2023 Interconnection Process Enhancements

Track 2 Draft Final Proposal

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Executive Summary

The proposed changes in this draft final proposal address the unprecedented and unsustainable interconnection request volumes in the California ISO's current processes and seek to better enable rapid deployment of new generation for reliability, affordability, and decarbonization. Through robust stakeholder feedback, and considering the urgent need to bring historic amounts of new capacity online as quickly and as efficiently as possible, the ISO proposes further revisions to a package of reforms that emphasize project viability and competition for resources identified in local and state resource planning efforts.

In this draft final proposal, the ISO has refined many elements of the revised straw proposal, based on stakeholder comments and working group discussions:

- Development of a generic timeline of the reformed process, as it is expected to align with FERC Order No. 2023 requirements;
- Refinements to the information provided to stakeholders to implement the zonal approach;
- Elimination of the proposed limitation on interconnection requests allowable per parent company;
- Additional explanation of the 150% zonal limitation;
- More detail on how to identify and fulfill 150% of each zone;
- Further balancing of a set of objective indicators for scoring criteria to evaluate project readiness;
- Minor modifications to the auction administration;
- Further modifications to the Merchant Deliverability pathway (formerly referred to as "Option B");
- Proposed elimination of the Off-Peak and Operational Deliverability Assessments from the study process;
- Removal of the proposal for a one-time withdrawal opportunity with refund;
- Elimination of the proposal to remove suspension rights from a Large Generator Interconnection Agreement (LGIA);

- Modification of the commercial viability proposal to require units to downsize if they do not have a Power Purchase Agreement (PPA) after 7 years in the queue;

- Updates to the viability criteria and a time-in-queue requirement for all projects in the queue;

- Introduction of an “implementation deposit” for queue management; and

- Update to the Phase Angle Measuring Units data

The proposed revisions align with the strategic direction established by a December 2022 Memorandum of Understanding between the ISO, California Public Utilities Commission (CPUC), and California Energy Commission (CEC), and are part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement.

The process reforms described in greater detail in this draft final 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 continuing to work with stakeholders to refine this proposal in the interest of deploying new resources to meet the grid’s evolving needs.

1. Introduction and Background

With this paper, the California ISO provides its Track 2 draft final 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 high level of resource development activities reflected in interconnection requests to the ISO, this Track 2 draft final proposal advances 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 caused 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 and its stakeholders seek 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. These processes must also align with transmission development necessary for longer-term resource expansion. The 2023 IPE initiative is part of a larger set of foundational framework improvements being coordinated among the CPUC, the 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 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:

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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, 2023, 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 similar 2010 MOU between the parties.

- The CPUC will provide clear direction to its jurisdictional load-serving entities (LSEs) to concentrate 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 and local 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. Also, supply resources will be stranded if they are developed before this infrastructure is planned, approved, permitted, and constructed.

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, the revised procedures 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 is focused 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 dramatic increase in projects in the queue, 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, LSEs, and industry need 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 on matters of generator interconnection and transmission planning of all LSEs and offtakers—CPUC jurisdictional, non-CPUC jurisdictional, and non-LSEs—within the ISO footprint, and seeks to ensure opportunities for non-CPUC jurisdictional entities to have their project needs considered in the TPP.[3]

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 only to the ISO Board of Governors, not to the Western Energy Imbalance Governing Body, because the changes apply to the ISO-controlled grid and the ISO is not proposing changes to real-time market rules.

This draft final proposal describes a number of new or modified elements to the ISO's interconnection process for additional stakeholder consideration. In Section 1 the ISO describes the stakeholder working group process and implications of FERC Order No. 2023 on the IPE initiative. Section 2 includes details of the draft final proposal elements related to interconnection request intake, and Section 3 outlines a number of proposed changes to the ISO's contract and queue management practices. Sections 4 and 5 outline next steps for the initiative and approvals.

1.1. Working Group Process

Recognizing the potential implications of significant interconnection reform on the ISO's stakeholders, the ISO engaged interested parties in an intensive working group process to inform development of the Revised 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.

During stakeholder working group meetings in summer 2023, the ISO and stakeholders developed agreed-upon principles and problem statements to assist

[3] Several stakeholders have noted the need for consistent treatment of various types of offtakers, including CPUC-jurisdictional, non-CPUC jurisdictional, and non-LSE offtakers. Currently, the ISO reviews power purchase agreements (PPAs) with entities without a resource adequacy obligation to verify the agreement requires Full Capacity Deliverability Status, and to ensure there are no corporate relationships between the contracting entities. The ISO rejects agreements that it deems are designed to circumvent the CAISO's tariff and purpose of prioritizing TPD allocation by groups to ensure that projects are considered for an allocation in order of viability based on contracting status.

in aligning objectives and developing solutions. Problem statements addressed two categories of challenges with the interconnection process – interconnection request intake and queue management. Once the agreed-upon principles and problem statements were established, working group meetings focused on proposed concepts and solutions. Stakeholders participated 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 participants spent to shape this Revised Straw Proposal and improve the ISO's interconnection process.

1.1.1. 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 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 ability of the interconnection process to support the procurement necessary to meet CPUC resource portfolios and CEC Senate Bill 100[4] 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 the reforms must also:

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

[4] California Renewables Portfolio Standard Program. 2018. https://legiscan.com/CA/text/SB100/id/1819458

1.1.2. Problem Statements: Interconnection Request Intake

1. Unsustainable increases in interconnection requests have overwhelmed 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, 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. Although the issue of project viability is a widely discussed industry topic, it 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 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).

1.1.3 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, meeting contract milestones) 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) 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.

1.2. FERC Order No. 2023 [Updated]

On July 27, 2023, the Federal Energy Regulatory Commission (FERC) Issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements.[5] Because FERC compliance is a prescriptive process for the ISO, the ISO does not open compliance filings to stakeholder feedback. Nevertheless, because Order No. 2023 compliance and IPE Track 2 will substantially revise the ISO's GIDAP, stakeholders should know that the ISO intends to comply with the order as fully and quickly as possible, with a compliance filing in early April 2024.[6] The vast majority of the ISO's resulting tariff revisions under Order No. 2023 will mirror FERC's revisions to its own *pro forma* procedures.

The ISO encourages stakeholders to continue to focus comments and feedback in future workshops and working group meetings on issues distinct to the IPE initiative. Proposed Order No. 2023 reforms are therefore considered beyond the scope of this initiative. At a high level, these reforms 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
- Study process timelines
- Financial posting requirements and withdrawal penalties
- Affected system processes
- Consideration of grid-enhancing technologies
- Consideration of planned storage operation

The ISO does not foresee Order No. 2023 compliance having a significant impact on Clusters 14 or earlier. The ISO intends to propose that Clusters 14 and earlier generally remain subject to the GIDAP requirements, and Clusters 15 and beyond will be subject to a new set of procedures and GIAs adopting Order No.

5 The order was subsequently published in the Federal Register on September 6, 2023.
6 FERC extended the compliance filing requirement from December 2023 to April 2024.

2023 revisions. The ISO will modify both the GIDAP and the new procedures as necessary based on this IPE initiative. It is important to understand, however, that these plans ultimately are subject to FERC's direction in Order No. 2023.

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 received ISO Board of Governors approval and is seeking FERC approval to not 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.

The ISO Tariff Appendix DD, Section 17. Cluster 15 Unique Procedures, Subsection 17.1 Study Procedures and Timelines, provides for the following:

> **c.** An Interconnection Customers that withdraws its Interconnection Request prior to April 1, 2024 will receive a refund of its Interconnection Study Deposit, including any interest earned, minus any costs expended under the GIDAP on the Interconnection Customer's behalf. If an Interconnection Customer submitted a Site Exclusivity Deposit, it will receive a complete refund of its Site Exclusivity Deposit, including any interest earned. Withdrawals effected pursuant to this provision will not affect Interconnection Customers' rights to withdraw after April 1, 2024, and receive any corresponding refund and interest under the GIDAP, including without limitation Section 3.5.1.1.

While other tariff sections would allow for similar treatment of withdrawing projects after April 1, 2024, the ISO proposes to revise this and other dates in Section 17 to align with the commencement of the interconnection studies for Cluster 15. These changes will likely be included in the ISO's compliance filing to FERC Order No. 2023. This will provide the ISO and interconnection customers with an appropriate milestone for the applicable deadlines and the flexibility to determine what the appropriate date should be within the IPE initiative.

2. Interconnection Request Intake

2.1. The Zonal Approach: Data Accessibility [Updated]

Background

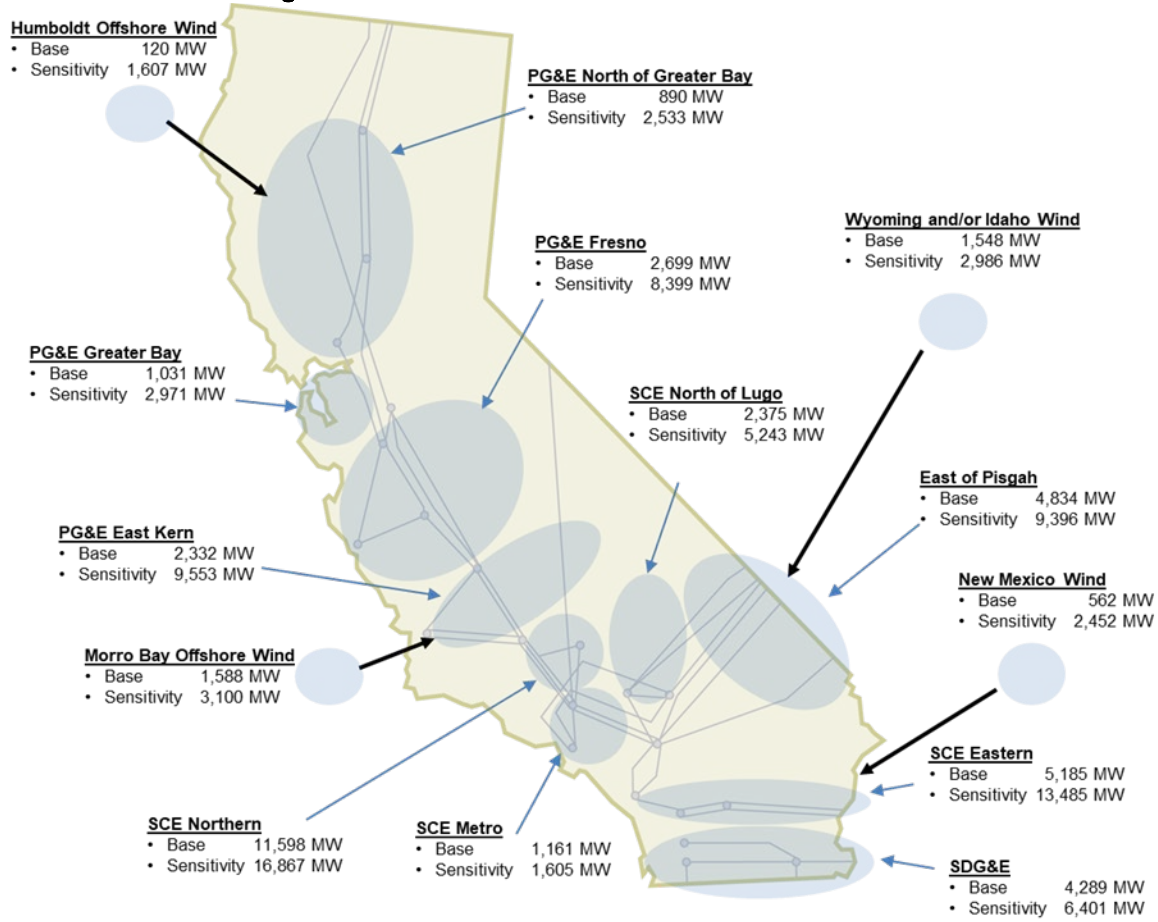
As noted in the first principle stated above, a central tenet of the ISO's reform is the zonal approach: the prioritization of projects that seek to utilize available capacity and are in zones where there are planned capacity additions approved in the ISO transmission planning process as established in state and local regulatory authority resource planning portfolios. The ISO will continue to provide a merchant pathway 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.

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).[7] The transmission zones illustrated below are also aligned with the transmission interconnection areas used in the generation interconnection process.

[7] 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

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



The CPUC has mapped the portfolios it generates with input from the CEC and the ISO to the substations[8] within each of the transmission areas or zones identifying the installed capacity and technology of the resources in the portfolios. 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

[8] 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

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.[9]

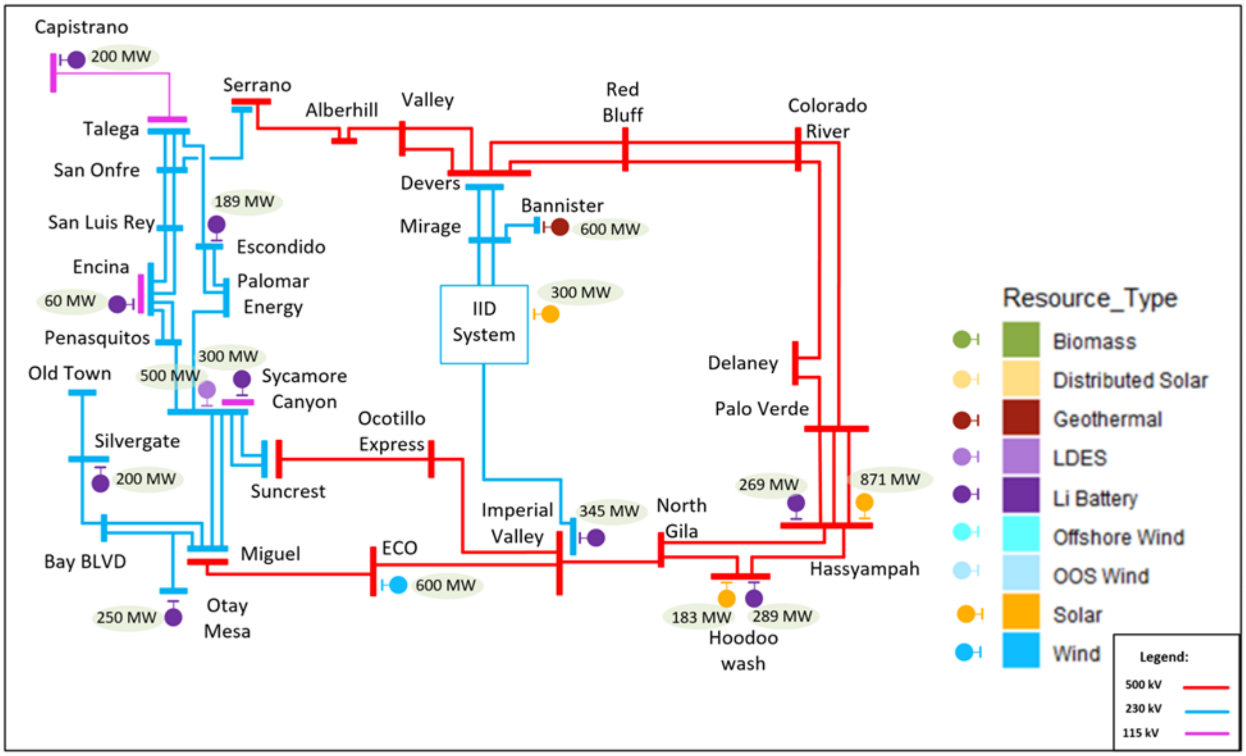
				22-23 TPP 38 MMT Proposed Base Case Final Mapped Amount		
Transmisison Area	Substation	Voltage	Resource Type	FCDS (MW)	EODS (MW)	Total (MW)
PG&E Fresno Study Area	Alpaugh	115	Biomass/Biogas	3	-	3
SCE Northern Area	Antelope	230	Distributed Solar	3	-	3
SCE Northern Area	Antelope	230	Li_Battery	439	-	439
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.[10]

9 https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08_v2.xlsx

10 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 ability to deliver resources to load for the resources identified in the CPUC portfolios. 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.

The ISO also provides data on the capability within the transmission zones in the ISO's Transmission Capability Estimates for the CPUC's Resource Planning Process[11] and for the ISO's annual Transmission Plan Deliverability Allocation Report.[12] 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

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

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 are provided. Some constraints may overlap more than one transmission zone. Table 2 illustrates the constraints in the San Diego transmission zone, as an example.

Table 2. Constraints in the San Diego Transmission Zone[13]

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[14] 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.

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[13] http://www.caiso.com/Documents/Transmission-Capability-Estimates-for-use-in-the-CPUCs-Integrated-Resource-Planning-Process.xlsx
[14] 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

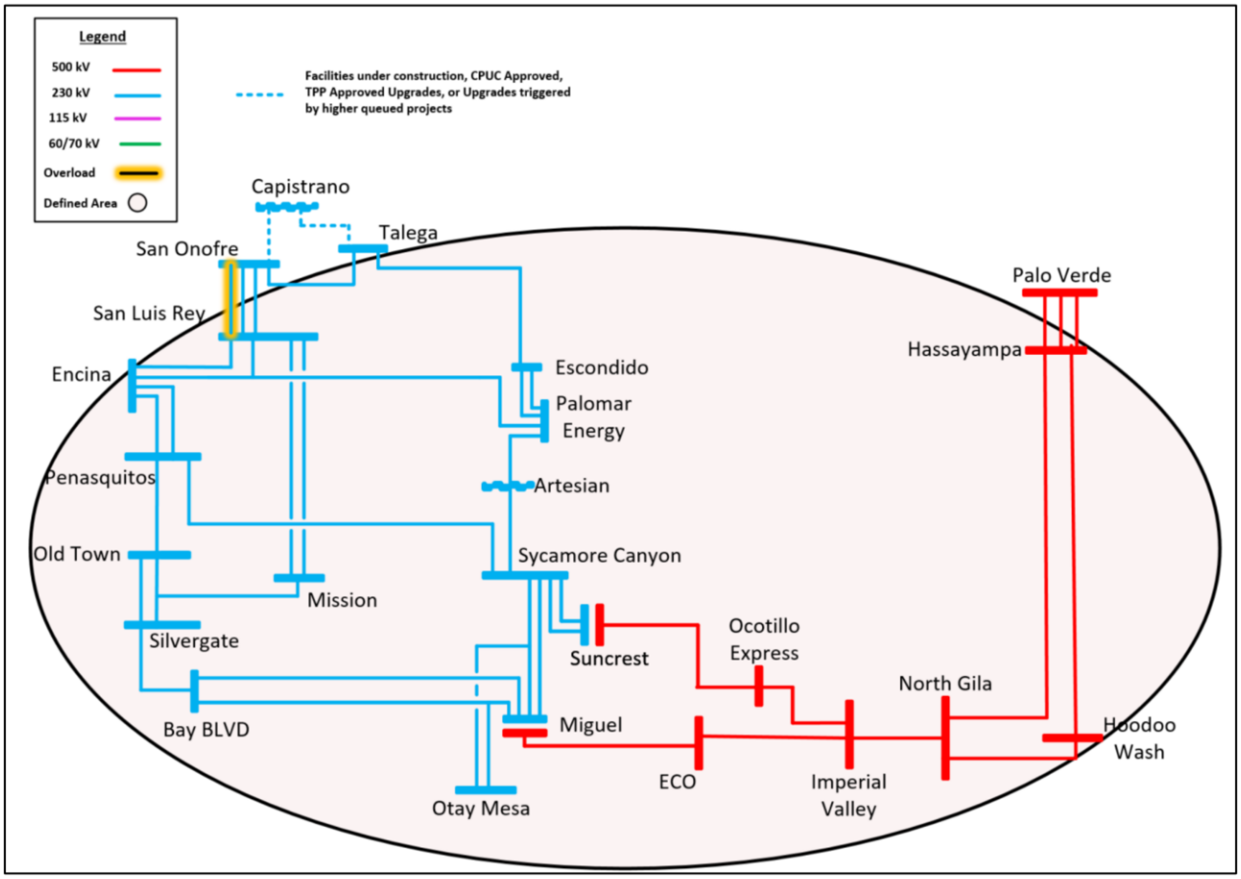


Table 3. Available TPD for one constraint within the San Diego transmission zone

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

The participating transmission owners (PTO) provide additional information on interconnection requirements in their respective Transmission Interconnection

Handbooks.[15] This includes information on specific points of interconnection (POI) that cannot accommodate further interconnections. The ISO suggests that stakeholders review the information above when assessing potential points of interconnection they are considering. The ISO will reference or document this guidance to interconnection customers prior to the request window.

In summary, for each major constraint limiting TPD 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 TPD capacity that has already been allocated, and
- any capacity remaining and available for future allocation.

Stakeholder feedback and discussion

Throughout working group discussions, stakeholders have emphasized the importance of (1) data transparency and accessibility to inform developers on where transmission capacity would be located, the costs of interconnection, and the timing of interconnection and (2) an alternative self-funding path to enable projects to interconnect outside of the priority zones.

Most parties, including ACP-California, AES, the CPUC, CPUC Office of Ratepayer Advocates, Clearway, LSA, Middle River Power, New Leaf Energy, Nightpeak Energy, NCPA, PG&E, Q Cells, SEIA, Six Cities, and Southern California Edison were generally supportive of the proposal to provide data to implement the zonal approach in the revised straw proposal. Nearly all sought additional clarification around the timing of data distribution to ensure transparency and clarity of decision-making prior to the interconnection request window. Most stakeholders requested more information on when the various

[15] Pacific Gas & Electric. Transmission Interconnection Handbook, Section G2
Southern California Edison. The Interconnection Handbook (Rev 12)
San Diego Gas & Electric Company. Generation Interconnection Handbook. 24 April 2023.

components of the data will be available within the zones. The ISO provides a generic timeline demonstrating data availability in the proposal below.

Avantus, Aypa Power, CalCCA, CESA, Clearway, ENGIE NA, GridStor, and New Leaf Energy also sought assurances that the data would be available far enough in advance of the opening of the interconnection request application window. Clearway and SEIA suggested that the ISO establish a 'cut-off date' or publish a report six months in advance of the interconnection request window and to use this fixed data to evaluate interconnection requests in that cycle. Under this approach, data updates and assumptions would be consistent between stakeholders and the ISO. Stakeholders are correct that the data that the ISO has identified becomes available at various times throughout the year and the various planning and generation interconnection study cycles. For example, new information becomes available when the ISO Board of Governors approves the annual transmission plan at its May meeting. Under FERC Order No. 2023, heat maps are to be provided within 30 days after each cluster study and restudy. The ISO has also proposed to provide a heat map within 30 days of the TPD Allocation study with similar information as the cluster heat maps. The ISO will provide stakeholders and interconnection customers with clarity around the data that will be used to determine whether a project will follow the TPD Deliverability Option (previously referred to as "Option A") or the Merchant Deliverability Option (previously referred to as "Option B"), and will provide clarity around the 'cut-off point' for that data. Doing so, the ISO will work with the same information as stakeholders when it evaluates whether projects will proceed as TPP Deliverability or merchant deliverability projects.

ACP-California notes that the availability and usefulness of some of this data may change in the transition to the zonal approach. For example, the information used for the Transmission Capability Estimates may be more limited than it is today, which will make it more difficult for developers to understand whether projects will have available capacity. The ISO notes that the available data may change from interconnection cluster to cluster and will update the information as it becomes available. Rev Renewables suggest that the ISO share a sample workbook for stakeholders to review and better understand what information will be included and what may need to be addressed or changed to support development. As data availability changes or evolves, the ISO will consider holding a workshop to go through the currently available data changes. Similarly, AES expresses concerns around the timing misalignment between the release of the ISO's 'consolidated report' and the 2023-2024 TPD allocation cycle. The ISO clarifies that it is not wedded to a report release at the end of January or any particular point in time; the ISO's priority is to align the data availability and heat map with other annual cycles to provide transparency and time to make important decisions prior to the interconnection window.

