Interconnection Process Enhancements 2021

Phase 2: Longer Term Enhancements
Revised Straw Proposal

June 7, 2022

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1 Introduction

This Phase 2 Revised Straw Proposal is the extension of the 2021 Interconnection Process Enhancements (IPE) Initiative, one aspect of 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 was launched 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. While the accelerating pace of needed resource development called for examination of opportunities for process improvement, the timing of this initiative was also heavily influenced by the circumstances of the April 2021 Cluster 14 interconnection application window.

During the Cluster 14 open window, the ISO received 373 interconnection requests, creating an overload of industry resources which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[1]. 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[2]. In addition to the issues related to the broader need for reforms, both in the short term and longer term, the ISO also identified a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

This led to the sequencing of the 2021 IPE initiative. Topics that would impact Cluster 14 Phase II were handled in the Phase 1 portion of this initiative. The Phase 1 package of changes, which was approved by the ISO Board on May 12, 2022, and submitted to FERC for approval on June 2, 2022,[3] accordingly focused on near-term enhancements

[1] For more information on the Supercluster Interconnection Procedures initiative please refer to the initiative webpage at: [FinalProposal-SuperclusterInterconnectionProcedures.pdf (caiso.com)]
[2] 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.
[3] Phase 1 tariff amendment filing is available at http://www.caiso.com/Documents/Jun2-2022-TariffAmendment-InterconnectionProcessEnhancements-ER22-2018.pdf.

to the existing interconnection processes that can be applied to Cluster 14 following the completion of the phase I interconnection studies in September.

Another impact of the Cluster 14 supercluster was the recognition 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. Phase 2 focuses on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities along with some additional issues that have arisen. It also addresses several residual issues that related to Phase 1 enhancements that were not fully resolved in the Phase 1 process. The ISO is targeting the ISO Board of Governors October 2022 meeting for approval of Phase 2.

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.

2 Background

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 plan approved by the ISO Board of Governors in March, 2022 was 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[4]. 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.[5] Responding to these signals and previously approved authorizations, the resource development industry submitted a record-setting number of new interconnections requests in April 2021, with 373 new interconnection requests being received in the

[4] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcess-Sep27-28-2021.pdf
[5] Cal. P.U.C., Dec. No. 21-06-035. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[6] 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 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 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[7]. 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,[8] was posted to the ISO website on December 13, 2021.

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative 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 was established to discuss and address interconnection-related issues the ISO and stakeholders have identified given current

[6] 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

[7] 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*

[8] "Resolving Interconnection Queue Logjams - Lessons for CAISO from the US and Abroad" October 2021, Rob Gramlich, Michael Goggin, Jay Caspary, Jesse Schneider. http://www.caiso.com/InitiativeDocuments/ResolvingInterconnectionQueueLogjamsFinalReport.pdf

circumstances, and to resolve concerns that have surfaced since the last IPE initiative in 2018.[9] 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.

This Phase 2 Revised Straw Proposal is intended to present proposed solutions that focus on long-term process enhancements based on comments received from stakeholders from the Issue Paper and Straw Proposal (posted December 2021), including some additional issues that have arisen since the original issues list was developed.

3 Phase 2 topics focused on moving resources through the interconnection queue more efficiently and potentially more quickly

This section discusses a number of topics focused on moving resources through the interconnection queue more efficiently and more quickly. One area for opportunity in achieving those objectives has focused more specifically on achieving greater alignment between the interconnection process, procurement activity, and the ISO's transmission planning process that integrates state resource planning results. Because alignment efforts involve consideration not only of the interconnection process but also those related processes, opportunities in this regard need to be considered not only in the IPE 2021 effort but in refining other processes as well.

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. The ISO has proposed a number of measures relating to this overall objective in this initiative, including several measures approved in Phase 1 and continuing the discussion of others in this Phase 2 paper. The Phase 1 effort in this regard focused primarily on revisiting the deliverability allocation framework, and aspects of that have been carried over for further review in Phase 2. Phase 2 discussions also touch on the consideration of how policy-driven transmission

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

should be made available for allocation (Section 3.4), and the potential role of solicitation models (Section 3.2).

Feedback from the stakeholder community to date generally supported various enhancements to current processes, but no structural changes that would disrupt the current interconnection queue process and prioritization within the queue. Beyond those already identified in the IPE 2021 process and in the ISO's transmission planning process, the ISO does not have further suggestions at this time on this broader topic of achieving greater alignment between the interconnection process, procurement activity, and the ISO's transmission planning process that integrates state resource planning results, but is interested in stakeholder feedback in this regard.

In the meantime, the ISO will continue to explore the various topics and proposals as set out below in the IPE initiative, as well as in other forums such as those relating to the transmission planning process.

3.1 Can the interconnection process and procurement activity better align with transmission system capabilities and policy objectives of renewable generation portfolios developed for planning purposes?

- Background

As noted above, the ISO's transmission planning process includes a framework for developing policy-driven transmission associated with state and federal policy needs and direction.

One area that warranted further attention is that while state policy direction for the need for additional transmission capacity can and has led to the development of transmission reinforcements, lack of coordination between processes may result in the policy objectives themselves ultimately not being achieved.

In the December 6, 2021 Issue Paper and Straw Proposal, section 3.4, the ISO sought stakeholder feedback on two concepts: 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.

- Stakeholder Feedback

  ACP-California, California Energy Storage Alliance (CESA), Golden State Clean Energy, NextEra, PG&E, SCE, and Six Cities support this issue being addressed within the scope of Phase 2: Long-Term Enhancements. ACP-California and CESA urge the ISO to utilize the ISO's 20-Year Transmission Outlook to assist in this developing proposals for this issue. Additionally, PG&E requests the ISO require that solutions developed in the TPP require some work with relevant LSEs to determine the best and most feasible solutions. PG&E notes that more joint work will allow the ISO and PTOs to meet procurement goals. Further, SCE encourages the ISO to develop proposals for this issue based on the needs and direction provided in the CPUC's IRP process. Finally, Six Cities urges more discussion on this issue in order to explore the root cause of the lack of alignment between planning and procurement activities arise and to determine if this issue is driven by a need for improved coordination with LRAs or other reasons.

  The CPUC supports the ISO developing proposals to improve the coordination between procurement activities and transmission planning process. They acknowledge there is room for improvement in coordination efforts and state they are taking additional action by starting the Transmission Development Forum and Tracking Energy Development (TED) Task Force to improve coordination with the ISO and others. Further, the CPUC request the ISO describe the issue of lack of coordination in more detail to ensure the design of the most effective solution. Similar to other stakeholders, the CPUC supports more discussion regarding the withholding and reservation of transmission capacity for projects that achieve policy goals. Specific to determining what qualifies for withheld transmission capacity, the CPUC requests the ISO consider 1) the resource types and amounts mapped to the relevant busbars and 2) the resource types that could utilize the transmission capacity to achieve policy goals. Additionally, the CPUC suggests that when a transmission upgrade is withheld, it is announced in a timely and transparent manner and that the ISO prioritize withholding transmission capacity for long-lead time and location constrained resources types.

