January 26, 2023

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER23-___-000

Tariff Amendment to Implement Interconnection Process Enhancements

Dear Secretary Bose:

The California Independent System Operator Corporation ("CAISO") submits this tariff amendment to improve its generator interconnection process.[1] This amendment represents tariff revisions resulting from the CAISO's most recent Interconnection Process Enhancements ("IPE") stakeholder initiative. The CAISO's proposed amendment comprises two distinct sets of substantive tariff revisions and some minor clarifications to existing policy. First, the CAISO proposes to elucidate the power purchase agreement requirements to qualify for higher priority in the transmission plan deliverability allocation process. These requirements will help ensure the CAISO first allocates deliverability to those projects most likely to secure financing and reach commercial operation. Second, the CAISO proposes to memorialize the study and reimbursement rules when the CAISO is an affected system. The CAISO proposes to use the same rules for network upgrades as an affected system as it does for internal interconnections. This will keep affected system rules simple and fair.

The CAISO notes that each set of revisions is separate and not dependent on the other, from both a substantive and an implementation perspective. The CAISO has filed them together because they were part of the same stakeholder process, because they represent enhancements to the generator interconnection process, and because a single filing promotes administrative efficiency. The CAISO requests an effective date of March 28, 2023, 61 days from this filing.

[1] The CAISO submits this filing pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff, and references to specific sections, articles, and appendices are references to sections, articles, and appendices in the current CAISO tariff and revised or proposed in this filing, unless otherwise indicated.

I. The Interconnection Process Enhancement Initiative History

California's renewable portfolio standard[2] and the changes in the capacity market have made it increasingly important for the CAISO to identify ways to administer its generator interconnection queue more efficiently. The CAISO's overriding goal has been to tailor its procedures for efficiency and equity. Because of the rapid evolution of generation development in California, achieving these goals has required the CAISO to engage in a process of continuous enhancement of its generator interconnection procedures.[3] After implementing significant generator interconnection reforms in 2008,[4] 2010,[5] and 2012,[6] the CAISO launched its first IPE initiative in 2013. The 2013 IPE initiative resulted in interconnection enhancements to the CAISO tariff, business practice manuals, and procedures in 2013 and 2014.[7] The CAISO conducted another IPE initiative in 2015 that resulted in two more sets of enhancements.[8] In 2017 the CAISO conducted an expedited IPE initiative to implement two minor but critical sets of enhancements.[9] In 2018 the CAISO conducted another IPE initiative to examine interconnection procedures comprehensively. That effort resulted in numerous enhancements divided among four filings, all approved by the Commission in 2019.[10]

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2 *See* California Public Utilities Commission, "Renewables Portfolio Standard (RPS) Program," *available at* https://www.cpuc.ca.gov/rps.

3 The generator interconnection process and related provisions are set forth primarily in section 25 and Appendix DD of the CAISO tariff. The interconnection procedures and *pro forma* generator interconnection agreements ("GIAs") are generally contained in appendices S through FF to the CAISO tariff.

4 *California Independent System Operator Corp.*, 124 FERC ¶ 61,292 (2008) (approving revisions to move from a serial to a cluster process, and to establish project viability and developer commitment as soon as interconnection customers have an estimate of the costs of their projects).

5 *California Independent System Operator Corp.*, 133 FERC ¶ 61,223 (2010) (approving revisions to harmonize the CAISO's Large Generator Interconnection Procedures ("LGIP") with its Small Generator Interconnection Procedures ("SGIP") by establishing integrated cluster study processes for small and large generators, and to expedite study processes for independent or otherwise adroit generators by implementing new independent study and fast track processes).

6 *California Independent System Operator Corp.*, 140 FERC ¶ 61,070 (2012) (approving revisions to integrate the transmission planning and generator interconnection processes).

7 *See, e.g., California Independent System Operator Corp.*, 149 FERC ¶ 61,231 (2014); *California Independent System Operator Corp.,* 148 FERC ¶ 61,077 (2014); *California Independent System Operator Corp.,* 145 FERC ¶ 61,172 (2013).

8 *California Independent System Operator Corp*., 153 FERC ¶ 61,242 (2015); 154 FERC ¶ 61,169 (2016).

9 *California Independent System Operator Corp.*, 162 FERC ¶ 61,207 (2018) (extending the deliverability parking period and reconfiguring the interconnection request window to allow more time for corrections).