AES and CalCCA requested that the ISO calculate a single number for the capacity in each zone. The ISO will calculate a single capacity number for each zone, which will be based on the CPUC portfolio. These zonal capacity numbers will be used to designate Transmission Plan Deliverability zones and Merchant Deliverability zones.

Clearway supports the ISO's proposal to post redacted versions of cluster study reports and individual interconnection reports to make more data available to interconnection customers. Rev Renewables does not support making individual [redacted] project reports available on the market portal, because it would provide others with proprietary information that an individual company paid to receive. Instead, Rev suggests that the ISO produce a summarized version of these reports in a compiled report. The ISO appreciates the concern, but notes that other ISOs and RTOs publish this kind of information and that it can prove useful to future interconnection customers while protecting confidential information.

CalWEA notes that the use of "zone" or "area" within the proposal is very confusing as treatment of interconnection requests based on available transmission capacity at the zonal level is not possible, and available capacity will be point-of-interconnection (POI)-specific. The zones are consistent with the interconnection areas utilized in the generator interconnection areas where the area constraints, which establish the capability in the zone or sub-zones are developed.

Stakeholders also requested additional short-circuit data be provided or a heat map developed of the short-circuit levels at each POI, but the short-circuit data is not available to develop a heat map. The ISO provides information in the Cluster Study Interconnection Area Reports on the overstressed breakers, and the short-circuit model is posted on the ISO's market participant portal for each cluster study. In addition, the PTOs also provide the breaker ratings for all breakers for interconnection customers to assess current short- circuit limitations at POIs they are considering for interconnection.

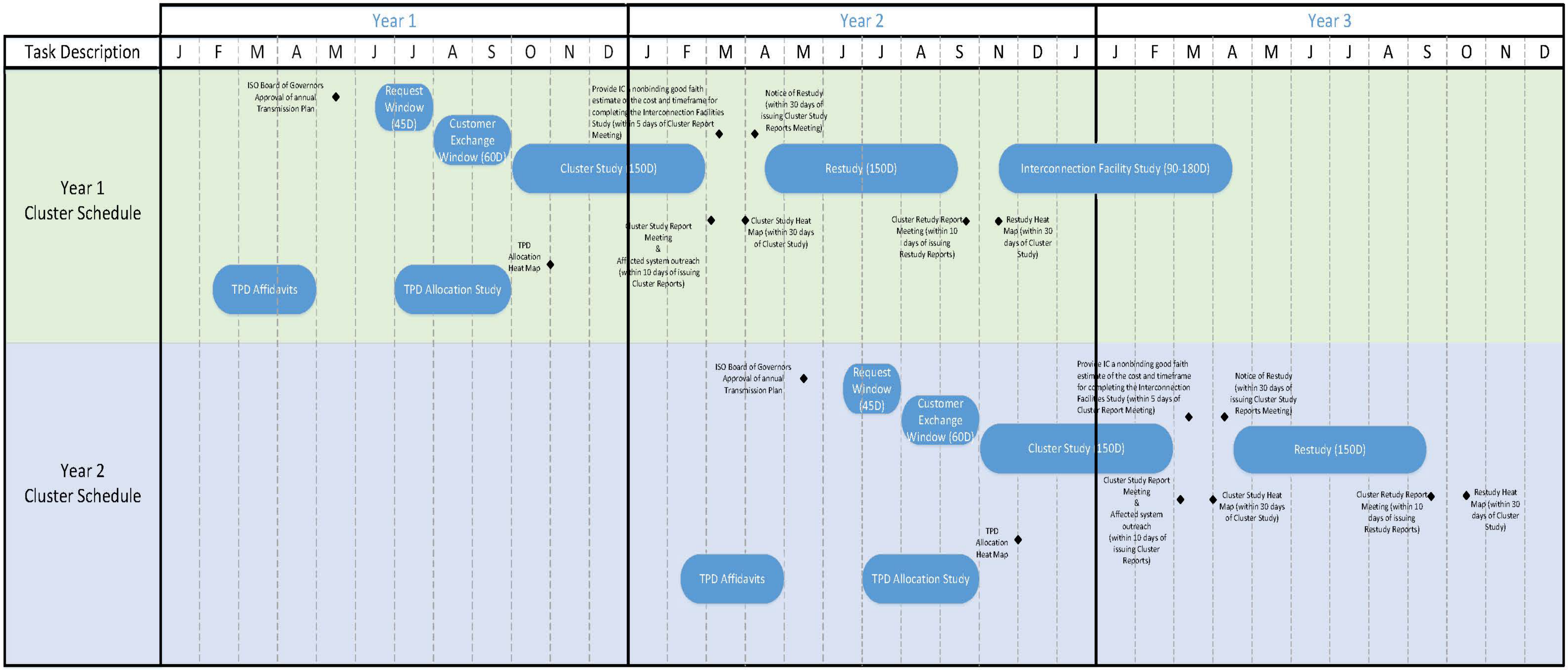
AES, Clearway, Intersect Power, LSA and New Leaf Energy provided feedback on the need for additional information on the feasibility of a POI for generation to be able to interconnect. PARS recommends that the ISO provide a list of substations to which utilities no longer accept interconnection requests. The ISO has indicated that the PTOs have provided within their interconnection handbooks known substations where there is not capacity to interconnect. In addition, the ISO proposes to post the individual interconnection reports on the ISO market participant portal in Appendix A of interconnection reports while redacting confidential data related to the interconnection customer, locational information of the generating facility and details of the specific technology or vendor.

Proposal

A central tenet of this initiative is the prioritization of projects in areas 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 areas 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 the zones will still have the option to self-fund network upgrades through a modified "Merchant Deliverability" process, as explained below.

The ISO understands that access to information is critical for the zonal approach, and will provide stakeholders with information on the available transmission capacity within the transmission zones prior to the interconnection request window. The ISO offers a proposed generic schedule in Figure 4 to demonstrate the relative timing of information availability related to key milestones and reports throughout the transmission planning, TPD allocation, and interconnection process.

Figure 4. Proposed generic schedule for information availability and interconnection study process.



Accessible information

Much of the information necessary to understand where transmission capacity exists or has been approved is currently available through a number of independent documents and workbooks. The ISO will consolidate the information for each of the interconnection areas into one document so it is easier to assess the available interconnection capability at points of interconnection. This will include:

- Single-line diagrams of the interconnection area with the CPUC portfolio resources identified at the substations to which he CPUC has mapped resources in its busbar mapping process;

- Transmission constraints that have been identified within each interconnection area, with the available TPD, the ADNU identified to increase beyond the current TPD along with the estimated cost and time to construct the identified ADNU; and

- Single-line diagrams that identify the points of interconnections that were studied and that are behind each of the identified constraints.

The ISO will also provide:

- A list of substations within each of the identified transmission interconnection areas;

- For each transmission constraint, points of interconnection where resources in the queue were located in the studies behind the constraints;

- The TPD that has been allocated for each transmission constraint.

As indicated, the resources identified within the CPUC portfolios mapped to the substations within the transmission interconnection areas are assessed in the annual transmission planning process. This is done to determine the capability of the existing transmission system and identify transmission projects for approval to address the constraints identified to deliver the capacity and types of resources to load at the locations identified in the CPUC portfolios. The transmission constraints in the Transmission Capabilities Estimates are used by the CPUC in development of its portfolios. While the ISO is planning the transmission up to the resource identified in the CPUC portfolio in each of the interconnection areas, the specific constraints provide the capability of sub-zones within the interconnection area. A particular interconnection point may be identified behind more than one constraint, as some of the constraints are either nested within or overlap other constraints. The capability of a POI for resource interconnection needs to consider all of the constraints that it would be behind. The ISO will utilize the transmission constraint information along with the allocated TPD to determine available transmission capability for future clusters to be studied, as set out below.

Updated Queue Reports

The ISO updated the information within the Queue Report in Q2 of 2023 to include additional details for each project in the active queue, including:

- Which projects have TPD allocated to them as FCDS, PCDS (with percentages), or are Energy Only.
- The interconnection area where the queue project is located. The interconnection areas that are in the queue report do not reflect the current interconnection areas identified in Figure 1.

The ISO proposes to identify in the queue report where FCDS has been allocated and where FCDS has been requested and not yet allocated to each interconnection customer. The ISO will also update in the Resource Interconnection Management System (RIMS) the area information based on the current interconnection areas.

Interconnection Heat Map

FERC Order No. 2023 requires transmission operators to make available a heat map, along with specific associated information, 30 days after the Cluster Study and 30 days after the Restudy. The ISO is in the process of developing requirements for the heat map and associated information and is working to provide an initial heat map based on the Cluster 14 Phase II base cases as well as the 2024 Reassessment base cases. Because this initial heat map is not part of compliance with FERC Order No. 2023, it will likely not be available 30 days after the Cluster 14 Phase II reports are issued. The ISO is targeting for the initial heat map information to be available within Q3 of 2024. The heat map will provide information at the POI level of available capacity based upon the generation that was included in the latest cluster study and after the restudy. In addition to providing the heat map based on the latest cluster study and restudy, the ISO proposes to provide the heat map information after the annual TPD allocation study. Additional information will be provided to generators assessing potential points of interconnection by virtue of having the heat map information of available capabilities based on the resources that were studied in the latest Cluster Study/Restudy, as well as the available capacity after the TPD has been allocated. After Order No. 2023 compliance, the ISO will continue to provide the data described in this proposal in addition to data required under Order No. 2023.

Interconnection Area Reports

Interconnection Area Reports from each Cluster Study are currently made publicly available on the ISO's market participant portal. This provides details of the Cluster Study and the associated network upgrades that have been identified. The interconnection area reports do not include the specific interconnection network upgrades required to interconnect the generator at the specified POI.

The ISO proposes to post the individual interconnection reports on the ISO market participant portal in Appendix A of interconnection reports in redacted form to remove confidential information. Appendix DD of the ISO tariff in Section 3.6 states: "Except in the case of an Affiliate, the list will not disclose the identity of the interconnection customer until the interconnection customer executes a GIA or requests that the applicable Participating TO(s) and the CAISO file an unexecuted GIA with FERC." At a minimum, this information will be redacted, unless an LGIA has been executed, and the ISO will assess if any additional information in the reports should be considered confidential. This will provide generators information on available interconnection capability and potential interconnection requirements at points of interconnection being considered. An example redacted interconnection report is provided as Appendix A to this proposal.

Non-CPUC jurisdictional LSE Resource Plans

In addition to the portfolios received by the CPUC for the annual transmission planning process, the ISO will coordinate with other LRAs and non-CPUC jurisdictional entities to determine their approved resources in their individual Integrated Resources Plans (IRP) to include in the transmission planning analysis. As part of the 2024-2025 transmission planning process, the ISO will request non-CPUC jurisdictional entities to provide their current approved resource plans as input into the development of the study plan that the ISO will engage stakeholders on in February.

2.2. Interconnection Request Requirements and Review [Updated]

Throughout this initiative and working group process, the ISO and stakeholders have explored new or elevated requirements (financial and non-financial) for a complete interconnection request to require a greater level of project readiness before study. In addition, stakeholders considered mechanisms to incorporate LSE input on priority projects, scoring criteria, and higher fees and deposits.

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 that advance to the study phase. In addition to FERC's new requirements, the ISO proposes that interconnection customers must submit a score-sheet in their interconnection request. This will be similar to the TPD scoring affidavits submitted today, but with different criteria.

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

As discussed below, the ISO does not propose to require interconnection customers to submit sealed bids for the potential zonal auction with interconnection requests.

The ISO explains each component, below.

2.2.1. Site Control [Updated]

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. Cluster 15 interconnection customers will need to provide site control documentation before their cluster study commences, or they will not be included in the cluster 15 study.

Several stakeholders requested sufficient notice and clarification of whether and when Cluster 14 projects would be required to obtain site control as required under Order No. 2023. The ISO does not propose to apply this requirement to

Cluster 14 projects as part of the IPE initiative. The ISO also does not intend to subject clusters 14 and earlier to new site control requirements through Order No. 2023. However, the ISO will be subject to FERC's compliance directives, which may differ from the ISO's proposed compliance. The ISO does not believe additional site control measures must apply to earlier clusters given where they are in the queue, commercial viability criteria requirements for site control, and the fact that cluster 14 site exclusivity deposits are now non-refundable.[16]

2.2.2. Entry Fees and Deposits

Order No. 2023 imposes several new entry fees and study deposits. Stakeholders have suggested that the ISO reconsider current levels of entry fees and study deposits, but the ISO does not propose such changes at this point.

2.2.3. Treatment of Full Capacity Deliverability Status and Energy Only resources [New]

The ISO received a number of requests for clarification regarding how Energy Only resources would be treated in the interconnection request intake process. The ISO proposes that the process of submitting and reviewing interconnection requests be the same for all projects seeking Full Capacity Deliverability Status (FCDS), Partial Capacity Deliverability Status (PCDS) and Energy Only status within zones with available transmission capacity. FCDS, PCDS, and Energy Only projects will be required to meet the same site control requirements, provide the same entry fees and study deposits, and provide a self-assessment IR score sheet. FCDS, PCDS, and Energy Only projects would go through the scoring process and compete to be studied.

Energy Only resource capacity will not count toward the 150% cap. The 150% cap is based on Transmission Plan Deliverability capacity and the inclusion of Energy Only projects would increase the number of projects that advance to the study process, but would not increase the deliverable capacity to be studied. As described in Section 2.4, below, if the scoring process is below the 150% threshold and a number of projects with the same score are up for consideration

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[16] Section 16.1(l) of the GIDAP.

for the last project(s) to cross the 150% threshold, the distribution factor (DFAX) will be used as the tie breaker.

Section 2.7, Modifications to Deliverability, explains that in order to maintain order and fairness in the queue, Energy Only projects will not be eligible to seek Transmission Plan Deliverability (TPD) allocations until they are online (currently under the current Group 3).

2.3. Interconnection Request Limitations [Updated]

Background

To ensure that no developer can overwhelm the processing of interconnection requests during a cluster window process or try to capture an inappropriate share of the available transmission capacity, the ISO proposed limiting the number of requests 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. The rationale for the proposal was that in previous clusters, and in several instances, the ISO has received over 20 interconnection requests from individual parent companies.

The ISO's goal is to maintain open access in a manner that encourages interconnection customers to bring real and viable projects to the queue so the ISO can process and score interconnection requests in a timely manner, consistent with the Order No. 2023 timeline.

Stakeholder feedback and discussion

AES, ACP-California, Avantus, Aypa Power, CESA, Clearway, EDP-Renewables, Engie NA, IEPA, Intersect Power, LSA, New Leaf Energy, NextEra Energy Resources, Qcells USA, Rev Renewables, and TerraGen expressed strong opposition to the proposal to limit the number of requests 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, despite the additional information shared by the ISO. The ISO understands the level of concern around the proposed limitation, which is reflected in the proposal below.

Several stakeholders recommended alternatives to the 25% cap on interconnection requests: CalWEA suggested that the ISO limit the number of requests, not the amount of capacity requested by each developer. PARS

Energy suggested that the proposed projects and capacity per project should also have size limits commensurate with the POI voltage class. Shell Energy recommended development of additional criteria to create greater flexibility. GridStor said any such cap be applied after all interconnection requests have been scored (including DFAX tie-breaking) but before the use of auctions for tie-breaking. The ISO appreciates parties' willingness to propose solutions but finds each of these proposals to be as complex as the original proposal.

PG&E noted support for the ISO taking steps to limit opportunities for market power, but supported continued discussion of the issue in working groups to identify alternative mechanisms. CalCCA supports maintaining a cap on the number of requests a single developer can submit. The ISO values these comments as well and will continue to work to provide a fair, open, and manageable interconnection process.

Proposal

Given the significant stakeholder response to such a cap, the ISO proposes to forego this limitation on the number of interconnection requests a developer can submit in a given cluster application window. The ISO may revisit this proposal in future Interconnection Process Enhancement initiatives if the other measures proposed in this draft final proposal do not sufficiently address excessive interconnection requests from a single entity in one queue cluster window.

2.4. Scoring Criteria for Prioritization to the Study Process [Updated]

Background

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

The ISO also sought feedback in the straw proposal on how best to incorporate LSE interest earlier in the process. Doing so would help satisfy the MOU goal of aligning resource and transmission planning with procurement and interconnection. Feedback on earlier proposals strongly favored removing any points associated with a PPA from the scoring criteria, with parties noting that commercial milestones (e.g., shortlisting, term sheets, and PPAs) were more relevant indicators of progress after interconnection studies. The ISO removed those commercial milestones and permitting indicators from the scoring criteria in the revised straw proposal.

Stakeholder feedback and discussion

AES, Avantus, Aypa, CalWEA, CESA, Clearway, EDF-Renewables, Engie NA, Intersect, Rev Renewables, SEIA, Terra-Gen, and Vistra indicated concern that the scoring criteria required additional refinement to balance readiness and viability indicators with LSE interest. The ISO reviewed specific alternative weights proposed by stakeholders and proposes a more balanced weighting in the revised scoring criteria proposal, below.

Several participants in this initiative process sought greater clarity on how Energy Only projects should engage with the interconnection process. ACP-California suggested that the ISO develop a process for Energy Only projects to enter the queue that does not rely on LSE interest. AES, Intersect, LSA also sought additional clarity. The ISO provided more detail on treatment of Energy Only resources above, in Section 2.2.3. While the ISO has not seen significant interest in or viability of Energy Only resources advancing through the queue, the ISO recognizes that the CPUC does include a number of Energy Only resources in the portfolios. Therefore, the ISO has clarified that Energy Only projects will be evaluated in the same manner as projects seeking FCDS status, including use of the DFAX as a tie-breaker. This process is described in greater detail in Section 2.2.3. To prevent disingenuous Energy Only representations, the ISO proposes that Energy Only projects may only seek TPD once they reach commercial online dates. This would prevent projects from beginning as Energy Only without contributing to the 150% threshold and then competing for TPD in queue with projects that accurately represented their need for deliverability at the outset.

Commercial interest

Throughout this initiative, the ISO has encouraged more discussion and stakeholder feedback on opportunities to incorporate LSE procurement activities earlier in the interconnection process. This would facilitate the zonal approach and appropriately sequence implementation of these practices for a more efficient process.

Based on the revised straw proposal, several stakeholders asked how the ISO could prevent LSEs from selecting their own projects under the proposed LSE interest category. AES, Avantus, Aypa, CESA, Engie NA, Clearway, MN8, New Leaf Energy, Rev Renewables, TerraGen, and Vistra all express concern that the proposed weighting in the revised straw proposal favored LSEs, and many sought clarification or assurance that LSEs would not be allowed to allocate points to their own projects. Middle River Power notes that restructuring displaced the IOUs as primary developers of power generation, and that the ISO's revised straw proposal was reasonable, but that the ISO must ensure that this weight is not leveraged to reinvigorate the utility-owned generation development model. CalCCA, PG&E, NCPA, Six Cities, Southern California Edison, supported the proposed scoring criteria and the opportunities to consider LSE interest. SDG&E sought more information on how information would be shared with LSEs, and kept confidential. The ISO proposes more detail on the process for obtaining information on interest from LSEs and commercial offtakers in the updated proposal, below. The ISO reviewed queue data over the past several clusters. Utility-owned projects are relatively rare in California because utilities must meet a higher burden with the CPUC to justify self-procurement. Generally utilities submit zero, one, or a few interconnection requests in a new cluster. From clusters 10 to 14, for instance, utilities submitted an average of less than one interconnection request, with a median of one. As such, the ISO does not foresee a significant risk of LSE self-favoritism but believes a limitation on self-built projects is prudent to avoid undue preference in the future.

Specifically, Shell suggested that the proposed 35% weighting factor is too low and should be closer to 50%. No other stakeholders opined on the appropriateness of this weighting factor. As the 35% weighting factor was initially proposed by LSEs based on familiarity with their own procurement processes and needs, the ISO will keep this value in the proposal as a means to ensure competition for LSE allocations.

Additionally, ACP-California, AES, Clearway, Intersect, Rev Renewables, and SEIA suggested expanding the scoring criteria to include interest from commercial offtakers. The ISO understands this concern and provides more detail in the proposal below, providing an opportunity for corporate offtakers to attest to their interest in a particular interconnection request/project through a signed affidavit from a procurement manager at the company.

NCPA and Six Cities strongly supported the proposed automatic inclusion of specific resources, while Southern California Edison and Rev Renewables opposed it. Shell Energy suggested some "check" on the bypass. Intersect and LSA also suggested modifications, such as a limit to small LSEs or expand to other small LSEs, as well as reducing the scope to limit impacts to other projects. NCPA and Six Cities provided supplemental comment on the issue, proposing revisions to the LSE-interest scoring criteria that would assure comparable access to the interconnection process for non-CPUC jurisdictional LSEs by ensuring that they receive sufficient LSE-interest points to have a meaningful opportunity to designate needed projects. The ISO understands concerns with an unbounded automatic bypass and proposes below a modified proposal based on the LSE allocation process.

Project viability

Many stakeholders support the removal of permitting criteria in the project viability category, including Recurrent Energy and Avantus. Defenders of Wildlife recommended reviving the proposal to include permitting status as a measure of project viability. IEPA also suggested that the ISO consider including previously proposed categories, such as level of site control beyond FERC Order No. 2023 requirements and permitting. The ISO understands that permitting is a useful indicator to consider project viability, but given the uniqueness of permitting pathways for each individual project, the ISO has neither the expertise, resources, nor objective criteria to evaluate a specific project's progress toward permitting so early in the interconnection process. The ISO does propose, however, to review permitting status as part of the commercial viability criteria in the TPD allocation process, described in Section 3.6 below.

Golden State Clean Energy and MN8 also highlight the potential to bias the scoring criteria away from greenfield projects by only having criteria relevant to expansion projects. They suggest that the ISO consider additional criteria to demonstrate a higher likelihood of permitting success, such as the CEC land use screens. The ISO considered this feedback and has refined the proposal to better balance opportunities for different types of development through additional opportunities to earn points for site control of the gen-tie.

CalWEA, Recurrent Energy, and Terra-Gen suggested that demonstration of a business partnership is too ambiguous to be meaningful, and that such arrangements are premature to consider in the scoring process. LSA and Intersect suggested alternatives, such as evidence of a Master Services Agreement (MSA) for purchases of major equipment or a purchase order (PO) for equipment that demonstrates that the equipment is specific to the project.

PG&E noted that these items only target readiness, not viability. The ISO appreciates this feedback but is concerned that verifying that MSAs and POs are dedicated to specific sites would be difficult, particularly when several other stakeholders (e.g. MN8) note that such specific business partnerships or purchases are unlikely this early in the project development process. Thus, the ISO proposes removing the demonstration of a business partnership indicator from the scoring criteria.