  CalWEA recommends this issue be addressed by the CPUC through the IRP process by optimizing the portfolio in a manner that does not seek to avoid transmission upgrades. REV Renewables also suggest the ISO work with the CPUC and other state agencies on this effort to better align procurement process with the ISO's TPP. Hanwha Q Cells notes this issue should be focused on adding efficiency to help California achieve its 2045 carbon neutrality goal.

  EDF-Renewables support the ISO leveraging the published Grid Strategies Report published on December 13, 2021 for reference to actionable steps to improve joint agency coordination. They recommend the ISO consider how and if its proposals in this initiative address changes needed as identified by the report. Specifically, EDF-Renewables support further discussion on the Grid Strategies suggestion of developing more stable interconnection costs to reduce uncertainty on developers and procurement entities.

ACP-California, CESA, and Middle River Power are unsure of a process that develops transmission capability targeting developing specific “policy-driven” resources and reserves transmission capability only for resources that meet the “policy-driven” definition. ACP-California notes that it is unclear how the ISO will pick “winners and losers” between similar “policy-driven” resources that are trying to interconnect. However, ACP-California advocates this type of proposal may work in the Diablo area that warrants unique policy-driven attention specific to Offshore Wind resources. ACP-California explains they are supportive of modifications to the transmission planning and deliverability allocation process that would allow for the ISO to receive public policy direction from the CPUC to “reserve” capacity for specific resource types such as geothermal or offshore wind. Alternatively, Middle River Power supports an open season model would be more beneficial as new technologies emerge and would not strand significant transmission investment.

RWE Renewables neither supports nor opposes this proposal. However, they are in favor of a proposal that is technology neutral. Similar to other stakeholders, they believe this proposal warrants more discussion and coordination with transmission planning. REV Renewables is also supportive of a proposal that is unbiased in its assessment of project technologies or locations.

Golden State Clean Energy do not support a proposal that considers a reservation system within the policy-driven process as a means of ensuring the intended resources are allocated deliverability. They note this proposal does not consider the current impediments to planning for new infrastructure and does not align with the ISO’s position that deliverability is not a right conferred on interconnection customers. Alternatively, Golden State Clean Energy support a proposal that focuses on locational considerations and least-regrets policy resource zones based on the ISO’s 20-year transmission outlook and zonal assessment supported by the state agencies and the SB 100 report. Finally, Golden State Clean Energy note that to the extent policy development requires changes to the TPP, the ISO should start a new initiative narrowly scoped to address changes to the IPE and TPP in tandem to ensure needed policy reforms are addressed.

LSA/SEIA oppose this proposal because it favors specific technology types, namely new offshore/imported wind and geothermal resources. They note this proposal is not consistent with the ISO tariff and associated rules which are technology-neutral and based on open-access principles. SCE also notes they do not support "withholding" capacity for any specific resources because it would violate open-access principles.

REV Renewables believe the ISO should not withhold any capacity for any projects studied in any process. They suggest that for out-of-state wind resources that are in CPUC renewable generation portfolios that they be evaluated at their points of interconnection in BAs outside of the ISO rather than at the ISO boundary injection points. REV Renewables note this evaluation would provide the ISO a better determination of transmission needs to deliver out-of-state renewable generation.

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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. Based on the discussions and feedback, the ISO has concluded that this topic is more appropriately considered in the context of the ISO's transmission planning process where policy-driven transmission needs are coordinated with state input. The ISO will not advance a specific proposal within Phase 2, but will seek further stakeholder input on this issue in a separate stakeholder process associated with the transmission planning process enhancements.

3.2 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 in its December 6, 2021 Issue Paper and Straw Proposal section 3.6, 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

Several entities (including CESA, MRP, PG&E, EDF-R, NextEra and REV) express support for exploring different solicitation type models. CESA focuses on locations where there is limited existing transmission availability relative to the interconnection requests, where the ISO's solicitation model concept could be considered, along with higher commercial viability criteria, fees, and/or deposits could be applied as screening and scoring criteria. EDF-R believes that solicitation model proposals need to be sufficiently detailed before their merit can be evaluated.

With respect to proposal (1), EDF asserts that a solicitation model to identify which projects should be carried forward into the interconnection process conducted in conjunction with load serving entity procurement processes, EDF-R requests that any coordination ISO does with LSEs as a part of the LSE's RA solicitation efforts be completely transparent to the interconnection customer.

EDF-R, REV and MRP supports further discussion on proposal (2) a solicitation model confirm interest in an area in which transmission capacity may be expanded with commitments from the resources helping support the transmission development.

PG&E expressed interest but looked to hear from the development community on the two solicitation models to identify projects which should be carried forward into the interconnection process and to identify interest in the development of transmission capacity where commercial interests would fund the transmission development in exchange for rights to interconnect ahead of projects in the queue.

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The ISO will not advance a specific proposal at this time, but will seek further stakeholder input on this issue in a separate stakeholder process associated with the 2021-2022 Transmission Plan.

The ISO notes that in the course of assessing proposed transmission options accessing out of state resources in the 2021-2022 Transmission Plan, the ISO concluded that information to help in the assessment may be gleaned by the ISO testing the market interest in accessing Idaho wind resources through the SWIP North project or similarly situated projects. The ISO therefore intends to engage further with industry participants to gauge interest in accessing Idaho resources. The ISO expects this effort to take the form of an open season-type process to assess the market interest and level of competition that exists for accessing the Idaho resources and will be consulting with industry on the form of this outreach, which may provide the basis for further discussion of this issue.

3.3 Transparency enhancements

- Background

In Phase I of the IPE initiative, the ISO agreed to conduct a parallel process for the requested data transparency issues requested by the stakeholders. In working through that discussion, a number of items that stakeholders requested to be public data are currently considered confidential by the CAISO tariff, the customers or generator owners, or FERC.

Confidential Information, as it pertains to generator interconnections, in Section 22 of CAISO tariff is limited to critical infrastructure information. In the GIDAP, Appendix DD, Section 15.1, confidential information is defined as all information relating to a Party's technology, research and development, business affairs, and pricing. Confidential Information does not include information that a party can demonstrate is generally available to the public other than as a result of a disclosure by the receiving party. Information designated as confidential information is no longer deemed confidential if the party that designated the information as confidential notifies the other parties that it no longer is confidential.

Based on the current tariff and business practices to date, the data elements that either meet the definition of confidential, as discussed above, or have been considered confidential consist of:

- PPA status is considered confidential due to pricing information and market sensitive.[10]
- Project "formerly known as" names are considered confidential due to business affairs.
- Site exclusivity documentation and status are considered confidential due to price and commercially sensitive.

The data the ISO has considered confidential but requested consists of:

- Percentage of PCDS and IDS could be interpreted as market sensitive and pricing information.
- Phase level data for the project including: gen and fuel type, MW, milestone dates, resource IDs, hybrid or co-located designation, MWh data for storage projects,[11] and TP Deliverability group and allocation.
- Suspension status and timing of a project
- PPA executed and MW
- Construction status
- Project parking status
- Project Affected System status

[10] Generally interconnection customers submit PPAs only after redacting financial values. The CAISO does not object to this practice and will continue to treat all PPAs as confidential regardless.