10 *California Independent System Operator Corp.*, 166 FERC ¶ 61,113 (2019); *California Independent System Operator Corp.*, 168 FERC ¶ 61,003 (2019); *California Independent System*

Faced with a 141 percent increase in interconnection requests in 2021, the CAISO conducted an expedited stakeholder initiative to address the cluster 14 "supercluster." The Commission approved the CAISO's proposed reforms, which gave the CAISO and transmission owners the time to study cluster 14 while providing interconnection customers more flexibility while in queue.[11] Shortly after that effort, the CAISO launched the 2021 IPE initiative to implement fundamental reforms for cluster 14 and beyond. On August 31, 2022, the Commission approved the CAISO's Phase 1 filing, consisting of 12 distinct sets of tariff revisions.[12] The CAISO also completed a separate initiative to examine interconnection data access comprehensively.[13] These proposed tariff revisions are the result of the Phase 2 of the 2021 IPE initiative.

II. Proposed Tariff Revisions

A. Deliverability Allocation Process

1. Background

An interconnection request includes many components: the point of interconnection, sufficient transmission capacity to deliver power reliably, construction of necessary network upgrades by the transmission owner, etc. Among these components, interconnection customers request a deliverability designation: Full Capacity Deliverability Status ("FCDS"), Partial Capacity Deliverability Status[14] ("PCDS"), or Energy Only. Interconnection customers may be awarded their requested FCDS or PCDS status only to the extent that deliverability is available, and thus clarity in the CAISO's rules for deliverability allocation priority is critical to developers. Deliverability refers to "the capability, measured in MW, of the CAISO Controlled Grid as modified by transmission upgrades and additions modeled or identified in the annual Transmission Plan to support the interconnection with FCDS or PCDS of additional

Operator Corp., Letter Order, Docket No. ER19-1013-000 (April 1, 2019); *California Independent System Operator Corp.*, Letter Order, ER19-2679-000 (Oct. 18, 2019).

11 *California Independent System Operator Corp.*, 176 FERC ¶ 61,207 (2021).

12 *California Independent System Operator Corp.*, 180 FERC ¶ 61,243 (2022).

13 Developers will be able to access more data and customized reports. Because packaging and providing the data was already consistent with the CAISO's tariff provisions, no tariff amendment was required.

14 Partial Capacity Deliverability Status entitles a generating facility to a Net Qualifying Capacity amount that cannot be larger than a specified fraction of its Qualifying Capacity and may be less pursuant to the assessment of its Net Qualifying Capacity by the CAISO. An Interconnection Customer requesting Partial Capacity Deliverability Status must specify the fraction of Full Capacity Deliverability Status it is seeking in its Interconnection Request.

Generating Facilities in a specified geographic or electrical area of the CAISO Controlled Grid."[15]

Being designated FCDS or PCDS represents that the grid can deliver the generator's maximum capacity (or partial capacity for PCDS) to the grid under peak load conditions.[16] An Energy Only designation represents that the generator's full output can be delivered only subject to grid conditions.[17] These designations play a key role in providing Resource Adequacy Capacity in California. An FCDS or PCDS designation qualifies the generator's output to count toward a load-serving entity's monthly Resource Adequacy requirement.[18] Only FCDS or PCDS generators will be assigned the financing costs for Delivery Network Upgrades, which are upgrades designed to relieve transmission constraints so the resource can physically deliver its designated output.[19] An Energy Only designation means that the interconnection customer will not be responsible for the costs of such upgrades, but it will be ineligible to be a Resource Adequacy Resource under current rules.[20]

An interconnection customer's ability to receive an FCDS or PCDS deliverability designation depends on the CAISO's Transmission Plan Deliverability ("TP Deliverability" or "Deliverability") studies. The CAISO transmission planning process identifies network upgrades based on the location and the amount of new resources

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[15] Appendix A to the CAISO tariff.

[16] *California Independent System Operator Corp.*, 124 FERC ¶ 61,292 at PP 94-112 (2008) ("For generators selecting full capacity deliverability, the maximum output of each facility can be delivered under peak conditions. Deliverability assessment(s) will be performed to determine the need for delivery network upgrades. The costs for delivery network upgrades will be assigned based on the flow impact of each generating facility on the CAISO controlled grid. In addition, an analysis for reliability impacts will be done to determine the need for reliability network upgrades"). Deliverability designations are slightly different for wind resources because their "maximum capacity" is not necessarily commensurate with their nameplate capacity (minus auxiliary load), like it is for most generators. In any case, being designated FCDS or PCDS is not a guarantee that such a generator's energy will be delivered. All generators—regardless of designation—are subject to security-constrained economic dispatch and curtailment by the CAISO.

