2023 Interconnection Process Enhancements

Track 2 Straw Proposal

September 21, 2023

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1. Executive Summary

The proposed changes in this Straw Proposal address the unprecedented interconnection request volumes that are unsustainable in the ISO's current processes, and seek to enable rapid deployment of new generation for reliability, affordability, and decarbonization. The proposed process aligns with the strategic direction established by a Memorandum of Understanding between the ISO, California Public Utilities Commission (CPUC), and California Energy Commission (CEC), and is part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement. Through robust stakeholder feedback, and considering the urgent need to bring unprecedented amounts of new capacity online, the ISO proposes a significantly reformed interconnection process that emphasizes project viability and competition for resources identified in local and state resource planning efforts.

- Central to the proposal is the zonal approach, which encourages interconnections in transmission zones with available and approved transmission capacity. Prior to the interconnection request window opening, the ISO will provide accessible data regarding transmission constraints within zones, available transmission plan deliverability (TPD) by constraint, and identification of priority zones, as well as the interconnection heat map, required in FERC Order No. 2023. Projects that seek to interconnect in zones that have no TPD available may only proceed as Option B projects, and thus the ISO proposes modifications to Option B to enable such projects to proceed.

- Interconnection requests will have to meet FERC Order No. 2023 requirements for site control, entry fees, and deposits, and are expected to submit documentation to enable their progression through the interconnection process. The ISO proposes to score each interconnection request based on a set of clear and verifiable criteria used to rank the projects for progression to the study process. If excess proposed capacity exists after applying the viability criteria, the ISO proposes to conduct a market-clearing, sealed-bid auction for the right to be prioritized and studied in a specific zone. Only projects that are deemed equal in viability rating and cause the total MW for a zone to cross the capacity limit for a zone would participate in the auction. Under this proposal, successful projects will succeed to a single-phase study process, consistent with FERC Order No. 2023.

- Once studies are complete, projects would compete to secure TPD in each zone. Recognizing transmission development timeframes, the ISO proposes to construct a methodology to allow multi-year interim deliverability to bridge the gap between the in-service date of a Local Delivery Network Upgrade (LDNU) and a project's requested commercial online date.

- To address the projects currently in the ISO's interconnection queue, the ISO proposes a number of changes to the contract and queue management process to enable projects an opportunity to either withdraw from the queue or advance to commercial operation.

    - Provide a one-time opportunity to withdraw from the queue and receive any unused portion of the applicant's interconnection financial security postings (possibly over time) and in-lieu-of site exclusivity deposits.

    - Extend time to submit a Limited Operation Study (LOS) request to nine months before synchronization. This allows additional time for processing the request, drafting and issuing the study plan, and completing the study with the intent of providing interconnection customers additional time to evaluate the results and make decisions accordingly.

    - Remove suspension rights for all projects that execute a Large Generator Interconnection Agreement (LGIA) in the future.

    - Limit use of TPD transfers to viable projects for legitimate purposes of right-sizing deliverability among different generating units.

    - Impose an unavoidable time-in-queue requirement for all projects in the queue without executed LGIAs to craft an interconnection agreement and subsequently provide notice to proceed and a third financial security posting; this places a financial obligation on the project if it desires to remain in the queue.

    - Modify requirements for asynchronous generators, suspension rights, TPD transferability, project modification requests, shared network financial security postings, timing of modification results and timing of commencing network upgrades.

The process reforms described in greater detail in this Straw Proposal are designed to accelerate progress toward execution of an interconnection agreement and commercial operations for the most viable and competitive projects in areas that align with local and state resource plans. The ISO looks forward to working with stakeholders to refine this proposal in the interest of deploying new resources to meet the ISO's evolving needs.

2. Introduction and Background

With this paper, the California Independent System Operator Corporation (ISO) provides its Track 2 Straw Proposal for the 2023 Interconnection Process Enhancements (IPE) initiative. Given the rapid acceleration of clean energy development to meet reliability and policy needs and the unprecedented level of resource development activities reflected in interconnection requests to the ISO, this Track 2 Straw Proposal explores concepts for significant and transformative improvements to the ISO's role in resource planning coordination, transmission planning, interconnection queuing and management, and power procurement.[1]

California's ambitious decarbonization goals and the large quantities of new clean resources required to meet them have led the ISO to receive unprecedented numbers of interconnection requests from interested resource developers. Many of these requests are in areas that have not been prioritized in the state's resource planning. The ISO seeks to re-imagine the grid interconnection, prioritization, and coordination processes to ensure resource procurement and queuing are effectively oriented toward planned and existing transmission and interconnection capacity, and that they align with transmission development necessary for longer-term resource development.

The 2023 IPE initiative is part of a larger set of foundational framework improvements being coordinated among the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the ISO. The overall strategic direction is set forth in a joint Memorandum of Understanding (MOU)[2] signed by the three parties in December 2022. The MOU sets the direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement. The ISO is now taking on additional reforms to the interconnection queuing process that will leverage the improved coordinated planning resulting from the MOU and help further break down barriers to efficient and timely resource development.

The expectations set out in the MOU are:

- The CPUC will provide clear direction to its jurisdictional load serving entities (LSEs) to focus procurement in the key zones;

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[1] The 2023 IPE initiative is utilizing two tracks. Track 1 focused on immediate adjustments to the Cluster 15 study schedule. The Track 1 tariff changes were approved by the ISO Board on May 18, and will soon be filed with the Federal Energy Regulatory Commission (FERC). Track 2 focuses on targeted modifications to the interconnection and queue management processes. The Track 2 modifications need to be in place when the Cluster 15 studies resume so they can be applied to those studies. It is currently anticipated that the processing for Cluster 15 interconnections requests will resume second quarter, 2024.

[2] The MOU (http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf) is an updated version of a 2010 MOU between the parties.

- Procurement will focus on the expected quantities enabled by the planned transmission development, as set forth in the ISO's transmission planning process (TPP);
- State agencies—including non-CPUC jurisdictional authorities—and LSEs' resource planning and procurement will continue to significantly inform the ISO's TPP.

This approach is necessary because of the long development timeframe of transmission resources relative to many energy supply resources: Procurement of new energy supply resources must consider the availability of transmission resources to ensure reliable delivery of the supply resources to the grid, and supply resources will be stranded if they are developed before this infrastructure is planned, approved, permitted, and constructed.

The ISO is implementing a more proactive approach to transmission planning and managing projects through the transmission and generation development processes. This approach is grounded in open access and the policy and reliability needs of the state to inform queuing and procurement and facilitate project development.

The ISO's strategic intent is for the revised interconnection procedures to prioritize interconnection requests aligned with priority zones where transmission capacity exists or is approved for development. This will help shape the interconnection queue as the resource development community responds with proposed projects in areas enabled by transmission development. Additionally, it will drive resource development with the operational characteristics and in geographic locations consistent with resource planning conducted by the CEC, CPUC, and other local regulatory authorities (LRAs) and the ISO's transmission planning, which is based on that resource planning.

This initiative will focus on the specific changes necessary for the ISO's cluster study and queue management processes to achieve these outcomes while maintaining open access to the transmission grid. With the significant increase in projects in the queue, the existing tools to move projects to commercial operation are insufficient. There are 188 gigawatts (GW) in the queue pre-Cluster 15, and 354 GW in Cluster 15 alone. The ISO needs a significantly reformed structure to advance viable projects and prevent stagnant projects from hindering the progress of viable projects in the queue.

The ISO also understands the need to ensure consistent treatment of all LSEs and offtakers – CPUC-jurisdictional and non-jurisdictional – within the ISO footprint on matters of generator interconnection and transmission planning, and seeks to ensure opportunities for non-CPUC jurisdictional entities to have their project needs considered in the TPP.

This initiative proposes certain tariff amendments to enhance the process for studying and approving interconnection requests and developing additional tools for managing the queue. The ISO plans for these proposed tariff changes to go to the Board of Governors only because the changes apply to the ISO-controlled grid, and the ISO is not proposing changes to real-time market rules.

This Straw Proposal describes a number of new or modified elements to the ISO's interconnection process for additional stakeholder consideration. In Section 3, the ISO describes the stakeholder working group process and implications of FERC Order No. 2023 on the Straw Proposal elements and the initiative. Section 4 includes descriptions of the details of the straw proposal elements related to interconnection request intake, and Section 5 outlines a number of proposed changes to the ISO's contract and queue management practices. Sections 6 and 7 outline next steps for the initiative and approvals.

3. Factors Influencing the Straw Proposal

Recognizing the potential implications of significant interconnection reform on the ISO's stakeholders, the ISO engaged stakeholders in an intensive working group process to inform development of the Straw Proposal. The ISO and stakeholders also need to respond to FERC Order No. 2023, which the ISO views as the new baseline for its interconnection process. The FERC Order will necessitate additional changes to the ISO's interconnection process, impacting the scope of this initiative.

3.1. Working Group Process

During stakeholder working group meetings in summer 2023, the ISO and stakeholders developed the following agreed-upon principles and problem statements to assist in aligning objectives in the solution-development process. Problem statements addressed two categories of challenges with the interconnection process; interconnection request intake and queue management. Once the ISO and stakeholders established agreed-upon principles and problem statements, working group meetings focused on proposed concepts and solutions. Stakeholders engaged by providing informal survey responses, candid feedback, experience, expertise, and thoughtful proposals that aligned with the agreed-upon principles and problem statements. The ISO greatly appreciates the time and effort stakeholders spent to shape this straw proposal and improve the ISO's interconnection process.

3.1.1. Principles

1. Prioritize interconnection in zones where transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades.

2. Ensure meaningful study results that take into account system capability, resource planning and procurement. Resource planning includes the CEC, CPUC, and other LRAs engaged in these activities.
3. Align interconnection and transmission plan deliverability processes with resource procurement functions.
4. Enhance the procedures, including contracting and queue management, for ensuring projects proceed to commercial operation and determine how to appropriately handle those that do not.
5. Enhance the interconnection process's ability to support the procurement necessary to meet CPUC resource portfolios and California Energy Commission (CEC) SB 100 portfolios, and portfolios established by non-CPUC jurisdictional LRAs.
6. Enhance public awareness and accessibility of data and information to support and enable the above principles.
7. All Parties share increased responsibility to improve the interconnection process.

Parties agreed that in addition, the reforms must:

- Continue to ensure open access and avoid discriminatory or preferential treatment, and
- Result in a process that is manageable, meaningful, and sustainable to the ISO and stakeholders.

3.1.2. Problem Statements: Interconnection Request Intake

1. Unsustainable increases in interconnection requests have overwhelmed the Generator Interconnection and Deliverability Allocation Procedures.
2. Increases in interconnection requests have overwhelmed critical planning and engineering resources across the industry.
3. The Generator Interconnection and Deliverability Allocation Procedures, as currently designed, simply cannot efficiently accommodate the increased amount of interconnection requests.
4. Study results lose accuracy, meaning and utility when the level of cluster interconnection request capacity is multiple times the existing or planned transmission capacity for an area.
5. Lack of accurate, actionable information on the location and amounts of available interconnection and deliverability capacity prior to opening the interconnection request windows results in increased numbers of interconnection requests.
6. The issue of project viability is a widely discussed industry topic. However, project viability is not well defined and not currently considered for interconnection request acceptance criteria in the Generator Interconnection and Deliverability Allocation Procedures.
7. Stakeholders need to define which viability criteria are appropriate for a new interconnection request, the point in the process viability is tested and determine if process revisions are needed.

8. Technology solutions to enhance interconnection request intake, validation and study process may exist and should be explored for opportunities to increase process efficiencies and reduce time and staff requirements.
9. Timelines for design and construction of interconnection customer required upgrades continue to increase, negatively impacting achievable commercial online dates (CODs).

3.1.3. Problem Statements: Queue Management

1. Following the study process, a number of projects in the interconnection queue do not proceed to commercial operations as expected (e.g. delay executing a GIA, meet contract milestones, etc.) and remain in the queue without indication of their intent to proceed to contracting or construction.
2. The current processes for managing the queue present certain challenges for projects proceeding to commercial operation (e.g. modifications, limited operation study, commercial viability criteria, etc.) and challenges for the ISO's enforcement of projects that are not.
3. There is a lack of common understanding of what it means for a project to maintain 'viability' as it moves through the stages to achieve commercial operation.

3.2. FERC Order No. 2023

On July 27, 2023, the Federal Energy Regulatory Commission (FERC) Issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements.[3] The ISO does not open compliance filings to stakeholder feedback, however due to the overlapping issues between FERC Order No. 2023 compliance and IPE Track 2, stakeholders should know that the ISO intends to comply with the order as fully and quickly as possible, with a compliance filing in early December.

The ISO encourages stakeholders to focus comments and feedback in future workshops and working group meetings on issues distinct to the IPE straw proposal. The Straw Proposal will identify any proposed reforms based on FERC Order No. 2023, and therefore out of scope of this initiative. At a high level, these elements include:

- Interconnection request requirements
- Information availability and heat map
- Entry fees and deposits for queue entry
- Site control requirements as defined in FERC Order No. 2023
- Single-phase study process
- Financial posting requirements and withdrawal penalties

[3] The order was subsequently published in the Federal Register on September 6, 2023.

- Affected system processes
- Consideration of grid-enhancing technologies
- Consideration of planned storage operation

Because the ISO must comply with Order No. 2023 and implement the proposals in this paper before commencing the Cluster 15 interconnection study, the ISO will maintain high volume in the queue in 2024. As such, the ISO proposes not to open an interconnection request window in 2024. The tariff requirements for such a cluster would be in flux, and additional queue volume would compound the challenges described below.