ACP-California suggested that the ISO update indicators of readiness to provide different levels of points for projects based on the quality of the demonstrated business partnership or Engineering Design Plans. While the ISO is removing the business partnership indicator, it finds some value in the use of existing industry guidelines as a means to develop more granular scoring criteria. While the ISO is removing the business partnership indicator, it finds some value in the use of existing industry guidelines as a means to develop more granular scoring criteria, and will further explore guidelines from the Association for the Advancement of Cost Engineering[17] or the Institute of Electrical and Electronics Engineers to validate and determine the percent completion of each engineering design plan, with consideration that projects at this stage in the development process should not be expected to demonstrate a complete engineering design plan.

Avantus suggested the addition of phased projects to the viability category, with incremental points available for expansion of a project under construction (not just operational). Avantus and Clearway noted that phased projects are more efficiently planned and sequenced to maximize a given gen-tie/bay position capacity limit (1100 MW), which translates to more comprehensive engineering, permitting, and procurement workflow prior to start of construction. The ISO understands the need for meaningful granularity in the scoring criteria and proposes a change to this item.

System need

The ISO provided two proposals for evaluating a project's contribution to system need: the ability to provide local resource adequacy (RA) in an LCRA and long lead-time resources identified in the most recent CPUC resource portfolio where

[17] Association for the Advancement of Cost Engineering. Cost estimate classification system – as applied in engineering, procurement, and construction for the process industries. https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

the TPP has approved transmission projects to provide necessary transmission requirements.

The ISO received several requests for additional clarification of these resources and considered a number of the alternatives proposed. AES also asked for more definition of long lead-time resources and suggested reducing the point allocation for this item because it is a limited resource pool. Rev Renewables similarly suggested not awarding points to enable these resources to “reserve capacity,” noting that if transmission needs to be reserved for specific technologies, it should be done through a merchant or subscriber transmission model. To achieve state policy goals and maintain alignment with California’s energy agencies as described in the MOU, the ISO continues to propose some consideration of long lead-time resources in the scoring criteria.

ACP-California suggested defining long lead-time resources consistent with AB 1373 and both ACP-California and CalCCA suggested working with the CPUC to define these resources in each preferred system plan, and to explicitly identify these resource types in the TPP transmittal letter. The ISO already notes that this item, as proposed in the revised straw proposal, could include resources procured under AB 1373.

Distribution factor tie-breaker

AES, the CPUC, CESA, EDF-Renewables, supported the proposal to use the distribution factor (DFAX) as a tie-breaker. Clearway supported the idea in concept but sought more information on how the analysis would be conducted. ENGIE NA also noted questions about how the scoring will trade-off against TPD in sub-zones or with a single zone for projects with different DFAX values on critical constraints.

Rev Renewables asks how the ISO would resolve a tie for the lowest DFAX if projects still exceed 150%, and recommend that the ISO allow all the tied lowest DFAX projects to be studied as long as the flow impact on the facility does not reach 5%. The ISO clarifies that projects tied after the DFAX tie-breaker will proceed to the auction process.

CalWEA and Terra-Gen noted that projects are generally situated behind multiple different constraints, creating complexity for project scoring. Instead, they suggested considering DFAX in TPD allocations. The ISO appreciates this concern but believes the DFAX tie-breaker approach will be both manageable and objective, and is therefore an appropriate means to resolve tied scores and minimize the need for an auction.

Proposal

The ISO continues to propose refined scoring criteria as a key mechanism to ensure that the most ready projects advance to the study process. The revised criteria, described below, attempt to enable the appropriate level of scoring granularity and opportunities to measure development progress while maintaining a simple process to validate scores.

The ISO proposes requiring interconnection customers to submit documentation supporting their score, as well as a self-assessment score sheet with their interconnection request(s) to minimize time required for the ISO to score and validate a large batch of requests in a narrow window. As discussed in greater detail below, the ISO proposes to receive LSE point allocations directly from LSEs rather than interconnection customers during the interconnection request application window.

Commercial interest

The ISO proposes two opportunities to obtain points in the commercial interest scoring category: an LSE Allocation Process and an opportunity to earn points by demonstrating commercial interest from a non-LSE/commercial offtaker. Interconnection projects may only receive 100 points for the Commercial Interest category, though those points may come from a combination of the LSE allocation process and the non-LSE interest indicators. If a projects scores 125 points, the ISO will reduce that score to 100. The ISO proposes that the commercial interest category constitute 30% of the overall project score.

LSE allocation process

As part of the scoring process, the ISO plans to collect feedback in the form of “points” from LSEs to allocate to individual interconnection requests.

Prior to the interconnection request application window, the ISO encourages LSEs to conduct Requests for Information (RFIs) for projects expecting to enter the queue to ensure that LSEs have the necessary information on individual projects in time to make informed decisions during the LSE allocation process of the scoring criteria. The ISO urges the LSEs to communicate clear evaluation criteria for this process to prospective interconnection customers.

In addition, the ISO expects interested interconnection customers to participate in LSE RFIs, solicitations, and bilateral discussions with LSEs to market their projects prior to the interconnection request application window to supplement information LSEs will be provided during the scoring process and therefore increase the projects' opportunity to obtain LSE-awarded points.

Each LSE (CPUC jurisdictional and non-CPUC jurisdictional) will receive a capacity allocation based on available and planned transmission capacity for a given cluster. The ISO will review and total these scores once it receives information from LSEs. The ISO proposes that non-CPUC jurisdictional LSEs participate in this process in the same manner as CPUC-jurisdictional LSEs.

The ISO proposes to require LSEs to provide the ISO with their elections during the interconnection request window to utilize their points, and the ISO will provide LSEs with a standard LSE Interconnection Allocation Form for submittal of selections. Points awarded to projects by LSEs will not be known or confirmed by the interconnection customer during the interconnection request application window, and therefore will not be included in the interconnection customer's self-assessment.

Allocation methodology

The ISO proposes the following allocation methodology

(a) The ISO calculates total LSE capacity allocation.

In this process, the ISO would determine how much capacity (MW) can be allocated across the ISO footprint, based on available and planned transmission capacity. To ensure that LSEs are selective in point allocation, 35% of the total TPD capacity for each LSE can be eligible to receive points, as an LSE weighting factor.

> *Example:*
> *Assume total TPD capacity across ISO footprint is 45,000 MW.*
> *Total LSE Capacity Allocation = TPD Capacity x LSE Weighting Factor*
> *= 45,000 x 0.35*
> *= 15,750 MW (to be shared by all LSEs)*

(b) The ISO calculates individual LSE capacity allocation.

In this step, the ISO would determine how much capacity (MW) the ISO can award to each individual LSE based on its load share[18].

> *Example:*
> *LSE 1 Load Share = 30%*
> *LSE1 Capacity Allocation = Total LSE Capacity Allocation x LSE Load Share*
> *= 15,750 MW x 0.30 = 4,725 MW*
> *LSE 1 is eligible to allocate 4,725 MW of project capacity*

(c) LSE allocates points to selected interconnection requests submitted in the cluster window for new applications

Each LSE determines how they want to allocate their points to selected interconnection requests.

> *Assumptions:*
> *LSE 1 Load Share = 30%*
> *LSE 1 Capacity Allocation = 4,725 MW (provided by ISO in Step 2)*
> *LSE 1 Scenario 1 = Two 300 MW Projects (P1 and P2)*
> > *Full Support of P1 and P2*
> > *Capacity allocation needed to fully support P1 and P2 = Total capacity in each Application x Number of Applications = 300 MW x 2 = 600 MW (LSE 1 has 4,125 MW capacity allocation remaining)*
> > *P1 and P2 receive the full points available to a project in the scoring criteria (because 100% of the capacity of each project was selected by an LSE)*
>
> *LSE 1 Scenario 2: One 1,000 MW project (Project 3) and LSE 1 has partial interest of 500 MW of the project (50% of project capacity was selected by LSE 1)*
> > *Partial Support for Project P3*
> > *Capacity allocation needed to support P3 = Partial Interest MW Interest = 500 MW (LSE 1 has 3,625 MW capacity allocation remaining)*
> > *Partial Capacity Interest / Full Project Capacity x Max. Points in Off Taker interest Category*

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[18] Load share based on the California Energy Commission's energy demand peak load forecasts for LSEs published in the latest available annual Integrated Energy Policy Report.

> > *P3 points = 500/1000 = 50% of the points available to a project in the scoring criteria (because 50% of the capacity of P3 was selected by LSE 1)*
>
> *If P3 does not receive any additional interest from other LSEs to increase its score, the interconnection customer would have the option to be scored based on 50% of the points available to a project in the scoring criteria or to downsize to 500 MW and receive the full points available to a project. (There are intermediate downsize options where P3 could downsize to 750 MW and receive 750/1000 = 75% of the points available to a project in the scoring criteria.)*

Full allocation election

If an LSE has a high priority interest in *one* project and does not have sufficient capacity to allocate to that project's full MW size, it may award all of its capacity towards that one project – and only that one project - and elect to have the project receive the full 100 points. The ISO proposes to limit use of this full allocation election to one project per cycle. Additionally, LSEs cannot make this election for a project that exceeds more than 150% of that LSE's individual capacity allocation for that particular cycle. The capacity awarded to these projects may, however, exceed the 150% of available capacity threshold to advance to the study process.

The option to award full points to a single project applies to all LSEs, whether CPUC-jurisdictional or not. An LSE must specify to the ISO that it is making this special election. The ISO will include a space for this election on the LSE Interconnection Allocation Form.

Limits on LSE-owned projects

To avoid preferential treatment of utility-owned resources, the ISO proposes that LSEs may only award points to one self-built project each cycle. If an LSE opts to use the full allocation election for a self-built project, that election may not exceed 150% of that LSE's total capacity allocation for the cluster. This limitation also applies to both CPUC-jurisdictional and non CPUC-jurisdictional LSEs.

Commercial interest from a non-LSE offtaker

The ISO proposes an additional opportunity for interconnection requests to obtain points in the Commercial Interest category, for projects that are being marketed to non-LSE offtakers, such as corporate and industrial offtakers.

Because commercial offtakers do not carry an obligation to serve load or provide resource adequacy, the ISO does not propose allowing them to participate in the same allocation process as LSEs. Instead, the ISO will award 25 points for documented, verifiable demonstration of commercial interest from a valid non-LSE offtaker.

Although stakeholders ask for guidance on what constitutes a "valid" non-LSE offtaker, the ISO is reluctant to provide a definition or criteria. The ISO's consideration of non-LSE power purchase agreements in IPE 2021 was premised on an evolving procurement landscape that warranted greater flexibility for developers and energy purchasers. Creating specific criteria may inadvertently prevent legitimate procurement and inhibit that flexibility. The ISO notes, however, that it continues to scrutinize every non-LSE commercial arrangement proffered to ensure the company is legitimate, procuring the capacity in a meaningful way, and not affiliated with the interconnection customer or its holding company. The ISO will continue to reject illegitimate power purchase agreements and commercial arrangements created to satisfy tariff criteria artificially before being replaced with legitimate, arrangements that would actually provide financing of a generator.

Project Viability

The ISO proposes refinements to criteria that are most appropriate early in the interconnection process. The ISO requires criteria that can be easily validated with interconnection requests during the cluster request window. To assist in the ISO's validation process, the ISO will require interconnection customers to provide both a self-assessment and proof of each scoring criterion below.

The ISO proposes four indicators of project viability, with the entire category comprising 35% of the overall scoring weight.

- Percent completion of engineering design plan, to be validated based on a set of pre-determined guidelines;
    - The ISO is exploring the availability of guidelines from the Association for the Advancement of Cost Engineering[19] or other

[19] Association for the Advancement of Cost Engineering. Cost estimate classification system – as applied in engineering, procurement, and construction for the process industries. https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

entities to validate and determine the percent completion of each engineering design plan. The ISO invites feedback on whether this approach will result in a true and objective assessment project readiness and whether it is worth the potential complexity it may bring to the project development process and the ISO scoring process.

- Expansion of a generation facility that is currently under construction;
- Expansion of an operating facility;
- Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource;
- 100% site control of the gen-tie.

System Need

The ISO proposes two indicators of system need, which together would make up 35% of the overall scoring weight:

- Ability to provide Local Resource Adequacy in an LCRA with an ISO-demonstrated need for additional capacity in that local area.
- Long lead-time resources: Meets the requirements of the CPUC resource portfolios where the TPP has approved transmission projects to provide necessary transmission requirements. Only long lead-time resources that are required to meet the CPUC resource portfolio requirements are eligible, including resource types that are considered for central procurement under Assembly Bill 1373 (2023), or as specifically identified by the CPUC in the portfolios provided to the ISO for use in the transmission planning process.

The table below provides the ISO’s current proposal. The total score is to demonstrate the concept, where in this example a project qualifies for each scoring criterion. The ISO proposes to use weighted scoring, multiplying the total points value by the weight to calculate the total score for each category.

Figure 5. Proposed Scoring Criteria

Indicators of Readiness	Points	Weight (%)	Max Points	Validation
Commercial Interest (Max points= 100)				
□ LSE allocations: Points based on the percentage of capacity allocated by LSEs to the project (e.g. a 500 MW project receiving 500 MW capacity allocation would earn 100 points for this category. A 500 MW project receiving 250 MW capacity allocation would earn 50 points for this category.) In instances where a non-CPUC jurisdictional LSE does not have enough points to award to an entire project, each non-CPUC jurisdictional LSE may award full capacity for one project per interconnection request application window.	100	30%	**30**	The ISO will provide LSEs with a form to fill out to assign points to desired interconnection requests, to return to the ISO during the interconnection request application window. The ISO will add the points to each project's score as part of the scoring process.
□ Non-LSE Interest Points	25			Signed affidavit indicating and affirming commercial interest from procurement division of non-LSE offtaker.
Project Viability (Max points=100)[20]				
Engineering Design Plan Completeness (check one)		35%	**35**	Alignment with AACEI cost estimate classification system.[21]
□ 0-5% complete = 10 points.	10			
□ 6-10% complete = 15 points	15			
□ 11-20% complete = 20 points	20			
Chose no more than one of the three expansion of a generation facility items				
□ Expansion of a generation facility that is currently under construction	10			IC submits information indicating that new IR uses same or directly adjacent site as a facility under construction

[20] Maximum points of 100 for Project Viability = 11-20% complete (20 points) + Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource (40 points) + 100% site control of the gen-tie (40 points)
[21] Association for the Advancement of Cost Engineering. Cost estimate classification system – as applied in engineering, procurement, and construction for the process industries. https://web.aacei.org/docs/default-source/toc/toc_18r-97.pdf?sfvrsn=4

☐ Expansion of an operating facility	20			IC submits information indicating that new IR uses same or directly adjacent site as an operating facility
☐ Expansion of a facility that is under construction or in operation, where the Gen-Tie already has sufficient surplus capability to accommodate the additional resource	40			IC submits information indicating that new IR uses same or directly adjacent site as an existing facility and documents the capacity of the gen-tie, the existing (under construction or in operation) facility and the new facility
☐ 100% site control of the gen-tie	40			
System Need (Check one. Max points=100)[22]				
☐ Ability to provide Local Resource Adequacy (RA) in an LCRA with an ISO demonstrated need for additional capacity in that local area	50	35%	**35**	
<u>Long Lead-time Resources</u> ☐ Meets the requirements of the CPUC resource portfolios where the TPP has approved transmission projects to provide the necessary transmission requirements.[23]	100			
Total		100%	**100**	
Distribution Factor	Value	Tie-Breaker		
☐ Value used as tie-breaker (lowest DFAX selected first)				Interconnection request

Distribution factors

The ISO will use each project's distribution factor (DFAX)[24] as a tie-breaker when the selection process reaches the 150% threshold with two or more projects tied and less capacity needed to reach 150% than the sum of the tied project's

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[22] The ISO assumes that these two categories are mutually exclusive and that projects would not be able to select both.
[23] Only long lead-time resources that are required to meet the CPUC resource portfolio requirements are eligible, including resource types that are considered for central procurement under Assembly Bill 1373 (2023), or as specifically identified by the CPUC in the portfolios provided to the ISO for use in the transmission planning process.
[24] Distribution Factor (DFAX): Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources in the Control Area.

capacity. DFAX is a measure of the impact of injections of energy from a generator at a particular location which could result in required network changes on the grid. The lower the DFAX, the lower the impact to the grid. The projects will be selected in order of the lowest DFAX with the selection process ending with the project that caused the 150% threshold to be exceeded, regardless of the size of the last project selected and the amount by which 150% is exceeded. The ISO will determine the DFAX for any projects that are tied and determine the project(s) that will be studied: interconnection customers should not provide this information. If project ties still exist after the use of projects' DFAX, the auction process will be used to break the ties.

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, the ISO still proposes selection of 150% of available or planned capacity per zone as appropriate.

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

2.5. Prioritization of Projects for the Study Process [Updated]

The ISO will review and score Interconnection Request information to identify projects most ready to proceed into the study process. The straw proposal and revised straw proposal suggested studying 150% of the available and planned transmission capacity in each zone as a means to right-size the number of studies with the necessary development to achieve resource planning portfolios. Such scaling will ensure more meaningful study results to interconnection customers as they move through a compressed, single phase study process. By studying a percentage above the capacity for each zone, the ISO will ensure sufficient availability of resources in and after the study process, balancing resource sufficiency with competition.

Stakeholders have asked the ISO to justify a rationale for the 150% capacity limitation, with some expressing concern that this cap would "arbitrarily" reduce the number of projects that can compete. They also flagged the cap's potential to drive-up resource adequacy costs due to limited supply. The ISO understands these concerns, but notes that the rationale for selecting 150% is to ensure continued competition and supply and each cluster will result in a surplus of studied capacity that will accumulate over time. Unlimited interconnection requests or a higher percentage would continue to grow the queue at an unsustainable rate, slowing study processes and making results less accurate. The ISO intends to create fair and reasonable limits on the amount of new generation it can study on a timely basis, and is testing the effect of the 150% cap using Cluster 15 data. The ISO will develop more data and analysis of cap results in this initiative through analysis and a survey of Cluster 15 interconnection customers.

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.

2.5.1. Fulfillment of 150% of Available and Planned Transmission Capacity [Updated]

Background

To fulfill each of the zones described in Section 2.1, the ISO proposes to analyze individual transmission zones with sub-zonal constraints. In the interest of transparency, the ISO will use the same information provided to stakeholders prior to the interconnection process.

In the process of selecting projects that can proceed to the study process within each TPD zone, the ISO will add projects to various POIs in descending order of a project's score, until the available and planned transmission capacity for each constraint is filled to 150% of that capacity, and until the capacity for each TPD zone based on the CPUC portfolio is filled to 150% of that capacity. Projects at a POI that are affected by a constraint with no available or planned transmission capacity will not be included in the study for that Option A zone. Projects in a TPD zone and at a POI that has not been previously studied will be evaluated using engineering judgement or based on its effectiveness to the known constraints.

Stakeholder feedback and discussion

Stakeholders are divided in their support for fulfillment of 150% of available and planned transmission capacity.

CPUC, Clearway Energy Group, Golden State Clean Energy, NextEra Energy Resources, Shell Energy, SCE, and Terra-gen, LLC generally supported the proposal.

AES, Aypa Power, California Community Choice Association, CPUC, California Wind Energy Association, CESA, Clearway Energy Group, ENGIE NA, Golden State Clean Energy, MN8 Energy, Qcells USA Corp, and Terra-Gen, LLC all voiced concerns that 150% was too restrictive. The ISO understands the concern, but points out that the 150% annual limit will result in 50% more projects year-over-year than the system can accommodate. This will result in a queue that will continue to swell with more resources than are needed based on state and local planning. For example, based on the 150%[25] limit, if no additional TPP is added to a zone and no un-procured projects withdraw, within a three-year period the queue will have at least 150%[26] more capacity in that zone than what the available transmission capacity for that zone was at the beginning of the three-year period.

AES, Golden State Clean Energy, Qcells USA Corp, SEIA, and Six Cities suggested that non-CPUC projects should not be counted toward the 150% limit, so they do not take positions in the study process for other, potentially higher-scoring projects. With the removal of the automatic inclusion of non-CPUC jurisdictional LSE projects from the scoring criteria as noted above, this concern has been addressed.

AES, Intersect Power, AES, Intersect, LSA, SEIA LSA, and SEIA suggested an option for projects to fund network upgrades triggered after the 150% limit. The ISO's response to this issue is addressed in Section 2.5.3, Modifications to Merchant Deliverability Option.

Avantus Clean Energy LLC, Clearway, Rev Renewables, and Terra-Gen request clarification regarding projects that don't make the 150% cut and requested an option to change POI in that case. Rev Renewables and Terra-Gen LLC asked

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[25] The 150% is based on 100% of the available capacity plus 50% over the available capacity.
[26] 50% over the available capacity in year one + 50% in year two + 50% in year three = 150% of year-one's available capacity that may be lingering in the queue.

whether projects that hit a sub-zone limit be allowed to change their interconnection point within the zone if the zonal limit is not yet reached. Due to the complexity of the process for determining what projects can be studied behind each constraint, the ISO cannot allow any changes in POI after a project submits its IR. The information provided prior to the opening of each interconnection request window should be sufficient for projects to select the best POI for their proposal.

Avantus also asked what happens to the 50% of 150% admitted project MWs that do not receive TPD after completing a study cycle and whether that capacity will be required to withdraw or convert to Energy Only. In Section 2.7.1 of the TPD Allocation Process Modifications, the ISO proposes that projects will have three consecutive opportunities to seek an allocation, beginning with the first affidavit window after receipt of all study reports for a given project. After the third opportunity to seek an allocation, projects that have not received an allocation will be converted to EO.

CalWEA asked how limits will be set for POIs without known constraints. The ISO will limit the overall capacity in a zone based on the CPUC portfolio.

CESA asked how earlier Energy Only projects will impact the available transmission capability of future cluster projects being studied. The ISO's deliverability studies do not include the capacity of Energy Only projects, so those projects in the queue will not impact later projects seeking deliverability status.

Gridstor asked whether calculation of the project's MW towards the 150% available & planned capacity of a zone will be impacted by the existence of WDAT projects that have also requested interconnection within a given zone. The ISO will include the capacity of WDAT projects seeking FCDS. However, this issue is also governed by the PTO's WDAT tariffs, and any changes to those tariffs could impact the ISO's treatment of WDAT projects.

Intersect Power and LSA asked why the ISO deleted the verbiage "other projects seeking to interconnect in that area will be eligible to interconnect in the broader zone until 150% of the capacity is reached." The ISO deleted this language because it was not consistent with the current proposed approach. If a Network Upgrade is triggered, it might be a very cost-effective investment given the additional capability it would enable, and in any case the projects triggering it should be given an opportunity to fund it under a Merchant Deliverability framework. The ISO's intent is to not trigger any additional ADNU beyond what would be approved in the TPP policy study based on the CPUC portfolio. The ISO's proposal in the Merchant Deliverability section 2.5.3 provides additional justification.

Recurrent Energy asked if the ISO will make available the information on sub-zones for every zone that the project will be assigned to, based on the constraints it is behind. The ISO will provide information on every constraint (sub-zone) that has been previously identified. Constraints define (create) sub-zones. The following example in the comment is correct. If a constraint (sub-zone) has 1,000 MW of available capability left after what has been previously allocated, including any allocations to C14, then the sub-zone available capacity is 1,000 MW.

Rev Renewables asked if the ISO will start with the highest scored projects and work down the list until 150% limit is reached, or if the ISO intends to add these scored projects until a network upgrade is triggered. In the scoring process, the ISO will start with the highest scored projects and work down the list until 150% limit is reached.