[17] *Id*. at P 95.

[18] Importantly, an FCDS designation does not entitle a generator to "firm capacity" or transmission priority to deliver energy to the grid. All generators are subject to congestion management, the CAISO's security-constrained economic dispatch and potential curtailment conditions. In other words, an FCDS designation has no bearing on a generator's market awards or dispatch, only its eligibility to provide resource adequacy capacity.

[19] *See* Appendix A to the CAISO tariff. Delivery Network Upgrades are different than Reliability Network Upgrades, which are the transmission facilities a generator needs to interconnect safely and reliably to the grid, regardless of its deliverability designation.

[20] Appendix A to the CAISO tariff. A Resource Adequacy Resource is "A resource that is designated in a Supply Plan to provide Resource Adequacy Capacity. The criteria for determining the types of resources that are eligible to provide Qualifying Capacity may be established by the CPUC or other applicable Local Regulatory Authority and provided to the CAISO."

anticipated to be ultimately developed in discrete geographic areas. These network upgrades will add a certain amount of transmission capacity to the grid, which will then be available to meet the deliverability requirements of proposed new generating facilities in those geographic areas.[21] The CAISO then determines the volume of new generation in each area whose deliverability can be met by the additional grid capacity the network upgrades will provide. The CAISO allocates the resulting MW volumes of deliverability to those proposed generating facilities in each area determined to be most viable based on a set of specified project development milestones.[22]

The CAISO allocates deliverability to interconnection customers in the following order:

(A) To interconnection customers that have executed power purchase agreements and to interconnection customers in the current Queue Cluster that are Load Serving Entities serving their own Load.[23]

(B) To interconnection customers that are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement.

(C) To interconnection customers that have achieved Commercial Operation for the capacity seeking TP Deliverability.

(D) To interconnection customers electing to be subject to Section 8.9.2.3.[24]

The CAISO first awards deliverability to interconnection customers described in group (A). If additional deliverability is available, the CAISO will allocate the remaining to group (B), and so on. An interconnection customer in the groups above that receives a deliverability allocation will be assigned the delivery network upgrades necessary for its generating units to achieve Full Capacity Deliverability Status or Partial Capacity Deliverability Status to be eligible to provide resource adequacy capacity.

Once an interconnection customer has a deliverability allocation, it must continue to progress commercially to retain the allocation. Shortlisted interconnection customers

[21] *See California Independent System Operator Corp.*, Tariff Amendment to Integrate Transmission Planning and Generator Interconnection Procedures, Docket No. ER12-1855-000 (May 25, 2012) at p. 4.

[22] *Id*.

[23] "Load serving entities serving their own Load" refers to utilities acting as both load-serving entities and generation developers. This carve-out has always been CAISO policy to avoid utilities needing to execute agreements with themselves or petition the Commission for waiver to meet CAISO requirements.

[24] Section 8.9.2 of Appendix DD to the CAISO tariff.

must execute a power purchase agreement, and interconnection customers not shortlisted must become so and then execute a power purchase agreement.[25]

The CAISO does not propose to change its allocation or retention requirements. In recent years, however, there has been some confusion regarding what types of commercial arrangements with new generators constitute "power purchase agreements" such that they should qualify for deliverability. Where developers traditionally contracted with load-serving entities for virtually everything the generator provided for decades, developers now face a slew of part and parcel requests for offers from a diverse array of parties. Some of these contracts may be only for energy, others for resource adequacy capacity, and others still for renewable energy credits. Large commercial customers may want to develop renewable energy for corporate or even philanthropic purposes. Other entities may need some generator services in their portfolio but want to re-sell the products they do not need to entities that do. The CAISO and stakeholders thus believe it is necessary to clarify which types of arrangements should qualify for deliverability allocations.

2. Proposed Tariff Revisions

Beginning with new deliverability allocations this Fall,[26] the CAISO proposes to clarify that for an interconnection customer representing it has, is negotiating, or is shortlisted for a power purchase agreement, the agreement must meet certain term and counterparty criteria. First, either the agreement must have a term of no less than five years, or the customer must have multiple agreements whose combined terms are no less than five years.[27] Although developers sometimes may enter into short-term contracts for resource adequacy capacity or renewable energy credits, there was no evidence in the IPE initiative that these contracts would secure the necessary long-term financing necessary for greenfield generation projects or expansions.[28] Load-serving entities and the California Public Utilities Commission noted that contracts for unbuilt generation are for ten years, and five years was a reasonable compromise with developers advocating for no-term or short-term requirements. A five-year term also

[25] Section 8.9.3 of Appendix DD to the CAISO tariff.

