apparent reason why, especially since these projects have been in the queue longer and may be ahead of newer projects in development.
    - LSA/SEIA Proposal: The ISO should consider merging Groups 1 & 4 into a new Group 1, and also 2 & 5 into a new Group 2, for new TPD allocations.

9. Option B reform: As ISO has pointed out, current TPP practices may not result in approval of sufficient upgrades in areas with high commercial interest. Option B offers one way for developers to finance such upgrades, but the rules are so punitive that it's possible that none has ever been built under those provisions.
    - LSA/SEIA Proposal: This initiative should reconsider the punitive aspects of this option, to make it fairer and more viable. Changes could include refund, cost cap, and/or financial security provisions.

10. Battery augmentation: Batteries will begin to degrade once they become operational even though NQC is fixed for a year at a time. Regular augmentation will be needed to maintain capability.

    This problem will become more acute with large amounts of storage expected to come on-line soon. The ISO could be faced with annual (or more frequent) MMA requests for each storage facility on the system when more streamlined procedures may be feasible.
    - LSA/SEIA Proposal: Consider this issue generally in this initiative. Two potential approaches are:
        - Allow expedited augmentation addition of batteries (no inverter additions or Interconnection Service Capacity increases) under the BPM for Generator Management, Section 6.2.1 - Modifications That Are Approved Without Material Modification Assessment.

    - Allow multi-year MMA augmentation requests (e.g., “X” MW/year) if inverters will be added (no increase in Interconnection Service Capacity).

11. Affected Systems – study options: Affected Systems continue to subject new projects to possible delays or cost increases late in the development process. In particular, developers have little recourse or options if Affected Systems make unreasonable financial demands.
    - LSA/SEIA Proposal: The ISO should consider implementation of a new Optional ISO study (upon request, applicant funding) of ISO-system options to mitigate identified adverse Affected System impacts.

- Stakeholder Feedback

The ISO received stakeholder comments from twelve stakeholders, including LSA/SEIA, related to the stakeholder presentation LSA/SEIA gave during the October, 19th stakeholder workshop.

ACP-California and Middle River Power are generally supportive of the issues LSA/SEIA have presented.

CPUC – Public Advocates Office and REV Renewables support LSA/SEIA proposed issue of increasing the transparency on interim deliverability. SCE and Vistra are supportive of the issue related to delays caused by new standards because standards are usually focused on maintaining the safety and reliability of the grid. However, PG&E opposes is concerned by this issue because it does not seem to be a common issue shared by stakeholders and should not be included within the scope of this initiative.

CESA, EDF-Renewables, and SCE support the Phase 1 issue of using the existing TPD more efficiently to re-stack of network upgrades to facilitate CODs without impacting cost responsibilities. REV Renewables opposes this issue from being included in the scope of this initiative because it would allow projects to jump ahead of others in the queue. SCE also supports the issue of using existing TPD more efficiently through TPD transferability.

CESA, REV Renewables, and Vistra support the Phase 1 issue related to reassessment accommodation. In particular, CESA is supportive of the consideration of an additional TPD allocation and retention cycle, which could offer more flexibility in getting resources online and accommodate major changes incurred as a result of reassessment studies.

CalWEA supports LSA/SEIA's proposed issues to include in Phase 2 to improve the TPD allocation process to provide greater flexibility and accessibility to deliverability.

SDG&E, SCE, and Vistra support including the Phase 2 issue of Option B reform in scope of the initiative.

CalWEA, EDF-Renewables, and REV Renewables support the Phase 2 issue of developing a procedure to address battery storage degradation.

CalWEA and REV Renewables support the Phase 2 issue of proposals related to Affected System issues. In particular CalWEA supports designing actions the ISO can take to help developers deal with high-cost upgrade requirements and significant delays of COD due to affected system studies.

- Proposal

The following are the ISO's proposals to address LSA/SEIA's 11 additional issues listed above:

1. Delays caused by Participating TOs:
   i) While the ISO understands the Interconnection Customers concerns regarding delays in construction by the Participating TOs, and the evolving landscape of technology, the ISO is simply not in a position to allow generating units to synchronize to the grid when reliability network upgrades are not completed. Moreover, due to the significant number of permutations of scenarios between project timing and transmission upgrades, there is no way to study the ability of a unit to come online in advance of the current LOS timeline.
   ii) LSA/SEIA proposed that the ISO should re-align the commercial viability criteria timeline if the COD is adjusted due to Participating TO delays and is beyond the seven (7) year maximum time in the queue. The interconnection customer should not lose their deliverability due to the Participating TO delaying the COD. Currently Section 6.7.4 of Appendix DD requires the ISO to assess the commercial viability of a project if there is a modification requested, regardless of who is making the request. The ISO agrees that the Interconnection Customer should not be harmed by taking away a project's deliverability if the Participating TO is delaying the COD of the project.