4. Interconnection Request Intake

4.1. The Zonal Approach: Data Accessibility

Background

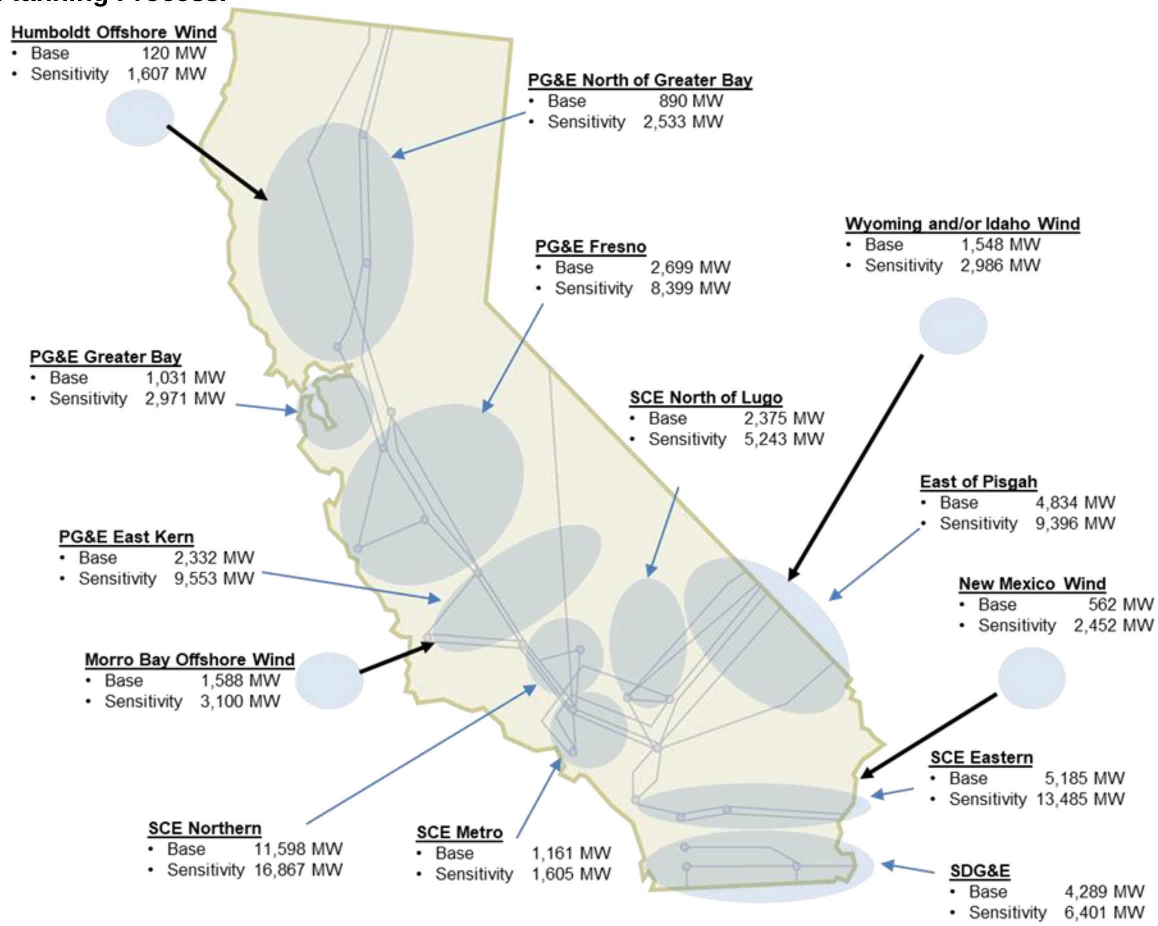
As noted in the first principle, a central tenet of the ISO's reform is the zonal approach; the prioritization of projects that seek to utilize available capacity and are in zones where there are planned capacity additions approved in the ISO TPP, as established in state and local regulatory authority resource planning portfolios. Along with this approach, the ISO understands the importance of maintaining open access and providing a path for projects that seek to interconnect where no transmission exists or has been approved.

The ISO relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU signed by the three parties in December 2022 reaffirms our respective roles and commitment to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement so the three entities are synchronized in integrating new resources promptly.

The ISO's 2022-2023 Transmission Plan took a zonal approach to planning for the resources in the portfolio provided by the CPUC for this planning cycle, setting the foundation for the alignment of procurement and interconnection process enhancements, as envisioned in the MOU.

Figure 1 identifies the transmission zones and the installed capacity of resources in the base and sensitivity portfolios provided by the CPUC for the 2022-2023 transmission planning process (TPP).[4] The transmission zones illustrated below are aligned with the transmission interconnection areas used in the generation interconnection process.

Figure 1. Transmission Zones and installed capacity of resources for the 2022-2023 Transmission Planning Process.



The portfolios that the CPUC generates have been mapped by the CPUC, with input from the CEC and the ISO, to the substations[5] within each of the transmission areas or zones identifying the installed capacity and technology of the resources in the portfolios.

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[4] Figure 3.4-1 on page 63 of the ISO's Board Approved 2022-2023 Transmission Plan. http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf

[5] The resource-to-busbar mapping process is documented in the CPUC report entitled Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP with further refinements as described in the CPUC staff report entitled Modeling Assumptions for the 2022-2023 Transmission Planning Process. https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP_V2021_12_21.pdf
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF

Table 1 lists the interconnection planning areas that the resources have been mapped to, based on the CPUC's busbar mapping effort. The table lists the transmission area/zone, substation, technology and capacity in the workbooks provided by the CPUC for the mapping of the resources.

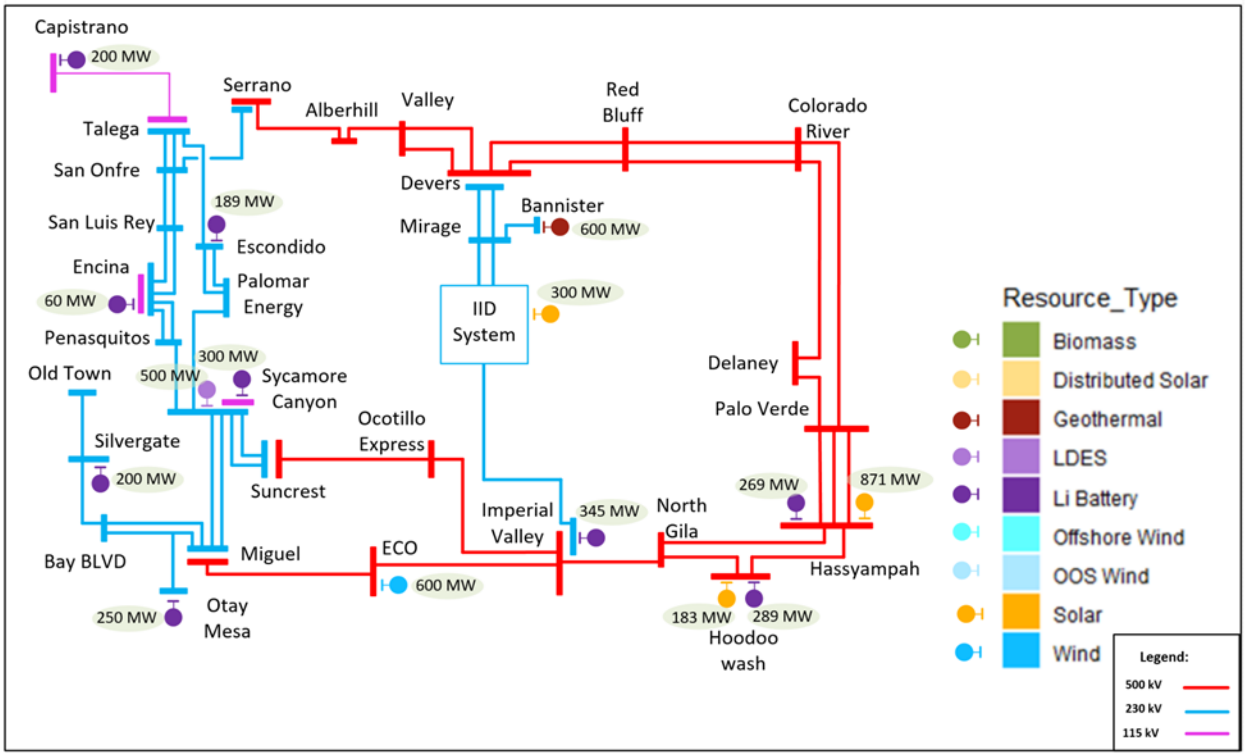
Table 1. Interconnection Planning Areas based on CPUC busbar mapping effort.[6]

				22-23 TPP 38 MMT Proposed Base Case Final Mapped Amount		
Transmisison Area	Substation	Voltage	Resource Type	FCDS (MW)	EODS (MW)	Total (MW)
PG&E Fresno Study Area	Alpaugh	115	Biomass/Biogas	3	-	3
SCE Northern Area	Antelope	230	Distributed Solar	3	-	3
SCE Northern Area	Antelope	230	Li_Battery	439	-	439
SCE Northern Area	Antelope	230	Solar	450	497	947
PG&E East Kern Study Area	Arco	230	Li_Battery	76	-	76
PG&E East Kern Study Area	Arco	230	Solar	125	28	153
SDG&E Study Area	Bannister	230	Geothermal	600	-	600
SCE Metro Study Area	Barre	230	Li_Battery	10	-	10
East of Pisgah Study Area	Beatty(VEA system	138	Geothermal	440	-	440
PG&E North of Greater Bay Study Area	Bellota	115	Biomass/Biogas	4	-	4
PG&E North of Greater Bay Study Area	Bellota	115	Li_Battery	132	-	132
SCE Northern Area	Big Creek Hydro Fa	230	Biomass/Biogas	6	-	6

The ISO's 2022-2023 Transmission Plan provided a single-line diagram for each of the transmission zones indicating the capacity and technology type where the resources in the portfolio were mapped to the electrical grid in the zone. Figure 2, below, is an example of the resource mapping in the San Diego transmission zone from the 2022-2023 Transmission Plan.[7]

[6] https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08_v2.xlsx
[7] Figure 3.5-15 on page 96 of the ISO's Board Approved 2022-2023 Transmission Plan. http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf

Figure 2. Example of resource mapping in the San Diego transmission zone.



In the ISO's annual transmission plan, the ISO assesses the reliability of the transmission system to meet the forecasted load requirements and the ability to deliver resources to load for the resources identified in the portfolios provided by the CPUC. If needs are identified in the base resource portfolio, the ISO assesses alternatives to determine the transmission mitigation solution to be recommended to the ISO's Board of Governors for approval in the transmission plan. In determining the best solution for the base case needs, the ISO also considers the needs of the sensitivity portfolios.

In addition to information in the transmission plan, the ISO provides information on the capability within the transmission zones in the ISO's Transmission Capability Estimates for the CPUC's Resource Planning Process[8] and for the ISO's annual Transmission Plan Deliverability Allocation Report.[9] Within the workbook for the transmission capability estimates for identified constraints in each of the transmission zones/areas, the available Transmission Plan Deliverability (TPD) is identified associated with the constraint along with the area deliverability network upgrade (ADNU) that would be needed to increase the TPD. For each ADNU, the estimated increase in TPD and the estimated cost and duration to construct the ADNU is provided. Some constraints may

[8] https://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf
[9] https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf (on Market Participant Portal)

overlap more than one of the transmission zones. Table 2 illustrates the constraints in the San Diego transmission zone, as an example.

Table 2. Constraints in the San Diego Transmission Zone[10]

Transmission capability estimates for use in the CPUC's IRP process - Revised 6/28/2023						
Transmission Constraint	Affected Resource Locations	Condition Under Which Constraint is Binding (On-peak and/or Off-peak)	Estimated FCDS Capability Based on On-peak Study Resource Output (MW)**		ADNU & Cost Estimate ($million)	
			Transmission Plan Capability***	Incremental due to ADNU	ADNU (Time to Construct)	Cost (2022$)
SDG&E Interconnection Area Constraints						
Capistrano-San Onofre 230 kV constraint	SDGE local area	On-peak	1,500	920	Capistrano-San Onofre 230 kV upgrade (60 months)	$58
Chicarita 138 kV constraint	Baja, Imperial, SDGE local area	On-peak	224	700	Chicarita 138 kV Upgrades (48 months)	$100
El Cajon 69 kV constraint	SDGE local area	On-peak	406	547	El Cajon 69 kV Upgrade (48 months)	$15
Internal San Diego Area constraint	Baja, Imperial, SDGE local area	On-Peak, Off-Peak	1,001	2,757	Internal San Diego Area reconductors (48 months)	$107
Miguel 69 kV constraint	SDGE local area	On-peak	231	431	Miguel 69 kV upgrades (48 months)	$671
Encina - San Luis Rey 230 kV constraint	Baja, Imperial, Arizona, SDGE local area	On-Peak, Off-Peak	1,922	4,660	New Encina - San Luis Rey 230 kV line (120 months)	$84
East of Miguel constraint	Baja, Imperial, Arizona, Riverside East	On-Peak, Off-Peak	1,035	1,286	New Imperial Valley - Serrano 500 kV line (188 months)	$2,713
San Luis Rey-San Onofre 230 kV line constraint	Baja, Imperial, Arizona, SDGE local area	On-Peak, Off-Peak	2,018	4,254	New San Luis Rey-San Onofre 230 kV line (120 months)	$107
Ocean Ranch 69 kV constraint	SDGE local area	On-peak	274	692	Ocean Ranch 69 kV upgrade (48 months)	$28
Otay Mesa 230 kV constraint	Imperial, SDGE local area	On-peak	1,425	2,189	Otay Mesa 230 kV upgrade (60 months)	$80
Silvergate - Bay Blvd 230 kV constraint	Baja, Imperial, SDGE local area	On-Peak, Off-Peak	663	4,887	Silvergate - Bay Blvd 230 kV 3-ohm Series Reactor (36 months)	$30
Silvergate-Old Town 230 kV constraint	Baja, Imperial, SDGE local area	On-peak	1,221	2,522	Silvergate-Old Town 230 kV Upgrades (60 months)	$283
Talega 230 kV constraint	SDGE local area	On-peak	1,205	2,201	Talega 230 kV Upgrades (60 months)	$211
Trabuco-Capistrano 138 kV constraint	SDGE local area	On-peak	501	556	Trabuco-Capistrano 138 kV upgrade (48 months)	$103

Below, Figure 3 and Table 3 from the 2023 Transmission Plan Deliverability Report[11] illustrate the transmission system area for one constraint within the San Diego transmission zone. Table 3 also includes the requested TPD, allocated TPD, and remaining TPD for one of the transmission constraints in the transmission zone. The report indicated that TPD is allocated to the TPD candidates after first preserving capacity for the 2,148 MW prior commitment that is not yet operational, and that there is no available TPD for the eligible candidates.