[26] Pursuant to the filed rate doctrine, interconnection customers that received and retained deliverability allocations before the 2023-2024 cycle are not subject to the minimum term or counterparty requirements for those allocations, including under Section 6.7.4 and Section 8.9 of Appendix DD to the CAISO tariff. If they re-seek TP Deliverability for any reason during or after the 2023-2024 cycle, they would be subject to these requirements in seeking a new allocation or retaining a new allocation. The CAISO proposes to memorialize this clarification in Section 8.9.2 of Appendix DD to the CAISO tariff.

[27] Proposed Section 8.9.2 of Appendix DD to the CAISO tariff.

[28] Short-term contracts generally go to generation that is already online.

aligns with the CAISO's tariff provisions to reimburse network upgrades within five years of achieving commercial operation.[29]

Second, the CAISO proposes to impose counterparty criteria on power purchase agreements to qualify for deliverability. The counterparty must be a load-serving entity procuring the capacity to meet its own resource adequacy obligation, or the counterparty must demonstrate that it has a contract to provide the capacity for at least one year to a load-serving entity for its resource adequacy obligations.[30] This requirement ties deliverability back to the public policy purpose of the delivery network upgrades that create deliverability: ensuring resource adequacy. The one-year term requirement will help ensure the contract is legitimate and the developer has not contracted to provide resource adequacy for only a month merely to meet the tariff requirements to receive deliverability.

Although interconnection customers provide the initial financing for local delivery network upgrades and approved project sponsors for area delivery network upgrades, both parties eventually receive reimbursement, and the ultimate costs go to ratepayers through transmission rates. The CAISO believes interconnection customers must demonstrate that their deliverability allocations will allow load-serving entities to meet their resource adequacy obligations. Any stranded deliverability would result in load-serving entities' being unable to meet their obligations—jeopardizing reliability—or overbuilding transmission capacity to provide more deliverability than actually needed. Either result would negatively impact ratepayers. However, the CAISO recognizes that the current commercial realities may result in some lag between contracting for new generation and finding an offtaker for the resource adequacy capacity. Large industrial customers or corporate entities may need everything from a generator *except* the resource adequacy capacity. It is beneficial to reliability and ratepayers that these customers be able to contract for new generation, receive deliverability allocations, and then provide the resource adequacy capacity to a load-serving entity that needs it. An interconnection customer with an offtaker for energy and capacity—even if it does not yet have a resource adequacy capacity offtaker—generally is commercially viable, and its odds of eventually selling the resource adequacy are high.[31]

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29 Article 11.4.1.1 of Appendix EE to the CAISO tariff.

30 Alternatively, the interconnection customer, rather than the counterparty, could have a separate agreement to meet this obligation.

31 This is not the case when a developer does not have a real counterparty and merely contracts with itself or an affiliate to appear as if it has a power purchase agreement to receive deliverability and then later market itself to actual offtakers. The CAISO has, and will continue, to reject such contracts as shams merely designed to circumvent the CAISO's filed rate. Any developer could enter into such an "agreement," thereby defeating the purpose of having different deliverability allocation groups in the first place.

As such, the CAISO proposes to allow interconnection customers to apply initially for deliverability allocations under Groups (A) and (B) if they meet the tariff criteria *except* the counterparty criterion.[32] In other words, they have secured or been shortlisted for a long-term power purchase agreement, but the counterparty is not a load-serving entity meeting a resource adequacy obligation. However, to ensure the deliverability does not end up stranded, within thirty (30) days of receiving a deliverability allocation, the interconnection customer must demonstrate it meets the counterparty criterion or it must provide a deposit of $10,000 per MW of allocated deliverability, but never less than $500,000.[33] The CAISO will refund the deposit when the generator begins commercial operation or meets the counterparty criterion, whichever is earlier. To the extent the Interconnection Customer withdraws, is deemed withdrawn, converts to Energy Only, or otherwise downsizes or eliminates the capacity allocated deliverability, the deposit or commensurate portion thereof will be non-refundable, and the CAISO will process it and any accrued interest with similarly forfeited funds.[34]