[11] The ISO does not currently have this data.

Requested data that is tracked in RIMS that, while not currently available, does not meet the confidential criteria and the ISO is willing to determine how the information can be made available in a public report:

- PTO study area
- TP Deliverability Allocation Group

Resource ID is already public and can be found on the final net qualifying capacity report on the caiso.com website. If the ISO does develop additional public reports, the ISO can evaluate at that time if the resource ID information can be included in those reports. With respect to a project's time in queue, stakeholders can be easily calculated that information if it is needed using the existing public queue report that is already provided in Excel format.

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The ISO proposes to amend the tariff, where possible and if needed, to allow certain data agreed to by stakeholders to be public information. The ISO is seeking comments directly from generator owners and interconnection customers on their willingness to share project-specific data publicly, and which requested data items set out above should be shared.

3.4 Revisiting the criteria for PPAs to be eligible for a Transmission Plan Deliverability (TPD) allocation

- Background

In the April 21, 2022, IPE Phase 1 Final Proposal, section 3.2, the ISO proposed to clarify the eligibility criteria of a power purchase agreement (PPA) to merit the highest level of priority ranking in the TPD allocation process. Having an executed PPA, being shortlisted for a PPA, or actively negotiating a PPA have been the foundational criteria for eligibility to qualify for obtaining TPD, with level of assurance of a PPA determining the priority for allocating TPD. The clarifications proposed in the Final Proposal include:

1. A PPA must require deliverability and the resource adequacy (RA) capacity must have a minimum contract term of three years.
2. Projects having a PPA with an entity who does not have an RA obligation, must demonstrate that the RA attributes of the project are procured by an entity with a RA obligation for a term of three years or more.

These two eligibility criteria were removed from the proposal approved by the ISO Board of Governors on May 12, 2022, to provide additional time for review and comment and will continue to be discussed in IPE 2021 phase 2.

- Stakeholder feedback

  Those that commented on the ISO proposed PPA eligibility criteria in the March 17, 2022, Draft Final Proposal, supported the proposal that a project having a PPA with an entity that does not have an RA obligation that can demonstrate that the RA attributes of the project are under contract with an entity with a RA obligation would be eligible for an allocation. However, AEE & AEBG and Amazon raised concerns that making the demonstration of the sale of the RA attributes within the timeline of the TPD allocation process would be difficult and that some time should be given to demonstrate the sale of the RA attributes. Additionally, some stakeholders had concerns with the minimum contract term for a PPA requiring deliverability be for five-years or more and did not support the three-year minimum term proposed in the Final Proposal.

- ISO Discussion of TPD Allocation PPA Eligibility Criteria

  The proposal for enhancing the TPD allocation process discussed in the IPE phase 1 process was fairly involved and stakeholder comments focused on the issues of greatest concern from each stakeholder's unique perspective. This produced general support by a number of stakeholders for the two PPA eligibility criteria discussed here, but more specific opposition from stakeholders that saw these issues as impacting them more specifically. The ISO Board of Governors received letters and heard verbal comments on these two specific proposals at the May 12, 2022 Board meeting from LSA focusing on the appropriateness of a minimum PPA term criteria, and Amazon Energy focusing on the PPA counterparty criteria. Based on discussions at the Board of Governors meeting, the ISO concluded additional time was needed to address these topics. As the discussion will now focus on the specific PPA eligibility criteria described below, the ISO seeks input from all stakeholders to guide the proposal development process.

  In the IPE phase 1 Final Proposal the ISO made two adjustments from the Draft Final Proposal, seeking to find a balance in the differing interests; (1) reduced the minimum term for a PPA's procurement of RA capacity from five to three years, and (2) removed the proposed lower priority within an allocation group for PPAs with an entity that does not have an RA obligation. Now that the PPA eligibility criteria has been reintroduced in the phase 2 discussion, the ISO believes the starting point for the discussions should revert to criteria in the Draft Final Proposal. The proposal from the Draft Final Proposal is provided below.

  1. Beginning with the 2023-2024 TPD allocation cycle and thereafter, a PPA must procure the deliverable capacity for a minimum of five years to be eligible.

2. If a project has a PPA that is with an entity that does not have an RA obligation, but it can demonstrate the RA attributes of the project are under contract with an entity with a RA obligation for a term of five years or more, the project would be eligible for an allocation. The priority for allocating TPD to projects with such contracts will be after allocations are made to eligible projects whose PPAs are with an entity with an RA obligation. Financial incentives, the intent to sell capacity, or being shortlisted with an entity with an RA obligation are insufficient to meet this requirement.

TPD capacity on the ISO system is designed to the level dictated by the CPUC Integrated Resource Planning process to meet the requirements of the RA program and to develop the public policy-driven transmission solutions needed to enable the grid infrastructure to support local, state, and federal directives. These transmission upgrades are paid for by ratepayers through the Transmission Access Charges of the Participating TOs. The amount of TPD available to allocate to interconnection projects is limited to the amounts and locations of TPD capacity needed to meet the IRP resource portfolios the CPUC provides to the ISO. The ISO believes the further clarifications of the eligibility criteria of a PPA are necessary to ensure system-supplied transmission capacity is allocated on a basis that prioritizes projects that are most ready to proceed, and can demonstrate a clear and timely path for providing resource adequacy capacity.

The 2021 CPUC procurement order for 11,500 MW of additional net qualifying capacity by June 1, 2026[12] requires; *"All contracts for resources, including imports, used to satisfy the requirements of this procurement order shall have a minimum duration of 10 years."* The 2019 CPUC procurement order for 3,300 MW of incremental resources by August 1, 2023,[13] requires; *"For any procurement of resources that are new after the date of this decision, load serving entities with procurement obligations under Ordering Paragraph 3 of this decision shall enter into contracts of at least ten years in length…"* While some portion of the combined total of 14,800 MW has already been awarded a PPA and received an allocation of TPD, these CPUC orders set the requirement for virtually all new capacity to be procured through 2026 to be under contract for a minimum of 10 years. This suggests that the eligibility criteria for a project with a PPA, or a project shortlisted or in active negotiations for a PPA, should procure the project's RA capacity for a minimum term 10 of years to receive an allocation of TPD.

[12] Decision 21-06-035: DECISION REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY (2023-2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF#page=50&zoom=100,96,703

[13] Decision 19-11-016: ECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

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  The ISO does not put forth a specific proposal at this time and seeks stakeholder input based on these more recent discussions to facilitate the development of a proposal for the next paper. The ISO seeks stakeholder input on two specific questions.

  1. Should the allocation of TPD require a PPA that procures the project's RA capacity for some minimum term,[14] and if so, what should that minimum term be?
  2. Should a PPA that is with an entity that does not have an RA obligation be eligible for an allocation[14] if the procuring entity demonstrates that it has a contract to sell the RA capacity procured to a load servicing entity that has an RA obligation? If yes, should the procuring entity be given extra time after the project receives an allocation to secure a contract with a load serving entity with an RA obligation, and if so, what length of extra time should be provided?