      The ISO proposes this issue be renamed to Modification to Commercial Viability Criteria and will move into the scope of Phase 1: Near-Term Enhancements. The commercial viability criteria should be assessed only if the Interconnection Customer submits the modification request and not the Participating TO.

2. Better differentiation within clusters:
   This issue requires additional stakeholder input to determine if this should be a topic in this initiative or is better suited for a discussion between the Participating TOs and the Interconnection Customers.

   The ISO proposes this issue be explored within the scope of Transmission Grid Data Transparency topic originally proposed by Gridwell in Section 6.2.

3. Interim Deliverability Status (IDS) transparency:
   Similar to LSA/SEIA issue 1, the ISO cannot determine with any certainty the amount of IDS that may be available in the future because of the various permutations of scenarios associated with the timing of both project and transmission upgrades. Therefore, this issue will not be included in the scope of this initiative.

4. Network Upgrade re-stack:
   The ISO proposes to include this issue for further discussion at this stage of the initiative. The sequencing of Network Upgrade construction is performed by the Participating TOs and is not something that the ISO can do.

5. Expanding Deliverability Transfer Opportunities.
   Appendix DD Section 8.9.9 requires an Interconnection Customer to reallocate its Generating Facility's deliverability among its own generating units or resource IDs at the same POI. The Generator Interconnection Agreement ("GIA") provides a specific POI which connects the generating facility between two breakers at the substation. Thus to transfer deliverability currently, the generating units or generating facilities are required to be both the same Interconnection Customer and connected to the same POI defined in the GIA. However, the deliverability impact to the system of different projects connecting to the same substation and voltage level should be the same and, in at least some situations, developers are contemplating attempting to combine projects under a single GIA for this purpose alone, a cumbersome and burdensome course of action for the ISO, Participating TOs, and Interconnection Customers.

   The ISO proposes to include this item in the scope of Phase 1: Near-Term Enhancements and revise the tariff to allow deliverability transfers to be expanded thereby allowing projects at the same substation and same voltage level versus the same interconnection Customer at a specific POI defined in the GIA.

6. Reassessment accommodation for TPD acquisition or retention:
   The ISO has incorporated this issue in Section 3.3 and will be in the scope of Phase 1: Near-Term Enhancements.

7. Improve TPD allocation process for Energy-Only projects:
   The ISO has incorporated this issue in Section 3.3 and will be in the scope of Phase 1: Near-Term Enhancements.

8. Energy-Only project qualification for new TPD allocations:
   The ISO has incorporated this issue in Section 3.3 and will be in the scope of Phase 1: Near-Term Enhancements.

9. Option B reform:
   The ISO does not agree that the GIDAP Option B process should be reformed. The ISO believes that the transmission planning process (TPP) is the best process for considering adding new area deliverability network upgrades to the system. If stakeholders believe that the TPP needs to be reformed in this area then such reforms should be proposed in that arena.

10. Battery Augmentation:
    The technical characteristics of batteries will change over time and the ISO already has the MMA process to approve changes to batteries. Because of the potential for changes in electric characteristics of different batteries, ISO Tariff Section 6.2.1 would not be applicable because a study would need to be done. A multi-year MMA could be considered if the interconnection customer is purchasing the equipment in bulk and the manufacturer, series and electrical characteristics will be the same. Absent ensuring the electrical characteristics are the same or have a process to be studied, the ISO cannot jeopardize the reliability of the grid with a blanket approval. Therefore, this issue will not be included in the scope of this initiative.

11. Affected System study options:
    Only the Affected System knows the reliability issues, electrical characteristics, protection setting, etc. of their system and any study done by someone else is useless. Until the Affected System identifies the reliability issue on their system, the ISO cannot determine potential solutions on the ISO's system. Moreover, the ISO does not have the technical capability of determining the reliability requirements of an Affected Systems. If an Interconnection Customer is having issues with an Affected System, Queue Management will try to assist the customer with escalating the issue. Therefore, this issue will not be included in the scope of this initiative.