Rev also asked if there could be a scenario where some of these highest scored projects get removed, as the initial score-based filtering was an estimate and network upgrades get triggered at less than 150% estimate based limit. There could also be a scenario where a network upgrade is not triggered based on section 2.5.1 assessment, and some of the projects that were screened out based on the 150% estimate can now be added back as network upgrades did not get triggered. Here again, the ISO will study all projects that fall within the 150% criteria. The ISO will not test or score whether a project triggers a network upgrade during the intake process.

Shell Energy asked how the ISO would treat a scenario when the project that crosses the 150% cap value is an extremely large project. In Section 2.5.1, Fulfillment of 150% of available and planned transmission capacity, the ISO proposes that projects will be selected in order of the lowest DFAX with the selection process ending with the project that caused the 150% threshold to be exceeded, regardless of the size of the last project selected and the amount by which 150% is exceeded.

Vistra requested the ISO clarify whether capacity counted towards the 150% cap is only FCDS or if it will include energy only capacity headroom or interim full capacity deliverability headroom and how partial capacity [PCDS] and energy only capacity projects be screened within this cap. The ISO provides answers to these questions in Section 2.2.3, and further clarifies that interim deliverability is determined after the study process for projects imminently coming online, not within the screening or study processes.

Proposal

The ISO is working to evaluate and analyze the potential application of the 150% zonal limitation through internal analysis. Additionally, the ISO plans to issue a survey to Cluster 15 interconnection customers to understand how Cluster 15 projects would score and compete based on available transmission capacity. The ISO continues to propose the 150% zonal limitation as a means to reasonably filter the most ready projects to the study process, maintain open access, and ensure competition after the studies are complete. Further analysis of Cluster 15 data and survey results will inform any potential final modifications to the 150% zonal limitation.

2.5.2. Auctions [Updated]

Background

In the May 2023 discussion paper, the ISO raised the concept of an auction to reduce the number of interconnection requests to a more manageable level. The ISO and stakeholders discussed the concept during workshops and working group meetings.

The straw proposal and revised straw proposal refined an auction design with the following key attributes:

- A market-clearing, sealed-bid auction for the right to be studied;
- Each zone would be studied at 150% of the individual constraint based and portfolio-driven available and planned capacity;
- Auctions would be conducted only if there is excess proposed capacity after applying a points-based viability scoring system that utilizes a distribution factor (DFAX) as an initial tie-breaker, and only for projects that are deemed equal in viability and DFAX ratings;
- Only tied projects that cause the total MW to cross the capacity limit will participate in the auction;

- Only Interconnection Customers participating in the auction will submit bids on a dollars-per-MW basis;
- Interconnection Customers that win an auction will be studied in their entirety, and will submit at-risk financial security accordingly;
- Interconnection Customers that reach commercial operation will be refunded their at-risk auction financial security;
- Interconnection Customers that withdraw (or are deemed withdrawn) will partially lose their at-risk financial security depending on the timing of the withdrawal; and,
- Use of non-refundable auction funds will offset and support still-needed network upgrades.

Stakeholder feedback and discussion

Stakeholders are divided in their support for the zonal auction as proposed in the revised straw proposal.

ACP-California, CPUC (Energy Division), Clearway Energy Group, ENGIE NA, PG&E, Rev Renewables, Shell Energy and SCE all support the most recent proposal. AES, Avantus Clean Energy LLC, Aypa Power, CalCCA, CalWEA, CESA, EDF-Renewables, Intersect Power; LSA , SEIA, Six Cities; Terra-Gen, LLC continue to oppose for various reasons that include concern about discriminatory treatment, increased development costs, bias toward large developers with greater access to capital, and increased administrative burden. The ISO has addressed each of these concerns in past papers, but will address them again.

The ISO recognizes that the proposed auction mechanism will subject some projects to different at-risk financial security requirements. The ISO does not believe this result is unduly discriminatory: All interconnection customers will have equal opportunity to site their projects and develop them sufficiently to avoid auctions, and all interconnection customers can elect to forego a project that triggers an auction. Nevertheless, the ISO agrees to monitor the success of auction projects compared to non-auctioned projects in queue to ensure auction requirements are not an unreasonable barrier to commercial operation.

The ISO agrees with stakeholders, and acknowledged in the straw and revised straw proposal, that the auction proposal will result in increased costs due to financing costs associated with auction postings. The ISO expects the auction to have a minimal impact on a project's total development costs, and the benefits of this proposal—reducing queue volumes to enable more timely study processes—outweigh that cost.

The ISO agrees that for projects required to participate in an auction, large, well-capitalized entities may have an advantage over those with less capital behind them. However, generation development requires significant capitalization, and developers will be able to allocate their auction funds to their most viable projects, with auction allocations thus providing a proxy for financial viability. The ISO believes this is a reasonable outcome and preferable to a high application deposit to limit interconnection requests. The ISO does not agree that the auction as proposed disadvantages more ready projects from the opportunity to be studied, as the auction will only be applied to projects with equal viability scores.

The ISO agrees that there will be an increased administrative burden to manage the auction, but believes it to be less burdensome and more manageable than the alternative of managing and studying far more projects than necessary. The results of the study process will also be more accurate and meaningful as a result of a smaller pool of projects to study and will enable the ISO, utilities and other LSEs and the regulatory community to effectively prioritize and focus their finite resources on successful commercial development of the key infrastructure projects necessary to achieve the state's policy and reliability objectives..

CalWEA suggested that if the ISO proceeds with an auction that the proposal be modified to allow a refund of auction financial security if the project does not receive a TPD allocation and has to withdraw. The ISO does not support this proposal because the auction only guarantees that a project will be studied, and does not guarantee a TPD allocation. Project developers will need to carefully consider whether they want to participate in an auction when their project did not have a high enough viability score or DFAX rating to be automatically studied.

Shell Companies suggested that the ISO implement the auction for projects competing for the last increment of capacity and whose readiness score are within 10% of each other in order to head off potential scoring ties and disputes arising from claims that some of the scoring criteria are being applied too subjectively. The ISO does not agree that the scoring criteria being proposed are subjective and believes the proposed viability scoring system followed by utilizing a DFAX tie breaker will appropriately rank projects. Requiring an auction for all projects that have viability scores within 10% of the viability score of the project(s) that cross the capacity limit may result in triggering an auction that would not otherwise be required. This might also lead to disputes that a less viable project was allowed to buy its way in to a study.

Intersect Power and LSA both commented that if the ISO proceeds with an auction mechanism, the proceeds should be completely refundable at COD, with interest (not over 5 years). It has always been the ISO proposal to refund the financial security, with any applicable earned interest, soon after being notified by the interconnection customer that the project has reached COD. Interest will not be accrued if the financial security is in the form of a letter of credit or other financial security that is not a cash deposit. The ISO provides further details below.

Middle River Power and Six Cities requests the ISO clarify how it will apply the DFAX tiebreaker and zonal auction process if both are necessary. MRP also requests the ISO discuss how likely it is that the zonal auction process will be used in conjunction with the DFAX tiebreaker. The viability ranking is the first step. If there are projects with the same viability score that cross the capacity limit, the ISO will determine each of the projects' distribution factor for the impacted constraint(s) and rank them accordingly. If there is more than one project with the same viability score and DFAX ranking that cross the capacity limit, these projects will participate in the auction to determine which ones get studied. At this time, the ISO does not know how likely the auction tie-breaker would be used, but will analyze cluster 15 data and survey results to gauge the relative likelihood of an auction tie-breaker.

Recurrent Energy requested the ISO clarify four points: 1) How and when the ISO anticipates it will communicate to the projects that an auction bid requirement has been triggered and that projects will need to submit a seal-in bid; 2) Whether the ISO will provide a starting point or minimum bid value for this option; 3) Whether the ISO will open the auction results, including the clearing price, to the public; and 4) Whether the ISO plans to introduce a cap on the unit size of the project based on the available transmission capacity in a zone? If, for some reason, a large size project has a very high viability score, it could take the entire transmission capacity in the zone, ultimately being selected and studied as the only project in the zone, which is not very favorable to the entire market. The ISO clarifies as follows: 1) Specific timing for notification to projects that an auction has been triggered still needs to be addressed as part of the overall project intake process, but it will occur promptly after the viability/DFAX project ranking. After notification, the ISO proposes that the project will have up to two weeks to provide a bid. 2) The ISO is not proposing a minimum bid. 3) The ISO plans to make the clearing price public, but not individual project bids. 4) At this time, the ISO is not proposing a cap on unit size of a project.

Power Applications and Research Systems (PARS) suggested upon validation of all IRs that the ISO identify the zones where the amount of MWs proposed exceeds 150% of that zone's capacity. At that stage, PARS proposes that all projects in those zones be allowed a one-time opportunity to reduce their requested capacity pro rata of the amount of MWs that exceed 150%. In their proposal, the projects that do reduce capacity will not enter the auction process and will be studied automatically, and only the projects that do not reduce their capacity will enter the auction process. The ISO does not support adding another administrative step to the process to allow all projects in a zone an opportunity to reduce their requested capacity, which also may result in the least viable projects being studied. It is also unlikely that projects that had to provide site exclusivity for 90% or more of their required land would be willing to downsize.

Proposal

Auction Design

The ISO understands that the novelty of this concept raises a number of questions for stakeholders, and has attempted to address them below in the revised proposal. The ISO continues to believe the auction may be essential to achieve manageable queue volumes and preserve the competition of viable projects in each zone.

As described above, the ISO proposes to use a points-based viability scoring system as the first and potentially final step for determining which projects will be studied. However, if the scoring system results in more than one project with the same viability score, and these projects cause the total MW to cross the 150% MW capacity limit, a project's DFAX will be used as an initial tie-breaker to determine which projects will be studied.

After applying both the viability scoring system and the DFAX tie-breaker, if there are still ties the tied projects will be allowed to participate in a market-clearing, sealed-bid auction as the final tie-breaker for the right to be studied. Shortly after the viability scoring and DFAX processes are completed, the ISO will notify any remaining tied projects they can participate in the auction tie-breaker and will be requested to submit an auction bid on a dollars per MW basis within two weeks of the ISO notification. If sufficient interconnection customers forego participating in the auction in a zone, the remaining interconnection customers would simply "win" the auction and not be required to post auction funds.

Since it is unlikely that the requested MW capacity in a zone will exactly equal the 150% MW cap, the ISO proposes that projects that submit the highest bids and are either within or the first project that crosses the 150% MW capacity be accepted to be studied *in their entirety* for that transmission zone. These interconnection customers must post financial security equal to the auction clearing price (the lower of the winning bids) prior to being studied. The ISO also proposes to post on the ISO website the clearing price of any auctions conducted, but not the individual project bids.

If a project reaches commercial operation, its auction financial security will be refunded with any applicable earned interest to the interconnection customer within 90 days of the interconnection customer notifying the ISO the project reached commercial operation. Interest will not be accrued if the financial security selected below does not earn interest. If the project withdraws from queue (or is deemed withdrawn), it would partially lose its auction financial security, depending on timing of the withdrawal, similar to the ISO's current financial security requirements or Order No. 2023's withdrawal penalty structure.

Example

- *Assume there is 266 MW of available transmission capacity, and thus 400 MW capacity deemed reasonable to study.*
- *Seven 100 MW projects apply in this capacity*
    - *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 do not need to compete in the auction.*
- *Only projects C, D, and E will be considered in the auction because their projects cross 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

The ISO proposes that non-refundable auction funds resulting from project withdrawals offset and support still-needed network upgrades, lowering costs for ratepayers. 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 notes that auction security can take any of the forms currently allowed for interconnection financial security, allowing developers to elect the most financially efficient form for their needs.

Like financial security, the ISO proposes that any liquidated auction funds go to the applicable PTO to fund still-needed network upgrades. Any amounts that exceed the costs of still-needed network upgrades will be applied to offset Transmission Revenue Requirements, as recovered through the ISO's Transmission Access Charges. The PTO would only liquidate and use auction security if the customer withdraws. If the project instead reaches commercial operation, the interconnection customer will be entitled to a release of the posted auction financial security.

The ISO does not propose that auction financial security be instantly 100 percent non-refundable. Like interconnection financial security, the refundability would decrease as the customer progresses in queue. The proposed forfeiture amounts are intentionally set to be significant to further discourage interconnection customers from submitting less viable projects. The ISO proposes the following refundability percentages:

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 GIA but before Interconnection customer has executed an GIA or has requested that its GIA be filed unexecuted	50%	50%
If Interconnection customer has executed a GIA or has requested that its GIA be filed unexecuted	0%	100%

Acceptable interconnection financial security instruments

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 business days of the credit rating change.

2.5.3. Modifications to the "Merchant Deliverability"[27] Option [Updated]

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.

[27] Formerly referred to as Option B

The ISO proposes to rename "Option A" projects that seek to utilize delivery network upgrades that are approved as policy driven upgrades in the TPP; the proposed name is the "TPD Option". The ISO also proposes to rename "Option B" projects that seek to build any ADNU required for deliverability as a merchant transmission project "Merchant Deliverability Option" projects. Dropping the A/B names will eliminate potential confusion with the designations for TPD allocation Groups A through D. The designation used for projects that seek to interconnect and meet the conditions required for the zonal studies where transmission capacity exists are "Transmission Plan Deliverability (TPD) Option." Projects that seek to interconnect in zones that have no TPD available may only proceed under the designated "Merchant Deliverability option."

Stakeholder feedback and discussion

Southern California Edison supported the proposed modifications to the Merchant Deliverability Option in the revised straw proposal, Shell Energy did not oppose, nineteen stakeholders support with modifications, and eighteen others did not comment.

Many developers continue to request that interconnection customers be allowed to fund network upgrades above the available capacity in TPD zones, and particularly to allow projects not selected in scoring to opt for Merchant Deliverability, while SCE disagrees with this option.

The ISO disagrees with that proposed approach because:

- The scoring criteria are designed to limit the number of projects studied in zones with available capacity (TPD areas) to 150% of the available capacity. Allowing Merchant Deliverability projects in TPD areas defeats that purpose by studying far more capacity in these areas than the system needs. Too many projects results in inaccurate study results and goes against the foundational principles agreed to at the beginning of the IPE initiative.
- By offering the Merchant Deliverability process and the TPD zonal process, the ISO ensures developers have open access to the entire ISO footprint while accounting for where policymakers have prioritized development.
- By definition, ADNUs are expensive for ratepayers. The ISO maintains that the primary method for approving ADNUs should be the integrated planning between the CPUC, LRAs, and the ISO, not the GIDAP. These ADNUs will have recovery through a cost-based rate. Merchant Deliverability ADNUs, in

contrast, will flow to ratepayers through a PPA or energy costs. Developers and procurement entities may decide whether to incur that risk of recovery.

- Allowing TPD Option projects to switch to Merchant Deliverability would result in projects trying to bypass the scoring criteria.

CalWEA, EDF, Intersect Power, and LSA do not support the proposal that if an ADNU is picked up by the TPP then Merchant Deliverability projects would be required to seek a TPD allocation through the affidavit process. They suggest that if a Merchant Deliverability ADNU is approved in the TPP, each applicable developer should have a choice between:

1. Accepting the proposed cost-responsibility and security relief, with the need to compete for an FCDS/PCDS allocation; or
2. Retaining the existing arrangement, with cost responsibility but a guaranteed FCDS/PCDS award. In particular, projects that are far along in the development process, or those participating in an SANU self-build arrangement, may simply choose to retain their existing arrangements for the certainty they would provide.

The ISO agrees that a modification to this item of the proposal is appropriate and the modification is reflected in item 7 of the proposal below.

Intersect Power, LSA, and New Leaf Energy suggested that reimbursement of applicable ADNU costs for Merchant Deliverability projects be allowed to the extent a developer can demonstrate system benefits from the relevant ADNUs. The ISO disagrees. First, such a process could be used simply to convert the Merchant Deliverability process into a backdoor through the scoring criteria provided above. Second, the Merchant Deliverability process is an existing, FERC-approved process, which provides Merchant Transmission CRRs as a form of reimbursement. Creating a new process to determine benefits, costs owed, and new ownership structures is beyond the scope of this initiative. This initiative is focused on integrating forward looking power and transmission planning with rational queue management to efficiently and cost-effectively meet key policy and reliability goals in a cost-effective fashion consistent with open access. The current queuing paradigm is simply broken and requires fundamental changes without creating exceptions that will undermine the effectiveness of the necessary reforms.

Intersect Power, LSA, and New Leaf Energy ask that, upon request, the ISO provide advance estimates of potential CRR revenue for the applicable ADNUs.

But the ISO doesn't perform estimates of potential CRR revenue for market participants. The ISO provides pricing information on OASIS and customers can download the data for their calculation of potential revenue from any Merchant Transmission CRRs provided.[28]

Intersect Power and LSA request that GIDAP Section 7.6 should be revised to allow the full benefit of forfeited ADNU security to go to remaining projects. Specifically, if the ISO is requiring additional up-front security for Merchant Deliverability customers to fund ADNUs, then this up-front amount should be added to any proportional allocation of other posted security.

In response, the ISO proposes that some form of the non-refundable amounts provisions of ISO Tariff Appendix DD Section 7.6 will be considered in the new tariff developed for the ISO FERC Order No. 2023 compliance filing that the IPE changes will be added to.

Proposal

The Merchant Deliverability path ensures that projects seeking to interconnect in areas/zones with no available deliverability capacity have a path forward to become deliverable by providing the opportunity for such projects to build any required ADNUs as a merchant transmission project. The ISO will not accept Merchant Deliverability interconnection requests within zones that have available or planned transmission capacity and will not allow projects that submitted an interconnection request as a TPD Option project to switch to the Merchant option if it is not selected to be studied through the scoring process. In addition, if a TPD Option project is selected and studied, but unable to receive a TPD allocation, it will not be eligible to convert to the Merchant Deliverability Option.[29]

[28] It is up to the customer to define the source and sink for the CRR estimation. All source and sink information is posted here: https://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx. If the new transmission element does not have a node defined yet, the customer would need to search for the electrically closest node from the on-line diagram and use the spreadsheet posted on the ISO website as a reference to confirm the electrically closest node chosen is available in the CRR market.

[29] Transmission Plan Deliverability projects will still be able to exercise Article 11.4.3 of the LGIA should they ultimately wish to forego cash reimbursement in favor of CRRs. This article does not impact intake or study processes.

1. Merchant Deliverability Option 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 require, without reducing the available deliverability from other delivery network upgrades needed by TP Deliverability projects.

2. Merchant Deliverability projects that require Local Delivery Network Upgrades (LDNUs) will be eligible for cost recovery of any posted financial security towards the cost of the LDNU in the same manner as TPD Option projects. LDNUs are more project specific than ADNUs that, outside of the Merchant Deliverability 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 Merchant Deliverability path being more viable.

3. A Merchant Deliverability project's funding of the construction of its required ADNU will not receive repayment. The interconnection customer will be eligible to receive Merchant Transmission CRRs in accordance with ISO Tariff Section 36.11. The ISO does not propose to revisit its policy that the interconnection process cannot enable new transmission owners. Developers can propose transmission projects in the TPP or as Subscriber PTOs.

4. Merchant Deliverability projects will be given a project status of FCDS or PCDS, as specified in their GIA and in accordance with the Resource Adequacy counting rules.

5. The project will be required to make an additional Commercial Readiness Deposit towards the cost of the ADNU with the submittal of its interconnection request during the cluster application window. The additional amount will be $10,000 per MW, but not less than $500,000 and not to exceed $5,000,000, based on the capacity amount of deliverability requested in its interconnection request. Fifty percent of this additional Commercial Readiness Deposit would be non-refundable if the project withdraws after the due date for interconnection request validations to be complete. The deposit is set to an amount deemed to be high enough to provide an incentive for interconnection customers that are confident of their project's viability under the Merchant Deliverability path.

6. Merchant Deliverability projects that complete the cluster study process will be required to increase their Commercial Readiness Deposit associated with their merchant ADNU(s) to 50% of its cost responsibility for the ADNUs (e.g., if the project provided $5,000,000 in accordance with (5) above and 50% of the projects cost responsibility of the ADNU is $20,000,000, then the project would be required to increase its Commercial Readiness Deposit by $15,000,000). Fifty percent of the Commercial Readiness Deposit associated with the merchant ADNU would be non-refundable if the project withdraws.

7. If a future TPP determines an ADNU that a Merchant Deliverability project is funding is needed to support a CPUC portfolio, then the following criteria would be used.

    a. If the Merchant Deliverability project(s) have not executed a GIA, and the ADNU has not been included in the TPP base case, any projects funding the ADNU will be released from their obligation to fund the ADNU and be refunded its posting for the ADNU once the Merchant Deliverability project executes its GIA.

        i. A Merchant Deliverability project that meets the criteria in (a) would be able to retain its requested deliverability associated with the ADNU for a period of approximately two years, with a TPD retention requirement that within the next two years the project would have to demonstrate it meets either the TPD allocation Group A or B requirements or it will lose the TPD. The deadline for retaining the TPD will be the affidavit due date of the second TPD allocation retention cycle that occurs after the ISO Board of Governors approve the transmission plan that includes the relevant ADNU (e.g. for a TPP Plan Board approval date of May 2026, the project must meet the retention requirements no later than the affidavit due date for TPD allocations made in 2028). If a Merchant Deliverability project is unable to retain its deliverability, it will be converted to Energy Only.

    b. If the Merchant Deliverability project(s) has executed a GIA, and has been included in the TPP base case as a merchant ADNU, the projects funding the ADNU will continue to be obligated to fund the ADNU and proceed as Merchant Deliverability project(s).

8. The Merchant Deliverability project's eligibility to self-build the merchant ADNU will be governed by the Stand Alone Network Upgrade provisions of the ISO Tariff Appendix DD.

2.6. Study Process

The ISO appreciates the thoughtful proposals from early working group meetings 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. Order No. 2023 requires a study process consisting of:

- A "cluster study," which identifies the interconnection facilities, reliability network upgrades, and delivery network upgrades that each interconnection request requires;
- A restudy evaluating the impact of withdrawals on the cluster study results; and
- An interconnection facilities study that provides more granular and accurate cost estimates for the upgrades and facilities identified in the cluster study report.

2.6.1. Off-Peak and Operational Deliverability Assessments [Updated]

Background

Order No. 2023 prescribes specific timelines for cluster studies: 150 days for the cluster study, 150 days for the cluster restudy, and 90-180 days for the interconnection facilities study.[30] The ISO believes that complying with these prescribed timelines requires the ISO to conform the scope of its interconnection studies to FERC's *pro forma*. Doing so would require the ISO to remove the off-peak deliverability assessment (and therefore all associated statuses), and the operational deliverability assessment. In addition to enabling the ISO to meet FERC's prescribed timelines, the ISO does not believe the off-peak deliverability assessment has significant value because there is not difference between Off-Peak Deliverability Status and Off-Peak Energy Only in the ISO Market or in

[30] Depending on the detail requested by the customer.

resource adequacy counting. Additionally, the operational deliverability assessment tends to only reconfirm the delivery network upgrades that each cluster of generators are waiting for to be completed, and this information is the same precursor network upgrade list that has already been identified.

Stakeholder feedback and discussion

Several stakeholders supported the proposal to remove both the off-peak and operational deliverability assessments, including AES, Aypa Power, CalWEA, CESA, Gridstor, PG&E, PARS, Rev Renewables, SEIA, and Southern California Edison.