4 Phase 2 topics on managing the overheated queue

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

- Background

  In the September 30, 2021 preliminary issue paper, section 4.1, the ISO sought stakeholder input on whether the bar for entry into the interconnection process should be raised to discourage numerous and perhaps excessive interconnection request submissions by a single developer, such as requiring higher fees or deposits for submitting an interconnection request, or imposing other requirements. Stakeholders were generally supportive for higher fees or imposing other requirements. Site exclusivity deposit requirements were addressed in Phase 1, and are not being revisited in Phase 2.

  In the December 6, 2021 Issue Paper and Straw Proposal, section 4.1 the ISO proposed that for the first two interconnection request submitted by a parent company/entity in an annual cluster window, the study deposit would be $250K per request, for interconnection requests 3-5 the study deposit would be $500K per request, and for any more than 5 interconnection requests, the study deposit would be $1M per request. The same percentages would be at risk as currently defined in the tariff.

[14] The PPA eligibility applies to group A, group B shortlist for PPA and actively negotiated PPAs and retention criteria for group B, and retention criteria for group D.

- Stakeholder feedback

Five stakeholders, Six Cities, SCE, Balanced Rock Power, Strata Clean Energy, and Upstream support the ISO's proposal to increase study deposits as is.

Four stakeholders support the ISO's proposal to increase study deposits but with modifications. PG&E states that there should also be a cap in the number of interconnection requests a company or affiliate can submit in total and at a given POI. Q Cells suggests the fee structure proposed by the ISO is excessive and recommends 1-5 IRs = $200K and > 5 IRs = $500K. NextEra proposes 1-5 IRs =$250K, 6-10 IRs = $500K, and >10 IRs = $1M. RWE Renewables supports raising costs but recommend a project cost scale or $/MW study deposit and further discussion on amount at risk.

Seven stakeholders oppose the ISO's proposal to increase study deposits. CalWEA opposes higher fees and study deposits that could be a barrier for smaller developers and any measures to pare down the queue should be aimed at developers that submit an inordinate number of applications, therefor recommends keeping study deposits for the first five IRs at the current level. CESA is open to considering some increase in study fee that is tied to actual study costs or historical precedent (e.g. $250K). Broad Reach Power ACP California stated the ISO did not provide evidence that multiple requests submitted by a single party were less serious than those parties that submitted few requests and the ISO proposal is unduly discriminatory. EDF Renewables stated the ISO proposal presupposes the outcome of FERC ANOPR RM21-17 which seeks to identify how to determine a just and reasonable limit to IRs. The ISO should continue to require $150K for IR. If the ISO proceeds, the ISO should provide reciprocal clarity in amount of information provided at scoping meeting and separate what amounts are "study deposit", and "scaling non-refundable fees". ACP California states the ISO Proposal is discriminatory. Recommend the ISO consider higher capital at risk requirements and increase transparency and provide info on the high-level likely viability early in the queue process. REV Renewables – Support higher fees but not the tiered structure for multiple IRs. Supports an increase to $250K, and could support beyond $250, but only on a per project basis. LSA/SEIA is neutral on increase to $250K, but strongly opposed to increasing scale with multiple requests. The ISO offered no evidence that entities that submit multiple requests are less solid or successful than entities that submit low numbers of IRs.

A number of stakeholders, whether they supported or opposed the ISO Proposal above, requested clarity on how the ISO would enforce/identify the number of IRs per parent company/entity and how it would apply to complex project ownership such as joint ventures.

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The following table illustrates the breakdown of the 373 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

This table demonstrates that a large percentage of interconnection requests come from a minority of parent companies. To accommodate this large cluster, the ISO filed with FERC to extend the study timelines for cluster 14 by approximately a year to accommodate the increase in the study burden and associated meeting requirements. Stakeholders have made it clear that a repeat of cluster 14 is not acceptable. This level of 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 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 goal of this initiative is to encourage developers to submit a reasonable number of interconnection requests for high quality resources and disincentivize developers from submitting a disproportionate number of interconnection requests that overwhelm resources and slow the cluster study process. There is valid concern that, rather than target a single or small number of well-developed, viable projects, parent companies can simply submit numerous interconnection requests to use the ISO interconnection study process to explore even remotely plausible projects. In addition to burdening staff resources at the ISO and the Participating TOs, this also means the initial phase 1 study results are based on much less reasonable volumes and study assumptions than would otherwise be the case. To validate this concern, the ISO analyzed the current status of projects in clusters 10 through 13, comparing the number of still active projects in each of these clusters as compared to the total number of projects originally submitted by unique parent companies. The following table shows the results of this analysis and as can be seen, when parent companies submit more than two interconnection requests, those projects withdraw at a higher percentage rate than parent companies that only submit one or two interconnection requests.

Cluster	Number of IRs submitted	Number of still active IRs	Total number of IRs Submitted	Percentage still active
10	1 or 2	14	36	38.89%
	3 or more	11	55	20.00%
11	1 or 2	14	34	41.18%
	3 or more	18	87	20.69%
12	1 or 2	11	24	45.83%
	3 or more	33	110	30.00%
13	1 or 2	19	43	44.19%
	3 or more	42	110	38.18%

The ISO continues to believe that increasing fees with more at risk earlier in the process will be an effective tool to discourage excessive interconnection requests. The ISO also believes that a tiered fee approach is appropriate to maintain a level playing field. Alternative proposals such as hard caps or higher fees for the entire cluster could disadvantage small developers that submit few interconnection requests and therefore do not contribute to this problem.

In any case, the ISO considers refinements to its original proposal are needed to address has some administrative challenges both for the ISO and for the interconnection customers. The ISO's original proposal was for the first two interconnection request submitted by a parent company in an annual cluster window the study deposit would be $250K per request, for interconnection requests 3-5 the study deposit would be $500K per request, and for any more than 5 interconnection requests, the study deposit would be $1M per request.. For example, each parent company that submits more than two interconnection requests would have to select which projects are associated with the lower and higher study deposits, as well as for the ISO in tracking these different deposits. It will be easier to administer if every interconnection request from a parent company would have the same study deposit required. The revised ISO proposal, as shown in the following table, addresses this by requiring the same study deposit per project per parent company/entity, with a similar per project deposit as compared to the average cost per project as originally proposed, and is based on the total number of projects submitted in a cluster window.

Number of interconnection requests submitted per parent company	Study deposit per interconnection request
1-2	$250,000
3-4	$375,000
5-7	$500,000
8-10	$650,000
11 or more	$800,000

The ISO's original proposal also imposed the same percentages of the study deposit at risk as currently defined in the tariff.[15] However after further consideration, the ISO believes that a portion of the study deposit should be immediately at risk after the interconnection request has been deemed complete. A significant amount of time and effort is put into validating interconnection request and preparing for and conducting scoping meetings. As such, an extensive number of interconnection requests could delay the overall cluster study process, even if withdrawn before actual studies begin.

The ISO also believes that execution of a GIA is no longer the appropriate milestone to refund remaining deposits to interconnection customers, and believes reaching commercial operation is a more appropriate milestone to achieve this initiative's objectives.