[10] http://www.caiso.com/Documents/Transmission-Capability-Estimates-for-use-in-the-CPUCs-Integrated-Resource-Planning-Process.xlsx
[11] Figure 4.1 and Table 4.2 on page 22 of the 2023 Transmission Plan Deliverability Allocation Report. https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf

Figure 3. Map of transmission system area for one constraint within the San Diego transmission zone

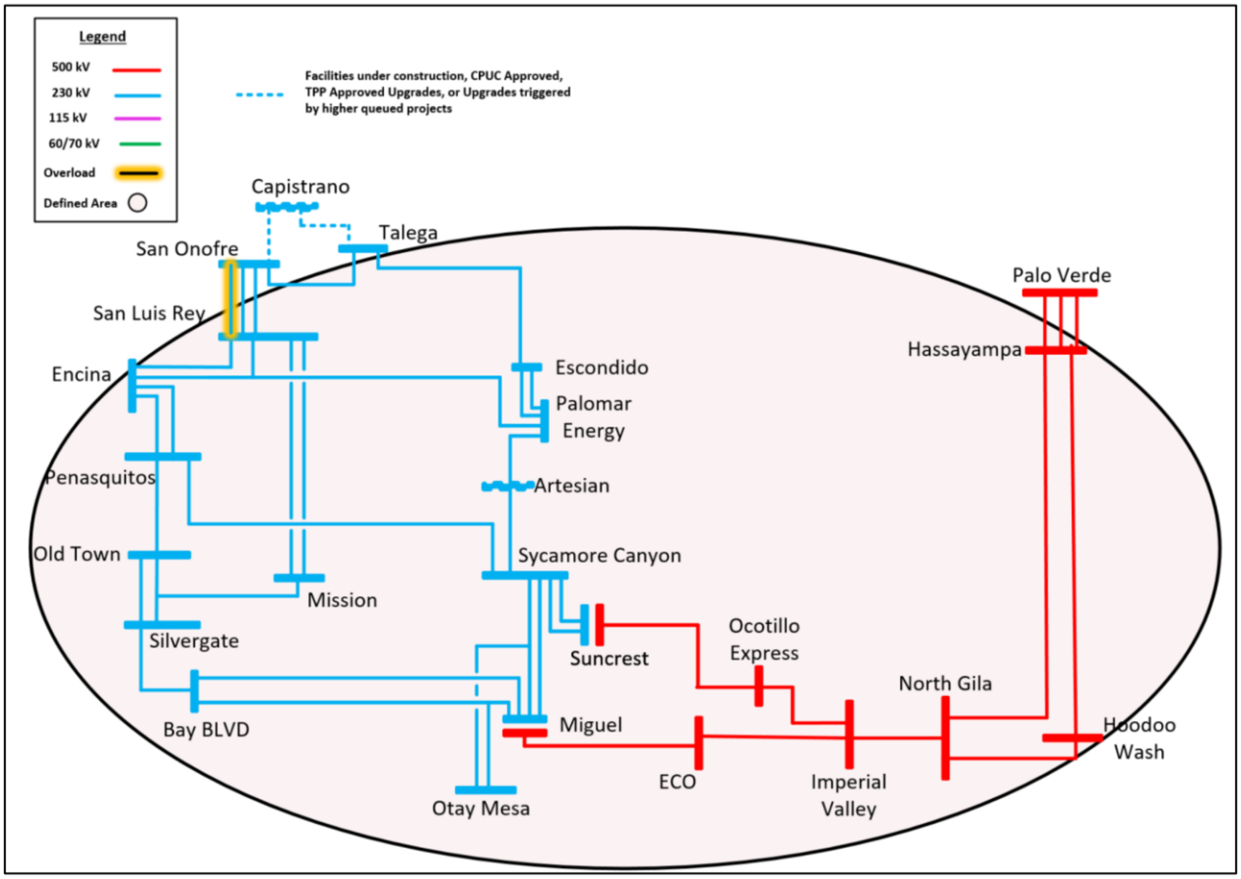


Table 3. Available TPD for one constraint within the San Diego transmission zone

Non-Operational Prior Commitment (MW)	2148
Eligible TPD Candidate (MW)	2747
TPD Allocated (MW)	0
Remaining TPD available (MW)	0

In summary, for each major constraint limiting resource capacity in a zone, the following information is available: the constraint, the limit imposed by the constraint, the cost and timeline associated with mitigating the constraint, the amount of capacity that has already been allocated, and the capacity remaining and available for future allocation (if any).

Stakeholder Feedback

Initial stakeholder feedback on the discussion draft concept of prioritizing interconnections in zones with available transmission capacity indicated some discomfort with the approach, particularly related to the ISO's ability to maintain open access. In working group meetings, stakeholders emphasized the importance of (1) data transparency and accessibility to inform developers on where transmission capacity would be located and (2) an alternative self-funding path (either Option B or a subscriber model) to enable projects to interconnect outside of the priority zones.

After working group discussions, and with caveats, stakeholder comments were more supportive of the zonal approach. LSA supported the provision of data to provide locational information, and additionally suggested "(1) better information about the boundaries of the proposed TPD zones; (2) available TPD for each zone, and smaller areas within zones; and (3) physical interconnection information, e.g., available positions within substations and substation expansion potential." Avantus supported the inclusion of this information, in addition to data on Points of Interconnection (POIs) located in Local Capacity Areas and on each POI's DFAX as it relates to known, binding constraints within the target zones. New Leaf Energy supported this information as well.

AES proposed development of an Annual Interconnection Overview Report (Annual Report) to be circulated at least 6 months prior to the cluster window opening, which would provide increased data, pricing transparency, and preferred resource guidance to interconnection customers.

NCPA expressed strong concerns with the zonal approach if the zones are limited to only those designated by the CPUC. NCPA noted that non-jurisdictional entities may have needs outside of the zones designated by the CPUC and cautioned the ISO against prohibiting projects outside of the zones. NCPA noted that the following types of projects should not be discouraged from entering the queue:

- Repowering or replacement projects at existing interconnection points.
- Projects located in local capacity zones.
- Projects to serve local load.

The CPUC expressed a commitment to working with the ISO in the next phase of the initiative to determine opportunities to align the timing of interconnection processes with the IRP planning and procurement process. The ISO shares this commitment and views this coordination and alignment, in addition to coordination and alignment with the CEC and LRAs, as a critical and foundational element of the IPE initiative.

Proposal

A central tenet of this Straw Proposal is the prioritization of projects in zones with available transmission capacity for progression into the study process. This proposal reflects the first principle established by the working group to "Prioritize interconnection in zones where transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades." Projects or interconnection requests outside of the zones will still have the option to self-fund network upgrades through a modified "Option B" process, as explained below.

The ISO understands that access to information is critical to the zonal approach. In order to provide stakeholders with information on the priority transmission zones prior to the interconnection request window, the ISO will develop a heat map along with the associated information, as required in FERC Order No. 2023. Based on discussions with entities that have already developed a heat map, the ISO anticipates developing a heat map by Q3/Q4 2024. Besides the heat map, the ISO will work to ensure consistency of single line diagrams for each of the transmission zones and transmission interconnection areas in the generation interconnection process. The diagrams will identify the boundaries of the zones/area, location of resources in the portfolios and the queue, the affected stations and the available TPD for allocation behind each of the transmission constraints.

In addition to the portfolios received by the CPUC for the annual transmission planning process, the ISO will coordinate with the LRAs and non-CPUC jurisdictional entities to determine their approved resources in their individual IRPs to include in the transmission planning analysis.

4.2. Interconnection Request Requirements and Review

Background

Throughout this initiative and working group process, the ISO and stakeholders have explored new or elevated requirements for a complete interconnection request as a means to require a greater level of project readiness before study. The Discussion Paper explored two key concepts related to interconnection request requirements and review, which the ISO and stakeholders explored further in the working group process:

1. Qualification process for determining projects studied for Full Capacity Delivery Status (FCDS) and study path for all others.
2. Only study projects requested by LSEs and other offtakers.

Additional concepts explored in working groups included elevated readiness requirements for queue entry, collection of LSE input on priority projects, scoring criteria, and higher fees and deposits.

Stakeholder Feedback

Several parties, including CalWEA, Rev Renewables, and GridStor opposed readiness requirements used as gating items to determine eligibility for queue entry. Other stakeholders supported scoring criteria applied to projects in the queue to advance the most ready projects, including Clearway, EDF-Renewables, EDP Renewables, Geothermal Rising, Golden State Clean Energy, GridStor, Hanwha Q Cells USA, Intersect Power, LSA, Ormat Technologies, Inc., Pacific Gas & Electric, Six Cities, Sonoma Clean Power Authority, Southern California Edison, and Vistra Corp. Stakeholders supported increased use of scoring criteria to assess viability and advancement to the study process. GridStor referred to this concept as a means to "merit-based rationing of resources" for interconnection study and completion.

During stakeholder working group meetings, developers raised strong concerns on the concept of limiting studies to projects requested by LSEs and other offtakers. PTOs and LSEs meanwhile expressed support for incorporating some indications of commercial interest (e.g. letter of interest) in the interconnection request review process. Several parties, including AES, EDF Renewables, and NCPA, suggested incorporation of off-taker interest in the scoring criteria. PG&E did not recommend the ISO use LSE interest as a viability criteria to prioritize projects in the Cluster Study Process since "interest" is non-binding and there is insufficient information at the initial stage for an LSE to understand the potential network upgrade costs and timeline that determine the ultimate cost to utility customers and the ability of a resource to meet RA online date requirements. Sonoma Clean Power raised similar concerns and recommended an election process that mimics the Remaining Import Capability election process, where LSE's influence is calibrated to load share.

Proposals

The detailed proposals below seek to comply with new FERC requirements, address stakeholder concerns and proposals, and gather information necessary to evaluate project readiness and inform prioritization of projects to the study phase. The ISO proposes the following requirements and procedural steps during the interconnection request intake and review window:

1. Site control requirements consistent with FERC Order No. 2023
2. Entry fees and study deposits consistent with FERC Order No. 2023
3. Information required with interconnection requests
4. Prioritization of long lead-time resources specific to resource planning portfolios

Upon submittal of an interconnection request, the ISO proposes to adopt the stakeholder proposal to apply scoring criteria to advance the most "ready" projects into the study process for each zone. If the scoring criteria does not sufficiently reduce the capacity to be studied in each zone, the ISO proposes a sealed-bid auction. The ISO explains each component, below.

4.2.1 Site Control

Among related reforms, FERC Order No. 2023 increases the site control requirement to 90% upon submission of an interconnection request; therefore, the IPE process will no longer consider changes to the current site exclusivity requirement. The ISO will comply with the site control requirements established in Order No. 2023, which will apply to Cluster 15.

4.2.2 Entry fees and deposits

Likewise, Order No. 2023 imposes several new entry fees and study deposits. The ISO will comply with FERC Order No. 2023, and does not intend to explore similar requirements in the IPE at this time, with the limited exception of Option B interconnection requests below.

4.2.3 Information Required with Interconnection Requests

The ISO and stakeholders agree on the importance of ensuring open access and avoiding discriminatory or preferential treatment while developing a process that is manageable, meaningful, and sustainable to the ISO and stakeholders. In developing qualification and eligibility criteria designed to limit the interconnection project capacity studied in the transmission zones to an amount relative to the available transmission capacity in each zone, the ISO agrees it is critical to consider potential design elements that prevent any entity from exerting market power. To ensure that no developer can capture an inappropriate market share of the available transmission capacity, the ISO proposes to limit the number of requests that a developer may submit in any given cluster application window to 25% of the available transmission MW capacity across the ISO footprint for that cluster.

Additionally, as discussed in the Auction section below, the ISO will require bidders to submit their bid prices associated with each interconnection request, if the zone requires an auction after scoring criteria are applied.

4.2.4 Prioritization of Long Lead-Time Resources Specific to Resource Planning Portfolios

The discussion above on the zonal approach describes the coordination of resource planning and the TPP. Within the portfolios, there are regions that the CPUC determines are of particular value for development of specific resource technologies. The portfolios designate the specific resource types and the amounts to be developed, which the TPP uses to determine the transmission projects needed to support those specific resource plans. This can result in the CPUC designating an area for significant resource development that would not typically be the focus of large transmission expansion due to the relatively lower load levels and low load growth of the area. When such an area becomes the focus of significant generation development due to an emerging generation technology or an emerging opportunity for resource diversity, a large transmission project may be needed to support the emerging need. In these circumstances, the basis for the TPP project is serving the specific technologies in the portfolio. In other words, the TPP project would not be needed but for the CPUC portfolio identifying the technology at the specific location.

Several stakeholders suggested specific mechanisms to recognize the unique need for certain long lead-time resources in the interconnection process. The ISO must ensure transmission capacity is reserved for the specific technologies the transmission project is designed to serve. It may take many years for the transmission project to be permitted, constructed, and go into service, requiring the associated TPD to not be allocated until the emerging technology is ready to enter the TPD allocation process. An example is transmission being developed to support the significant capacity amounts of offshore wind designated by the CPUC portfolio for Northern California.

The ISO intends to develop a specific methodology to appropriately handle this issue as part of the modifications to the TPD allocation process within this IPE initiative. The ISO will convene stakeholder discussions once the ISO finalizes the details related to scoring criteria and the zonal study process, which are needed before contemplating significant changes to the TPD allocation process.

4.2.5 Scoring Criteria for Prioritization to the Study Process

Background

In the Discussion Document, the ISO raised the possibility of instituting a scoring process based on a set of criteria that would rank interconnection requests based on their readiness. The scoring process would be the first and – if effective – the final process for determining the projects that would be studied in each of the transmission zones. If the scoring process did not result in enough diversity in project scores to produce a project ranking that clearly determines the projects that would be studied in each transmission zone, a second mechanism would be needed.

Stakeholder Feedback

Many stakeholders supported the use of scoring criteria to evaluate readiness of interconnection requests that should progress to the study process, with AES and Intersect proposing specific systems to assess project readiness. Several stakeholders supported the AES and Intersect proposals for a preliminary scoring system for interconnection priority zones.