ACP-California requested that the ISO retain an option for interconnection customers to request OPDS or to provide “indicative” OPDS results such that this status can be maintained and the ISO can comply with Order No. 2023 timelines. Clearway, ENGIE NA, Golden State Clean Energy, agreed, noting that the OPDS assessment may be valuable under the Slice-of-Day RA counting regime. ENGIE NA suggested that the ISO should either retain an option for the study or agree to re-initiate the option if it becomes a tangible design component of the Slice-of-Day program. The ISO notes that the OPDS study is currently an optional study that is no longer feasible within the 150-day timeline. However, the ISO does plan to continue to include this analysis in the transmission planning studies.

Avantus, Intersect Power, LSA, Middle River Power, and San Diego Gas & Electric requested more information about the new study timeline and noted that multiple stakeholders advocated for the use of generic models for initial studies in the process, and that the idea was widely supported as a means to move the intensive model validation process to later in the interconnection process. The ISO has not explored this concept further because the expectation is that the new intake process will result in fewer projects to study, and fewer of those projects would withdraw.

Proposal

The ISO thus proposes to remove both the off-peak and operational deliverability assessments to enable it to meet a faster study schedule, and because of the limited value of those studies. The ISO intends to remove the assessments through IPE and its related filing under Section 205 of the Federal Power Act. However, the ISO also may have to remove these assessments through its Order

No. 2023 compliance filing. Because removing the assessments may not be clear from the scope of Order No. 2023, the ISO has included them here for transparency and feedback on the assessments' values. The ISO intends to continue to include the off-peak deliverability analysis in the transmission planning process.

2.7. Modifications to Deliverability [Updated]

Background

The ISO's discussion paper and straw proposal 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.

Because 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.

The resource portfolios designate the specific resource types and the amounts to be developed, which the TPP uses to determine the transmission projects necessary to support those specific resource plans. This can result in the CPUC or a LRA 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 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 or LRA 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 a 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 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.

Recognizing these challenges, 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.

The ISO will implement a related change in the Deliverability Assessment Methodology initiative, providing deliverability to resources waiting for the n-2 related deliverability upgrades to be completed, assuming they would not cause cascading outages. Also, through that initiative, the ISO will increase the cost threshold for determining whether a delivery network upgrade (DNU) is an LDNU or an ADNU. The change will allow more DNUs to be deemed LDNUs, which would allow larger/more costly DNUs to move forward within the GIDAP and allow interconnection customers to choose to fund them instead of waiting for the TPP to propose them as ADNUs. This would give interconnection customers greater control over the destiny of their projects.

2.7.1. TPD Allocation Process Modifications [New]

Background

The ISO is providing an initial proposal for modifications to the TPD allocation process. Since this paper is the ISO's IPE Track 2 draft final proposal, the ISO recognizes that the TPD allocation discussions may not advance to the final proposal stage in time for the May 2024 ISO Board of Governors meeting. If that is the case, the TPD allocation discussions will continue in an IPE 2023 Track 3, targeting the July 2024 Board of Governors meeting.

Proposal

1. The Parking process will be discontinued. The ISO believes expectations of how projects progress thought the GIDAP have changed and the tariff parking criteria may no longer serve its original purpose or the needs of interconnection customers.

    1.1. All projects must make any required increases to their Commercial Readiness Deposits following the completion of the cluster studies on the required due dates. The timing of such posting will be defined in the ISO's FERC Order No. 2023 compliance filing.

2. Projects will have three consecutive opportunities to seek an allocation, beginning with the first affidavit window after the interconnection facilities study.

    2.1. After the third opportunity to seek an allocation, projects that have not received an allocation will be converted to Energy Only.

3. Energy Only projects are only eligible for an allocation through allocation Group C – in commercial operation, regardless of how they became Energy Only.

    3.1. This applies to all new and existing Energy Only projects in the queue. Projects that have a Partial Capacity Delivery Status may seek an allocation for the Energy Only portion of the project.

4. GIA tendering and execution requirements will be based on FERC requirements.

5. Allocation Group D will be discontinued because it would likely hinder new projects seeking to interconnect by reducing the amount of available transmission capacity used to determine the amount of capacity to be studied in zones that have available (unallocated) TPD.

6. Appendix DD section 8.9.1 will be the basis for reserving and allocating TPD for long lead-time projects that align with TPP approved new transmission to meet specific CPUC portfolio requirements for specific resource types, such as offshore wind, out-of-state wind and geothermal. Appendix DD Sections 8.9.1 (b) and (c) allow the ISO to reserve TPD capacity for resources outside the ISO and resources internal to the ISO that are designated as resource technologies and in locations that are needed to meet state policy goals. This tariff language allows the ISO to reserve TPD for resources meeting specific portfolio policy goals when other resource types may be able to utilize that TPD capacity sooner, but do not meet the specific resource needs of the portfolio.

    8.9.1 First Component: Representing TP Deliverability Used by Prior Commitments

    The CAISO will identify the following commitments that will utilize MW quantities of TP Deliverability:

    a. The proposed Generating Facilities corresponding to earlier queued Interconnection Requests meeting the criteria set forth below:
        i. proposed Generating Facilities in Queue Cluster 4 or earlier that have executed PPAs with Load-Serving Entities and have GIAs that are in good standing.
        ii. proposed Generating Facilities in Queue Cluster 5 and subsequent Queue Clusters that were previously allocated TP Deliverability and have met the criteria to retain the allocation set forth in Section 8.9.3.
    b. any Maximum Import Capability included as a planning objective in the Transmission Plan;
    c. any other commitments having a basis in the Transmission Plan.

The scoring criteria for determining the ranking of projects eligible to receive a TPD allocation will be developed later, when scoring criteria for the interconnection request intake process is completed. That scoring criteria will be useful in the consideration of modified scoring criteria for the TPD allocation process.

2.7.2. Modifications to Interim Deliverability

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. However, there is not expected to be a significant amount of longer-term interim deliverability available. TPD is allocated annually and typically all available TPD is allocated. Generation projects receiving allocations are expected to utilize that deliverability as soon as the precursor delivery network upgrades are completed and the deliverability becomes available in order to meet the high demand for new generation needed to meet the States' goals within the required timelines. As more TPD is created through the annual approval of new transmission projects it is immediately allocated as well and is expected to be utilized as soon as it becomes available.

3. Contract and Queue Management

3.1. One-Time Withdrawal Opportunity [Updated]

Background

Many projects unduly linger in the queue while they compete in multiple requests for offers (RFOs). 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 may be inadequate incentives for projects to withdraw if they can remain in the queue and continue to seek a buyer for the project. These lingering projects also may affect upgrade requirements for later-queued projects. 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.

In the straw proposal, the ISO proposed a one-time opportunity for projects to withdraw from the queue and receive any unused portion of their interconnection financial security postings and site-exclusivity deposits, possibly over time. Under this proposal, the withdrawn projects' previously non-refundable portion of the IFS that was posted for still-needed upgrades would continue to be held and used by the PTO to fund these upgrades. Once the upgrades are in service, the PTO would refund the withdrawn project's money to the interconnection customer consistent with the existing tariff reimbursement requirements. The ISO initially proposed that this opportunity apply to all active projects in the queue, including Cluster 14.

The original proposal attempted to create a solution that would reduce the PTOs' financing cost burden for the still-needed network upgrades under a one-time withdrawal opportunity by delaying the refund of the current non-refundable portion of the security posting until the upgrade is in-service or later removed from the project's responsibility. However, the challenge lies in the re-assignment of costs and financial responsibility of precursor network upgrades (PNUs) associated with withdrawn interconnection projects that remain needed for other resources remaining in the queue. Under the ISO tariff, if an interconnection customer has executed a generator interconnection agreement (GIA) and withdraws, then the PTO must fund that project's allocated cost share of any network upgrades still needed by later-queued projects. The cost of these projects coupled with the responsibility for obtaining financing for them exceeds the amount of interconnection financial security (IFS) postings made by the interconnection customer who was initially assigned responsibility for that upgrade.

The ISO has observed that PTO access to capital is increasingly a barrier to timely completion of network upgrades. Therefore, the assignment of additional costs and financing obligations could exacerbate delays of network upgrades, which are critical to getting more deliverability on the system to meet the ISO's reliability and policy needs. Thus, in the revised straw proposal, the ISO proposed two options:

1. Seek additional sources of funding for network upgrade costs associated with withdrawals, either through a green bank or government grant or loan program.
2. Remove this option from this initiative and focus on other mechanisms to encourage withdrawals of stagnant projects.

Stakeholder feedback and discussion

Many stakeholders continue to support the concept of allowing a one-time opportunity to withdraw and receive refunds, acknowledging that it would provide significant opportunity to reduce existing queue volumes and eliminate the need for network upgrades that are no longer needed.

The ISO has explored alternative sources of funding for network upgrade costs associated with withdrawals, but has not identified a willing source at this time. Because the results of a potential refundable withdrawal opportunity are unknown, the ISO cannot currently predict how many interconnection customers will take advantage of the opportunity to withdraw, nor can the ISO predict which network upgrades would be affected by voluntary withdrawals.

Proposal

Agreement for the funding of the one-time withdrawal proposal could not be achieved. The ISO will not proceed with this proposal at this time

3.2. 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 plan and then completing the study, interconnection customers may be left with just a few months to make business and construction decisions based on the results. The reason for the five-month timeline is that the PTO must conduct the LOS using operations and not planning data. Longer lead times would substantially diminish the accuracy of the LOS results, potentially making them infeasible for the PTO and the customer. This is not a trivial issue. A LOS is premised on the interconnection customer lacking its identified reliability network upgrades. Inaccuracies in the LOS could result in reliability and safety issues.

Additionally, developers frequently submit modification requests simultaneous with their LOS request, which may impact the ability to start the study or publish results of a completed LOS. The ISO seeks to clarify situations where modification requests are submitted that may impact the LOS process or study results.

Stakeholder Feedback and Discussion

AES, Avantus Clean Energy, Aypa Power, CESA, Clearway, EDF-Renewables, Intersect Power, LSA, PG&E, Power ARS, Rev Renewables, SEIA, and SCE all provided comments generally supporting the straw proposal to extend the current five-month timeframe to submit a LOS to nine months. SCE provided additional comments, outlining how the extension from five to nine months allows more time for the study process and enhances the ability of interconnection customers to evaluate the results and make timely decisions.

Avantus, Aypa Power, California Wind Energy Association, Intersect Power, and LSA provided additional comments stating that requests for LOS should be available at least 2 years prior to synchronization, some suggesting that an LOS should be available at any time. Clearway believes that an LOS should be available at the time the upgrade delay is discovered and that PTOs should be timely in their notification of upgrade delays. The ISO recognizes the request for LOS to be submitted sooner than 9 months prior to synchronization. However, the LOS requires analyzing the grid's current ability to accommodate additional generation with the assumption that the assigned reliability network upgrades are not online. Performing this evaluation earlier would lead to less accurate results and risk liability and safety of the ISO Grid. The ISO cannot extend the LOS start timeline beyond nine months prior to synchronization. Additionally, earlier LOS's would divert planning and operational resources away from the primary interconnection studies.

Clearway also requested additional clarification around how it would be determined that a modification request impacts an LOS and if certain technical specification change requests (e.g. inverters, transformers, collector system design, gen-tie design, etc.) could proceed in parallel with the LOS. The ISO and PTO engineers would review the MMA results at the end of the MMA process to ensure that the LOS is not impacted. If the LOS is impacted, then the LOS would need to be restudied to determine the operating limited with the new technical specifications.

Recurrent Energy asked if the ISO would be willing to implement this process for projects that are affecting the ISO system. The ISO believes Recurrent is referring to the ISO as an Affected System, if so, the ISO will not consider a LOS option for such projects.

Proposal

The ISO maintains its proposal to increase time to submit an 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 reason for adjusting the policy is to assist projects in knowing to what extent the project may synchronize to the grid, or must await the completion of its assigned reliability network upgrades.

The ISO's proposed change does not reflect a greater ability to study system impacts further into the future, the 5-to-9 month extension is the limit to which the ISO can reasonably determine system reliability and provide customers with more time to evaluate and respond to the LOS results.

The ISO also proposes to clarify the interaction between the MMA and LOS. The ISO will clarify in the Business Practice Manual for Generator Management that any modification request submitted concurrently with an LOS that may impact the LOS must be deemed complete and valid prior to the ISO starting the LOS. If an MMA is submitted after an LOS is completed and the MMA results may impact the LOS, the ISO may need to re-evaluate the LOS results or potentially require the interconnection customer to submit a new LOS request to ensure the modification results do not impact the reliability of the ISO Grid. The customer also could withdraw the MMA to avoid disrupting the LOS.

3.3. 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

Aypa Power, California Wind Energy Association, EDF-Renewables, Middle River Power, and SCE support the proposal to bring consistency to the two agreements.

Proposal

For consistency across all asynchronous generating facilities, the ISO maintains its proposal 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).

3.4. Remove Suspension Rights from LGIA[31] [Updated]

Background

As presented in the August 1st workgroup discussion, to date, only one of seven projects over the past several years 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 the current suspension provisions to enter the interconnection process with not-ready projects and then use suspension while they attempt to find an off-taker.

Stakeholder feedback and discussion

The development community, including ACP-California, AES, Avantus Clean Energy LLC, Aypa Power, CESA, ENGIE NA, Intersect Power, LSA, New Leaf Energy, Rev Renewables, SEIA, Shell Energy, and Vistra Corp oppose any proposals that would remove or alter the ability for a project to request suspension of LGIA. The general belief is that suspension rights provide indispensable flexibility to generators in the interconnection process, a process where they generally do not have much flexibility.

ACP-California, Avantus Clean Energy LLC, Intersect Power, LSA, New Leaf Energy, and Vistra Corp further argued that because suspensions are a rare occurrence, with only seven occurring in the last couple years, suspensions present a low impact to ISO resources and overall Queue Management.

SCE, PG&E, and esVolta, support the removal of suspension rights.

SCE shares the ISO's concern that with a move to a "first-ready, first-served" paradigm, developers may seek to exercise the suspension provision with more frequency, which will halt and place the entire project on hold for up to three (3) years (except shared Network Upgrades) if retained because they have a "not-ready" project. SCE notes that developers have historically rarely invoked the current suspension provision (Article 5.16 of the LGIA), due in part to having the option to extend their project's commercial operation date multiple times through

[31] Suspension rights are in Section 5.16 of Appendix EE of the ISO tariff. Small generating project are not allowed to suspend.

the modification process (resulting in deferment of project payments, financial security, and milestones).

CESA supports proposing language to limit suspension rights to more specific circumstances or for more limited durations rather than removing them altogether.

ACP commented further that given the infrequent use of suspension rights, however, it seems the proposed elimination may not provide significant benefits to managing the queue. Thus, ACP encourages ISO to consider whether it can maintain suspension rights going forward.

Calpine inquired if there would be a mechanism available to otherwise viable projects to delay, for example, changes in market conditions or equipment supply or regulatory requirements.

Proposal

The ISO understands stakeholder concerns regarding suspension, and the need for flexibility for sudden barriers. FERC Order No. 2023 also reaffirms developers' need for suspension rights. The ISO will not proceed with this proposal at this time.

3.5. Limitations to Transmission Plan Deliverability (TPD) Transferability

Background

The ISO is committed to providing projects the flexibility to become commercially viable and achieve commercial operation. As such, the ISO recently granted projects the right to transfer deliverability from one project to another at the same point of interconnection. The ISO does not propose to eliminate such transfer rights, but place reasonable limitations to such transfer opportunities to prevent gaming. The ISO recognizes that deliverability transfers enable the most viable projects to proceed.

After the ISO permitted 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 to try to avoid the 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 has rejected them.

The ISO also has observed that the assignor projects (transferring their TPD) withdraw from queue or become stagnant as the developer tries to find an off-taker and re-seek deliverability. The ISO believes this is an undesirable result causing queue backlogs. Energy Only projects rarely, if ever, achieve commercial operation. The ISO believes developers should only proceed with TPD transfers when they recognize the project transferring its TPD is no longer viable.

Stakeholder feedback and discussion

CPUC, Six Cities, and SCE provided comments in support of the proposal. Six Cities additionally asks if there are other exceptions to transfers that could be included in the proposal. The ISO is not considering any other exceptions to transfers at this time.

AES opposes the requirement that the Energy Only portion of the originating project be withdrawn if it cannot produce a PPA at the time of the transfer. They believe the ISO should be flexible in TPD transfers and that obtaining a PPA before the transfer is not a viable options. Because off-takers may require that the transfer be complete before executing an agreement, they suggest providing 90 days post-transfer to provide a PPA. SEIA supports the comments provided by AES. While the ISO understands this opposition, it maintains its position that, unless the Energy Only portion of the project produces a PPA at the time of the transfer, that Energy Only portion will be withdrawn.

Aypa Power and CalWEA commented that projects should be allowed to develop as Energy Only regardless of PPA status. Aypa also believes that projects receiving transfer should be subject to current TPD requirements, not the requirements from original allocation. The ISO disagrees. Historically, Energy Only projects have not proceeded to commercial operation. Withdrawing the Energy Only project or portion of the project will free-up space for projects that are proceeding to commercial operation. To avoid circumventing TPD tariff requirements, rights, and obligations, any project receiving a TPD transfer from another project will be subject to the conditions of the original TPD allocation. Projects cannot use transfers to reduce their TPD retention obligations.

Clearway, Intersect Power, and LSA proposed giving the “from” project a year to provide an EO PPA to remain in the queue. LSA provided additional comments disagreeing that the now EO project could only seek a new allocation under

Group C. If the project has an RA PPA or shortlist, it should qualify to receive a new TPD allocation. Clearway adds too that the Energy Only project should be allowed to seek a TPD allocation under Group A & B. Additionally, Middle River Power questioned why downsizing or withdrawal of an Energy Only project is necessary. Based on ISO experience, it is unlikely that an Energy Only project would be able to execute a PPA and proceed to commercial operation. The ISO never intended for TPD to be a tradable commodity. Allowing transfers is intended to help the most viable projects proceed forward. By enabling projects to seek a new allocation, the ISO would further encourage TPD to be a commodity, which must be avoided.

Power Applications and Research Systems, Inc. suggest the ISO expand transfers to allow projects to transfer TPD within zones as well as to projects that are not under ISO control area. The ISO appreciates the suggestion, however, is not considering these options at this time.

Shell Energy requests clarification on TPD transfers between projects with different CODs, how transfers are handled between different technology types, and if the ISO is planning to revisit or update GM BPM section 6.5.4.1.The process for transfers between projects and technology types is described in Section 6.5.4 of the GM BPM. The ISO will look at updating Section 6.5.4.1 to include any updates to transfer methodology.

Proposal

The ISO maintains its earlier proposal 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 the time of transfer. However, recognizing stakeholder comments that there may be some Energy Only procurement, the ISO will forego such withdrawal of the transferring project if the transferring project provides an Energy Only PPA at the time of its transfer request.

The ISO also will add clarifying language to the tariff that TPD transfers cannot be used to escape deliverability retention requirements. If the assignor received TPD from Group 3, for example, the assignee would inherit all of those obligations and restrictions as if it had sought and received deliverability in that group. This clarification will provide more transparent notice that TPD transfers cannot be used to circumvent tariff requirements.

3.6. Viability Criteria and Time in Queue [Updated]

Background

Although the ISO has tariff and BPM language to limit a project's time in queue, enforcing these provisions often requires a time-intensive, project-specific analysis and assumption to ensure the project is still in compliance. Additional straightforward milestones, black-and-white requirements, and universal time-in-queue limitations will help manage older projects, provide clear and transparent rules, and prevent projects from stagnating.

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 be effective when the ISO's makes its compliance filing with FERC.

The straw proposal proposed an unavoidable time-in-queue for projects to execute the interconnection agreement and provide their third financial security posting and notice to proceed. This draft final proposal suggests strict commercial viability criteria and time-in-queue requirements for all projects in the queue. These requirements will supplement new FERC Order No. 2023 restrictions.

Stakeholder feedback and discussion

CalCCA, the CPUC, the CPUC's Public Advocates Office, Defenders of Wildlife, Intersect Power, PG&E, SDG&E, Shell Energy, Six Cities, and SCE support the ISO's commercial viability criteria proposal.

ACP-California, AES, Aypa Power, Avantus Clean Energy, CESA, and Engie NA said the ISO should consider timing requirements for CVC to account for long-lead time development or upgrades, or that CVC should not be based on time-in-queue. They suggested some other trigger such as planned upgrades, the Transmission Planning Process identified upgrades, or projects that may not be able to demonstrate a PPA until later than seven years. ACP-California suggested a later-of-rule where resources must demonstrate Commercial Viability Criteria at the later of seven years after entering the queue or three years prior to their initially submitted commercial online date. The ISO recognizes there are long-lead development projects as well as long-lead upgrades that are identified or being proposed. However, long-lead development projects are a small minority of the queue. Also, as demonstrated by recent queue history, projects are highly unlikely to begin procurement of equipment or begin construction of long-lead type situations without entering into an offtake or purchase agreement. Additionally, those long-lead timelines should generally begin within the seven-year window to ensure the project maintains and can achieve the expected commercial operation date. In other words, if the project cannot be procured due to such long-lead timelines and could not acquire a PPA, it is possible that the project was submitted too early into the queue or is being proposed in an already overloaded area. The ISO is maintaining the time-in-queue concept. Nevertheless, the ISO recognizes that cluster 15 would currently be eating into its seven-year window while awaiting the study process to start. The ISO will consider a new start date for the seven-year time in queue for cluster 15 provided the recent application window and validation delays.

ACP-California and ENGIE NA suggested that the ISO provide more than 12 months to projects that lose their PPA due to a PTO delay, and that developers be provided with the greater of three years or the length of the PTO delay. The ISO appreciates that it may take longer than 12 months to negotiate and execute a PPA and has updated the proposal below.

Avantus Clean Energy continued to disagree with 1) CVC criteria on EO projects and 2) PPA being part of that CVC criteria for EO projects, requesting the ISO provide projects an opportunity to build as a merchant power plant. Historically, the ISO has offered various paths for projects to proceed by self-financing (prior to TPD groupings), obtain TPD via Group 3 - claiming that the project will proceed without a PPA, or Group D as a means to obtain TPD without a PPA. To date, the ISO is not aware of any projects that have developed ‘as merchant’ and does not expect to create a specific means for projects to do so in this policy and will review this as part of the Merchant Deliverability path.

Aypa Power also suggested the following updates: 1) Provide 3rd IFS within 90 days of GIA execution, whereby GIAs must be signed within 90 days of study completion (TPD allocations under current process), 2) 100% site control within 90 days of GIA execution, 3) COD date in GIA within seven years of queue date or align with long-term policy upgrades if needed for Deliverability, 4) Limit suspensions or modifications to three years maximum from GIA COD date. The ISO believes these are reasonable proposals; however, they generally overlap with new FERC requirements or other proposals in this initiative.

Defenders of Wildlife believe that a project’s permitting demonstration is a good indicator of a project’s viability. The ISO agrees, but permitting is very project-specific, often occurs later than ISO studies, and requires expertise beyond ISO purview.

Intersect Power and LSA maintained that simply setting deadlines without any other timeline or process structure is not fair or workable and is concerned that each project might separately have to request a draft GIA on its own. They believe that the process would be much more transparent and effective if the ISO would establish uniform dates for PTO tender of draft GIAs for each cluster's contracts, without the need for each developer to request a draft separately and set uniform turnaround times for drafts applicable to each side. The ISO recognizes the complexity here with the volume of work and potential need for some projects to progress more quickly. The ISO and PTOs are also concerned with the volume of GIAs that require execution and are working to prioritize and maintain a manageable workload. The ISO notes that Order No. 2023 provides clear and inescapable deadlines to tender, negotiate, and execute GIAs.