Ultimately, the intent of the deliverability allocation process is to allocate deliverability first to projects most likely to provide the deliverable energy to the grid. Deliverability is finite: the amount is based on the delivery network upgrades designed to meet procurement portfolios provided by local regulatory authorities. When interconnection customers receive deliverability but cannot secure financing and withdraw, the CAISO must re-allocate the deliverability, and the grid goes without that deliverable generation until a successful project comes online. The CAISO believes that its proposed revisions provide developers with two paths to demonstrate their viability and receive deliverability priority while still ensuring ratepayers receive the benefit of their bargain. An interconnection customer can either sell its bundled services to a load-serving entity, or it can sell its capacity to another corporate entity, and then the interconnection customer or the initial offtaker can sell the resource adequacy capacity to a load-serving entity that needs it.[35] The CAISO's proposed deposit requirement for interconnection customers that take the latter path helps incentivize them to find an offtaker for the resource adequacy capacity as soon as possible and protects ratepayers from the risk the deliverability is hoarded in queue by an interconnection customer that ultimately withdraws. If that situation occurs, the forfeited

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32 Proposed Section 8.9.2 of Appendix DD to the CAISO tariff.

33 The CAISO will deposit these funds in an interest-bearing account at a bank or financial institution designated by the CAISO. The CAISO did not propose a deposit cap to avoid large customers tying up significant amounts of deliverability. The CAISO and stakeholders believe the deposit floor is necessary to ensure the deposit is meaningful for every interconnection customer, and to avoid small generating facilities' tying up deliverability.

34 *Id*. (incorporating Section 7.6 of Appendix DD to the CAISO tariff by reference).

35 These arrangements are beginning to occur in California already.

funds would offset still-needed network upgrade costs or transmission revenue requirements.[36]

The CAISO's proposed tariff provisions are just and reasonable. They allow developers to contract with the various counterparties in the various arrangements proliferating in California today while helping the CAISO to ensure that deliverability goes first to those interconnection customers most likely to get it to the grid without disadvantaging ratepayers.

B. CAISO as Affected System

1. Background

In the last decade, there have been virtually no instances where a generator's interconnection to a neighboring balancing authority area would affect the reliability of the CAISO grid. In interconnection terms, the CAISO is rarely an "affected system." However, recently the CAISO has received a few notices from neighboring transmission providers that a proposed interconnection to their system may affect the CAISO, and therefore warrants study. The CAISO developed a study process and agreement for such studies early in 2022,[37] but it deferred memorializing what base case transmission providers would use to conduct such studies, or how interconnection customers would finance any required network upgrades on the CAISO system.[38] Some stakeholders advocated for interconnection customers to finance CAISO network upgrades on a merchant basis, while other stakeholders advocated to treat CAISO network upgrades the same regardless of whether they were triggered externally or internally.

2. Proposed Tariff Revisions

First, the CAISO proposes that the CAISO and affected participating transmission owner will use the base case effective upon execution of the CAISO's affected system study agreement, essentially the beginning of when an external interconnection customer engages with the CAISO.[39] Using this base case will allow the transmission owner to begin reliability studies as soon as practical without the need to wait for the base case to evolve based on the CAISO's current cluster studies.

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36 *See* Section 7.6 of Appendix DD to the CAISO tariff.

37 *California Independent System Operator Corp.*, 178 FERC ¶ 61,223 (2022).

38 Had a project needed such rules before now, the parties would have executed a non-conforming agreement and filed it with the Commission; however, as usual, there were no such cases.

39 Proposed Section 14.5 of Appendix DD to the CAISO tariff. The CAISO updates its base case throughout the year based on the completion of the interconnection cluster study phases and the transmission planning process.

Second, the CAISO proposes that external interconnection customers will be eligible for repayment of amounts advanced for network upgrades consistent with the CAISO's rules of internal interconnection customers.[40] This means that external interconnection customers can finance any network upgrades internal to the CAISO needed to maintain reliability, and the transmission owner will reimburse them in cash within five years of commercial operation, then include those costs in its transmission revenue requirement.

The CAISO believes its proposal to use its existing policy to reimburse the costs for network upgrades on the CAISO grid when the CAISO is an affected system is just and reasonable and does not plan to revert to merchant financing. The CAISO believes Commission precedent is clear that "network upgrades represent improvements to the integrated transmission system and [their] benefits to the transmission system are considered independent from any benefits customers may receive as a result of generation that interconnects to the system."[41] As such, the network upgrade costs should be included in the relevant transmission revenue requirement, similar to any other upgrade.