The ISO proposes the following study deposit refund criteria:

If an interconnection request is withdrawn for any reason, the study deposit is:

- Refundable minus costs until the interconnection request is determined complete.
- 20% non-refundable once the interconnection request is determined complete up until 30 calendar days following the scoping meeting.
- 50% non-refundable after 30 days following the scoping meeting and up to 30 days following the Phase I study results.
- 100% non-refundable after 30 days following the Phase I study results.
- 100% refundable minus costs upon reaching commercial operation.

[15] 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

A number of stakeholders questioned how the ISO would enforce/identify the number of IRs per parent company/entity and how it would apply to complex project ownership such as joint ventures. The ISO has not had any issues to date being able to identify parent companies and does not see monitoring this as an issue. For complex joint ventures, a parent company that has a majority stake in a joint venture will consider this project as one of their submitted projects and provide an appropriate study deposit. In any case, commensurate with this proposal, the ISO can add requirements to identify parent companies in the interconnection request.

5 Phase 2 topics - 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]

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

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.1, the ISO proposed 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.

- Stakeholder Feedback

The ISO received stakeholder comments from 12 stakeholders of which PG&E strongly supported the proposal outlined above and SCE does not oppose. While VEA originally opposed the ISO proposal, VEA now supports the ISO proposal.

Three stakeholders oppose the ISO's proposal and some of these stakeholders suggested alternative proposals. CalWEA strongly opposes requiring that interconnection customers finance network upgrade costs exceeding the funding cap and states that the treatment of network upgrade costs should not differ simply due to a different interconnection voltage level. ACP California states the ISO's proposal fails to properly allocate costs to beneficiaries, could be unduly discriminatory to, and likely serve to inhibit, generation that interconnects to the VEA area. ACP recommends that ISO further consider implementation of alternatives submitted in VEA's prior comments. LSA/SEIA oppose the ISO's proposal because it is unjust and unreasonable to impose different and discriminatory refundability rules in different ISO-area locations. Recommends addressing FERC's problems with earlier proposal; consider system wide uniform LVTAC rate; system wide LVTAC adder to fund interconnection-related upgrades; allocation of "excess" costs to other PTO LVTAC rate based on contracting of projects in the VEA area by LSE's in other PTO areas; or approaches originally recommended by VEA.

There were six entities that neither support nor oppose the proposal but provided comments. Six Cities states the current structure and delineation between high and low voltage is not in need of revision, however the ISO proposal addresses Six Cities concerns with transfer of cost from low voltage to high voltage. Six Cities requested the ISO to provide examples how this proposal would apply to each PTO. The CPUC requested clarifications to a number of questions, including how it impacts PTOs besides VEA. The CPUC also notes that cost allocation mechanism for distribution upgrades triggered by interconnection is under consideration as part of Phase 2 of CPUC's Rulemaking ® 17-07-007. CalCCA supports an allocation methodology that allocates costs to all those who receive benefits. The ISO's proposal to cap the percentage of interconnection-related network upgrade costs in each PTO's LTRR improves the current structure with respect to protecting local ratepayers from the cost impact of network upgrades that benefit all customers. However, the ISO should describe how the proposal will treat upgrades that benefit all customers if they fall under the proposed cap. If the purpose of the network upgrades is for generation projects to be deliverable anywhere on the grid, then all customers benefit and should share the costs. Hanwha Q Cells generally supports pushing costs regionally so that local customers are not burdened, and communities do not push back on projects due to high local costs. Further, Q CELLS believes that interconnection customers should receive a fair treatment from a cost reimbursement standpoint if the generation addition provides grid benefits to ratepayers outside the local area of the PTO. REV Renewables state the ISO should reconsider the cost allocation rules in broad context of the FERC Advanced Notice of Proposed Rulemaking: Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection - Docket No. RM21-17-000 ("ANOPR"). Given the overwhelming comments received on the ANOPR, reforms to the transmission planning, cost allocation, and interconnection processes are imminent in order to support transformation of the electricity sector. The definition of "local" vs "regional" was one of the most discussed topics in this proceeding. The CPUC's comments on the ANOPR, for example, provide several references to and examples of the ISO processes, questioning whether the definition of "local" should be redefined to include facilities lower than 200 kV. Additionally, whether these lower voltage facilities should be competitively built, which could reduce overall upgrade costs. Strata would like to gain more understanding on how ISO expects to mitigate risk on a single set of ratepayers and how the funding cap is established.

- Revised Straw Proposal

The ISO is not proposing to revise or change its December 6th proposal at this time, and is seeking continue to flesh out details of this proposal before further refinements or a final proposal. The ISO also seeks to address overarching stakeholder concerns and questions with the best available information at this time. This is a particularly challenging issue due to the diverse circumstances of the participating transmission owners, and warrants further discussion with stakeholders.

1. Request the ISO provide information about where each of the PTOs currently stand in relation to the ISO's proposal, which is shown in the following table:

<u>ISO Response:</u> The following table includes high level estimates provided by each PTO on where they currently stand in relation to the ISO's proposal:

PTO	(A) Estimated investment for all low voltage network facilities	(B) Estimated investment for low voltage network upgrades driven by generation interconnections	Percentage = B/A	Estimated available investment before the proposed 15% cap is reached
PG&E				
SCE	$387,761,394	$3,532,187	0.9%	$54,632,022
SDGE	$3,387,000,000	$264,480,000	7.8%	$243,570,000
VEA	$23,049,376	$0	0%	$3,457,406

As this table illustrates, there is little chance that SCE or SDGE will reach the proposed 15% cap in the foreseeable future, however there is a very high likelihood that VEA will reach the cap. Data is not yet available for PG&E, which will be essential in considering the efficacy of the current proposal.

2. Concern that the ISO's proposal may be unjust and unreasonable to impose different and discriminatory refundability rules in different ISO-area locations.

   ISO Response: The ISO proposal will apply to all PTOs consistently and therefore will not impose different or discriminatory rules in different ISO-area locations.

3. Concern that treatment of network upgrade costs should not differ simply due to a different interconnection voltage level.

   ISO Response: Stakeholders have commented on various differences that the proposal would either create or exacerbate. The current cost recovery mechanisms of regional (high voltage) transmission access charges and local (low voltage) transmission access charges has been in place for some time, and has proven very robust at managing cost recovery issues since first introduced. This longstanding and FERC-approved different treatment of network upgrade costs due to voltage level already exists as described in the background section above. It is the common metric among ISO/RTOs to allocate costs commensurate with benefits.

   The local transmission access charges tend to vary among service areas due to fundamental grid architecture differences that developed over many decades, with various transmission owners having more or less transmission below 200 kV, and inversely proportional amounts of facilities in those same voltage ranges classified as distribution with interconnections managed through the utilities' wholesale distribution access tariffs. This impacts the current discussion in two ways. First, the widely differing local TAC charges would make any attempt to levelize all local cost recovery to a single system-wide rate unlikely and unfair, given the local recovery of distribution costs. Also, the different grid architecture means the different utilities have different proportions of local transmission versus distribution for generation to connect to, so attempts to create a cost averaging of just network upgrades related to generation interconnections would also be problematic. The ISO also notes that some stakeholders objected to revisiting this regional/local transmission access charge cost recovery framework, recognizing that the current structure has provided a durable framework taking into account the broader use of the high voltage system to move energy across the entire footprint, the nuances of local grid architecture, and the interplay with distribution system and wholesale distribution access tariffs that generally do not include refunds of generation interconnection costs.