Stakeholders supported development of a points system, as proposed by AES, which would result in ranking projects highest to lowest. Stakeholders also proposed the following criteria for assessing project readiness:

- Level of site control
- Commercial viability of proposed technology at utility scale
- Project attributes:
  - Ability to provide Local RA (with criteria related to need)
  - CPUC mid-term reliability (MTR) eligibility
  - Unique or needed operational capabilities:
    - Resource diversity
    - Location-specific limitations
    - Specific benefits to the system
    - State policy requirements or needs
  - Expansions of existing facilities and sites
- Permitting status
  - Conditional use permit
  - Land, water, and air permits
- Engineering design status (5% to 30% engineering design)
- Location
  - Energy communities (as defined by IRS)
  - Use of existing Gen-Tie
  - Location in load pockets not needing ADNUs
  - Uncontested, available open substation position
- Deposits in lieu of various items

NCPA noted that commercial “criteria such as a Power Purchase Agreement (PPA) letter of intent, RFP shortlist or inclusion in an LSE resource plan might not be generally appropriate for all proposed projects at the time of queue entry. However, these criteria should still be incorporated into the queue process and given significant weight in maintaining queue positions over time.” NCPA also noted that the TPD allocation criteria embodies many of these considerations and could serve as a starting point.

Proposal

This proposal builds on the scoring criteria proposed by AES and Intersect, and supported by many others, with modifications based on stakeholder comment. The ISO proposes to use a points-based scoring system in specific zones where interconnection requests and their capacity exceed available transmission capacity within each zone by more than 150 percent. The ISO considered criteria suggested by stakeholders and selected criteria the ISO believes are appropriate at this early point in the interconnection process. The ISO also preferred those criteria easily validated upon acceptance of interconnection requests during the cluster request window. To assist in the ISO's validation process, the ISO will require interconnection customers to provide proof of each scoring criterion below.

Many stakeholders noted, and the ISO understands, that several criteria may be improbable to expect before the study process (e.g. an executed PPA); however, it is important to include factors that indicate, and thus incentivize, advanced development projects. Doing so aligns with the concept of first-ready, first-served projects, and enables prompt development strategies.

The ISO requests additional stakeholder comments on the proposed scoring criteria regarding the reasonableness of interconnection customers to provide information at the interconnection request application stage and on the expected ease for the ISO to validate on a timely basis the information within the interconnection request window. If necessary and if stakeholder interest exists, the ISO will convene a subgroup of stakeholders to refine these criteria. However, if stakeholders and the ISO are unable to develop a sufficiently clear and easily verifiable scoring mechanism, the ISO must rely on the auction to filter interconnection requests to a manageable amount for study.

Interest from an offtaker □ Letter of interest from a California LSE or eligible commercial offtaker (20) Note: The ISO intends to establish requirements for what constitutes “interest” and how to validate it.	0-20
Commercial readiness (select only one – 50 points max) □ Shortlisted with a California LSE or eligible commercial offtaker (20) □ Included as a preferred resource in an LRA-approved LSE’s resource plan (30) □ Executed term sheet for a power purchase agreement (30) □ Executed Power Purchase Agreement of a minimum term five years (50) *Note: The ISO understands that historically, few projects have progressed far into commercial conversations before the study process, particularly without specific pricing information. The ISO invites stakeholder feedback on new procedures or commercial criteria for prioritization of interconnection requests.	0-50
Permitting status (select all that apply – 50 points max) □ Indication of community support (5) □ Application of land use permit (10) □ Initiation of California Environmental Quality Act (CEQA) review or application for AB 205 expedited environmental review of eligible projects filed (15) □ Conditional use permit (CUP) granted [or demonstration of alternative permitting] (20) *Note: Some projects may have permit waivers or not require National Environmental Policy Act (NEPA)/CEQA. The ISO needs to consider treatment of exemptions or special cases and invites stakeholder feedback on this category. Stakeholders also should suggest other permits the ISO should consider. The ISO notes, however, that it does not employ permitting experts, and can only use straightforward and easily verifiable permitting criteria.	0-50
Project attributes (select all that apply – 40 points max) □ Ability to provide Local Resource Adequacy (RA) in an LCRA with an ISO demonstrated need for additional capacity in that local area (20) □ Meets the requirements of a current CPUC procurement order or non-jurisdictional LSE’s Request for Proposals (20) *Note: The ISO seeks stakeholder feedback on how best to validate that a project meets these requirements.	0-40
Project location (select all that apply – 30 points max) □ Energy community as defined by Internal Revenue Service guidance in the Inflation Reduction Act (10) □ Location in load pockets not needing Area Delivery Network Upgrades (ADNUs) (20)	0-30
Expansion on an operational facility – (select only one – 50 points max) □ Expansion of an existing facility (40) □ Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource (50)	0-50
Scoring range	**0-240 points**

This proposal does not include the following criteria:

- Additional site control scoring or requirements: Because 90% site control will be a requirement for study, the ISO does not propose additional requirements.
- Diversity adders and prioritization of specific resource types: Conformance with IRP scenarios and state policy needs should be inherent in the zonal approach, which is based on CEC and CPUC resource planning. Including scoring criteria may result in double-counting the same analysis. Stakeholders requested prioritization of projects that can satisfy mid-term procurement orders and prioritization of long lead-time resources; however, both are necessary, and prioritizing both would counteract in the scoring criteria. The ISO recognizes that certain considerations may be warranted for both types of resources in the TPD allocation process, as previously discussed in Section 4.2.4.of this proposal, dealing with prioritization of long lead-time resources specific to resource planning portfolios.

The ISO proposes to apply the following scoring criteria on a points system to select projects that can fulfill 150% of the available and/or planned transmission capacity in each zone. Stakeholder feedback suggested a range between 150-300% of available TPD in each zone to enhance competition. In addition to the limit on the number of requests that a developer may submit in any given cluster application window, as discussed in Section 4.2.3, the ISO believes that selection of 150% of available or planned capacity per zone is appropriate.

As discussed below in Section 4.3.1, the ISO proposes to study 150% of the available and/or planned transmission capacity in each zone.

Interest from non-CPUC jurisdictional LSEs

With any scoring process, the ISO proposes to automatically include any project that a non-CPUC jurisdictional LSE demonstrates is a preferred resource in its resource plan that has been approved by its Local Regulatory Authority.

Incorporation of LSE Interest and Procurement Activities

With the MOU on resource and transmission planning, procurement, and interconnection in mind, the ISO encourages more discussion and stakeholder feedback on opportunities to incorporate LSE procurement activities[12] earlier in the interconnection process, in order to facilitate the zonal approach and appropriately sequence implementation of these practices to lead to a more efficient process. The

[12] Activities could take a number of forms, including, results from LSE requests for information or offers, project screening, bilateral discussions, and narrowing the list of projects to those of interest within their procurement processes.

ISO recognizes the challenges and stakeholder concerns associated with the use of commercial status as an indicator of viability early in the interconnection process (i.e. during the interconnection request window). As described below, based on strong stakeholder support, the ISO will consider modifications to the TPD Allocation criteria as a means to incorporate commercial interest once studies are complete and parties have a clearer picture of costs. Nevertheless, the ISO encourages further discussion of how best to incorporate LSE input throughout the reformed interconnection process.

As described above, the objectives set forth in the MOU are:

- The CPUC will provide clear direction to its jurisdictional load serving entities (LSEs) to focus procurement in the key zones;
- Procurement will focus on the expected quantities enabled by the planned transmission development, as set forth in the ISO's transmission planning process (TPP);
- State agencies—including non-CPUC jurisdictional authorities—and LSEs' resource planning and procurement will continue to significantly inform the ISO's TPP.

These objectives necessitate clear alignment on roles and processes between planning, procurement, and interconnection, and will be a topic of ongoing discussion and refinement in this initiative.

4.2.6 Requirements for Option B Projects

The ISO proposes that projects filing interconnection requests outside of priority transmission zones will be placed into Option B, meaning these projects must finance all assigned network upgrades without cash reimbursement. These projects must still meet all requirements for submitting an interconnection request, including the information required for project scoring. The ISO may still require a minimum viability score to be studied and invites feedback from stakeholders on the necessity of a threshold score for Option B projects. The ISO does not believe that requiring a minimum viability score would inhibit open access. A minimum viability score would simply be another transparent requirement, like site control and commercial readiness deposits.

4.3 Prioritization of Projects for the Study Process

The ISO will review and score Interconnection Request information to identify projects most ready to proceed into the study process. This scoring process is described in Section 4.2.5. The ISO will apply the scoring criteria to select projects that can fulfill 150% of the available and planned transmission capacity in each zone. However, if the scoring process does not sufficiently reduce the number of viable projects in a transmission zone, the ISO proposes to conduct an auction.

4.3.1 Zonal Auctions

Background

The ISO initially raised the concept of an auction to reduce the number of interconnection requests to a more manageable number in the discussion paper, posted in May of 2023, and discussed the concept during stakeholder workshops and working group meetings this summer.

The paper proposed to study only projects that win an auction, and suggested a working group process to develop an auction methodology where the results would determine the specific projects to be studied in that year's cluster studies.

Stakeholder Feedback

Except for one auction proposal from Shell and Savion, the majority of stakeholders either fully opposed or questioned an auction. Stakeholders raised a number of questions associated with these concerns:

- How can the auction design prevent single-entity market power?
- Could auction winners transfer or sell awarded deliverability to other entities?
- Would auction winners be subject to penalties for failure to produce allocated resource in a timely manner?
- How would resource attributes be factored into the auction process to ensure a diverse resource portfolio?
- To what extent would auction payments be refunded?
- How would auction revenues be used?

Proposal

Auction Design

The ISO understands the novelty of this concept raises a number of questions for stakeholders, and has attempted to them in the proposal below. The ISO proposes continued discussion of an auction, as it may be essential to achieve manageable queue volumes and preserve the competition of viable projects in each zone.

The ISO proposes to conduct a market-clearing, sealed-bid auction for the right to be prioritized and studied in a specific zone. The supply in the auction would be determined in advance by the ISO as a reasonable MW quantity to study. The ISO proposes to study 150% of the available and planned transmission capacity for each zone. The ISO considered stakeholder feedback suggesting capacity quantities between 150%-300% of the available TPD in each zone, and continues to believe that a 150% capacity threshold will enhance the efficiency and value of the study process while ensuring sufficient competition to secure TPD in each zone after the study process.

Interconnection customers would submit bids on a dollars per MW basis as part of their initial interconnection request. Bidders would only submit at-risk auction financial security based on their bid if an auction is required and they win the auction and proceed to be studied. If a project reaches commercial operation, its auction dollars bid would be refunded to the interconnection customer. If it withdraws from queue (or is deemed withdrawn), it would partially lose its bid value, depending on timing of the withdrawal, similar to the ISO's current financial security requirements or Order No. 2023's withdrawal penalty structure.

Dollars at risk would be based on a clearing price set by the marginal bid. All interconnection customers would have the same $/MW rate applied to their specific capacity where the auction clears.

Through the auction process, the ISO proposes to accept project capacity in any zone up to 150% of that zone's available transmission capacity. Due to the variability and "lumpiness" of project sizes, it likely will not be possible to exactly hit the 150% mark in zones where an auction is performed. It is also possible that a single relatively large project will try to utilize all of the available transmission in a particular zone, which may be problematic. For example, in a zone that has 1,000 MW of available capacity, a 1,000 MW single technology project may not be the best solution if there are a number of other smaller projects with a variety of project technologies that more closely match the CPUC's portfolio for that zone. The optimal solution for handling these issues may require other design elements or more experience with the process. Like any new market function, it is reasonable to expect the need to refine the optimal solution over time.

The ISO will conduct auctions only if there is excess proposed capacity after applying the viability criteria. Only projects that are deemed equal in viability rating and cause the total MW for a zone to cross the capacity limit for a zone will participate in the auction. Projects with high viability scores that do not cause the total MW for a zone to cross the capacity limit will be studied and not required to participate in an auction. Projects with lower viability scores that exceed the MW capacity for a zone will not participate in the auction and will not be studied. This aligns with the ISO's objective to ensure that the most viable projects move forward into the study process, through the auction, if necessary. However, this also magnifies the need for clear and verifiable viability scoring criteria.

For example:

- Assume there is 266 MW of available transmission capacity in a zone, and thus 400 MW capacity deemed reasonable to study
- Seven 100 MW projects apply in this zone
  - Projects A and B have a viability score of 70
  - Projects C, D, and E have a viability score of 60
  - Project F and G have a viability score of 50
- Projects A and B are selected to be studied since they have the highest viability score, and therefore they do not need to compete in the auction,
- Only projects C, D and E will be considered in the auction because their projects cross the 400 MW. The two projects with the highest auction bids will win the auction, be studied, and must post the clearing price (the lower of the two winning bids) prior to being studied.
- Projects F and G will not be considered in the auction and will not be studied.

Use of Auction Revenues

Stakeholders voiced concerns that the auction process may increase costs to ratepayers. The ISO proposes that non-refundable auction funds resulting from project withdrawals offset and support still-needed network upgrades. Projects that successfully compete in an auction and reach commercial operation will be refunded their auction-posted security. Even if setting aside the value of the posted auction security for several years may slightly increase a project's development cost, the ISO believes the benefits of this proposal outweigh that cost.

The ISO proposes that any auction funds posted by an interconnection customer be in favor of the applicable Participating Transmission Owner (TO), meaning that the interconnection customer would post the financial security, allowing the Participating TO to liquidate (or cash out) the financial security at the appropriate time to fund network upgrades. Once the project reaches commercial operation, the interconnection customer will be entitled to a refund or release of the posted auction financial security. However if a project withdraws, or is withdrawn prior to reaching commercial operation, some or all of the posted auction financial security will be forfeited. The proposed forfeiture amounts are intentionally set to be significant to further discourage interconnection customers from submitting less viable projects. If a project withdraws, the applicable Participating TO will liquidate the posted financial security for the withdrawn project and forward the auction funds to the ISO. The ISO will then disperse these funds to the applicable Participating TO or the interconnection customer as illustrated in the following table:

Withdrawal Timeline (Timeline is consistent with FERC Order 2023)	Amount to be refunded to the Interconnection Customer	Amount to be dispersed to the applicable Participating TO
If Interconnection customer withdraws or is deemed withdrawn during the Cluster Study or after receipt of a Cluster Study Report, but prior to commencement of the Cluster Restudy or Interconnection Facilities Study	85%	15%
If Interconnection customer withdraws or is deemed withdrawn during the Cluster Restudy or after receipt of any applicable restudy reports issued, but prior to commencement of the Interconnection Facilities Study	70%	30%
If Interconnection customer withdraws or is deemed withdrawn during the Interconnection Facilities Study, after receipt of the Interconnection Facilities Study Report issued, or after receipt of the draft LGIA but before Interconnection customer has executed an LGIA or has requested that its LGIA be filed unexecuted	50%	50%
If Interconnection customer has executed an LGIA or has requested that its LGIA be filed unexecuted	0%	100%

The amounts dispersed to the applicable TO will be used as a contribution in aid of construction for still needed Network Upgrades.[13] The dispersed amounts will be reflected as a reduction in the cost of these network upgrades for purposes of reallocating the cost responsibility for these network upgrades. Any amounts that exceed the costs of still needed network upgrades will be applied to offset Regional Transmission Revenue Requirements, as recovered through the CAISO's Transmission Access Charge, and to offset Local Transmission Revenue Requirements.