Some stakeholders advocated for the CAISO to forego its existing reimbursement policy for affected system upgrades because the CAISO's affected systems do not offer reimbursement to interconnection customers interconnecting within the CAISO. Although neighboring transmission providers may require CAISO interconnection customers to finance network upgrades without cash reimbursement, they also require their own internal interconnection customers to finance network upgrades without cash reimbursement. In other words, neighboring utilities are not discriminating against affected system upgrades; they are simply applying their own policy consistently for all network upgrades, regardless of cause, just as the CAISO proposes to do here. The CAISO's proposed policy also ensures network upgrades are rightsized to mitigate the specific impact and removes any incentive to use affected system mitigation to replace or defer other upgrades for the utility's benefit and at the developer's expense.

The CAISO's proposed tariff provisions are just and reasonable. They provide straightforward, clear rules based on existing interconnection procedures. If the CAISO ever needs the affected system process, CAISO transmission owners should be able to study the interconnection expeditiously and fairly because the study process mirrors internal interconnection study procedures. The CAISO, transmission owners, and

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40 Proposed Sections 14.4 and 14.5.1 of Appendix DD to the CAISO tariff (incorporating Section 14.3.2.1 by reference). The changes to 14.4 remove the prior language that deferred each potential reimbursement question until the instant policy became effective. The CAISO also proposes to incorporate and summarize the reimbursement provisions in Article 2.7 of the study agreement, Article 2.7 of Appendix B.23 to the CAISO tariff. This includes any portion ineligible for cash reimbursement, consistent with Section 14.3.2 of Appendix DD to the CAISO tariff.

41 *California Independent System Operator Corp.*, 160 FERC ¶ 61,047 at P 34 (2017).

stakeholders also can monitor this process and make improvements if they gain experience with it in the CAISO.

C. Tariff Clarifications

The CAISO also proposes two minor tariff revisions to clarify interconnection policy. First, the CAISO proposes to remove requirements that interconnection customers provide evidence that their power purchase agreements have received regulatory approval to comply with the CAISO's commercial viability criteria or to extend their commercial operation dates to align with power purchase agreements.[42] The CAISO already removed this requirement for normal deliverability retention because it is unnecessary and can result in administrative confusion due to the proliferation of new load-serving entities and new regulatory authorities and processes.[43] The CAISO proposes to remove it from the other processes for the same reasons and to align the deliverability retention criteria.

Second, the CAISO proposes to remove impractical and confusing language regarding Cluster 14 interconnection study timelines. The tariff states that "Interconnection Customers must post their second Interconnection Financial Security no later than the earlier of (1) ninety (90) days after the publication of the Phase II Interconnection Study or (2) May 4, 2024."[44] The CAISO proposes to remove the first clause so the deadline is simply May 4, 2024.[45] The CAISO already removed a similar clause for the initial financial security deadline because the CAISO realized it was not possible to have all the study results meetings quickly enough for interconnection customers to have the same amount of time to decide whether to post security and proceed in queue.[46] The CAISO proposes to make the same revisions for the second financial security posting deadline for the same reasons and to simplify the administration of the deadline for interconnection customers. Doing so will ensure all interconnection customers in Cluster 14 have sufficient time to review their study results, have study results meetings with CAISO and transmission owner engineers, and determine whether to post their second financial security to progress in queue.

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[42] Proposed Sections 6.7.4 and 6.7.5 of Appendix DD to the CAISO tariff. The commercial viability criteria is a separate set of deliverability retention criteria for interconnection customers seeking to extend their commercial operation dates beyond seven years from their interconnection request.

[43] *California Independent System Operator Corp.*, 180 FERC ¶ 61,243 at PP 6, 39 (2022).

[44] Section 16.1 of Appendix DD to the CAISO tariff.

[45] Proposed Section 16.1 of Appendix DD to the CAISO tariff.

[46] *California Independent System Operator Corp*., Tariff Revisions, Docket No. ER22-2956-000 (Sep. 29, 2022), approved by Letter Order (Nov. 21, 2022).

III. Stakeholder Process

The instant tariff revisions resulted from a long and robust stakeholder process with significant participation from developers, utilities, regulators, and industry participants. All materials and calls are available on the CAISO website.[47] The proposals were presented to the CAISO Governing Board during its public meeting on October 25, 2022. The Board voted unanimously to authorize this filing.[48]

IV. Effective Date

The CAISO requests an effective date of March 28, 2023, 61 days from this filing.