The ISO's proposal works within this framework to provide a cap on the rate impact to local ratepayers in anomalous circumstances, where interest in resource-rich areas may greatly exceed the local load requirements, and where it is unreasonable to burden the ratepayers in those areas with excessive low voltage network upgrade costs disproportionate to the benefits provided to the same ratepayers. Practical guardrails to limit this exposure seems necessary, as the ISO would not want to see VEA—or others at risk of this level of rate shock—seeing the need to depart from the ISO to manage this risk.

The ISO's proposal to cap the rate impact would lead to either generators funding the excess costs on a non-refundable basis or moving to higher voltage interconnections. Given these anomalous circumstances of disproportional low voltage TAC impacts appear the strongest where the interest in developing generation greatly exceeds the local need and clearly resulting in the export of power to other parts of the grid over regional facilities, it also does raise the question of whether evolving the local (low voltage) network into essentially a collector system that then needs multiple voltage transformations to evacuate power from the system is in fact an effective outcome, in any event.

4. Concern that the ISO's proposal fails to properly allocate costs to beneficiaries.

   <u>ISO Response:</u> The ISO notes that its initial proposal in 2017 sought to distribute disproportionate generation driven low voltage network upgrade costs more

broadly through the regional high voltage transmission access charge, focusing on the VEA-type situation where resource development interest far exceeds local loads. FERC rejected this proposal.

5. How did the ISO land on 15% as the cap threshold?

   ISO Response: The ISO's proposal remains consistent with established cost responsibility framework but addresses directly and proactively the potential for rate shock should a resource-rich area see a disproportionate increase in generation-driven low voltage network upgrades that cannot reasonably be absorbed by the local TAC area's ratepayers. In this context, the 15% threshold was previously approved by FERC as a reasonable limit on early investment in location constrained resource interconnection facilities, and appears a reasonable threshold here. Input on the appropriateness of this threshold is one issue the ISO is seeking input on.

As noted above, the ISO's proposal remains unchanged at this time, but the ISO is looking to continue the discussion through this paper and subsequent stakeholder outreach.

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.

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.[17] The ISO also needs to determine what base cases would be used for affected system studies.

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.2, the ISO proposed the base case assumptions for the ISO as an affected system study to be based on previously queued projects as of the affected system study agreement execution date. The ISO also proposed 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. 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.
- 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 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.

[17] 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 loop flow.

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

- Stakeholder Feedback

The ISO received comments from nine stakeholders on the ISO's proposal outlined above. No stakeholder opposed the ISO's proposal that the base case assumptions for the study to be based on the previously queued projects as of the affected system study agreement execution date.

Five stakeholders, CalWEA, LSA/SEIA, Strata Clean Energy, Hanwha Q Cells, and Middle River Power, support the ISO's proposal to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. LSA/SEIA also urges the ISO to seek reciprocal arrangements with other jurisdictions. Hanwha Q Cells state that timelines for repayment should be shorter than one-time cash payment at the end of 20 years and should provide an option other than Transmission Service Credits.

Two stakeholders opposed this proposal. Six Cities is not convinced the ISO's proposal is reasonable or appropriate. Is the ISO's position that FERC policy has specifically dictated that network upgrade costs due to affected system impacts must be reimbursed? Or only that FERC's general policy provides for network upgrade cost reimbursement, and since network upgrades may be identified as a result of affected system studies, affected system upgrades should be subsumed within that policy? The concept of providing reimbursement has less to do with the jurisdictional status of neighboring entities and whether or not their policies provide for reimbursement of network upgrades at all, and has more to do with fairness and reciprocity. SCE opposes the ISO's current proposal and agrees with the ISO's proposal regarding Affected Systems in its Contract Management "COMA" Enhancements Initiative Issue Paper / Straw Proposal issued August 10, 2021, that "Participating TOs will not reimburse external interconnection customers for network upgrades. This practice is consistent with neighboring utilities' practices for ISO interconnection customers.

Two stakeholders that neither support nor oppose the ISO's proposal but provided comments. RWE Renewables is neutral but would definitely ask the ISO to make sure that the same is reciprocated by the affected system i.e. ISO projects would receive a similar repayment mechanism from the affected system. PG&E supports the inclusion of this enhancement in the IPE and agrees that it should be addressed in the long-term phase of the IPE. PG&E looks forward to further discussions with the ISO and other stakeholders on this enhancement and how it would affect the timelines of studies and cost reimbursement.

- Revised Straw Proposal

  There is no change to the ISO proposal that the base case assumptions for the study to be based on previously queued projects as of the affected system study agreement execution date.

  The ISO also believes that its proposal to use its existing policy to reimburse the costs for network upgrades on the ISO grid when the ISO is an affected system is just and reasonable and does not plan on making any changes. The ISO believes network upgrades, regardless of their cause, benefit the local ratepayers, and therefore should be included in the relevant transmission revenue requirement, similar to any other upgrade. The ISO believes this is consistent with general FERC policy, as set forth in Order No. 2003 and FERC's recent ANOPR on transmission planning and interconnections. The ISO believes that neighboring utilities' practices are not determinative. The ISO also notes that neighboring utilities in general do not reimburse developers in cash for network upgrades triggered by internal interconnections either. In other words, neighboring utilities are not discriminating against affected system upgrades; they are simply applying their own policy consistently for all network upgrades, regardless of cause, just as the ISO proposes to do here. The ISO's proposed policy also ensures network upgrades are right-sized to mitigate the specific impact, and removes any incentive to use affected system mitigation to replace or defer other upgrades for the utility's benefit and at the developer's expense. The ISO also continues to believe its five-year repayment term is appropriate. The interest costs of longer terms would be significant.

5.3 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

  The December 6th Issue Paper and Straw Proposal identified five specific questions the ISO requested to be answered to determine if this issue had merit in this process. The 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 provided the required reports, even after numerous attempts by the ISO to find out the project status.[18] 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

In the Issue Paper, the ISO asked for feedback on the following:

1) Should projects that are energy-only be allowed to stay in the queue forever?

CalWEA doesn't see any harm in Energy-Only projects remaining in the queue except that it could contribute to the need for short circuit duty mitigation. If an Energy-Only project contributes to critical short circuit duty needs and has made no progress towards COD beyond the 7-year period, the project could be terminated.

The Six Cities, SCE, LSA/SEIA, MRP and RWE agree with the ISO's concerns that interconnection customers that are occupying space in the interconnection queue without taking meaningful steps to advance their projects should not be entitled to remain in the queue indefinitely.

LSA/SEIA notes that BPM for Generator Management, Section 6.5.2.1 states that "projects requesting to remain in the queue" beyond the applicable limit "clearly demonstrate that:" (1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC's control; and (3) "the requested COD is achievable in light of any engineering, permitting and/or construction impediments." This language does not seem like a license to stay in the queue "forever." However, LSA/SEIA do not object to consideration of reasonable Energy-Only viability criteria or time limits.

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?