Acceptable Interconnection Financial Security Instruments

[13] Dispersed on a pro-rata percentage basis of the original allocated costs to the withdrawn project.

The auction funds posted by an interconnection customer may be any combination of the following types of financial security instruments provided in favor of the applicable Participating TO(s):

a. an irrevocable and unconditional letter of credit issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's;
b. an irrevocable and unconditional surety bond issued by an insurance company that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's;
c. an unconditional and irrevocable guaranty issued by a company that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's;
d. a cash deposit standing to the credit of the applicable Participating TO(s) in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the applicable Participating TO(s);
e. a certificate of deposit in the name of the applicable Participating TO(s) issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's; or
f. a payment bond certificate in the name of the applicable Participating TO(s) issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's.

If at any time the guarantor of the auction fund financial security fails to maintain the credit rating required above, the Interconnection customer shall provide to the applicable Participating TO(s) replacement Interconnection Financial Security meeting the requirements within five (5) Business Days of the change in credit rating.

4.3.2 Modifications to the Merchant-Financing "Option B" Process

Background

As discussed above, the zonal approach is foundational to this straw proposal, so the ISO proposes to prioritize the study process to focus on interconnection requests that seek to interconnect in areas that have available transmission capacity, including planned capacity that will be available for allocation in the TPD allocation process. However, stakeholders emphasized the importance of retaining and providing opportunities to identify and provide alternative points of interconnection or upgrades.

Projects that seek to interconnect and meet the conditions required for the zonal studies where transmission capacity exists are eligible to proceed as Option A projects. Projects that seek to interconnect in zones that have no TPD available may only proceed as Option B projects.[14] The ISO will not provide any opportunity for these projects to convert to Option A later in queue.

Stakeholder Feedback

Several stakeholders supported modifications to Option B, including LSA, Clearway Energy, EDP Renewables, Geothermal Rising, Golden State Clean Energy, New Leaf Energy, Rev Renewables, Sonoma Clean Power Authority, and Vistra. No stakeholders opposed Option B changes or usability.

LSA and Rev Renewables presented several ideas to reform Option B, given that the option may be used more often under a zonal framework. A number of stakeholders were supportive of these proposals. LSA Option B suggestions included:

- Voluntary disclosure and notice within cluster groups of developers and projects willing to explore Option B funding
- Facilitated project financing support
- Post-TPD allocation election option
- Reversion option
- Clear path toward TPD allocation for Option B projects

Vistra proposed a network upgrade subscription approach under Option B. AES, BAMx, Rev Renewables, and New Leaf Energy supported this proposal. Several other stakeholders supported further exploration of this concept either in future iterations of IPE or in the Transmission Planning Process. The ISO suggests this proposal is most relevant to the Transmission Planning Process Initiative.

Sonoma Clean Power noted support for the concept of expanding interconnection options for projects, but regarding Vistra's network upgrade subscription proposal, SCP noted that as a load serving entity, it "would likely only consider contracting with subscription resources that have a high market value (e.g., out-of-state wind, geothermal, or offshore wind) that can justify the project-specific costs that would be directly passed along to its ratepayers." SCE opposed this model as well.

Proposal

[14] The exceptions to this are projects that meet the criteria in section 3.2.5 of this paper related to criteria for non-CPUC jurisdictional LSEs.

The ISO proposes the following modifications to Option B in the ISO Tariff Appendix DD.

Only projects seeking to interconnect in areas that have no available or planned TPD capacity are eligible to select Option B. Option B will not be available to projects that were not selected to be studied in transmission zones that have available or planned capacity. Doing so would be counterproductive to solving the issue identified in the problem statements, above, of studying capacity levels so high that the study results lose accuracy, meaning and utility.

The Option B path ensures that projects seeking to interconnect in areas with no available deliverability capacity have a path forward. Areas with available deliverability capacity are open to all projects through a competitive process. If an Option A project is unable to receive an allocation of TPD, it will not be eligible to convert to Option B because that would require a restudy.

1. Option B projects will not have to compete for TPD in the allocation process because they will trigger and finance all of the delivery network upgrades they will require, without taking any deliverability from other delivery network upgrades.

2. Option B projects that require Local Delivery Network Upgrades (LDNUs) will be eligible for cost recovery of the Interconnection Financial Security (IFS) posted for the LDNU in the same manner as an Option A projects. LDNUs are more project specific than Area Delivery Network Upgrades (ADNUs) that, outside of the Option B process, are developed in the TPP. In the transition to the study approach based on the available deliverability within zones, the ISO believes it is appropriate to allow developers to be reimbursed for LDNUs. This will also result in the Option B path being more viable.

3. An Option B project's funding of the construction of its required ADNU will not receive repayment. The interconnection customer will be eligible to receive Merchant Transmission Congestion Revenue Rights (CRRs) in accordance with CAISO Tariff Section 36.11.

4. Option B projects will be given a project status of Full Capacity Deliverability Status (FCDS) or Partial Capacity Deliverability Status (PCDS), as specified in its GIA and in accordance with the Resource Adequacy counting rules.

5. The ISO will publish the estimated cost of ADNUs, in dollars per MW, as available from prior cluster studies. The project would be required to make an initial IFS posting of 30% of the cost of the ADNU, based on the amount of deliverability requested as part of its interconnection request during the cluster

application window. Fifty percent of the IFS posting would be non-refundable if the project withdraws after its interconnection request is determined to be complete. The 30% amount is higher than the FERC Order No. 2023 various deposit levels because it only applies to the cost of the ADNU and because the interconnection customer has a pre-study estimate of its cost. The deposit needs to be high enough to ensure that only interconnection customers confident of their project’s viability under the Option B path chose the option.

6. If no applicable ADNU cost estimate is available, the project would be required to post an amount equal to $10,000 per MW, but not less than $500,000. The amount is equal to the FERC Order No. 2023 deposit in lieu of site control, but without an upper limit. If no ADNU estimate is available, an interconnection customer could request the ISO develop an estimate for a specific zone in the ensuing cluster study and submit its interconnection request in the following cluster application window. An interconnection customer may only request one such estimate per cluster. If the interconnection customer has affiliated entities, the one estimate request per cluster will apply to all affiliated entities.

7. Option B projects that complete the single cluster study process will be required to increase their posting to 50% to remain active and will no longer be eligible for a partial refund of their IFS posting upon withdrawal.

4.3.3 Single-Phase Study Process

The ISO appreciates the thoughtful stakeholder proposals on improvements to the study process, as well as support for a single-phase study process. As noted, the ISO intends to comply with the FERC Order No. 2023 study process to the greatest extent possible. This will include adopting a single-phase study process. In other words, the ISO will perform the reliability and deliverability studies as it does today with the Phase II interconnection study. Study results will provide the same information as the Phase II study results. The ISO likely will continue to perform the annual reassessment or use a similar mechanism to update study results and cost allocations just as it does today, maintaining cost caps and providing relief for any errors or omissions identified after the initial study. The ISO believes with the revised interconnection request selection and study processes described in this paper, a two-phase study process is no longer needed, and a single-phase study will significantly expedite the study process.

4.4 Competition to Secure TPD in Each Zone

4.4.1 Modifications to the Transmission Plan Deliverability Allocation Process

Background

The ISO's Discussion Paper noted timing challenges for projects entering the queue. Projects aligned with the CPUC's 2022-2023 IRP and TPP portfolios will likely need to stay in the queue for a number of years, waiting for required upgrades to be completed. Projects become eligible to seek an allocation after the cluster studies are completed and then have a limited period where they are eligible to seek an allocation before being converted to Energy Only. The TPD allocation process gives highest priority to projects that have executed a PPA or are shortlisted. For projects with longer lead-time network upgrades, the window of opportunity to seek an allocation can be several years before their network upgrades can be completed and possibly before LSEs are seeking to procure projects with later CODs.

Since most offtakers require a project to be eligible for resource adequacy (RA), the TPD allocation process is very important to project developers. Thus, it is necessary to consider changes to the TPD allocation criteria within the framework of the proposed changes to the interconnection process within IPE and the changes required by FERC Order No. 2023.

Stakeholder Feedback

Clearway and NextEra raised this issue in comments on the Discussion Paper as well as working groups and comments on the working group process. NextEra proposed alignment of the TPD allocation process with first-ready, first-served principles through revisions to the current affidavit scoring process associated with the TPD allocation process. Clearway noted that pre-Cluster 15 projects in the upcoming 2024 TPD allocation process currently face a deadline of 2026-2027 to sign PPAs to obtain an allocation of deliverability, which is not realistic for projects reliant on deliverability upgrades that will not be completed until 2032 or beyond. Clearway's proposed solution was also to revise or relax the TPD allocation requirements for projects entering the 2024 TPD allocation process to provide evidence of shortlist or PPA execution.

Clearway also suggested exploration of broader solutions to timing challenges, such as creation of an "open window" to seek deliverability for the next three years or timing the TPD allocation and retention requirements based on when TPD will be available, working backwards from expected in-service dates for NUs.

Rev Renewables proposed that CAISO work backwards from the date of the longest lead-time of the expected upgrade to be complete to a to-be-defined number of years to set the requirement to show at least a shortlist and allow a type of "parking" that holds deliverability until then.

Many stakeholders encouraged refinements to the deliverability allocation methodology, including ACP-California, CPUC, EDF-R, GridStor, LSA, New Leaf Energy (proposal), NextEra, and Vistra (proposal).The ISO and stakeholders have identified a number of issues that need to be addressed in proposed new TPD allocation procedures.

1. Allocation procedures that take into account long lead-time ADNUs where LSEs are likely not procuring resources with commercial operation dates that align with the in-service date of long lead-time ADNUs.
2. Consideration of the interim deliverability methodology to provide multi-year interim deliverability to projects that have not yet achieved commercial operation. This issue is discussed below in the Modifications to Interim Deliverability section.
3. Reservations of TPD associated with long lead-time ADNUs planned to serve specific generation technologies in the CPUC portfolio, particularly where the designated resource has a long development timeline.
4. Whether to modify the TPD allocation scoring rubric to award points to projects that can provide Local RA or reduce impacts on overloaded transmission elements.
5. Whether to allow Energy Only (EO) projects to be eligible to seek an allocation of TPD in allocation groups A, B and D.[15]
6. Whether to allow offtakers to seek an allocation for projects that meet the allocation eligibility requirements for groups A and B, and other options to better align resource procurement with the TPD allocation processes.
7. Requirement of TPD request affidavits to provide a processing fee.

Proposal

The ISO received significant stakeholder feedback on the need to refine the TPD allocation process. The ISO will continue to explore these issues with stakeholders to develop a proposal that effectively addresses all of the issues listed above. The ISO would like to finalize details around scoring criteria and the study process before contemplating significant changes to the TPD allocation process.

Longer-term procurement may be appropriate and aligned with the MOU, so that LSEs are contracting for these resources with longer lead times on a timely basis.

The TPD allocation process must align with the following processes:

- Interconnection studies

[15] Continuing to allow EO projects to seek an allocation of TPD in allocation group C – any project that has achieved commercial operation.

- Resource procurement processes of offtakers
- Availability of existing TPD
- In-service dates of ADNUs approved in the transmission planning process, and
- Changes resulting from the generation deliverability methodology review initiative.

At this time, the ISO only proposes to limit the eligibility of Energy Only projects to seek an allocation of TPD to allocation group C: projects that have achieved commercial operation.[16] The ISO believes this proposal would significantly reduce the number of low-viability projects lingering in the queue. The ISO queue has many Energy Only projects that linger in the queue while waiting to execute a PPA and re-seek an allocation. Rarely do LSEs contract with these projects and if they do, the project still must be studied to determine if it is behind a deliverability constraint. If an Energy Only project is currently behind a deliverability constraint, the project is not eligible for an allocation.

In this initiative, the ISO invites continued discussion of the stakeholder proposals on TPD allocations described above. If stakeholder interest exists, the ISO suggests formation of a subgroup to develop a more defined proposal.

4.4.2 Modifications to Interim Deliverability

Background

The ISO is committed to bringing new, approved, and necessary transmission resources into service as soon as possible to ensure reliability and an affordable pathway to decarbonization. The pace of generation development and procurement, however, must align with the pace of transmission development. The State is experiencing heightened levels of competition for new generation, as evidenced by the swelling of the ISO's interconnection queue in Clusters 14 and 15. The ISO has approved many new transmission projects in the last two TPP cycles and is committed to facilitating their on-time completion. But many of these projects will take 8-10 years to complete. Available transmission capacity on the system is finite, which limits the amount of TPD the ISO can allocate to assure generators they can deliver to load during stressed system conditions.

Stakeholders have asked the ISO to provide longer-term interim deliverability for projects that can go into commercial operation prior to the completion of associated network upgrades.

[16] This proposal would not limit the ability of partial deliverability projects or projects adding storage from seeking an allocation for the EO portion of their projects.

The ISO addressed a similar issue in the Deliverability Assessment Methodology Straw Proposal with the following proposals:

- Provide a new type of interim deliverability, “conditional deliverability,” to projects waiting for completion of delayed network upgrades, taking a risk-based approach and respecting reliability needs.
- Provide “conditional deliverability” to resources waiting for the n-2 related deliverability upgrades to be completed, assuming they would not cause cascading outages.