6.4 Additional Stakeholder Suggested Proposals

The following additional issues to be included in the scope of the 2021 IPE initiative were received in stakeholder comments on the Preliminary Issue Paper[30]:

- **CESA:** Beyond ISO interconnection study processes, a key barrier to near- and mid-term resource deployments and buildout is the timely construction and completion of network upgrades by Participating TOs. While specific performance standards or incentives may not be an IPE matter, ISO should consider if there is a role for it to play in reporting on transmission upgrade project status – as part of an effort for ISO to more effectively implement its tariff and ensure standardized reporting to LSEs and developers.

  - Proposal
    The ISO proposes this issue be explored within the scope of Transmission Grid Data Transparency topic originally proposed by Gridwell in Section 6.2.

- **CalWEA:** Although the ISO allows generators to interconnect before all the RNUs are in service through a limited operational study (LOS), the process is still missing pieces. The LOS is done 5 months ahead of the synchronization date. However, without knowing if the generator can interconnect, the IC can't plan for the synchronization date. The process needs to be streamlined to allow generators to interconnect until the triggered GRNUs are actually needed and have policy on treating generators after the actual needs arise.

  - Proposal
    The ISO has provided a response to this issue within Section 6.3 issue 1.

- **CalWEA:** When a generator seeks interconnection to an old substation, the Participating TO may require the substation to be converted in accordance with current design standards. In such a situation, the Participating TO should not assign the full converting cost to the generator. The generator should only be assigned the cost for the facilities it uses to interconnect.

  - Proposal
    The ISO supports ongoing conversations on this issue, but this process is not under ISO control. Rather, this is a Participating TO process and therefore this issue will not be included in the scope of this initiative.

[30] Additional stakeholder suggested proposals can be found at California ISO - All comments (caiso.com).

- **CalWEA:** The ISP electrical independence test should be re-examined by the ISO. Per the electrical independence test criteria, projects of any size with >= 5% shift factor on the selected transmission element fails the electrical independence test. However, the flow impact of a small project is insignificant and non-material for a high voltage transmission facility. CalWEA recommends a flow impact consideration for projects with impacts, e.g., shift factor >= 5% and flow impact >=2%. Also with the super-cluster timeline, a requirement to perform the electrical independence test using the current cluster results should be re-considered and revised.

  - Proposal
    The statement above does not accurately describe the existing tariff. Appendix DD Section 4.2.1.1(ii) states "The incremental power flow on the transmission facility identified in Section 4.2.1.1(i) that is caused by the Generating Facility being tested will be divided by the lesser of the Generating Facility's size or the transmission facility capacity. If the result is five percent (5%) or less, the Generating Facility shall pass the flow impact test." The ISO would like stakeholder justification on why the existing tariff criteria is not just and reasonable.

    Regarding the proposal that in light of the super-cluster timeline, the requirement to perform the electrical independence test using the current cluster results should be re-considered and revised, the ISO asks stakeholders for specific proposals for revisions to the ISP electrical independence test criteria that provides a methodology that addresses the condition where a Cluster 14 project is impacted or a potential impact cannot be ruled out.

- **PG&E:** PG&E has identified concerns on timely construction of shared network upgrades that have cross cluster dependencies like Conditionally Assigned Network upgrades (CANU) and Precursor Network Upgrades (PNU). As it is now, the triggering project must post 100% of the estimated upgrade cost in financial security for PG&E to kickoff construction activities for these upgrades which are not required at the time of IA execution. As a result, downstream queued projects are on the hook for the completion of upgrades that have typically not began in a timely basis. This may result in queued project's in-service dates being jeopardized by a delay in financial security postings. If the triggering project is required to post 3rd financial security posting at the time of IA execution, this delay/ risk in online date would be eliminated.

  - Proposal
    Appendix DD Section 11.3.2 provides that the third posting is made after the second posting but no later than the start of Construction Activities for Network Upgrades or Participating TO's Interconnection Facilities, whichever is earlier.

Construction Activity is defined as “actions by a Participating TO that result in irrevocable financial commitments for the purchase of major electrical equipment or land for Participating TO’s Interconnection Facilities or Network Upgrades assigned to the Interconnection Customer that occur after receipt of all appropriate governmental approvals needed for the Participating TO’s Interconnection Facilities or Network Upgrades.” It is common practice of some Participating TO’s to include in the GIA payment schedules to increase the third posting incrementally when engineering and development work commences on the project.

Because PG&E can require in the negotiation of the GIA the timeline of the third posting, provided it is between the second posting and the start of Construction Activities, the ISO believes this issue can be resolved without further tariff changes.