EDF-R has managed many interconnection requests and has submitted dozens of quarterly status reports to the ISO. This requirement is not burdensome, and EDF-R, LSA/ SEIA and RWE are comfortable supporting a proposal where a project's failure to provide quarterly status reports is considered a material breach to the GIA and the primary driver for holding a project in breach. EDF-R, LSA/ SEIA and RWE requests ISO explicitly confirm in this initiative that upon notice of this breach the

[18] 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.

interconnection customer will have 30 days to cure the breach, and submitting a completed Queue Management Status Report is sufficient to cure this breach.

The Six Cities agree that it is necessary to provide improved clarity in the tariff and in interconnection-related agreements regarding expectations of project advancement, and to provide the ISO with a remedy – namely, termination of the interconnection agreement and removal from the queue – when projects do not sufficiently advance and/or appear to be inactive as a result of failures to respond to information requests or submit material modification requests when needed.

LSA/SEIA and RWE do not oppose the ISO issuance of a default notice, and appropriate deficiency remediation timeline (e.g., 30 CDs – see above), when a major milestone is missed. RWE suggested certain instances may require 30+ days but the IC should be in open communication with ISO.

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, how long should the ISO wait before invoking the default clause?

SCE supports limiting the number of modification requests [with the number of MMA requests allowed to be discussed with stakeholders] in order to extend a project's COD. It appears to SCE that in many cases interconnection customers are using the MMA process to dramatically lengthen the execution/construction phase of the interconnection process (post GIA). There may be legitimate reasons for doing so, but it appears that at times the ICs are using MMAs as a defacto suspension, without "using up" its suspension rights. Certainly, delays can occur for many reasons, and PTOs can also encounter delays in the execution/construction phase. The problem with execution/construction phase delays is the impact on scarce resources, such as those resources required to engineer, design, and construct the required interconnection facilities and network upgrades on behalf of ICs. With so many projects seeking to come online to meet commercial goals, these resources are scarce and precious. The ISO and PTOs need to be able to use these scarce resources for "real and ready" projects, allowing those to move forward to in-service and commercial operations, while avoiding expending these resources on projects that are not moving forward (for various reasons) and appear to be "queue squatting". Unless an interconnection customer can demonstrate that an extension is required to secure tax credits, or a PPA, (if GIDAP Section 8.9.2.2 does not apply) or to secure the necessary permits to advance a project towards commercial operation, it should not be allowed to make an unlimited number of MMA requests. If the IC cannot demonstrate to the ISO and PTO's satisfaction, that the delays are reasonable, then interconnection customer(s) should be required to suspend its project by submitting a modification request pursuant to Article 5.16 – Suspension of the GIA or UFA. In accordance with the Generator Management BPM Section 10 -

Suspension, interconnection customer(s) must demonstrate to the ISO and PTO(s) how they plan to advance project(s) towards commercial operation prior to coming out of suspension. If interconnection customers fail to do so, the ISO and SCE should have the ability to terminate interconnection customers GIAs or UFAs that are not advancing towards commercial operation.

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 Six Cities also question if seven years remains the appropriate duration for interconnection customers to remain in the queue. Does the ISO have information about the average length of time in queue for projects that have entered commercial operation? Is there data showing that a different period might be appropriate? If so, revisiting the seven year period could be warranted as a way to remove inactive projects.

SCE supports the ISO developing criteria in Phase 2 of the IPE that grants the ISO and PTO(s) the ability to remove project(s) allocated partial or full deliverability or are energy-only from the queue that fail to advance towards commercial operation in less than seven years by terminating its GIA or UFA, unless interconnection customer(s) can demonstrate that the delay is due to an event not reasonably within its control.

PG&E is supportive of this enhancement's inclusion in the IPE and agrees that it should be addressed in the long-term phase of the IPE. In scenarios where a customer accepts their study, but ceases advancement and communication for over 1 year, the project should be terminated. The continued participation of these inactive projects has a negative effect on the advancement of other generation projects.

LSA/SEIA are not supportive of the ISO taking action other than meeting milestones as it seems beyond the scope of ISO authority, and very burdensome to the ISO, to decide when an IC "should" be taking actions when a GIA milestone has not been missed, and besides the project would not be in violation of the GIA at that point. However, LSA/SEIA have long supported development of a uniform GIA Appendix B milestone table template (and other GIA Appendix formats and content), and that uniform templates could contain standard and appropriate milestones to ensure that a project is not languishing.

5) Any other stakeholder suggestions about moving stalled projects through the queue to completion or withdrawal are welcome.

LSA/SEIA continue to support exploration of voluntary incentives for queue withdrawals, e.g., refundability of security before the 7-year time limit is reached. (LSA/SEIA note that its proposal for enhanced TP Deliverability transfers below is one such proposal, since it would allow projects with deliverability that are not progressing to monetize the value of that deliverability and then withdraw from the queue.)

- Revised Straw Proposal

Stakeholders agreed the Energy-Only projects should not be allowed to stay in the queue forever. Suggestions were made that the ISO should be more assertive in implementing BPM for Generator Management, Section 6.5.2.1 states that "projects requesting to remain in the queue" beyond the applicable limit "clearly demonstrate that: "(1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC's control; and (3) the requested COD is achievable in light of any engineering, permitting and/or construction impediments." The ISO supports CalWEA's proposal that if the Energy-Only project contribute to the short circuit duty on the grid then the project should be terminated.

All stakeholders were in agreement that Interconnection Customers should be reporting the status of their projects and if the customer does not respond, then the ISO should invoke the default clause in the GIA. Section 17.1.1 already provides the Breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist. The ISO supports this proposal.

With respect to 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 were divided. Six Cities asked what the average time in queue was for projects that have achieved COD. The ISO has data on 177 projects that have achieved COD and the average time in queue is 5.7 years. The ISO supports requiring the projects to meet the milestone dates in the GIAs, and to be more proactive if a milestone date is not achieved by providing a notice of breach consistent with Section 17 of the LGIA and Article 7.6 of the SGIA.

For MMAs, SCE proposed limiting the number of COD extension MMAs to securing tax credits, obtaining a PPA or securing permits, otherwise the project should suspend until an actual timeline can be determined. While the ISO understands SCE's concern, the projects are still limited to 7 years in the queue unless network upgrades are extended beyond that time, the project's COD is moved to align with a PPA, or there are legal actions. Limiting the number of CODs would be more complicated to track than relying on the existing mechanisms. The ISO does not propose to change the existing MMA rules.

6 Phase 2 topics - Other Stakeholder Suggested Proposals

6.1 Making it express that when ICs agree to share a gen tie-line, PTO interconnection facilities, and any related IRNUs at a substation across clusters, the shared IRNUs are not subject to GIDAP Section 14.2.2

- Background

SCE's comments to the Issue Paper and Straw Proposal are provided here as a description of the topic details.