Stakeholder Feedback

Clearway proposed an assurance of interim deliverability in response to this challenge, whereby the ISO would perform an additional study to provide an earlier look at interim deliverability and produce a report that would ensure interim deliverability.

The CPUC supports continued exploration of improvements to the interim deliverability allocation to ensure that existing deliverability is utilized as much as possible. CalCCA suggested that the ISO analyze the magnitude, locations, and durations of deliverability shortages flagged by stakeholders and work with the CPUC to explore opportunities to improve the deliverability retention process and interim deliverability process to mitigate the potential impacts of lengthy transmission upgrades and network upgrades on project Commercial Operation Dates (CODs).

The ISO understands that the request is for a new multi-year interim deliverability allocation that bridges the gap between a long lead-time TPP upgrade needed for deliverability and the projects’ requested COD that could be years before the TPP upgrade is in service. However, after the 2023 TPD Allocation there was no TPD available in the areas where major TPP projects were approved in the 2021-2022 and 2022-2023 TPP processes. Therefore, there would be nothing available to allocate until those transmission projects go into service. One small opportunity would be long-lead time LDNUs. All generators responsible for funding an LDNU must wait until that LDNU goes into service before they can obtain FCDS. For some LDNUs there may be some interim deliverability available for some generators responsible for that upgrade, but not enough for all. The new interim deliverability would only apply to generators behind LDNUs and not behind any other constraints. It would be requested within the standard TPD allocation process and could allow a resource to go into operation several years before the LDNU is in service, which would enable the resource to compete for a PPA where LSEs are procuring projects with nearer-term CODs.

Proposal

The ISO will continue to work with stakeholders in both the IPE initiative and the Deliverability Assessment Methodology initiative to construct a methodology where a multi-year interim deliverability allocation process could bridge the gap between the in-service date of an LDNU and the project's requested COD. The proposal would be centered on the use case where a project needs to wait for an LDNU to go into service before it can be deemed deliverable, but would go into commercial operation sooner if it could receive interim deliverability on a multi-years basis. This is a new form of multi-year interim deliverability that would allow a project to seek a TPD allocation earlier in its development process. The ISO believes that more time and stakeholder discussion are necessary to consider the various complexities of this new provision.

5 Contract and Queue Management

5.1 One-Time Withdrawal Opportunity

Background

Many projects linger in the queue without justification. Some of these may have significant financial commitments, including deposits and financial security postings, so a voluntary withdrawal from the queue could pose financial risk to the projects. Further, there are little to no incentives for projects to withdraw if they can remain in the queue and continue to seek a buyer for the project. These lingering projects may also impact upgrade requirements for later-queued projects or clusters. Allowing lingering projects a one-time incentive to withdraw may change the cost calculus for lingering projects, which will improve study results for other-queued projects and potentially allow for cancellation of some network upgrades.

Through several stakeholder working group discussions, stakeholders have discussed many opportunities that limit a party’s risk of financial obligation due to cascading costs associated with a volume of projects withdrawing. As such, the ISO and stakeholders could not gain consensus from all stakeholders on a suggested approach for this straw proposal.

Stakeholder Feedback

Most stakeholders, including PTOs and developers, support the proposal to allow a one-time withdrawal opportunity. However, stakeholder comments did not indicate consensus on how to assign costs of network upgrades if a project withdraws. A number of stakeholders indicated that a one-time option for projects to withdraw from the queue with limited financial implications may help to remove some projects from the queue and potentially eliminate the need for certain upgrades for projects proceeding to commercial operation, in addition to creating opportunities for new projects that may be more viable and ready to proceed.

AES, Avantus, Clearway, EDF-Renewables, EDPR, Gridstor, Geothermal Rising. Gridwell, Intersect Power, LSA, New Leaf Energy, and NextEra support a minimum one-time opportunity for sensible/strategic penalty free withdrawals subject to CAISO determination.

Avantus also supports a cyclic penalty free withdrawal scheme when queue conditions warrant the need (e.g., opposite of Appendix DD Section 3.10 Emergency Interconnection Process). Akin to suspension and emergency processes established in GIDAP, this policy would be meant for preserving some flexibility to supplement primary policies.

Middle River Power supported this idea in concept but noted concerns that there is not enough money "at risk" to motivate developers to take advantage of such an opportunity.

New Leaf Energy also supports the concept and is sympathetic to arguments that withdrawals could lead to increased costs in the short term if projects currently responsible for approved upgrades exit the queue. But New Leaf feels the reduced need for future developer/ratepayer funding for unneeded upgrades would outweigh the costs of any refunds.

The PTOs expressed strong opposition to any cost-shifting from the withdrawing projects to the PTOs, even if the costs would ultimately be reimbursed to the original interconnection customer. PG&E and SCE support the one-time withdrawal opportunity from the queue, contingent on the waiving of Appendix DD Section 14.2.2 to not shift the cost burden onto the Participating TOs of interconnection upgrade costs that are being caused by applications of interconnection customers. PG&E and SCE only support this proposal if Participating TOs are able to:

1. Recover the withdrawing customer's share of actual costs incurred from either a deposit previously received or, if costs exceed deposit amounts, then collect the incremental amount for the interconnection customer; and

2. Recover costs needed to complete withdrawal of the interconnection customer, including any engineering activities needed to remove the project from the Participating TO, up to the end of the applicable reconciliation period per the interconnection customer GIA at the time of withdrawal.

3. SCE further noted that all cost responsibility/shifts will fall to any current or later-clustered project(s) that have a shared NU, and/or a PNU that the withdrawal project was supposed to fund; cost responsibilities may increase.

SDG&E supported the one-time withdrawal opportunity, but cautioned against allowing it to become a regular occurrence. Six Cities noted that the ISO and stakeholders should proceed cautiously in evaluating proposals that might shift cost or risk to transmission customers.

Proposal

The ISO agrees with stakeholders that there is value in providing an incentive for lingering projects to exit the queue such as improving study results for other-queued projects, potentially allowing for cancellation of some network upgrades, and allowing new projects to move forward. The ISO proposes to provide a one-time opportunity for projects to withdraw from the queue and receive any unused portion of their interconnection financial security postings (possibly over time) and in-lieu-of site exclusivity deposits. This proposal would be applicable to all active projects in the queue.

Under current circumstances, when a project withdraws, a portion of the non-refundable funds[17] is withheld from a project's IFS posting and is utilized to fund shared network upgrades assigned to that project. Providing an immediate refund of the non-refundable financial security to interconnection customers who withdraw under a one-time opportunity could result in additional financing costs to the Participating TOs under Appendix DD Section 14.2.2. This section requires the Participating TO to fund certain upgrades, identified as precursor network upgrades (PNUs), that are still needed by the same-or later-queued projects where at least one GIA was executed by a withdrawn project and where costs would not cascade to later queued projects still requiring those upgrades.

The straw proposal attempts to share the financing cost burden for the still-needed PNUs among the Participating TOs and the withdrawing interconnection customer.

The ISO proposes that the withdrawn project's previously non-refundable portion of the IFS that is posted for a still-needed PNU(s) continue to be held and used by the Participating TO to fund the specific PNU(s). Once the PNUs are in service, the Participating TO will refund the withdrawn project's money to the interconnection customer consistent with the existing reimbursement requirements.

Process Example:

- QXXX1 (the Project) is assigned Upgrade A
- Project posted 30% IFS = $1,000,000
- Project withdraws as part of this one-time opportunity
- Upgrade A is still required for a same- or later-cluster project
- Up-to 50% of 30% IFS (currently non-refundable) = $500,000

[17] Section 7.6 of the CAISO Tariff Appendix DD for GIDAP

- the currently refundable portion ($500,000) is returned to the Project
- The remaining non-refundable portion ($500,000) continues to be held by the Participating TO

- Participating TO will use the $500,000 funds to help fund Upgrade A
- Once upgrade is developed and in service, the Participating TO refunds $500,000 to the Project

The ISO believes that this one-time withdrawal proposal presents a balance of benefits and cost impacts to all parties and will incentivize lingering interconnection customers to withdraw. Interconnection customers that withdraw can recover all of their unused portion of interconnection financial security; however, some of these funds may take years to be refunded depending on the timing of construction of still-needed PNUs.

The ISO also considered a cost shift for PNUs from withdrawing interconnection customers to the same-or-later queued interconnection customers that may see their overall current cost responsibility reduced due to this one-time withdrawal opportunity. But ultimately, the ISO determined that it would result in retroactive ratemaking.

As an alternative to the above proposal, the ISO believes stakeholders should continue to explore the Participating TOs covering the cost of PNUs, which they otherwise would have ultimately included in their rate base. The ISO is concerned that the timing and mechanics of the above proposal may not sufficiently incentivize projects to withdraw, whereas immediate and full refunds would have a better chance at success.

5.2 Limited Operation Study Process Updates

Background

Under Section 14.2.4 of the GIDAP, projects are currently limited to requesting a Limited Operation Study (LOS) five months before the project’s synchronization date. Including the full timeline of developing, reviewing, and finalizing the LOS study plan and then completing the LOS itself, interconnection customers may be left with few months to make business and construction decisions based on the results. The reason for the five-month timeline is the LOS is completed using operations data and not planning data. Therefore, operations data is more likely to change from when the study is complete to when it is implemented. The further out or longer-lead time LOS would substantially diminish the accuracy of the results, and whether the results could actually be implemented.

Additionally, developers simultaneously submit modification requests that may impact the ability to start the study or the results of a completed LOS. The ISO seeks to clarify situations where modifications requests are submitted that may impact the LOS process or study results.

Stakeholder Feedback

Intersect Power, SCE, PG&E and LSA appreciated the proposed timeline extension to nine months. However, because of the extremely high benefit from such earlier information, Intersect Power recommended continued consideration of ways to offer a longer timeline of at least 2 years. SCE commented that submitting a LOS request too early could trigger the need for a LOS restudy if system assumptions change. PG&E commented that LOSs should not commence until Material Modification Assessment (MMA) results are published if the modification involves any change in technical parameters of the project.

Avantus believes this adjustment is likely to only help projects that may be threatened by upgrade delays while falling short on giving interconnection customers an opportunity to partially bring a project online where the longest and second longest upgrade have substantial lead time differences. Avantus urges the ISO to consider allowing interconnection customers to submit LOS requests 5-to-9 months prior to the 2nd or 3rd longest lead upgrade to determine the capacity that can be brought online ahead of such upgrades. Avantus expressed concerns of impacts to a project when submitting late-stage MMA when a LOS is needed. Avantus also supports Clearway's proposal to allowing multiple LOS limits achievable in a given COD year e.g., X MW between Y and Z hours for A and B seasons.

REV suggests that CAISO maintain MMA and LOS as independent processes. These often happen during critical phases of project development and timely resolution of the request is important.

Clearway believes there are occasions when the project requires an MMA to finalize the facility's design basis, equipment selection and amended LGIA to support project financing during the 6-month window when the interconnection customer is first allowed to request an LOS report. Limiting when an LOS can be requested impacts how quickly certain projects can be placed in-service.

Proposal

The ISO proposes to increase time to submit a LOS request to 9 months before synchronization. This allows additional time for processing the request, drafting and issuing the study plan, and 45 days to complete the study with the intent of providing interconnection customers additional time to evaluate the results and make decisions accordingly. The ISO cannot extend this timeline further. As stakeholders noted, the LOS already represents a re-evaluation of the customer's interconnection studies. The LOS requires analyzing the grid's current ability to accommodate additional generation knowing the assigned *reliability* network upgrades are not online. Performing this evaluation earlier would lead to less accurate results and risk reliability and safety. Additional, earlier LOSs also would divert planning and operational resources away from the primary interconnection studies.

The ISO also proposes to clarify the interaction between the MMA and LOS. The ISO will clarify in the Business Practice Manual (BPM) for Generator Management that a technical-MMA interconnection request package submitted simultaneously with a LOS must be deemed complete and valid prior to the start of the LOS. If an MMA is submitted after a LOS is completed and the MMA results may impact the LOS, the LOS will need to be re-evaluated and potentially restarted.

5.3 Consistent requirements for all asynchronous generating facilities.

Background

The ISO has seen increased deployment of asynchronous resources and has experienced operational issues with a varying size of resources. Currently, the requirements for large and small generating facilities differ in the operating, recording, and reporting requirements for inverters. The ISO seeks to bring consistency for all generating facilities.

Stakeholder Feedback

SCE supports the proposal to bring consistency to the two agreements.

Proposal

For consistency across all asynchronous generating facilities, the ISO proposes to make Attachment 7 of the Small Generator Interconnection Agreement (SGIA) – Interconnection Requirements for Asynchronous Generating Facilities consistent with Appendix H of the Large Generator Interconnection Agreement (LGIA).

5.4 Remove Suspension Rights from LGIA[18]

Background

As presented in the August 1st workgroup discussion, to date, only one of seven identified projects that have requested suspension has achieved commercial operation, two have withdrawn, two are currently in suspended status, and two are still active in the queue. The ISO's concern is that interconnection customers have the ability to use

[18] Suspension rights are in Section 5.16 of Appendix EE of the ISO tariff.

the current suspension provisions to enter the interconnection process with not-ready projects and then use suspension while they attempt to find an offtaker.

Stakeholder Feedback

ACP-California, Avantus, and Clearway oppose any proposals that would remove or alter the ability for a project to request suspension of LGIA. Suspension rights provide indispensable flexibility to generators in the interconnection process, a process where they generally do not have much flexibility.

EDPR supports proposing language to limit suspension rights to more specific circumstances or for more limited durations rather than removing them altogether. While EDPR appreciates the problem caused by projects parked in the queue for long periods, there are legitimate reasons for a project to be suspended and that option should still be available with reasonable limits. ACP-California proposed that if suspension rights were to be modified, at a minimum, the ISO should provide other types of flexibility to generators to address permitting and other delays that may affect projects. This is even more important today than it has been in the past given supply chain issues and other developments that have the potential to delay projects.

SCE and PG&E support the removal of suspension rights. SCE notes that if interconnection customers have intentions of moving forward to a LGIA and construction, and have the necessary site control requirements in place, there should be no reason to suspend a project. Network upgrades are studied at a point in time and the cost caps are set at that time. The ability to suspend projects creates more volatility to PTOs due to increase in costs, scope changes, and system changes. Removing suspension rights will help reduce the cost impacts to our ratepayers.