Intersect Power and LSA also believe the current CVC policy is working well and that projects with deliverability should have longer in the queue to execute a PPA. Additionally, they believe that PTO-caused delays should extend the CVC demonstration dates when disrupted by a PTO delay. The ISO responds that the current CVC policy only converts those projects that do not meet CVC to Energy Only deliverability status (total of 57 EO and 23 PCDS as of January 22, 2024) leaving those projects to linger in the queue without distinct progress to commercial operation. This proposed policy places distinct and express requirements to proceed to acquiring a PPA and commercial operation, with or without deliverability, or the project will be removed from the queue. The ISO has identified a provision for when a PTO-caused delay has impacted a given project.

Intersect Power and LSA also noted that the ISO needs to clarify the definition of a qualifying PPA as many projects received an allocation prior to the current 5-year minimum term and believes the required PPA terms should be consistent with the required PPA terms when the TPD award was received.

MRP appreciates that the ISO is attempting to identify criteria for project viability; however it is concerned that this CVC policy will 1) favor well-capitalized investors or developers, and 2) impose requirements that are too early in the development process. MRP believes these criteria should be embodied in the interconnection agreement rather than before the IR is studied and is concerned that this requirement is too early in the process. MRP also wants to confirm if these requirements will be implemented for expansions of existing generating facilities. The ISO's CVC proposal is intended to be fair and equal to all projects that reach a pre-determined time-in-queue, thus eliminating any favoritism or bias. Secondly, the CVC requirements are being imposed only when the project proposes to be in queue beyond seven years. Projects have ample time to market their project and position themselves to meet the CVC requirements as proposed. The CVC requirements will be effective for generating facilities that add a BESS system or expand their existing generating facility.

Recurrent Energy believes the ISO should incorporate more accountability for PTOs when it comes to procurement status. The ISO coordinates with the PTOs to assist in the management of projects and progression to construction and development. Projects must provide notices to proceed and continue to fund upgrades and project development for PTOs to maintain their construction milestones and progress. Construction schedules are set forth in GIAs, and interconnection customers may seek to enforce them as signatories.

REV Renewable inquired about situations where a project receives a PPA and meets CVC for only a portion of the project and requests that the ISO not impose CVC for that portion that does not meet CVC when the remaining portion does. REV also noted that regulatory approval of executing amendments to PPAs to update or extend the COD is sometimes a timely process and asked the ISO to consider a letter agreement in place of a PPA for COD extensions. The ISO understands this concern. In general, the purpose of the CVC requirements is intended to ensure that only the most viable projects proceed forward. Allowing a portion of a project to proceed that does not have an off-take agreement and that can meet such CVC is conflicting with the intent of the policy. The ISO also understands that regulatory approval may be required for some PPAs and related amendments. However, the ISO wants to ensure that such PPAs are approved and accepted prior to extending milestones. The ISO maintains that PPAs must be executed prior to allowing a modification request to align the COD.

SDG&E encouraged the ISO to consider a more expedited implementation timeframe and encourages the ISO to reduce the CVC requirement dates so the coming study results can be more useful and meaningful. The ISO appreciates consideration to reduce the CVC requirement timeline; however, the ISO is working to find the right balance and reasonable approach for the project currently in the queue to meet such CVC requirements while maintaining consistency and progress of the policy implementation.

SCE reiterated its support and believes ISO's diligent enforcement of both its revamped commercial viability criteria and a project's time-in-queue proposals can have a significant and positive impact in effectively managing and clearing the interconnection queue so only viable projects ready to proceed towards commercial operation remain, culminating in more informed and useful interconnection study results.

Proposal

The ISO continues to propose requiring all projects in the queue to demonstrate commercial viability to remain in queue beyond seven years, regardless of deliverability status. The ISO also proposes requiring each project to meet the CVC by an unavoidable time-in-queue requirement. Projects must demonstrate annually that CVC remains valid. Failure to meet these requirements will result in withdrawal or default of the project. To clarify, the ISO will remove the current CVC policy that requires CVC only to retain TPD allocations.

Once CVC has been met, the project is required to demonstrate specific and distinct progress to commercial operation on an annual basis and is prohibited from extending milestones except when aligning the COD with that of an executed purchase agreement.

As detailed in Table 1 and 2 below, the ISO proposes that all projects will be required to meet the following CVC by no later than the date defined for all active projects currently in the ISO queue through Cluster 14. For all projects in Cluster 15 and later, projects will be required to meet CVC by 5 years from the publication of the interconnection facilities study, which is the last study in the Order No. 2023 study process. In contrast to current practice, projects will be required to meet these criteria when they are in queue for five years from the interconnection facilities study (or cluster 15 equivalent):[32]

A. Providing proof of having an (or multiple) executed power purchase agreement (whether for Resource Adequacy requiring TPD or for Energy Only) by providing the ISO a copy of such executed agreement(s) and other supporting documentation as applicable.

[32] If a PTO construction delay changes the COD or construction schedule beyond the limit, CVC does not apply. Consistent with today, PTO construction delays are caused unilaterally by the PTO, and do not result from any customer action or election.

1) Power purchase agreements must have and maintain the following criteria and remain consistent with the project's ISO queue project, Interconnection Request, and GIA:

    i. A minimum 5-year term

    ii. TPD status/requirements that matches the project's TPD status with the ISO. For example, if the projects is Energy Only at the time of meeting CVC, the ISO will not accept a PPA that required 'resource adequacy benefits' or TPD to be acquired. This is consistent with the ISO's proposal above to remove options to obtain deliverability late in the queue process.

    iii. Point of interconnection, capacity, fuel type, technology, site location and Interconnection Customer(s) legal entity.

2) In the event the PPA is not consistent with such ISO or GIA criteria above, the Interconnection Request will be withdrawn or terminated. If such differences could be corrected with a material modification request, to the extent permitted, the project will be required to immediately submit a modification request to align the interconnection request with the executed PPA.

3) In the event a PTO extension causes the interconnection customer's PPA to be terminated, the interconnection customer will have 12 months from the date of the PTO extension report to demonstrate that the project is on a shortlist or is actively negotiating a PPA or provide an executed PPA. If the project demonstrates a shortlist or is negotiating a PPA, the project must provide the ISO with an executed PPA by no later than 24 months from the date of the PTO extension report. If a PPA is not provided by the due date, the ISO will place the project in breach of contract and move to terminate the GIA and withdraw the queue position.

B. Provide the GIA deposit in accordance with FERC Order No. 2023.

C. Demonstrate Site Control for 100% of the property necessary to construct the facility through the approved Commercial Operation Date.

D. Be in good standing with the GIA such that neither the Participating TO nor the ISO has provided a Notice of Breach that has not been cured and the Interconnection Customer has not commenced sufficient curative actions.

E. Provide a report that includes a detailed description and demonstrate status of the following:

   1) Progression of the project's established GIA milestones, including, at a minimum:

      i. Notice to proceed has been provided to the PTO

      ii. Third interconnection financial security has been posted in full or the project is up-to-date on the payment schedule defined in the GIA

   2) A list of all necessary permits, environmental assessments, or other authorizations required for constructing the Generating Facility and the contact persons and contact information for each required authorization.

   3) The status of the engineering and design of the generating facility, and network and interconnection upgrades.

   4) The status of the procurement of major equipment necessary to construct the generating facility.

   5) The status of the construction activities of the generating facility and interconnection facilities.

Then, annually, the project must continue to demonstrate that:

A. The CVC criteria (A) through (E) above remains valid and accurate;

   1) The project must continue to satisfy this CVC with the PPA it provided in its initial CVC demonstration. In the event a project's PPA is terminated, it must execute a replacement PPA before the next annual review period.

B. Specific and distinct progress has been made for all of the following items:

   1) GIA Milestones.

2) Submission of or approvals from the regulating authorities for all necessary permits, environmental assessments, or other authorizations required for constructing the Generating Facility.

3) Status of engineering and design of the generating facility, and network and interconnection upgrades.

4) Status of the procurement of equipment necessary to construct the generating facility. Status of the construction activities of the generating facility and interconnection facilities.

Projects that meet CVC for only a portion of the project (only provide a PPA for 50 MW of a 100 MW project for example) will be required to downsize to the capacity that meets CVC requirements.

Consistent with the CVC and suspension today, when a project submits a modification request to determine whether suspension will have a material impact on other projects, the ISO will assess whether the suspension will place the project beyond the tariff-prescribed terms. If so, the project must comply with the CVC at the time it enters suspension. This will continue to avoid projects' using suspension to linger in queue while avoiding CVC requirements.

Projects in queue beyond the tariff-prescribed timelines will not have an option to construct as a merchant plant or proceed without a PPA and proceed to construction without having met and continue to meet CVC requirements. This will prevent projects from creating pretexts to linger in queue while searching for an off-taker.

Failure to meet the GIA or CVC requirements will result in the ISO proceeding to withdraw the interconnection request. With this CVC policy, the ISO proposes to eliminate the monthly or quarterly status report submissions as established in the generator interconnection agreements and rely on the initial and annual demonstration of CVC for project status updates.

Tables 1 and 2 establish the proposed due dates for all projects in the queue through cluster 14 to (1) execute an interconnection agreement, and (2) subsequently demonstrate the project's CVC.

Table 1: GIA Execution Requirement

	# Projects with unexecuted GIAs	MW Capacity at POI	IR Received Date (April)	7 years in queue	Years in Queue as of Nov. 2023	**GIA Executed No Later Than:**	Years-in-queue
Cluster 8 and prior	1	50	2015	2022	8.5+	June 30, 2025	10.2+
Cluster 9	3	450	2016	2023	7.5	June 30, 2025	9.2
Cluster 10	2	300	2017	2024	6.5	June 30, 2025	8.2
Cluster 11	6	921	2018	2025	5.5	June 30, 2025	7.2
Cluster 12	13	3915	2019	2026	4.5	Sept. 30, 2025	6.4
Cluster 13	46	12,117	2020	2027	3.5	Dec. 31, 2025	5.7
Cluster 14	204	65,506	2021	2028	2.5	April 30, 2026	5.0

Table 2: CVC Demonstration Requirement

	# Projects impacted	MW Capacity at POI	IR Received Date (April)	7 years in queue	Years in Queue as of Nov. 2023	**Demonstrate all CVC No Later Than:**	Years-in-queue	Months to demonstrate CVC after GIA execution
Cluster 8 and prior	49	7,377	2015 and prior	2022 and prior	8.5+	Dec. 31, 2025	10.7+	6 Months
Cluster 9	27	5,367	2016	2023	7.5	Dec. 31, 2025	9.7	6Months
Cluster 10	21	6,501	2017	2024	6.5	Dec. 31, 2025	8.7	6 Months
Cluster 11	30	5,362	2018	2025	5.5	April 30, 2026	8.0	10 Months
Cluster 12	44	14,768	2019	2026	4.5	Sept. 30, 2026	7.4	12 Months
Cluster 13	60	16,323	2020	2027	3.5	April 30, 2027	7.0	16 Months
Cluster 14	204	65,506	2021	2028	2.5	April 30, 2028	7.0	24 Months

Examples:

1. A long-term build project (such as offshore wind) with a COD needed of 2040 enters the queue in April 2025 with a seven -year CVC requirement of April 2032. With a long-lead development and upgrades of 10 years, the project must start construction by 2030. Therefore, as long as the project executes a PPA by April 2032 (meaning it had roughly four years to market and seek an off-taker following the study process), and demonstrate all other CVC, it can request a COD that aligns with that PPA.

2. The project has a long-lead upgrade that results in the project COD extending beyond seven years-in-queue, the project can have any COD it needs, as long as it demonstrates all CVC by seven years-in-queue (or date established below), continues to demonstrate such CVC annually and makes continual progression to achieve its commercial operation. If a project executes a PPA, it can submit a modification request to align the project COD to the PPA.

3. If the project has Energy Only Deliverability Status, an Energy Only PPA would permit the project to align its COD with that Energy Only PPA and the project would remain in good standing as long as it meets all CVC by seven years-in-queue (or date established below) and continues to meet such CVC annually making continual progression to commercial operation.

4. The Queue Management team will continue to work to maintain project's CODs as it does today, allowing modification requests for CODs and managing projects accordingly.

3.7. Project Modification Request Policy Updates

Background

The increase in the volume of modification requests has become challenging to manage and the ISO proposed several suggested approaches to 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 working group meetings, the ISO and stakeholders sought ways 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. Limiting a project to a certain number of MMA requests or requiring that MMAs may only be either submitted at certain times during the year or based on contract milestones.
5. Implementing 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 due to the cost of processing modifications being greater than the current $10,000 deposit.

Stakeholder feedback and discussion

Avantus Clean Energy requested clarification as to whether construction sequencing changes would be for nine months prior to initial synchronization or nine months prior to COD. They also argued that the ISO has not thoroughly explained or demonstrated sufficient reasoning on how this would bring improvements. For clarification, the ISO confirms that construction sequencing may be submitted nine months before initial synchronization.

Aypa Power, Clearway Energy Group, and LSA all advocated for a longer window to submit construction sequencing requests, or that there be no limits on when they can be submitted. The ISO holds that construction sequencing is intended for small adjustments to milestones for projects that experience minor delays during construction, but otherwise have a reasonable idea of when they will be coming online. Extending the window for submissions would increase the likelihood of this being used for circumventing other tariff requirements. Additionally, the earlier they are submitted, the more likely it is that the milestones would need to be adjusted again, increasing the administrative burden for minimal benefit.

EDF-R supports the ISO proposal for the changes to construction sequencing requests. However, EDF-R also strongly requested that the deposit for modifications only be raised to $15,000, as this would cover 80% of modifications. The ISO assumes that the 80% figure was calculated from the annual modification report, which only provides information for MMAs, and not for Post-COD modifications, which are generally more likely to go over the current deposit amount. Additionally, the ISO wants to make shortfalls as rare as possible, as each one puts a significant administrative burden on ISO resources.

Intersect Power did not object to the requirement that a project should begin construction before noticing the ISO that it is invoking construction sequencing. However, once construction starts, Intersect Power said it does not see how delaying this notice helps either PTOs or developers in scheduling the work. Moreover, they hold that the proposal still does not address situations where developers seek to accelerate CODs. The ISO believes that requiring requests to be submitted within nine months of synchronization will minimize the amount of adjustments needed. Construction sequencing requests can be used to accelerate CODs as well, but this requires that all parties are able to accommodate the earlier COD.

Aypa Power, Clearway Energy Group, and Rev Renewables have asked that the ISO continue to pursue developing a list of modifications which would not require an MMA, or could otherwise use a more streamlined process. While the ISO is still interested in this idea, there are not currently any modifications which can be streamlined more than the current permissible technological advancements.

CPUC, Cal Advocates, California Wind Energy Association, Rev Renewables, SCE, and PG&E generally support the proposal.

Proposal

The ISO maintains its proposal to update the following 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 Facility Reassessment Report 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) to specify that projects must have started construction and be within nine months of achieving their then-current synchronization or commercial operation date to submit a construction sequencing delay request. If updates to the COD are necessary beyond nine months, a modification request must be submitted.

3.8. Earlier Financial Security Postings for Projects with Shared Upgrades [Updated]

Background

Interconnection customers have raised concerns that the PTOs are not meeting the milestone dates, particularly 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. 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.

In the revised straw proposal, the ISO in coordination with the PTO, agreed to notify all the other developers whose projects were allocated a pro-rata share of the same shared network upgrade that they will be required to make the 3rd Interconnection Financial Security (IFS) posting for their pro-rata portion of the shared network upgrade.[33] If the project is parked, it would need to execute an engineering and procurement ("E&P") agreement for the shared network upgrades with the PTO within 90 calendar days of notification or be withdrawn.[34] If the GIA is not executed, the interconnection customer will have 90 days to execute the GIA or be withdrawn. The GIA could incorporate two NTPs' and 3rd IFS postings, one for the shared network upgrade and one for the remainder of the project.[35] The IFS and first payment would be due at the time of execution of the GIA and payments would commence. Failure to post is grounds for termination of the engineering and procurement agreement or GIA.[36] If the GIA is already executed, the interconnection customer would have 60 days from the date of notification to post the IFS for the shared network upgrade and make payments to the PTO. The GIA could subsequently be amended to incorporate two NTPs and IFS postings, if desired. The shared network upgrade can be any network upgrade (PNU, CANU, ADNU, LDNU, RNU or DNU). If a project withdraws because it has to post earlier than anticipated in its schedule, then withdrawal funds will be treated consistent with Section 7.6 and 11.4 of the tariff. Also, as discussed in Section 3.10 below, once the PTO has received the NTP and 3rd IFS posting from all of the impacted interconnection customers, it will have 30 business days to commence working on the upgrades.

Stakeholder feedback and discussion

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[33] For Cluster 15 and beyond, in accordance with Order No. 2023, the project will need to post their Commercial Readiness and GIA Deposits along with the discrete portion of the shared network upgrade at least thirty (30) days prior to the commencement of procurement, installation or construction of the shared network upgrade.
[34] This is applicable to Cluster 14 and previous clusters.
[35] For Cluster 15 and beyond, the posting for discrete upgrades resolves this issue.
[36] Section 8.4.8 of Appendix DD, LGIA Article 2.3 or SGIA Article 3.3, whichever is applicable

The following parties support this proposal: AES, Aypa Power, CPUC, Cal Advocates, CESA, Clearway, PG&E, REV, SEIA, and SCE. Intersect Power and LSA do not object to the proposal.

AES and SEIA are seeking clarity on how and when the due dates for the payments will be communicated. As discussed in the revised straw proposal, the interconnection customers of shared network upgrades will be notified by the ISO in coordination with the PTO. AES also commented that if a customer without an executed GIA withdraws, all other customers should not be financially responsible for the withdrawn customer's pro rata cost responsibility. Costs should be originally allocated so interconnection customers do not bear the full cost of the shared upgrade. The ISO is not proposing any changes in the allocation of costs among projects from withdrawals and a GIA has not been executed. AES and SEIA also wanted clarity on how shared upgrades will be allocated to multiple projects (i.e. MW, total cost, number of projects). The ISO is not proposing any changes in the allocation of costs for shared network upgrades.

Avantus requested clarification of how the parking allowance would be reflected in Appendix C of the GIA if a parked project were required to post and provide the 3rd IFS for a shared network upgrade. In the case of a parked project, the project would execute an E&P agreement for the shared network upgrade and not the GIA as discussed in the proposal.

EDF-R believes the ISO's proposal may be acceptable but asked the ISO to work through two example scenarios to ensure the proposal is well understood by all. While EDF-R did not propose the scenarios, the ISO hopes this example for Cluster 14 and earlier facilitates a full understanding of the proposal.

> A network upgrade is shared by three Interconnection Customers (ICs). IC1 and IC2 are not parked but IC3 is parked. IC1 executes its GIA and provides the NTP, 3rd IFS and starts payments for its project including the shared network upgrade. The PTO notifies the ISO, IC2 and IC3 that IC1 has provided an NTP and IFS for the shared network upgrade.
>
> If IC2 has already executed its GIA then it has 60 calendar days to provide the NTP, 3rd IFS and start making payment for only the shared network upgrade. The GIA may be amended to incorporate two NTPs, 3rd IFS and payment schedules. If IC2 has not executed its GIA then it has 90 days to

> execute the GIA presumably with two NTPs, 3rd IFS and payment schedules.
>
> IC3 would execute an E&P Agreement and provide a NTP and start making payments within 90 days of notice.

For cluster 15 and beyond the proposal would be implemented as follows:

> IC1 executes the GIA and has milestones that require the shared upgrade to start procurement, installation and construction in 2 months. Upon IC1 GIA execution, IC2 would be notified it has 60 days to fund the shared network upgrade or be withdrawn. IC2 has not executed their GIA due to an affected system issue. IC2 would execute an E&P Agreement and provide the discrete amount required for the shared upgrade including the GIA deposit and the amount for the procurement, installation and construction.

EDF-R also asked what happens if the PTO does not initiate construction within 30 days. Will security be returned to interconnection customers and NTP considered void? Return of security is unlikely, the issue would need to be evaluated on a case-by-case basis. If the PTO were significantly delayed, then it is more likely an adjustment should be made to the security. EDF-R can imagine a situation where this procedure is initiated and then a project gets “re-prioritized” by the PTO, resulting in the IC having inappropriate levels of funds at risk.

GSCE supports more advanced notice be provided to help balance this proposal. Given that the ISO will be requiring the notice to proceed and third posting dates to be included in the GIA, the earliest notice to proceed date for a shared upgrade should be known by the ISO and PTO potentially well in advance of the 60-day notice currently proposed. GSCE recommended that the ISO or PTO share with all interconnection customers of a shared network upgrade the earliest notice to proceed date included in an executed GIA as an informational notice, perhaps as part of the quarterly transmission development forums to account for the fact the earliest NTP date may move a bit earlier in the study process and create administrative burdens to track. Official notice would then again be provided each interconnection customer in the 60 to 90 day window as is currently proposed. The ISO appreciates GSCE’s recommendation, believes it will improve the proposal and will add this additional information into the notifications to the interconnection customers.

Recurrent Energy requested that a provision to have the PTO provide a concrete schedule for the NTP date that the PTO plans to achieve along with the notification of payment be added to this section. Recurrent Energy is concerned that the 60 to 90-day window is insufficient time for a project to plan its financing and would result in drawing on emergency funds or reserves. With the suggestion made by GSCE above and incorporated into the proposal, the interconnection customers will have this information once the GIA is signed. Recurrent is also concerned that the 30 days for the PTO to commence the upgrade is not enforceable and believes the language should be modified. The ISO proposes to clarify the language, below.

SDG&E noted that the ISO's proposal calls for third postings for shared upgrades deadlines to be scheduled in the GIA. This contrasts with SDG&E's previously stated position that the entire third posting – not just those related to shared upgrades – be due prior to execution of the GIA. The ISO agrees with SDG&E that the entire third posting should be included as a milestone in the GIA and due when it is appropriate given the specific project timeline. This proposal is to narrowly address when one interconnection customer of a shared network upgrade is ready to move forward and the other interconnection customers have not executed the GIA or are parked and therefore not in the same position to move forward but have a cost obligation that must be met. SDG&E noted that the current proposal may encourage the execution of speculative GIAs and further inundate the study process with speculative generation absent the appropriate process sequence. The ISO disagrees. Requiring all parties to a shared network upgrade to provide the NTP, 3rd IFS and start payments for all network upgrades when the first customer is ready to proceed with a shared network upgrade is unreasonable for Clusters 15 and prior. Order No. 2023 solves this issue by requiring discrete posting milestones for each interconnection facility and network upgrade.