- **REV Renewables:** REV Renewables suggests that when a developer issues a notice to proceed to the Participating TO, Participating TO/ISO should start planning for all upgrades that are required for a project to attain FCDS, including the upgrades that get triggered by a group of projects. Sometimes there are upgrades such as new Remedial Action Schemes that are triggered by a group of projects, and not by individual projects themselves, and ISO/Participating TOs wait to start planning for these upgrades until enough projects achieve commercial operations. This can cause material risk to the first project which stays under an Interim Deliverability status until the required upgrade is built. The deliverability status of this project is tested every year under the annual process which is conducted around middle of the year and if enough deliverability is available this project is allowed to be full capacity for the upcoming year. The concern with this approach is if the annual deliverability process does not show enough deliverability, ISO and Participating TO may then decide to build the required upgrade but this may be too late for this project to sell full capacity RA for the upcoming year. Six months is typically not enough lead time for the upgrade to be completed and hence the project may not be able to meet its RA obligations for the upcoming year. In addition, this could cause a reliability risk for ISO if supply conditions for this upcoming year were constrained. Therefore, REV proposes that when a developer issues a notice to proceed to the Participating TO, Participating TO/ISO should either a) start planning for all upgrades required for FCDS status, including upgrades triggered by a group of projects or b) allow the project that is ready to achieve COD to proceed as FCDS if ISO/Participating TO make a determination that the network upgrade doesn’t get triggered if only this project proceeded forward.

- Discussion
  Section 5.5 of the GIA states that if the responsibility for construction of the Participating TO's Interconnection Facilities or Network Upgrades is to be borne by the Participating TO, then the Participating TO shall commence design of the Participating TO's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

  (a) The ISO, in coordination with the applicable Participating TO(s), has completed the Phase II Interconnection Study or Governing Independent Study Interconnection Study pursuant to the applicable Generator Interconnection Study Process Agreement or other applicable study process agreement;

  (b) The Participating TO has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B, Milestones; and

  (c) The Interconnection Customer has provided security to the Participating TO in accordance with Article 11.5 of the GIA by the dates specified in Appendix B, Milestones of the GIA.

  Therefore, in general the Participating TO should commence design and procurement of all Participating TO's Interconnection Facilities or Network Upgrades upon receiving the notice to proceed from the Interconnection Customer. However, there are instances where an upgrade is required only if all the projects in the cluster are built. So to avoid overcharging ratepayers for upgrades that may not be required, it makes sense to delay the buildout of all upgrade(s) required for a project.

- Proposal
  The ISO agrees with REV's concern and would like additional stakeholder feedback to determine in these specific instances if FCDS can be provided to the Interconnection Customer that has achieved commercial operation provided the Interconnection Customer agrees to pay the cost of the upgrade(s) that have not yet been built and agrees to defer repayment of Network Upgrades until all upgrades are built or a reassessment study determines that the Network Upgrade(s) is no longer required.

- **SDG&E**: SDG&E recommends the following additions to the scope of issues:
  - Charging Study (Phase I): ISO study plan includes a section on charging study for each cluster, but the results are informational only. With the extreme increase of Battery Energy Storage Systems in the queue (~83% of C14 applications in

SDG&E study area). ISO should provide more guidance on how charging should be performed and include tariff language to how upgrades can be assessed and allocated to project to overloads/issued introduced by charging overloads.

- Proposal
  The ISO does not agree that specific study criteria guidance belongs in the tariff. Such guidance should be worked into the cluster study plans developed by the ISO in coordination with the Participating TOs. Charging studies are also performed in the transmission planning process and can be discussed further in the development of the TPP study plan.

- Gen-Tie Sharing (Phase I): Interconnection Customers (IC) are allowed to indicate Gen-Tie Sharing with an existing or proposed project with gen-tie to existing Participating TO substation, or to a proposed switchyard for earlier queued project, without being required to have approval to use that gen-tie by the existing gen-tie owner (GO). There should be a requirement that IC's obtain approval as part of their Interconnection Request (IR). Additionally, existing generator(s) should be notified of future interconnection requests that impact their project(s) or gen-tie configuration. SDG&E experienced a situation where two proposed loop-ins to an existing gen-tie were proposed and went through both phases of the interconnection study before the GO was aware of any changes.