Proposal

The ISO proposes to remove suspension rights for all projects that execute a Large Generator Interconnection Agreement (LGIA)[19] in the future. The ISO recognizes the desire from the development community to retain suspension rights. However, the ISO believes there are other options provided in the agreement for projects to continue in the queue without the need to suspend, such as a) a project's suspension rights do not provide automatic time-in-queue extensions, b) projects may request COD extensions in accordance with MMA provisions, c) projects must fund shared upgrades even while suspended, and d) that suspension use in the ISO is not significantly utilized for the reasons above.

[19] SGIAs are not allowed to suspend.

5.5 Limitations to Transmission Plan Deliverability (TPD) Transferability

Background

After the ISO recently enabled the transferring of a project's TPD to another project at the same point of interconnection, several projects attempted to transfer TPD to later queued projects that would not otherwise be subject to the same tariff requirements as the project that received the original TPD allocation (usually the TPD requirements for proceeding without a power purchase agreement). Because these transfers would circumvent tariff rules, the ISO generally has rejected them. Additionally, over the past 10 years, only one project has achieved commercial operation as Energy Only. Although LSEs procure Energy Only projects already online, the deliverability/Resource Adequacy component of any project is what makes it financially viable. The ISO seeks to ensure TPD transfers are limited only to viable projects for legitimate purposes of right-sizing deliverability among different generating units.

Stakeholder Feedback

REV Renewables suggested that the ISO develop a new retention process whereby the ISO works backwards from the date of the longest lead-time of the expected upgrade to be complete, to a defined number of years to set the requirement to show at least a shortlist and allow a type of "parking" that holds deliverability until then. For example, if in the next TPD cycle a project receives deliverability, but the longest upgrade timeline is expected to be complete in 2030, if the ISO chooses 3 years before COD, then that project could keep its deliverability allocation without having to show at least a shortlist until 2027. The ISO could set requirements to show progress on the project during that time (e.g. permits obtained). LSA also suggests delaying the required PPA showings until a timeframe where LSE procurement would actually occur.

AES, LSA, Clearway, NextEra and Intersect Power opposed the ISO's initial consideration to withdraw a project that transfers its TPD allocation to another project. Clearway noted that the off-taker often requires a certain bundle of attributes in projects in the PPA that would require developers to transfer TPD allocation within their own projects to fulfill the PPA requirements. Clearway's view is that the ISO should not deem projects withdrawn if TPD allocation transfers occur within the same developer's projects.[20]

SCE supports the concept of limitations and requirements around TPD transfers, given that, as ISO points out, only one EO project has achieved COD.

[20] The ISO allows projects to transfer deliverability within various resource IDs of the project. That allocation process is not considered TPD transfer.

Proposal

The ISO proposes that a project transferring its deliverability must withdraw from the queue or downsize its generating capacity to its remaining deliverability. If a project is in Partial Capacity Delivery Status (PCDS) and transferring all of its allocation, the project must withdraw the entire project from the queue at time of the transfer. This proposal recognizes that with the proposed changes to the TPD allocation process, after a deliverability transfer, the remaining Energy Only generation would only be able to seek an allocation of TPD using allocation group C. Although possible, few projects have utilized that path.

The ISO recognizes that a single parent company entity may own a number of queue positions interconnecting at the same point of interconnection and may need to request a transfer between those positions to maintain viability and commercial or power purchase agreement status. In these limited circumstances, the ISO would consider these transfers being able to occur, provided the interconnection customer can demonstrate such transfer request by providing the redacted power purchase agreements that support a resource adequacy obligation for such end-state deliverability status for the projects and or technology types.

5.6 Viability Criteria and Time-in-Queue Limit

Background

Although the ISO has tariff and BPM language to limit projects' time in queue, enforcing these provisions often requires a time-intensive, project-specific review to ensure the project is still in compliance. Additional straightforward milestones and universal time-in-queue limitations may help manage older projects and reduce projects lingering in queue without progress.

FERC Order No. 2023 includes specific timelines and guidance for projects to negotiate and execute GIAs as well as a limitation of three cumulative years to extend the commercial operation date. These policy changes will not be effective until the ISO's compliance filing is approved by FERC.

Lastly, the ISO intends to clarify the commercial viability criteria language in Section 6.7.4 of Appendix DD to specify the time an interconnection customer has to submit a PPA to allow the project to utilize the one year limited exception to provide such PPA and retain deliverability.

Stakeholder Feedback

AES does not believe that creating a hard stop development timeline, such as 10 years in the queue, is a proper metric for project viability. Each project has its unique challenges, resulting in varying developing timelines. Instead of mandating a development timeline, AES supports milestone requirements demonstrating development progress.

ACP-California seeks clarification that Participating TO delays will not impact a project's ability to remain in the queue, and shares a concern that criteria that are too stringent should not preclude viable projects from proceeding through development.

CalCCA supports the ISO exercising its ability to remove projects from the queue if they cannot demonstrate progress toward development milestones. CalCCA notes that the milestones and timelines for removal will likely be dependent on technology, and that a full seven years from interconnection request and COD will likely be unnecessary for "first ready" projects that are not long lead time, while long lead-time projects like geothermal and offshore wind will likely require more time between entering the queue and reaching COD. CalCCA supports the ISO ensuring projects are on track, and removing those that are not making progress, while recognizing the differences in technology and factors outside the control of the developer.

Clearway conditionally supports requiring Energy Only projects to demonstrate commercial viability criteria. Clearway believes that EO projects that don't withdraw with a one-time penalty-free withdrawal could be required to securitize the upgrades for which they are responsible.

EDF-Renewables believes the ISO should proceed with the principle that interconnection agreements and subsequent modification outcomes establish specific Notice to Proceed dates, and that any such implementation must be coupled with a requirement for the participating transmission owner to initiate engineering, procurement, as well as construction on the necessary upgrades if NTP is received by the specified date. EDF-R suggests that the framework for assessing commercial viability should encompass:

- Negotiation and execution of a Generator Interconnection Agreement (GIA) (CAISO already possesses the authority to withdraw due to failure in negotiation)
- Posting of a third financial security (bringing the total security to 100%)
- Provision of written notice to proceed on network upgrades
- Fulfillment of all payment obligations for work
- Submission of evidence of participation in the Request for Offer (RFO) process

- Submission of tangible evidence of site exclusivity (recognizing that some legacy projects still utilize deposits in lieu), and
- Achievement of commercial operation for a portion of the total megawatt capacity.

Avantus disagrees with ISO's reasoning to hold projects accountable based on time in queue and believes the ISO and Participating TOs should, to the extent possible, assist and ensure projects that have an impact on each other are moving through the QM process as smoothly as possible to not exacerbate withdrawals. Additionally, Avantus notes that to hold projects accountable that do not impact others strictly based on their time in queue may be off-base and have the potential to take away candidates for future procurement needs.

Geothermal Rising and New Leaf Energy commented that any proposed limitations of time in queue must also account for the increased development time for long lead-time resources, locations, or late-discovered issues and provide for demonstration of progress toward completion rather than a fixed time limit.

Golden State Clean Energy agrees that Energy Only projects have limited commercial viability and supports further exploring proposals that involve withdrawing certain Energy Only projects from the queue. Given that only one Energy Only project has achieved commercial operation as a stand-alone project in the past eight years, it is concerning how many EO projects are in the queue.

LSA strongly supports measures to prevent non-viable projects from “lingering” in the queue. LSA recognizes that the CAISO has been stepping up enforcement in these areas, and it appears that these efforts are having impacts in removing non-viable projects from the queue. LSA also supports the addition of reasonable milestones to the standard GIA Appendix B template, such as Notice to Proceed and start of construction. LSA has supported (and continues to support) the Commercial Viability Criteria for TPD retention, BPM for Generator Management Section 6.5.2.1 criteria for assessing time-in-queue extensions for both FCDS/PCDS and Energy Only projects, and active and proactive enforcement of GIA milestones. However, LSA strongly opposes arbitrary time-in-queue limitations for projects that continue to show that they are viable, based on the applicable viability demonstrations. If these projects meet the viability demonstration requirements but are not viable, LSA suggests the requirements should be changed; if these projects are viable, then they should not be removed from the queue, especially since such removals would likely come late in the development process, with the resulting project loss adversely impacting both the developer and the project off-takers.

PG&E supports stricter rules and guidelines to move towards commercial operation in a more efficient and timely manner, and suggests that this criterion should also include more stringent and upfront posting deadlines at the time of LGIA execution so Participating TOs can proceed with ordering long-lead materials sooner due to supply chain issues that the industry is facing.

SCE supports including viability criteria and time in queue. It notes that such a policy would 1) provide ISO greater authority to hold projects accountable based on time in queue and COD/milestone extensions, not whether another project is impacted; 2) limit projects' ability to linger in queue; intent to force progression to GIA execution, Notice to Proceed, construction, and commercial operation; and 3) establish stronger milestones and documentation requirements for meeting construction, permitting, and other criteria.

Proposal

The ISO proposes to impose an unavoidable time-in-queue requirement for all projects in the queue without executed GIAs to execute an interconnection agreement and subsequently provide notice to proceed and third financial security posting, as described in the tables below. This finite time-in-queue proposal ultimately places a financial obligation on the project if it desires to remain in the queue.

	IR Received Date (April)	7 years in queue	**GIA Executed No Later Than:**	Years-in-queue	Time to negotiate & execute after Phase 2 study results published
Cluster 6 (and prior)	2013	2020	Dec. 31, 2024	11.7+	121+ Months
Cluster 7	2014	2021	Dec. 31, 2024	10.7	109 Months
Cluster 8	2015	2022	Dec. 31, 2024	9.7	97 Months
Cluster 9	2016	2023	Dec. 31, 2024	8.7	85 Months
Cluster 10	2017	2024	Dec. 31, 2024	7.7	73 Months
Cluster 11	2018	2025	Dec. 31, 2024	6.7	61 Months
Cluster 12	2019	2026	Dec. 31, 2024	5.7	49 Months
Cluster 13	2020	2027	June 30, 2025	5.3	43 Months
Cluster 14	2021	2028	Dec. 31, 2025	4.7	23 Months

	IR Received Date (April)	7 years in queue	**Notice To Proceed & 100% 3rd posting No Later Than:**	Years-in-queue	Time to Provide after GIA Execution
Cluster 6 (and prior)	2013	2020	June 30, 2025	12	6 Months
Cluster 7	2014	2021	June 30, 2025	11	6 Months
Cluster 8	2015	2022	Sept. 30, 2025	10.4	9 Months
Cluster 9	2016	2023	Sept. 30, 2025	9.4	9 Months
Cluster 10	2017	2024	Sept. 30, 2025	8.4	9 Months
Cluster 11	2018	2025	Sept. 30, 2025	7.4	9 Months
Cluster 12	2019	2026	Sept. 30, 2026	7.4	9 Months
Cluster 13	2020	2027	June 30, 2026	6.3	12 Months
Cluster 14	2021	2028	Dec. 31, 2026	5.7	12 Months

The commercial viability criteria (CVC) currently established in the tariff and BPMs will not change. For example, a project requesting a COD beyond seven years in the queue must meet the CVC requirements. If they do not, their deliverability status will be converted to Energy Only.

The ISO may consider specific exceptions to the above timelines for PTO extensions, other long-lead time network upgrades, or long-lead projects as identified by a state agency or other regulatory authority. However, the ISO would need to develop specific definitions and examples for exceptions to this proposed requirement.

Additionally, the ISO proposes to revise section 6.7.4 of Appendix DD. Currently this section allows customers to satisfy all the commercial viability criteria except criterion (b) of section 6.7.4, (having a PPA), to provide a PPA within "one year from the day the Interconnection Customer submits the modification request, or eight years after the ISO received the Interconnection Request, whichever occurs later." To ensure customers do not linger in queue, the ISO proposes to remove the current opportunity to submit the modification requests within a year of the modification report. Instead, the ISO would postpone converting the Generating Facility to Energy Only Deliverability Status if the interconnection customer provides the ISO a copy of the executed PPA the meets criterion (b) by the eighth year from the day the ISO received the original interconnection request. Interconnection customers exercising this provision must continue to meet all other commercial viability criteria. Interconnection customers already beyond eight years in queue would not be eligible for any safe harbor, and could not extend their COD further and maintain deliverability without a PPA.

5.7 Project Modification Request Policy Updates

Background

The increase in the volume of modification requests has become challenging to manage and the ISO must reduce the number of modification requests to a workable level. Currently, projects submit multiple MMA requests for equipment, technology, and configuration changes prior to execution of the Generator Interconnection Agreement (GIA) and through their Commercial Operation Date (COD). In the initial discussion paper and through the IPE stakeholder workgroup meetings, the ISO and stakeholders sought how to reduce the pace and volume of modification requests.

The ISO and stakeholders discussed options that included:

1. Define a list of modifications that would not require a request and that could be approved without a formal review.
2. A tiered approach to simple COD-only requests as compared to complex requests that include technology or interconnection changes. This tiered approach would also consider a different deposit or fee amount.
3. Requiring PTO validation timeline turns.
4. Limit a project to a certain number of MMA requests or require that MMAs may only be either submitted at certain times during the year or based on contract milestones.
5. Implement a financial penalty ($X/day) for projects that do not submit an MMA as requested by the ISO or PTO.

Additionally, the ISO has recently seen an increase in the number of shortfalls dues to the cost of processing modifications being greater than the current $10,000 deposit.

Stakeholder Feedback

AES generally supports enhancements to the MMA process. AES, EDF-R, New Leaf Energy, NextEra highly supports the concept to expand the list of changes that don't require MMA submissions, or to adopt timing targets for the ISO and PTO to conduct the initial validation review for MMA requests. From AES's experience, the initial validation process can delay the start of the MMA study process up to 6 months due to iteration between ISO, PTO, and IC. Finally, AES supports the concept to simplify certain MMA request modeling requirements for requests that do not require modeling changes, such as adding grid charging and extending CODs.

EDF-Renewables commented that inverter data could be established as a milestone in the GIA that projects must achieve or during a suitable phase of the study process when data collection aligns with operational studies.