Proposal

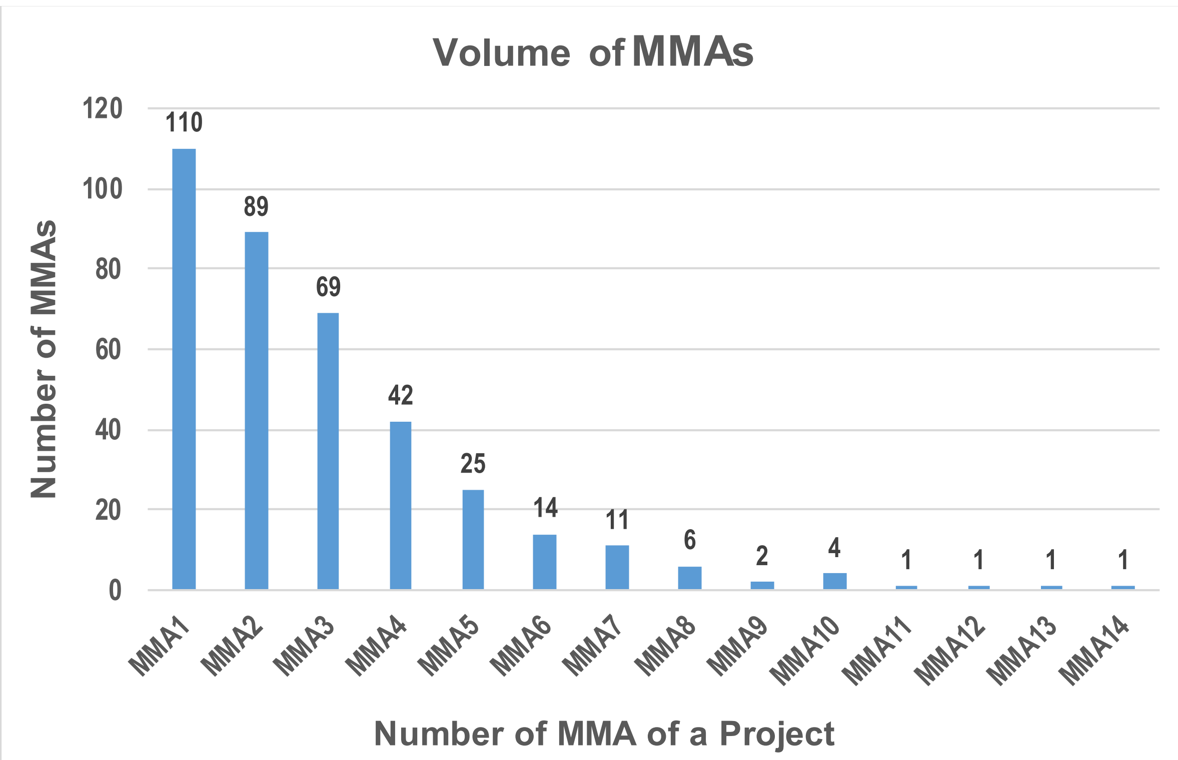
As discussed above, the ISO proposes to make a minor addition to the revised straw proposal. When GIAs are executed that have shared network upgrades included, the other interconnection customers of the shared network upgrades will be notified of the Notice to Proceed date of the executed GIA.

Once the PTO has received the NTP and 3rd IFS posting for cluster 14 and prior, or received the commercial readiness and GIA deposit along with the discrete procurement, installation and construction amount for the shared network upgrade from all the projects, it will have 30 days to commence the upgrades.

3.9. Revise Timing of GIA Amendments to Incorporate Modification Results [Updated]

Background

In the revised straw proposal, the ISO noted that with the continuous revisions to projects through the MMA process, the contract negotiators for the interconnection customer, PTO and ISO are required to continually amend the GIAs. From 2021 to date, the ISO and Participating TOs have processed 376 MMAs.[37]



[37] The volume of MMAs is based on the number of MMAs each project has requested. As an example, 110 projects have one MMA whereas 25 projects have 5 MMAs to date.

Some projects have made more than five modification requests. One project has had 14. Trying to keep up with this ever-changing churn required to move the projects forward is time consuming. In the revised straw proposal, the ISO proposed that the MMA results be the binding document and the LGIA would be amended nine months before the synchronization of the first element of the project.

In this draft final proposal, the ISO proposes that the process of amending the GIA that will include all of the MMAs should start no later than nine months prior to synchronization of the first block or phase of the project to the grid. Doing so will facilitate inclusion of the final or near-final configuration of the project in the GIA.

The proposal will also revise the NRI process to align with this proposal. In addition, upon 120 days advance written notice, a GIA incorporating all MMAs to date could be tendered and executed by the parties if needed for financing purposes.

Stakeholder feedback and discussion

AES, Cal Advocates, CalWEA, EDF-R, Intersect Power, LSA, PG&E, REV, SDG&E, and SEIA support the ISO's proposal to have the GIA updated nine months before synchronization and aligning the NRI process. The MMA results would include both the results, the financial milestone changes and payment schedules, if applicable. Cal Advocates and PG&E noted that by addressing the timing of the GIA amendments, ISO and PTO resources would be more efficiently utilized, which in turn lowers costs to ratepayers. SDG&E commented that it supports this approach, as it gives PTOs the scheduling flexibility when finalizing amendments. SDG&E already incorporates this into our procedures and finds that it has many benefits that greatly streamline the MMA process. SDG&E encouraged the ISO to proceed with the proposal as written.

Aypa Power believes the timing of amendments is a secondary issue and is concerned more about the number of MMAs per project. From the ISO's perspective, the number of MMAs is not a concern. Equipment changes over time due to technology and supply change issues, and projects change hands and evolve. This is all part of the normal development cycle.

Intersect Power encouraged the ISO to better formalize the understanding that MMA approvals are effective and enforceable within the tariff and/or pro forma

LGIA so that financing parties can confidently rely upon the final MMA approvals, in lieu of an amended LGIA, which should eliminate the push from interconnection customers to make subsequent revisions to the LGIA. The ISO has already incorporated language in the MMA report to implement the enforcement of the MMA change. Intersect Power and LSA also noted that the ISO and PTOs need to reach a consensus on this proposal.

MRP's concerns about this aspect of the proposal stemmed from the fact that the developer often has little or no control over timing of the MMA reports, and recent experience has demonstrated significant timeline overruns, even if those reports are intended to be binding as proposed in this paper. While the ISO understands MRP's concern with delay in the MMA reports, an amendment to the GIA could not be started until the MMA report is done regardless of whether every MMA amends the GIA, or the MMAs are held until closer to synchronization.

SCE reiterated its opposition to the ISO's proposal to amend a GIA and/or UFA that will include all approved modification changes over a span of year(s) to a project no earlier than nine months prior to the approved synchronization date of the first block or phase of the project to the grid for numerous reasons. In particular, SCE is concerned that the proposal does not effectively address each legal change to the GIA on a timely basis. Their position is that project scope changes through MMA submissions and language in the MMA is not a substitute for amending the GIA. SCE also said it is impractical to wait years to amend the GIA and/or UFA to incorporate all approved MMAs which would create confusion relative to the scope of work, schedule, and the project's overall budget. SCE also opposed being required to finance costs associated with incremental scope changes triggered by a developer's request modify its project. Accordingly, SCE would oppose any delay in amending the GIA and/or UFA to collect additional project payments and financial security (ITCC and IFS)[38] not included in an MMA/Facilities Reassessment Report. While the other PTOs supported the proposal, the ISO understands SCE's position and will make the proposal discretionary and up to the parties as to when the GIA is amended.

Proposal

[38] Or Order No. 2023 financial equivalent.

The ISO proposes in this draft final proposal that the process of amending the GIA that will include all of the MMAs should start no later than nine months prior to synchronization of the first block or phase of the project to the grid. However, developers and PTOs may have a variety of reasons to amend GIAs to incorporate modifications sooner or later. The ISO will thus continue to provide flexibility for the parties to decide when they will amend GIAs, and will not propose tariff rules regarding when parties can amend GIAs to incorporate modifications. The ISO notes that either party also can submit unexecuted GIA amendments to FERC whenever the other party is reluctant to amend a GIA or there is an impasse in amendment negotiations.

PTOs may amend the GIA after every MMA, addendum or changes to the GIA but to the extent parties want to wait until closer to the synchronization, doing so will facilitate inclusion of the final or near-final configuration of the project in the GIA. All modification reports would include scope changes, project payments, updating costs, changes to financial security amounts (ITCC and IFS) and their due dates, and schedule (i.e., recalibration of milestone due dates based on the revised COD), as applicable. This true-up of the MMA Reports and the GIA does not preclude the project from making additional modification requests if needed.

The proposal is also being expanded to facilitate concerns raised by stakeholders. The NRI process will be revised to align with this proposal and upon 120 days advance written notice, a GIA incorporating all MMAs to date could be tendered and executed by the parties if needed for financing purposes.

3.10. 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 its PPA, which would likely result in financial penalties for the interconnection customer.

The ISO previously proposed that a specific date for the NTP be 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 agreed 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. This will allow milestones to be specifically tracked.

The ISO also proposed 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, which should be within 30 business days after receiving the NTP and 3rd IFS posting. This would 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.

Stakeholder feedback and discussion

Several parties supported this element of the proposal, including AES, Aypa Power, CPUC, Cal Advocates, CalWEA, CESA, Clearway, EDF-R, GridStor, Intersect Power, LSA, MRP, PG&E, REV, SCE, and Vistra.

Clearway highlighted the importance of this measure within the many elements of the IPE initiative. Requiring PTOs to commence work as soon as a NTP is issued and financial security posted is an important step toward predictable timelines for network upgrades, which is critical if California is to meet its reliability and clean-energy goals.

PG&E said it understands the proposal to imply that if the date is not met, the interconnection customer would be held in breach/default of the agreement. The ISO agrees. However, PG&E's requests that the ISO clarify whether the requirement on the interconnect customers and PTO is initial as the construction activities commence or ongoing and frequent reporting with a pre-determined cadence. The ISO's proposal is focused on the NTP, 3rd IFS, and commencing payments,[39] however the ISO assumes that the project will continue to move forward and will not stall due to lack of PTO performance.

Recurrent Energy commented that it will be crucial for the true realization of the proposal that PTOs are held accountable if they digress from the dates they

[39] Or the Order No. 2023 financial equivalent.

commit to in the GIA, and are subjected to similar due diligence such as interconnection customers when they seek t such delays. The modification process in Section 5.19 of the GIA allows the PTO to make modifications similar to any other party to the agreement. Parties to GIAs are free to enforce their terms and hold the other parties accountable for any potential breach.

SCE's position that the commencement of activities associated with PTO interconnection facilities, network upgrades, and distribution upgrades, if applicable, are not only dependent on the PTO receiving the NTP and the 3rd IFS posting, but also predicated upon the IC ensuring:

1. Agreement(s) (Letter Agreement, GIA, or both GIA/UFA) remain in good standing.

2. Project payments are received by their respective due dates.

3. All predecessor milestones are completed by the specific due dates reflected in Appendix B, milestones of the agreement.

If any of these conditions are not met, commencement of activities within 30 business days of receiving the NTP and the 3rd IFS posting will be impacted. The ISO agrees with SCE's position.

Proposal

The ISO is not proposing any changes to the revised straw proposal in the draft final proposal.

3.11. Deposit for ISO Implementation of Interconnection Projects

Background

The revised straw proposal said that upon execution of the GIA, the interconnection customer will provide a $100,000 deposit to the ISO to compensate the ISO for the project management and new resource implementation processes for each project in the queue. There are roughly five teams and several people involved in project implementation following GIA execution. This includes:

- Queue Management – project management, facilitating issues, assisting projects to understand next steps

- Regulatory Contracts – implementing amendments to the GIA, developing market agreements, establishing co-located and hybrid Accumulated Capacity Constraints

- New Resource Implementation – overseeing implementation of projects into the market systems

- Energy Data Acquisition – ensuring the metering and telemetry are accurate and meet market criteria

- Full Network Model – developing and testing the model of the generator in the market systems.

Assuming a $190 average loaded cost per hour in 2023, the $100,000 deposit provides the ISO 526 hours to be charged over approximately five years remaining after the study process. This deposit is in addition to those costs or processes that are not currently reimbursed, such as MMAs, LOS, and PTAs. In addition, WDAT projects will need to provide a $10,000 deposit to go through the NRI process.

Stakeholder feedback and discussion

Several parties expressed support for this element of the proposal, including Cal Advocates, EDF-R, and MRP.

AES, Intersect Power, and Shell Companies do not oppose the ISO including an implementation cost for its project management and resource implementation processes to hire additional resources. But they requested the ISO publish a periodic report of resource development progress. The ISO currently publishes the Generator Interconnection Queue Report which provides information on study status, deliverability and GIA execution. The ISO also publishes a Generator Interconnection Resource ID Report which provides information on projects that have started the NRI process. If AES is proposing an additional report, that could be discussed as part of the BPM change management process.

Avantus requested the ISO to 1) tally unused non-refundable interconnection study deposit amounts from the last few clusters and 2) consider updating the GIDAP section 7.6 to redirect interconnection study deposit and non-refundable site exclusivity deposits toward post-LGIA administrative costs before implementing additional fees at the time of LGIA execution. The revenue from non-refundable study deposits and site exclusivity deposits currently flows to the

PTO to decrease the costs of upgrades. The intent of the deposit for ISO project management and NRI process is to cover the costs associated with the projects that are moving forward and using the ISO's services during the project's development. It would therefore be inconsistent to use funds from the non-refundable study deposits and site exclusivity deposits for project management by ISO staff.

Aypa Power, CESA, EDF-R, Recurrent Energy, and Vistra requested additional information be provided to justify the proposed deposit and overall cost. This cost appears to be significantly higher than other ISOs and automation and other business process efficiencies should be considered prior to implementing a drastic new deposit/fee. The ISO is proposing the amount as a deposit to allow the actual cost incurred for the project to be assessed against the project and not some set fee. Most projects have a life cycle of seven years, and some projects are significantly more complex and require extra work by the ISO staff at various stages of the project. Other projects are very straightforward but stakeholders are requesting more ISO involvement, tracking of major milestones, and additional transparency of project status. The project will get any remaining deposit back with interest,[40] with the funds being used for additional staff to support the generator interconnection process.

CalWEA suggested using remaining study deposit funds instead of requiring a new deposit. If a project withdraws, CalWEA also suggested the deposit should be $50,000 or less. As discussed in the proposal, the ISO believes the $100,000 is appropriate given the timeframe the workload covers.

REV requested clarification on when the ISO proposes to start implementing this new deposit. Will it be imposed only on GIAs after approval of this proposal or any previous projects as well? The ISO's intent would be to implement the deposit on any project that is still in the queue that has executed a GIA. For projects that have not executed a GIA the deposit would be due upon execution of the GIA. For WDAT projects, the deposit would be due when the project first requests to enter the NRI process. REV also requested clarification on what this new cost will cover and how it is not covered today. As stated in the proposal, the deposit is for project management and new resource implementation processes. These costs are currently covered by the market through the grid management

[40] Consistent with existing ISO procedures, any ISO costs are subject to audit.

charge. With the significant increase in generator interconnections the costs based on cost causation should be borne by the developers using the service and not the market.

Proposal

The ISO proposes a $100,000 deposit for ISO connected resources and $10,000 deposit for WDAT resources. This is consistent with cost causation and the use of ISO resources for generator interconnection processes.[41] The $100,000 deposit would be due for all projects with executed GIAs currently in the queue within 120 calendar days of FERC approval. The $10,000 deposit would be assessed to WDAT projects when they enter the NRI process.

3.12. Update to the Phase Angle Measuring Units Data

Background

The GIA requires an asynchronous generating facility to provide all phase angle measuring unit (PMU) data at a resolution of 30 samples per second and upon request from the ISO or Participating TOs. With the increase in asynchronous generating facilities on the grid, the ISO is finding that the resolution of 30 samples per second is not granular enough to be of use for any analysis when there are faults on the system and most sites are using their protective relays versus PMUs to capture events. The ISO proposes to change this to 16 samples per cycle which is already consistent with present day relays.

Stakeholder feedback and discussion

Several parties supported this element of the proposal, including CPUC, MRP, and SCE.

AES, Aypa Power, and CESA do not oppose requiring more granularity for the PMU but questioned whether 16 samples per second actually provides more granularity. AES and CalWEA suggested a limit of 60 samples per second. As proposed above, the ISO believes it should be changed to 16 samples per cycle.

[41] The WDAT fee is considerably lower because it only covers the few ISO-related aspects for WDAT projects, which are otherwise subject to PTO WDAT tariffs, processes, and fees.

PG&E uses a PMU sample rate of 60 samples per second, and recommended the ISO modify the proposal to use this sample rate. PG&E said PMU data is not the best platform for fault analysis and that fault recorders with a sample rate of 16 samples/cycle or greater is the appropriate device for fault analysis.

PARS Energy requested that the terminology be revised to "Phasor Measurement Unit". The PMUs that are being used are not specifically phasor measuring units. They are identified as a phase angle measuring unit or functional equivalent. A modern microprocessor based relay can meet this requirement. The ISO is not asking for synchro phasor measuring units, so the change in terminology is not required.

Recurrent Energy questioned if enough inverter manufacturers have shown proof of operational feasibility of providing 16 samples per second. Based on discussions the ISO has had with project developers and manufacturers, 16 samples per second is feasible.

REV requests clarification on this proposal and whether there are any expected technical problems or unanticipated costs with achieving the desired granularity resolution. The ISO understands that the existing relays already meet the requirements.

Proposal

The ISO proposes that the phase angle measuring unit resolution should be revised in Appendix H of the GIA to 16 samples per cycle, not second.

4. 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 need to be considered only by the Board of Governors and that the WEIM Governing Body has 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."*[42]

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 be applicable "only to … the CAISO-controlled grid." Accordingly, these proposed changes to implement these enhancements would 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.

5. Stakeholder Initiative Schedule

The schedule for stakeholder engagement is provided below. The ISO presented its proposal for Track 1 to the Board of Governors in May 2023. The ISO intends to present Track 2 enhancements to the Board of Governors in May 2024.

[42] Charter for EIM Governance § 2.2.1.

Date	Milestone
2/15/2024	Stakeholder workshop on draft final proposal
2/29/2024	Comments due on draft final proposal
3/29/2024	Final proposal posting
4/4/2024	Stakeholder workshop on final proposal
May 2024	Board of Governors Meeting

Appendix A – <Qxxxx>

[redacted]

<ProjectName>

Queue Cluster 14 Phase II Study

[Exemplar] Final Report

January 31, 2024

Confidential – Subject to Transmission Planning NDA

This study has been completed in coordination with Pacific Gas and Electric per CAISO Tariff Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Appendix DD

[redacted] Indicates redacted information

Table of Contents

Attachments:

1. **Allocation of Deliverability Driven Network Upgrades for Cost Estimates**
2. **Not Used**
3. **Not Used**
4. **Short Circuit Calculation Study Results (Refer to Appendix H of the PG&E <Area> Interconnection Area Report)**
5. **Deliverability Assessment Results (Refer to Appendix I of the PG&E <Area> Interconnection Area Report)**
6. **Generator Dynamic Data**
7. **Transient Stability Plots**
8. **Preliminary Protection Requirements**
9. **Transient Stability Contingency List**
10. **Substation and Transmission Line Work Scope**
11. **Reliability Study of Charging Energy Storage Facilities (Refer to Appendix J of the PG&E <Area> Interconnection Area Report)**

1. Introduction

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Appendix DD, the Project was grouped with Queue Cluster 14 (QCLUSTER 14) Phase II Study projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The PG&E <Area> Interconnection Area report has been prepared separately identifying the combined impacts of all projects in the interconnection area on the CAISO Controlled Grid. This report focuses only on the impacts or impact contributions of this Project, and it is not intended to supersede any contractual terms or conditions specified in an interconnection agreement.

The report provides the following:

1. Transmission system impacts caused by the Project;
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions;
3. A list of required facilities and a non-binding, good faith estimate of the Project's cost responsibility and time to construct[1] these facilities.
4. Estimated earliest achievable In-Service Date and Commercial Operation Date based on the Interconnection Study timelines.

Additionally, if the Project encompasses energy storage equipment that required additional analysis be performed to evaluate the impacts of the Generating Facility (GF) within Participating TO's (PG&E) Transmission System. These analyses focused on the charging demand[2] aspects of the GF and consider varying levels of system demand with minimal generation dispatch within the local transmission system.

Consequently, the report also discloses the adequacy of PG&E's Transmission System to support the GF when operating in charging demand mode, identifies system limitations that may restrict the GF when operating in charging demand mode during certain demand conditions, and provides a high-level explanation of potential exposure to the GF of charging restrictions on the electric system. The GF will follow CAISO market dispatch instructions when in charging demand mode and in discharging mode.

If the Generating Facility has the capability of producing and delivering more MW at the Point of Interconnection than the requested amount, the Interconnection Customer will need to install or demonstrate that a control system will be put in place which will manage the Generating Facility output to not exceed the maximum requested Point of Interconnection delivery amount, which takes into account the expected losses on the generation tie line.

[1] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work.

[2] Charging Demand is defined as when the Project's GF draws energy from the grid and/or on-site generation to "charge" the Project-associated energy storage facilities.

All the equipment and facilities comprising the Project are as disclosed by the IC in its Interconnection Request (IR) or may have been amended during the Interconnection Study process and validated by the CAISO.

Table 1-1 provides general information about the Project, as modeled in the Phase II study based on the IC-provided IR.

Table 1-1: Project General Information as Modeled

Project Parameters	**Project Specific Data**
Interconnection Customer	[redacted]
Project Name	<ProjectName>
Requested Deliverability Status	<ProjDeliverability>
Project Queue Number	<Qxxxx>
Project Technology Type	<ProjectType>
Project Location	[redacted] GPS Coordinates: [redacted]
Participating TO's Planning Area	<Area>
Number and Type of Generators	[redacted]
Interconnection Voltage	<POIVoltage> kV
Maximum Generator Output at Generator Terminal	<GeneratorRatedOutput> MW
Generator Auxiliary Load	<AuxLoad> MW
Requested Maximum Project Output as measured at the POI[3]	<ProjectSize> MW
Shared Reactive Resources	<Shared Reactive>
Step-up Transformer(s)	<XFMR data>
Point of Interconnection (POI)	<POI>
Interconnection Customer Requested In-Service Date	<InServiceDate>
Initial Synchronization Date/Trial Operation	<TrialOpDate>
Interconnection Customer Requested Commercial Operation Date	<CommercialOpDate>

Figure 1-1 provides a map of the Project location and transmission facilities in the vicinity. Figure 1-2 shows the conceptual single line diagram of the Project as modeled in the study.

[3] If the Generating Facility has the capability of producing and delivering more MW at the Point of Interconnection than the requested amount of MW, the Interconnection Customer will need to install or demonstrate that a control system will be put in place which will manage the Generating Facility output to not exceed the maximum requested MW at the Point of Interconnection delivery amount, which takes into account the expected losses on the generation tie line.

Figure 1-1: Project Vicinity Map

[redacted]

Figure 1-2: Proposed Single-Line Diagram

[Redacted]

[redacted]

2. Study Assumptions

For detailed assumptions, refer to Section 2 of the PG&E <Area> Interconnection Area report.

The following assumptions are only specific to the Project:

1. The IC will engineer, procure, construct, own, operate and maintain its project facility, including the generator tie line.