V. Communications

In accordance to Rule 203(b)(3) to the Commission's Rules of Practice and Procedure,[49] the CAISO respectfully requests that correspondence and other communications regarding this filing should be directed to:

William H. Weaver
  Assistant General Counsel
Sarah Kozal
  Counsel
California Independent System
  Operator Corporation
250 Outcropping Way
Folsom, CA 95630
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VI. Service

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of this filing on the CAISO website.

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47 https://stakeholdercenter.caiso.com/StakeholderInitiatives/Interconnection-process-enhancements-2021.

48 Materials related to the Board's authorization to prepare and submit this filing are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. The Memoranda provided to the Board is provided in attachment D to this filing.

49 18 C.F.R. § 385.203(b)(3).

VII. Contents of Filing

Besides this transmittal letter, this filing includes these attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment;
Attachment B	Red-lined document showing the revisions in this tariff amendment;
Attachment C	Final policy paper on this tariff amendment; and
Attachment D	Board memoranda.

VIII. Conclusion

For the reasons in this filing, the CAISO respectfully requests that the Commission accept the tariff revisions proposed in the filing effective March 28, 2023.

Respectfully submitted,

/s/ William H. Weaver
Roger E. Collanton
General Counsel
William H. Weaver
Assistant General Counsel
Sarah E. Kozal
Counsel

Counsel for the California Independent System Operator Corporation

Attachment A – Clean Tariff

Tariff Amendment – Interconnection Process Enhancements – Phase 2

California Independent System Operator Corporation

January 26, 2023

Appendix DD

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6.7.4 Commercial Viability Criteria for Retention of Deliverability beyond Seven Years in Queue

The CAISO's agreement to modifications requested by the Interconnection Customer pursuant to Section 6.7.2.3 for a Generating Facility with a Commercial Operation Date that has exceeded or will exceed seven (7) years from the date the Interconnection Request is received by the CAISO with retention of TP Deliverability will be predicated upon the Interconnection Customer's ability to meet and maintain the following commercial viability criteria:

a) Providing proof of having, at a minimum, applied for the necessary governmental permits or authorizations, and that the permitting authority has deemed such documentation as data adequate for the authority to initiate its review process;

b) Providing proof of having an executed power purchase agreement. Power purchase agreements must have the point of interconnection, capacity, fuel type, technology, and site location in common with the Interconnection Customer and GIA;

c) Demonstrating Site Exclusivity for 100% of the property necessary to construct the facility through the Commercial Operation Date requested in the modification request. A Site Exclusivity Deposit does not satisfy this criterion;

d) Having an executed Generator Interconnection Agreement ("GIA"); and

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

Interconnection Customers that satisfied these commercial viability criteria before November 27, 2018 on the basis of balance-sheet or binding financing may continue to do so in their annual review. The CAISO's agreement to an extension of the proposed Commercial Operation Date does not relieve the Interconnection Customer from compliance with the requirements of any of the criteria in Section 8.9.3 to retain TP Deliverability. The CAISO will not consider the addition of energy storage; changes to the type, number, or manufacturer of inverters; or insubstantial changes to the Generating Facility as modifications under this Section. Interconnection Customers may request such modifications pursuant to this GIDAP.

If the Interconnection Customer fails to meet all of the commercial viability criteria but informs the CAISO that it intends to proceed with the modified Commercial Operation Date, the Generating Facility's Deliverability Status will become Energy Only Deliverability Status. Interconnection Customers that become Energy Only for failure to meet these criteria may not reduce their cost responsibility or Interconnection Financial Security for any assigned Delivery Network Upgrades as a result of converting to Energy Only unless the CAISO and Participating TO(s) determine that the Interconnection Customer's assigned Delivery Network Upgrade(s) is no longer needed for current Interconnection Customers.

If an Interconnection Customer satisfies all the commercial viability criteria except criterion (b), the CAISO will postpone converting the Generating Facility to Energy-Only Deliverability Status for one year from the day the Interconnection Customer submits the modification request, or eight years after the CAISO received the Interconnection Request, whichever occurs later. Interconnection Customers exercising this provision must continue to meet all other commercial viability criteria.

If an Interconnection Customer has declared Commercial Operation for a portion of a Generating Facility, or one or more Phases of a Phased Generating Facility, the CAISO will not convert to Energy-Only the portion of the Generating Facility that is in service and operating in the CAISO markets. Instead, the portion of the Generating Facility that has not been developed will be converted to Energy-Only Deliverability Status, resulting in Partial Capacity Deliverability Status for the Generating Facility. However, where the Generating Facility has multiple Resource IDs for the Generating Facility, each Resource ID will have its own Deliverability Status independent from the Generating Facility. Any individual Resource ID may have Full Capacity Deliverability Status where the Generating Facility as a whole would have Partial Capacity Deliverability Status. If the Generating Facility downsizes to the amount in service and operating in the CAISO markets, it will revert to Full Capacity Deliverability Status.