EDPR and Six Cities support the concept for simplifying the MMA, but EDPR does not support concepts that would limit interconnection customers' ability to modify projects when dictated by the realities of project development. EDPR believes the ISO should consider a process where these types of changes can be made without requiring an MMA request.

LSA, MRP, and Intersect Power strongly oppose limitations on the number or timing of MMA requests and believe the ISO should consider other steps, both in its internal processing and interaction with developers, to streamline this process. Steps for consideration include allowing a simple developer confirmation that earlier modeling data are still current.

New Leaf Energy commented that if the ISO determines there are issues with certain modifications (e.g., inverter changes), it could reserve the right to require an MMA and later adjust the list of modifications requiring MMAs. New Leaf Energy also supports the idea to require a joint meeting with the ISO, the applicable PTO, and the developer to address validation issues within 15 calendar days of MMA submission.

SDG&E disagrees with any proposals to reduce the changes that constitute an MMA. Despite historically high MMA approval rates, all MMA requests must be formally documented and properly evaluated to ensure safety and reliability of the system. It is important that PTOs maintain the most recent and updated generating facility related equipment being installed. Therefore, SDG&E recommends that all MMA requests continue to go through the formal evaluation process.

PG&E recommends a strict limit on the number of modification requests to change milestone dates that are not PTO-triggered. PG&E also suggests the ISO adopt measures to limit the number of MMA requests submitted by interconnection customers for changes in project information or extensions of in-service date or commercial operation. One option is to establish a separate MMA type for COD extensions, and change to fee-based instead of deposits and increase costs for changes included in the MMA. For example, PG&E suggests the ISO could establish a 'fee' for milestone extensions and a larger deposit for technology and other changes.

SCE supports enhancing the MMA process to limit the use and timing of modification requests, as well as increased deposit amounts. SCE also supports 60 days to complete modifications, and extending the Facilities Reassessment Report (FRR) timeline from 45 to 60 calendar days.

Proposal

The ISO proposes the following updates to the MMA and post-COD modification processes:

- Increase deposit to $30,000
- Increase time to complete engineering analysis from 45 days to 60 days
- Increase time to complete the FRR from 45 days to 60 days

The ISO proposes process updates that the Queue Management team will work on to enhance the overall modification processes as follows:

1. Work to host modification calls between the ISO and PTO engineering teams and the interconnection customer following the second or third validation turn.
2. Coordinate with the PTOs to improve the initial and subsequent validation reviews for modification requests.
3. The ISO and PTOs will work to identify specific milestones such as executing the GIA or providing notice to proceed in the modification results.
4. The ISO proposes to update the BPM for Generator Management (Section 6.2.1.4) that projects must have started construction and be within six months of achieving their then-current synchronization or commercial operation date to submit a construction sequencing delay request.

Through stakeholder discussions and meetings between the PTO/ISO engineering teams, and given the number of variables, ambiguity, modeling requirements, and nuances between projects, a number of potential commercial or development related risks were identified that limited the types of requests or when they can be submitted.

There is not a risk-free way to accept modifications without a formal review and evaluation.

Lastly, the ISO realized that a tiered approach to the type or cost of modification requests does not provide process improvements. For example, regardless of the deposit or fee amount, the ISO and PTO must process the request and financial accounting the same way. Therefore, any tiered modification type or cost approach would not improve the process. They would hinder it due to increased tracking and processing requirements.

5.8 Earlier Financial Security Postings for Projects with Shared Upgrades

Background

Appendix B of the LGIA and Attachment 4 of the SGIA establish milestones for the interconnection customer and PTO to meet the commercial operation date specified in the agreement. Section 5.1.1 of the LGIA provides:

> **5.1.1 Standard Option.** *The Participating TO shall design, procure, and construct the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, using Reasonable Efforts to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the dates set forth in Appendix B, Milestones.* (Emphasis added.) The Participating TO shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Participating TO reasonably expects that it will not be able to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the specified dates, the Participating TO shall promptly provide written notice to the Interconnection Customer and the CAISO and shall undertake Reasonable Efforts to meet the earliest dates thereafter

Interconnection customers have raised numerous concerns that the PTOs are not meeting the milestone dates and one of the reasons is that with shared network upgrades. In some instances, the PTOs are waiting until all or the majority of the interconnection customers responsible for the shared network upgrade have provided their notice to proceed (NTP). A consequence of this is that a project ready to go is delayed because the PTO is waiting for the NTP for all parties, or the majority of the parties.

Stakeholder Feedback

As several entities noted, the deployment of projects can be slowed by the current system in which a Participating TO will not proceed with constructing network upgrades that may be shared among several projects until all projects are ready to proceed. Given the long lead time necessary for building transmission, MRP suggests consideration of a process where network upgrades can proceed when the first project that requires those upgrades is ready to give notice to proceed. It also suggests socializing the cost of upgrades if enough projects withdraw so that assuming costs of the upgrades would threaten other projects' economic viability. MRP acknowledges that this is a complex and difficult topic. But it remains concerned that the long lead time required for transmission development will undermine the timely deployment of resources needed to meet state policy goals. REV supports CAISO's proposal requiring all projects to post financial security by the earliest date of one of the projects. At this time, it is not exactly clear how this requirement will be applicable to projects without LGIAs, but it is a step in the right direction for enabling the timely completion of shared network upgrades required for projects to come online.

PG&E supports the concept that all projects need to post security for shared upgrades when the first project executes its LGIA. SCE supports all projects being required to post their share of financial security by the earliest date of one of the projects. However, SCE conditions its support of this proposal on whether it would also apply to projects that "park" and are sharing NUs with other projects in the same queue cluster.

Proposal

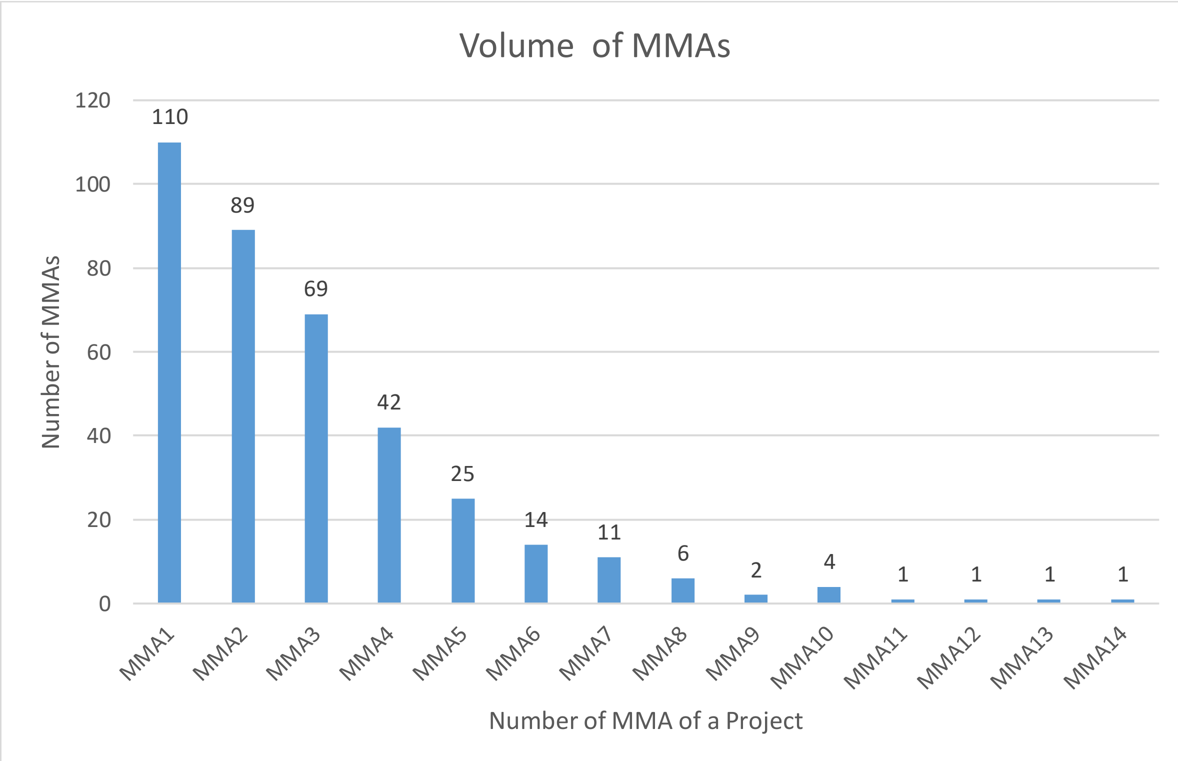
The ISO agrees with stakeholders that if one interconnection customer is ready to proceed with construction of a shared network upgrade then all participants in that upgrade must post the needed security for and fully fund that upgrade as applicable. This should occur regardless of their deliverability status or whether they have executed a GIA.

For projects that have already executed GIAs, the ISO supports the Participating TOs requiring security from all shared network upgrade interconnection customers when the first customer provides a notice to proceed and the upgrade needs to be funded for construction.

5.9 Revise Timing of GIA Amendments to Incorporate Modification Results

Background

With the continuous revisions to projects through the MMA process, the contract negotiators for the Interconnection Customer, Participating TO and ISO are required to continually amend the GIAs. Looking at the data, just from 2021 to date, the ISO and Participating TOs have processed 376 MMAs.



This results in 376 amendments to GIAs being required and as demonstrated above, some projects have made 14 modification requests for the same project. Trying to keep up with this ever-changing churn required to move the projects forward is time consuming.

Proposal

The ISO proposes that amending the GIA should wait until close to the time the project is set to synchronize to the grid. Doing so will facilitate inclusion of the final or near-final configuration in the GIA. To effectuate the GIA amendment, the MMA report would be controlling even when the GIA amendment hasn't been executed yet. All modifications would be incorporated into the agreement nine months before the synchronization date in the GIA.

5.10 Commence Network Upgrades When the First Notice to Proceed is Provided to the PTO

Background

Interconnection customers are concerned that once a notice to proceed (NTP) is provided to the PTO, it may be months before the PTO actually starts engineering, design, or project management of the network upgrade. This can result in the network upgrade being delayed from the original online date in the GIA. This then could force the interconnection customer to be delayed in meeting the timeline in their PPAs, which likely results in financial penalties for the Interconnection Customer.

Stakeholder Feedback

AES Clean Energy and EDF-R supports Rev Renewable's proposal to require PTOs to move forward with network upgrades once the NTP is provided by the Interconnection Customer. AES Clean Energy has experienced delays of three to six months between NTP issuance and proceeding with network upgrades.

REV agrees there should be shared responsibility throughout the interconnection process. If interconnection customers are held to stricter requirements and timelines, there should be similar accountability on the ISO and PTO side on completing studies and required network upgrades. REV notes that this can provide greater certainty for all parties and bring projects online in a timely manner, and that if studies or network upgrades cannot be completed in the necessary timeframe, qualified third parties should be allowed to complete the studies or construct the facilities. REV proposed that the ISO should hold PTOs to LGIA schedules to ensure network upgrades start when the interconnection customer issues NTP, including the upgrades that get triggered by a group of projects.

SCE commented that GIA and future modification results should identify a specific date for NTP. If NTP is not received by that date, the project is in breach/withdrawn.

EDF-R commented that there is broad stakeholder consensus on requiring milestone updates for every project that exceeds its scheduled dates, and ensuring equitable enforcement of Generator Interconnection Agreement (GIA) milestones, including timely commencement of construction on network upgrades and submission of PTO delay notices.

Proposal

The ISO agrees with concerns raised by both the interconnection customers and the PTOs. With respect to SCE's comments, the ISO agrees that a specific date for the NTP must be included in the GIA. If an MMA modifies the NTP date then the new date will be included in the MMA report which is then an amendment to the GIA. The ISO also agrees with the Interconnection customers that the PTOs need to move forward once the NTP and third security posting is received and meet the Initial Synchronization Date in the GIA to allow Interconnection customers to meet their PPA requirements. The ISO proposes that the GIAs have specific dates for NTP and third posting. That way, milestones can be specifically tracked. The ISO also proposes that a new milestone be added requiring the PTO to notify the interconnection customer and ISO when activity has begun on the network upgrade and interconnection facilities. This will provide transparency as to when the upgrades are started and open communication among the parties to ensure that transmission is being built within the terms and conditions of the GIA.

6 WEIM Governing Body Role

This initiative proposes certain tariff amendments to enhance the process for studying and approving interconnection requests. ISO staff believes that these proposed tariff changes will go to the Board of Governors only and that the WEIM Governing Body will have no role in the decision.

The Board and the WEIM Governing Body have joint authority over any

> *"proposal to change or establish any CAISO tariff rule(s) applicable to the WEIM entity balancing authority areas, EIM Entities, or other market participants within the EIM Entity balancing authority areas, in their capacity as participants in EIM. This scope excludes from joint authority, without limitation, any proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid."*[21]

Charter for EIM Governance § 2.2.1. The tariff changes proposed here would not be "applicable to EIM Entity balancing authority areas, EIM Entities, or other market participants within EIM Entity balancing authority areas, in their capacity as participants in EIM." Rather, they would not be applicable "only to … the CAISO-controlled grid." Accordingly, these proposed changes to implement these enhancements would not fall outside the scope of joint authority.

The WEIM Governing Body also has an advisory role that extends to any proposal to change or establish tariff rules that would apply to the real-time market but are not within the scope of joint authority. This initiative, however, does not propose changes to real-time market rules.

Stakeholders are encouraged to submit a response in their written comments to the proposed classification as described above, particularly if they have concerns or questions.

7 Stakeholder Initiative Schedule

The schedule for stakeholder engagement is provided below. The ISO presented its

[21] Charter for EIM Governance § 2.2.1.

proposal for Track 1 to the Board of Governors in May 2023.

Date	Milestone
09/21/23	Straw Proposal posting
09/28/23	Stakeholder call on Straw Proposal
10/12/23	Comments due
11/21/23	Draft Final Proposal posting
11/28/23	Stakeholder call on Draft Final Proposal
12/12/23	Comments due
01/8/24	Final Proposal posting
01/16/24	Stakeholder call on Final Proposal
01/20/24	Comments due
02/08/24	Board of Governors meeting

The schedule for Track 2 anticipates that to meet the proposed schedule for implementing process changes ahead of commencing Cluster 15 phase I studies. The ISO intends to present this to the Board of Governors in February 2024.