  - Proposal
    The ISO agrees that the issue of an interconnection customer submitting an IR that proposes to utilize a gen-tie owned by a third party without receiving a commitment from the gen-tie owner to use their facilities has been problematic in the past. The ISO proposes that any IR that proposes to utilize and third party owned gen-tie must provide documentation as part of their IR that demonstrates that the gen-tie owned has agreed to the project proposed in the IR using its gen-tie.

- Stranded Cost Responsibility for IRNU Switchyards (Phase I): If an IC proposes to connect to a switchyard of an earlier queued project(s) that has executed a LGIA, the new IC does not have any cost responsibility or cost exposure related to the switchyard. If the earlier queued project(s) terminates the LGIA, then the Participating TO is responsible for funding the switchyard. There should be a mechanism for IRNU reallocations with associated cost responsibility and cost exposure assigned to later queued project(s).

  - Proposal
    This issue will be explored further in the initiative in conjunction with issue 4 in Section 6.1.

- RIMS Document Management (Phase I or Phase II): During IR validation period, RIMS is heavily used for files to be share between IC, ISO and Participating TO. The system does not categorize, group, version or organize the documents well. RIMS needs enhancements or (if not already) use of more features to streamline the IR validation process. After IR validation, ISO should be consistent in using RIMS for all documents, details, etc. related to the project. Currently MMA requests, letters, etc. are not uploaded to RIMS. ISO, in efforts with CPUC, is seeking to be the central repository of all interconnection queue information. If RIMS is supposed to be the system of use, then modifications are needed.
  - Proposal
    The existing documents tab in RIMS has filtering functionality. By clicking on any column heading, it will sort the documents in ascending or descending order based on the data in the selected column. There is also an Inline Filter icon that allows the user to filter for specific data based on the available data choices under a specific heading. There is also an Advanced Filter icon that allows the user to further define their search.

    While the ISO does not currently upload MMA document into RIMS, RIMS does have the capability of accepting documents, excel files and other data. If it is helpful for Stakeholders, all of the MMA, repowering and limited operations study documents including requests, data files, study plans, study results and other files could be added to RIMS. The ISO would be interested in additional Stakeholder feedback of this functionality.
- IR Validation Forms (Phase I): Multiple items within the spreadsheet and Word doc need to be updated: Primary Frequency response (static or dynamic), MW value at High Side Main Step-Up Transformer, updated to IR Validation tab for which items PTO is supposed to verify (remove Site Exclusivity, Signatory document), removal of ISD/COD achievable question from IR review.
  - Proposal
    The ISO currently reviews and updates the Appendix 1 – Interconnection Request form and the Attachment A to Appendix 1 Generating Facility Data spreadsheet prior to each cluster window. These items will be included in the review prior to the Cluster 15 application window. Therefore, this issue will not be included in the scope of this initiative.

7 Stakeholder engagement

The schedule for stakeholder engagement is provided below. The ISO will present its proposal for phase 1 to the Board of Governors in May 2022, and phase 2 will presented to the Board of Governors in November 2022.

Date	Event
09/30/21	Publish preliminary issue paper
10/08/21	Stakeholder suggestions due
10/19/21	Stakeholder workshop on preliminary issue paper
10/28/21	Stakeholder comments due on preliminary issue paper and workshop
12/06/21	Publish issue paper/straw proposal
12/13/21	Stakeholder conference call on issue paper/straw proposal
01/03/22	Stakeholder comments due on issue paper/straw proposal
01/25/22	Publish revised straw proposal
02/01/22	Stakeholder conference call on revised straw proposal
02/15/22	Stakeholder comments due on revised straw proposal
Phase 1	
03/10/22	Publish draft final proposal
03/17/22	Stakeholder conference call on draft final proposal
03/31/22	Stakeholder comments due on draft final proposal
04/11/22	Publish draft tariff language
04/21/22	Publish final proposal
04/25/22	Stakeholder comments due on draft tariff language
04/28/22	Stakeholder conference call on final proposal
05/12/22	Stakeholder comments due on final proposal
May 2022	Board of Governors Meeting
Phase 2	
06/07/22	Publish draft final proposal
06/14/22	Stakeholder conference call on draft final proposal
06/28/22	Stakeholder comments due on draft final proposal
07/26/22	Publish draft tariff language and final proposal
08/09/22	Stakeholder comments due on draft tariff language
08/16/22	Stakeholder conference call on final proposal
08/30/22	Stakeholder comments due on final proposal
November 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on December 13, 2021 to review the Issue Paper and Straw Proposal. Stakeholders are encouraged to submit comments on this Issue Paper and Straw proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on January 3, 2022.