SCE would like the ISO to make it explicit that when an Interconnection Customer requests to share a Generation Tie-Line, PTO Interconnection Facilities, and any related IRNUs at a substation or switchyard (e.g., line position to terminate the shared Generation Tie-Line) with an earlier-queued affiliate or non-affiliate project with an executed GIA across clusters, that the shared IRNUs shall not be subject to GIDAP Section 14.2.2 if the interconnection customer of the earlier-queued project terminates its GIA. It is also SCE's position that the Interconnection Studies and IA will reflect that the interconnection customer of the later-queued project will be jointly and severally liable for up to one hundred percent (100%) of the shared IRNU costs, IFS, and ITCC, if applicable. In essence, the Interconnection Studies for the later-queued project will treat the shared IRNUs as CANUs, 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). Once this exclusion is reflected in GIDAP and BPMs, SCE will no longer have to treat applicable GIAs as non-conforming and have to file these GIAs with FERC requesting a waiver of GIDAP Section 14.2.2.

- Stakeholder Feedback

The ISO received comments from nine stakeholders on the proposal outlined above. SCE, PG&E, Strata Clean Energy, NextEra, and Balanced Rock Power indicated their support for the proposal. Specifically, PG&E agreed that the PTO should not be responsible for funding IRNU's when interconnection customers agree to share these facilities across clusters.

CalWEA, REV Renewables, LSA/SEIA, and RWE Renewables oppose this proposal. CalWEA noted that they do not support shared IRNUs being exempted from GIDAP 14.2.2 if projects sharing upgrades have no affiliation with each other. REV Renewables does not support this initiative as it shifts costs of the PHUs to the generators and increases the MCE. Changes to the MCE pose a significant risk to the commercial viability of a project. LSA/SEIA opposes because this would treat an IRNU assigned to one or more earlier-queued projects as a CANU for later-queued projects needing that upgrade after GIA execution by an earlier-queued project assigned that upgrade. The issue is limited to projects that drop out after executing GIAs, which is likely a small subset of drop-outs overall. The issue is further limited to the window between GIA execution by the earlier-queued project(s) and the third posting, which provides the PTO full coverage of IRNU costs. The most costly IRNUs – switching stations – have significant lead times, so the third posting for those upgrades would typically be due soon after GIA execution even where the third posting is phased, because other upgrades have shorter lead times.

- ISO response to Stakeholder comments

Stakeholder comments are fairly evenly split on this issue. The ISO does not have data on the frequency of the issues of concern to SCE, but agrees with LSA/SEIA that the likelihood relatively low. However, SCE believes the impact is significant enough to warrant its consideration. SCE has addressed the issue by filing a non-conforming GIA where parties are sharing facilities. SCE has stated to the ISO that FERC has asked them several times to not file as many non-conforming GIAs. The issue has occurred enough that FERC has noticed the frequency of the issue and SCE would rather have the GIDAP address the issue rather than continue to rely on filings to FERC.

LSA/SEIA commented that for shared IRNUs each project sharing the IRNU must post as though they will bear 100% of the costs until the third posting is made. However, Appendix DD only requires an IC to post its current cost responsibility for an IRNU. The remaining potential cost responsibility for any non-allocation portion of an IRNU is part of the MCE, which has no current posting requirement.

SCE's proposal seeks to deal with issues associated with shared generation tie-lines, PTO interconnection facilities, and IRNUs. Shared gen-tie costs do not have the potential to fall to the PTO, but the shared PTO interconnection facilities that result from a shared gen-tie could. Typically, the cost for IRNUs are significantly greater than the cost of PTO interconnection facilities. IRNUs already have a unique cost allocation treatment to handle SCE's concern when projects sharing an IRNU are in the same cluster. The ISO believes it would not be an unreasonable change to include the same protection for cases that an IRNU is shared across cluster groups.

- Revised Straw Proposal

  The ISO has researched the number of non-conforming GIAs that SCE has filed with FERC due to this issue and has concluded that the number is not sufficient to warrant the tariff changes that SCE is seeking. Furthermore, the ISO believes that PTOs are able to protect themselves in these circumstances by aligning their GIA execution, third posting, and commencement of construction activities, as the tariff contemplates.[19]

  This topic will be dropped from the IPE phase 2 initiative.

6.2 Examining the issue of when a developer issues a notice to proceed to the PTO, requesting the PTO/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

- Background

  In the December 6th Issue Paper and Straw Proposal, the ISO agreed with REV Renewables suggestion to examine the instances when a developer issues a notice to proceed to the Participating TO, and assess the proposal that the 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. The ISO sought stakeholder feedback from stakeholders 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.

- Stakeholder Feedback

  The ISO received stakeholder comments from eight stakeholders regarding REV Renewables added scope item to determine when a developer issues a notice to proceed to the Participating TO, the PTO/ISO should start planning for all upgrades that are required for a project to attain FCDS. CESA, EDF-Renewables, LSA/SEIA, Middle River Power, REV Renewables, and RWE Renewables support adding this

[19] *See* Section 13.1 of the GIDAP (explaining GIAs should be tendered based on construction timelines, thereby aligning with third financial security postings).

scope item. Additionally, CESA encourages deeper discussion to determine how work plans for network upgrades are prioritizes and initiated. Further, LSA/SEIA and RWE Renewables specifically mention the Participating TO should begin on all upgrades as soon as the GIA is executed and the notice to proceed is provided. This will have an immediate impact on construction schedules for network upgrades and Participating TO schedules to meet committed milestones.

CalWEA notes that FCDS should only be granted after the required upgrades are in service unless the ISO revises the NQC reduction methodology. They explain that if a resource is designated FCDS before the needed upgrades, the NQC reduction is ultimately unfairly spread to other FCDS resources that do not require upgrades.

Finally, SCE suggests the ISO consider the minimal incremental benefit of including this proposed topic in scope of the initiative versus the significant added implementation complexity.

- Proposal

The ISO had a Transmission Forum stakeholder meeting on January 21, 2022 and April 26, 2022,[20] that allowed each of the Participating TOs to give a presentation on the status of their transmission upgrade projects which was well received. As of May 23, 2022, the ISO queue has the following projects with executed GIAs with CODs ranging from this 2022 to 2028:

Utility	#	MW
PG&E	62	9,697
SCE	61	17,208
SDG&E	18	3,470
VEA, GLW, DCRT	6	4,147
Total	147	34,523

With this many projects inflight, it's not practical to require the Participating TOs to start every project's network upgrades when the GIA is executed or the notice to proceed is received by the Participating TO. The network upgrades need to be sequenced to meet each project's COD and the work force available for construction. The ISO encourages the Interconnection Customers to work closely with the Participating TO to ensure that both the generation and transmission projects are on track to meet the GIA milestone dates.

[20] California ISO - User groups and recurring meetings (caiso.com)

7 Stakeholder engagement

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

IPE Phase 2	
Date	**Event**
06/07/22	Publish revised straw proposal
06/14/22	Stakeholder conference call on revised straw proposal
06/28/22	Stakeholder comments due on revised straw proposal
07/26/22	Publish draft final proposal
08/02/22	Stakeholder conference call on draft final proposal
08/16/22	Stakeholder comments due on draft final proposal
09/13/22	Publish final proposal and draft tariff language
09/20/22	Stakeholder conference call on final proposal and draft tariff language
10/04/22	Stakeholder comments due on final proposal and draft tariff language
October 26-27 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on June 14, 2022 to review the Phase 2 Revised Straw Proposal. Stakeholders are encouraged to submit comments on this Revised Straw Proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on June 28, 2022.