2. The Project was modeled with the ability to meet 0.95 leading/lagging power factor at the high side of the main transformer according to FERC Order 827 [redacted]

3. Energy Storage Generating Facility Considerations:
   The Project encompasses energy storage facilities. The details pertaining to the Reliability Study for the Generating Facility when operating in charging demand mode is included in this Appendix A report. *<Remove if there is no energy storage component>*

   <Insert the following only if there are other potential network upgrades. DELETE any of the below bullets if not applicable to the Project.>

4. <The Project proposed to share a generation tie-line with a previously queued project (Q#). Since the generation tie-line is required to interconnect the Project regardless of the other project, the Project is assumed as a stand-alone project and as such was allocated 100% of the Interconnection Facilities cost to establish the maximum cost cap.>

5. Conditionally Assigned Network Upgrade(s) (CANU):

   - The Project is dependent upon the installation of CANUs listed in Section 8.3.4. The CANUs are counted towards the IC's Maximum Cost Exposure (MCE) and may affect the Project's in-service date. The IC is not responsible for posting Interconnection Financial Security for these CANUs unless a CANU becomes an Assigned Network Upgrade (ANU) and becomes part of the Generating Facility's Current Cost Responsibility (CCR) in accordance with the CAISO Tariff.
   - Any change in the IC's Current Cost Responsibility and Maximum Cost Responsibility resulting from a CANU becoming an ANU will be reflected in a revision to this study report or reassessment as applicable and amendment to the GIA
   - The process by which these other CANUs can become the responsibility of the Project is set forth in Section 14.2.2 of the Appendix DD GIDAP.

6. Precursor Network Upgrades (PNUs): PNUs needed to achieve the Commercial Operation status and/or Deliverability Status for the Generating Facilities.
7. Local Off-peak Network Upgrades (LOPNUs): LOPNUs needed for Generating Facilities selecting Off-Peak Deliverability Status, and provide final cost estimates.

8. <#Deliverability rights><Qxxxx> will be using the deliverability rights of the existing <Existing Generator name> Unit X which retired <Retirement Date> and the original unit is being entirely replaced by the new Project.

3. Reliability Standards, Study Criteria and Methodology

The generator interconnection studies were conducted to ensure the CAISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards. Refer to Section 3 of the PG&E <Area> Interconnection Area Study report for details of the applicable reliability standards, study criteria and methodology.

4. Reliability and Deliverability Assessment Results

The Project was studied as part of other Cluster 14 Phase II projects in the PG&E <Area>. Refer to the PG&E <Area> Interconnection Area Study Report, Section 4 – Reliability Assessment for details of the Reliability Assessment.

Table 4-1: Reliability Assessment Results

Index	Criteria	Violation Result	Reference for additional detail	Type	Notes
2.1	Steady State Thermal Overloads	YES/NO	Appendix E	Reliability	The reliability thermal analysis was performed on power flow cases that include all Energy-Only and Full Capacity projects dispatched to maximum values. Congestion Management is relied upon for mitigation where applicable.
2.2	Bus Flow Analysis	YES/NO	Appendix G Area Report	Reliability	Impacts of projects on the loadings of buses and switching devices
2.3	Steady State Voltage	YES/NO		Reliability	The Project's buses may experience high/low voltages and/or voltage deviations. The IC will need to manage the Project's reactive power to meet the CAISO reactive power requirements and to control the plant side voltages within equipment tolerances

Index	Criteria	Violation Result	Reference for additional detail	Type	Notes
2.4	Post-Transient Voltage	YES/NO		Reliability	
2.5	Reactive Power Deficiency	YES/NO		Reliability	
2.6	Short Circuit Duty Analysis	YES/NO	Appendix G Appendix H Attachment 8 Area Report	Reliability	
2.7	Transient Stability	YES/NO	Attachment 6 Attachment 9	Reliability	Disturbance simulations were performed for a study period of 20 seconds for selected Category P1 (loss of single element) and Category P2, P4 and P7 (loss of multiple elements) outages. For this Project, the following outages were evaluated
2.8	Reliability for storage Charging	YES/NO	Appendix J	Reliability	Appendix J informational report will be provided later.
2.9	SSR Requirement	YES/NO		Reliability	If YES EMT models should be submitted to PG&E at least one year prior to the initial synchronization of the Project. If any mitigation is required, it should be in service prior to the initial synchronization of the Project.

Table 4-2: Deliverability Assessment Results

Index	Criteria	Violation Result	Reference for additional detail	Type	Notes
3.1	On peak Deliverability-Local	YES/NO	Appendix I	Deliverability	
3.2	Off Peak Deliverability-Local	YES/NO	Appendix I	Deliverability	
3.3	On peak Deliverability-Area	YES/NO	Appendix I	Deliverability	
3.4	Off Peak Deliverability-Area	YES/NO	Appendix I	Deliverability	

5. In-Service Date and Commercial Operation Date Assessment

An ISD and COD assessment was performed for this project to establish the PTO's estimate of the earliest achievable ISD based on the QCLUSTER 14 Phase II Interconnection Study process timelines and the time required for the PTO to complete the facilities needed to enable physical interconnection as Energy-Only for the Project (If the project's DNUs are not yet in service). This date may be different from the Interconnection Customer's requested ISD and will be the basis for establishing the associated milestones in the GIA. Subsequently, these dates may change based on the updated information and as part of the GIA negotiation.

5.1 IC Proposed Timeline

The IC has requested <ProjDeliverability> Deliverability Status, a proposed ISD of <InServiceDate> and COD of <CommercialOpDate>.

5.2 ISD Calculation Details

If the ISD proposed by the IC in its Appendix B is prior to the calculated earliest ISD in Table 6-1 below, then the customer must update the ISD and COD to the calculated earliest achievable ISD or to a later date. If the ISD proposed by the IC occurs later than the calculated earliest achievable ISD in Table 5-1 below, then the proposed date is achievable, and no change is required by the IC. The GIA tender date of the Interconnection Agreement will occur based on the calculation of Footnote 4 below to meet the project's ISD (IC selected ISD as indicated in Appendix B, earliest achievable ISD, or revised Appendix B).

In accordance with the CAISO Tariff Section 13.1 and back calculating the GIA tender date[4], the requested ISD and COD are <not achievable>. The estimated earliest achievable ISD is derived by the time requirements to complete the QCLUSTER 14 Interconnection Study Process and tender a draft GIA as described below in Table 5-1.

[4] In-Service Date (<InServiceDate>) minus GIA negotiation time and milestones leading to construction start (180 calendar days) minus longest lead time facility or network upgrade from study report (<NUDuration> months) equals Proposed GIA tender date (<GIATenderDate>).

Table 5-1: ISD and COD Assessment (Sample)

Reference starting point	Days/Months	Issuance of Phase II Interconnection Study Report	1/31/2024
Add:	30 CD	Phase II Results Meetings	2/30/2024
Add:	15 BD (20 CD)	Starting Point: any Addenda/Revisions to arrive at final Phase II Study Report.	3/22/2024
Add:	30 CD	Tender draft GIA	4/21/2024
Add:	180 CD	GIA development and negotiation time as outlined in GIDAP	10/18/2024
Add:	2 months	Project Startup Time	12/18/2024
Add: Construction Duration ANU	<NUDuration> months	Construction duration outlined in the Phase II Study Report. Construction completion no earlier than date which reflects earliest ISD	<EstimatedISD>
If this project is behind Conditionally Assigned Network Upgrades and/or Pre-Cursor Network Upgrades whose construction durations are not taken into account in this ISD estimate but can affect the Earliest ISD. Refer to Table 5-2 below for details.			
		IC-requested ISD via Appendix B	<InServiceDate>
		IC-requested COD via Appendix B	<CommercialOpDate>
Add: Difference between IC ISD and COD	<+mon> months	Earliest achievable Commercial Operating Date (COD)	<EarliestCOD>

Notes on the Achievable ISD and COD calculation:

1. Assumes Interconnection Facilities timelines needed for an Interim Energy-Only Interconnection or Energy Only interconnection (as applicable) for the Project until the applicable DNUs are completed.
2. The ISD and COD durations shown represent the estimated amount of time needed to design, procure, and construct the facilities with the start date of the duration based on the effective date of the GIA; and necessarily include timely receipt of all required information and written authorizations to proceed (ATP), and timely receipt of construction payments and financial security postings and other milestones.
3. These ISD and COD durations are good faith estimates provided for planning purpose and should not be construed as agreement by Parties to achieve said dates.

Table 5-2: Estimated Timeline of CANUs and PNUs Required for Interconnection

Type	Upgrade	Estimated ISD or Duration
CANU		
PNU		

Notes:
1. Actual ISD, Initial Synchronization Date, and COD also depend on CANUs and PNUs required for the interconnection of the Generating Facility. Table 5-2 provides the current estimated in service date or duration of the CANUs and PNUs. The dates are subject to change due to the same factors as what would impact the ANU duration assigned to the Generating Facility.

5.3 ISD Calculation Conclusion

Based on these timelines, the IC's requested ISD is <not achievable>.

Consistent with the CAISO Tariff, the Participating TO should tender a draft GIA no later than <GIATenderDate> to achieve IC's requested ISD and COD. However, based on the above calculation in Table 5-1, the earliest achievable ISD will be <EstimatedISD> and COD will be <EarliestCOD>.

Subsequent to the start of GIA negotiations, the CAISO will perform its Annual Reassessment and Transmission Plan Deliverability (TPD) Allocation. Any changes to the deliverability allocation resulting in changes in scope, cost, or schedule requirements that come out of CAISO's Annual Reassessment and TPD Allocation will be reflected in a Reassessment Report which will be used to revise the draft GIA if still under negotiation or amend the GIA if already executed.

If CAISO and PG&E determine that the TPD Allocation Study Process outcomes do not change the scope requirements for the Project, a letter will be provided informing the IC that there will be no changes to the allocated Network Upgrades requirements.

5.4 System Upgrades Required for Full Capacity Deliverability Status

The Project would be granted its requested FCDS only if the Project receives TPD allocation in the forthcoming TPD Allocation Study Process. Furthermore, timing of obtaining the requested FCDS is dependent on the completion of DNUs identified below in this report, which may be updated in any subsequent annual reassessment. Until such time that these DNUs are completed and placed in service, the Project may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of FCDS, Interim Deliverability Status, Area Constraints, and Operational Information.

5.4.1 Precursor Delivery Network /Approved Transmission Upgrades required by the project

It was found in the COD Assessment that the projects rely on Pre-Cluster 14 and approved TPP upgrades to achieve Full Capacity Deliverability Status (FCDS). Section 7 describes the facilities that are required for the project to achieve FCDS.

5.4.2 Interim Operational Deliverability Assessment - For Information Only

The operational deliverability assessment was performed for study years 2024 ~ 2027 by modeling the transmission and generation in service in the corresponding study year. For details of the transmission and generation assumptions, refer to Section 5.3 of the Area Report.

6. Scope of Upgrades – Interconnection Facilities and Network Upgrades

Refer to Tables 7-2 through 7-7 for the scope of the required upgrades.

7. Interconnection Facilities, Network Upgrades and their Cost and Construction Duration Estimates

The Participating Transmission Owner's (PTO) Interconnection Facilities and Network Upgrades described in this section are based on the Participating Transmission Owner's (PTO) preliminary engineering and design. The Interconnection Facilities and Network Upgrades described in this study are subject to modification to reflect the actual facilities constructed and installed following the PTO's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

To determine the cost responsibility of each generation project in the Cluster 14 Phase II Study, the CAISO developed cost allocation factors based on the individual contribution of each project to each required upgrade included in sections 8.2 and 8.3 of this report. Tables 7-1 through 7-7 below provide the cost in 2023 dollars and their cost escalated to the estimated operating year for Interconnection Facilities, Reliability Network Upgrades, and Delivery Network Upgrades (LDNU, LOPNU and ADNU). Table 7-1 below provides the PTO Interconnection Facilities itemized Cost Estimate Summary.

The non-binding construction schedule to engineer and construct the facilities is based on the assumptions outlined in Section 2 of this report and is applicable from the signing of the Generator Interconnection Agreement (GIA). The estimated durations provided represent the amount of time needed to permit, engineer, procure and construct the identified facilities starting from the date of execution of the GIA. This is also based upon the assumption that the environmental permitting obtained by the IC is adequate for permitting all PG&E activities.

It is assumed that the IC will include the PG&E's Interconnection Facilities and Network Upgrades work scope, as they apply to work within public domains, in its environmental impact report to the CPUC. However, note that CPUC may still require the PG&E to obtain a Permit to Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) for the generator tie line and Network Upgrades work associated with the Project. Hence, the facilities needed for the project interconnection could require an additional two to three years to complete. The cost for obtaining any of this type of permitting is not included in the above estimates.

Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.

The non-binding construction schedule to license, engineer and construct the PTO's Interconnection Facilities and Reliability Network Upgrades is approximately <LongestMonths> months from the signing of the Generator Interconnection Agreement (GIA), receipt of financial posting, plus two-month estimated project kickoff time.

7.1 PTO Interconnection Facilities (IF) Cost Estimate Summary

Table 7-1: PTO Interconnection Facilities Cost Estimate Summary

Interconnection Facility Element	**Cost** **(Subject to ITCC)**	**Total Cost (Excluding ITCC)** *(Note 1)*
Substation Work	[redacted]	[redacted]
Engineering	[redacted]	[redacted]
Land and Land Rights	[redacted]	[redacted]
Project Management	[redacted]	[redacted]
Property Improvements	[redacted]	[redacted]
Civil Foundations	[redacted]	[redacted]
Station Equipment & Materials	[redacted]	[redacted]
Removal	[redacted]	[redacted]
Telecommunications	[redacted]	[redacted]
Insulation and Coating and Various	[redacted]	[redacted]
Station Test Group	[redacted]	[redacted]
Maintenance & Operations	[redacted]	[redacted]
Metering	[redacted]	[redacted]
EPC Contracting Costs (Percentage of Total costs)	[redacted]	[redacted]
Subtotal	[redacted]	[redacted]
Transmission Line Work	[redacted]	[redacted]
Engineering and Equipment	[redacted]	[redacted]
	[redacted]	[redacted]
Total (2023 Dollars)	[redacted]	[redacted]
Total (Escalated Dollars)	[redacted]	[redacted]

Note 1: Not subject to ITCC on contribution. ITCC is exempt for wholesale generators that meet the IRS Safe Harbor Provisions. PG&E currently does not require the Interconnection Customer to provide security to cover the potential tax liability on the Interconnection Facilities, Distribution Upgrades, and Network Upgrades per the IRS Safe Harbor Provisions (IRS Notice 88-129). PG&E reserves the right to require the Interconnection Customer to provide such security, in a form reasonably acceptable to PG&E as indicated in Article 12 of the SGIA, an amount up to the cost consequences of any current tax liability. Upon request and within sixty (60) Calendar Days' notice, the Interconnection Customer shall provide PG&E such ITCC security or ITCC payment in the event that Safe Harbor Provisions have not been met, in the form requested by PG&E.

7.2 Interconnection Facilities

Table 7-2: Escalated Cost and Time to Construct for Interconnection Facilities - IF

Type of Upgrade	Upgrade	Description	Cost Allocation Factor	Estimated Cost x 1,000	Escalated Costs x 1,000	Estimated Time (Months) to Construct (Note 1)
PTO's Interconnection Facilities ***(Note 2)***		•				
		•				
		•				
			Total	**$xx**	**$xx**	

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

The estimated time to construct forms the basis for escalated costs. The escalation factors to convert the Estimated cost (in 2023 dollars) to the operating year is found in the published per unit table in CAISO website http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx.

Note 2: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

7.3 Network Upgrade

Tables 7-3, 7-4 and 7-5 are the ANUs for this project which are comprised of IRNU-A, GRNU, LDNU, and LOPNU.

7.3.1 Reliability Network Upgrades - RNU

Table 7-3: Escalated Cost and Time to Construct for Reliability Network Upgrades

Type of Upgrade	Upgrade Classification (GRNU, IRNU)	Upgrade	Description	Cost Allocation Factor	Estimated Cost x 1,000	Escalated Costs x 1,000	Estimated Time (Months) to Construct (Note 1)
Reliability Network Upgrade			•				
			•				
			•				
				Total	**$xx**	**$xx**	

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

The estimated time to construct forms the basis for escalated costs. The escalation factors to convert the Estimated cost (in 2023 dollars) to the operating year is found in the published per unit table in CAISO website http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx.

Note 2: The Interconnection Customer will be reimbursed for a portion of the upgrades cost as per the Tariff GIDAP Section 14.3.2.1

7.3.2 Local Delivery Network Upgrades – LDNU

Table 7-4: Escalated Cost and Time to Construct for Local Delivery Network Upgrades

Type of Upgrade	Upgrade	Description	Cost Allocation Factor	Estimated Cost x 1,000	Escalated Costs x 1,000	Estimated Time (Months) to Construct (Note 1)
Local Delivery Network Upgrade		•				
		•				
		•				
			Total	$xx	$xx	

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility assuming an estimated construction start date is December 18, 2024. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

The estimated time to construct forms the basis for escalated costs. The escalation factors to convert the Estimated cost (in 2023 dollars) to the operating year is found in the published per unit table in CAISO website http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx.

Note 2: The Interconnection Customer will be reimbursed for the upgrades cost as per the Tariff GIDAP Section 14.3.2.1

7.3.3 Local Off-Peak Network Upgrades – LOPNU

Table 7-5: Escalated Cost and Time to Construct for Local Off-Peak Network Upgrades

Type of Upgrade	Upgrade	Description	Cost Allocation Factor	Estimated Cost x 1,000	Escalated Costs x 1,000	Estimated Time (Months) to Construct (Note 1)
Local Off-Peak Network Upgrade		•				
		•				
		•				
			Total	$xx	$xx	

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility assuming an estimated construction start date is December 18, 2024. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

The estimated time to construct forms the basis for escalated costs. The escalation factors to convert the Estimated cost (in 2023 dollars) to the operating year is found in the published per unit table in CAISO website http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx.

Note 2: The Interconnection Customer will be reimbursed for the upgrades cost as per the Tariff GIDAP Section 14.3.2.1

7.3.4 Area Delivery Constraints – ADC

Please refer to Appendix I to the area report for details.

7.3.5 Conditionally Assigned Network Upgrades and Potential Changes in Cost Responsibility

Table 7-6 shows CANUs that are the responsibility of Pre-Cluster projects but could impact the IC's Cost Responsibility. The IC is not required to post Interconnection Financial Security for these CANUs, however the obligation to finance and construct these CANUs shall be included in the IC's Maximum Cost Exposure.

Table 7-6: Escalated Cost and Time to Construct for Conditionally Assigned Network Upgrades

Type of Upgrade	Upgrade Classification	Upgrade	Description	Cost Allocation Factor	Estimated Cost x 1,000	Escalated Costs x 1,000	Estimated Time (Months) to Construct (Note 1)
CANUs			•				
			•				
			•				
			•				

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

7.3.6 Precursor Network Upgrades (PNU)

Table 7-7 shows PNUs and their in-service dates. The project depends on these upgrades to receive ISD and or FCDS.

Table 7-7: Precursor Network Upgrades (PNU) and Estimated in-Service Date

Triggering Queue/Process	Upgrade Classification	Dependent System Upgrade	Project Type	Estimated In-Service Date

Note 1: The Estimated Time to Construct is the schedule for the PTO to complete only the construction activities for the specified facility. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

7.3.7 Cost Responsibility Breakdown

Table 7-8 shows the Current Cost Responsibility (CCR), Maximum Cost Responsibility (MCR) and Maximum Cost Exposure (MCE) for the project.

Table 7-8: Cost Responsibility Breakdown

<ProjectName>	**<Qxxxx>**
Deliverability Option	A
A. Phase II ANU Cost Allocation for Current Cost Responsibility (CCR)	
A.1 GRNU Cost ($k)	$ -
A.2 LDNU Cost ($k)	$ -
A.3 LOPNU Cost ($k)	$ -
A.4 IRNU Cost ($k)	$ -
Phase II ANU Cost Allocation for CCR ($k) (A = A.1 + A.2 + A.3+A.4)	$ -
B. Phase II ANU Cost Allocation for Maximum Cost Responsibility (MCR)	
B.1 GRNU Cost ($k)	$ -
B.2 LDNU Cost ($k)	$ -
B.3 LOPNU Cost ($k)	$ -
B.4 IRNU Cost ($k)	$ -
Phase II ANU Cost Allocation for MCR ($k) (B = B.1 + B.2 + B.3+B.4)	$ -
C. Phase II CANU Cost Allocation	
C.1 CANU - GRNU ($k)	$ -
C.2 CANU - LDNU ($k)	$ -
C.3 CANU - LOPNU ($k)	$ -
C.3 CANU - IRNU ($k)	$ -
Phase II CANU Cost Allocation ($k) (C = C.1 + C.2 + C.3)	$ -
D. MCR from Phase I	
D.1 Phase I CCR for ANU ($k)	$ -
D.2 Phase I CANU Cost for Upgrades Becoming ANU in Phase II ($k)	$ -
Phase I MCR ($k) (D = D.1 + D.2)	$ -
E. Maximum Cost Responsibility ($k) (E = min{B, D})	**$**
F. Current Cost Responsibility ($k) (F = min{A, E})	**$**
G. Maximum Cost Exposure ($k) (G = C + E)	**$**
H. Project ADNU Cost Responsibility ($k)	**$**

8. Subsynchronous Interaction Evaluation

Certain generators or inverter-based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Subsynchronous Interaction (SI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter-based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 230 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study may need to be performed to evaluate the SI between generating facilities and the transmission system, prior to initial synchronization. The study will require that the IC provide a detailed PSCAD model of its Large Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any potential SI issues and potential mitigation(s) that will be required prior to initial synchronization of the Large Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter-based generators that are compatible with the series compensation in the area.

9. PG&E Technical Requirements

Refer to Section 9 of the Cluster 14 Phase II PG&E <Area> Interconnection Area Study Report

10. Environmental Evaluation / Permitting Requirements

Refer to Section 12 of the Cluster 14 Phase II PG&E <Area> Interconnection Area Study Report

11. Items Not Covered in this Report

Refer to Section 12 of the PG&E <Area> Interconnection Area Study Report for the list of items that are not covered in this study.

12. Definitions

ADNU	Area Delivery Network Upgrade
ANU	Assigned Network Upgrade
BES	Bulk Electric System
CAISO	California Independent System Operator Corporation
CANU	Conditionally Assigned Network Upgrade
CCR	Current Cost Responsibility
CCSF	City and County of San Francisco
CDWR	California Department of Water Resources
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EO	Energy-Only Deliverability Status
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
GIP	Generator Interconnection Procedures
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
GRNU	General Reliability Network Upgrade
IC	Interconnection Customer
IID	Imperial Irrigation District
IRNU	Interconnection Reliability Network Upgrade
LDNU	Local Delivery Network Upgrade in ANU category
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
LMUD	Lassen Municipal Utility District
LOPNU	Local off-peak Network Upgrade
MeID	Merced Irrigation District
MCE	Maximum Cost Exposure
MCR	Maximum Cost Responsibility
MID	Modesto Irrigation District
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment:
PG&E	Pacific Gas and Electric Company
PMax	Maximum generation output
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
PNU	Precursor Network Upgrade
POI	Point of Interconnection
POS	Plan of Service
PSREC	Plumas Sierra Rural Electric Cooperative
RNU	Reliability Network Upgrade except ISRNU in ANU category
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
SPS	Special Protection System (also known as RAS)
SVC	Static VAr Compensator
SVP	Silicon Valley Power
TANC	Transmission Agency of Northern California
TID	Turlock Irrigation District

TPP	CAISO's Transmission Planning Process
TPD	Transmission Plan Deliverability - Deliverability supported by the CAISO's Transmission Plan
WAPA	Western Area Power Administration
WDT	Wholesale Distribution Tariff
WECC	Western Electricity Coordinating Council