Interconnection Customers in Queue Cluster 7 and beyond whose Phase II Interconnection Study reports require a timeline beyond the seven-year threshold are exempt from the commercial viability criteria in this section provided that they modify their Commercial Operation Dates within six (6) months of the CAISO's publishing the Phase II Interconnection Study report. This exemption is inapplicable to report addenda or revisions required by a request from an Interconnection Customer for any reason.

6.7.4.1 Annual Review

For Interconnection Customers extending their Commercial Operation Date beyond the seven-year threshold and retaining their TP Deliverability pursuant to Section 6.7.4, the CAISO will perform an annual review of commercial viability. If any Interconnection Customer fails to maintain its level of commercial viability, the Deliverability Status of the Generating Facility corresponding to the Interconnection Request will convert to Energy-Only Deliverability Status.

6.7.5 Alignment with Power Purchase Agreements

An Interconnection Customer with an executed GIA and an executed power purchase agreement may request to automatically extend the GIA Commercial Operation Date to align with its power purchase agreement for that Generating Facility, including any extension or amendment. Interconnection Customers requesting alignment must (1) provide a copy of the power purchase agreement, and (2) confirm the power purchase agreement's standing and details in the annual TP Deliverability affidavit process. Requests to align the Commercial Operation Date with power purchase agreements are not exempt from the commercial viability criteria provisions in Section 6.7.4, where applicable.

* * * * *

8.9.2 Second Component: Allocating TP Deliverability

Following the process set forth in Section 8.9.1, the CAISO will allocate any remaining TP Deliverability in the following order.

The CAISO shall allocate available TP Deliverability to all or a portion of the full MW capacity of the Generating Facility as specified in the Interconnection Request. Where a criterion is met by a portion of the full MW generating capacity of the Generating Facility, the eligibility score associated with that criterion shall apply to the portion that meets the criterion. The demonstration must relate to the same proposed Generating Facility as described in the Interconnection Request.

(A) To Interconnection Customers that have executed power purchase agreements, and to Interconnection Customers in the current Queue Cluster that are Load Serving Entities serving their own Load.

(B) To Interconnection Customers that are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement.

(C) To Interconnection Customers that have achieved Commercial Operation for the capacity seeking TP Deliverability.

(D) To Interconnection Customers electing to be subject to Section 8.9.2.3.

Energy Only capacity seeking TP Deliverability may not trigger the construction of Delivery Network Upgrades pursuant to Section 6.3.2. This includes, without limitation, capacity expansions effected through modification requests and capacity converted to Energy Only after failing to receive or retain a TP Deliverability allocation. The CAISO will allocate TP Deliverability to Energy Only Interconnection Customers requesting Deliverability after FCDS and PCDS Interconnection Customers within its allocation group and solely based on TP Deliverability available from existing transmission facilities, from already planned upgrades in the CAISO Transmission Planning Process, or upgrades assigned to an interconnection project that has an executed GIA and currently has a TP Deliverability allocation.

Interconnection Customers requesting Deliverability for Energy Only capacity must submit to the CAISO a $60,000 study deposit for each Interconnection Request seeking TP Deliverability. The CAISO will deposit these funds in an interest-bearing account at a bank or financial institution designated by the CAISO. The funds will be applied to pay for prudent costs incurred by the CAISO, the Participating TO(s), and/or third parties at the direction of the CAISO or applicable Participating TO(s), as applicable, to perform and administer the TP Deliverability studies for the Energy Only Interconnection Customers. Any and all costs of the Energy Only TP Deliverability study will be borne by the Interconnection Customer. The CAISO will coordinate the study with the Participating TO(s). The Participating TO(s) will invoice the CAISO for any work within seventy-five (75) calendar days of completion of the study, and, within thirty (30) days thereafter, the CAISO will issue an invoice or refund to the Interconnection Customer, as applicable, based upon such submitted Participating TO invoices and the CAISO's own costs for the study. If the actual costs of the study are greater than the deposit provided by the Interconnection Customer, the Interconnection Customer will pay the balance within thirty (30) days of being invoiced.

Beginning with new awards in the 2023-2024 TP Deliverability allocation cycle, for an Interconnection Customer seeking to receive or retain TP Deliverability to represent that it has, is negotiating, or is shortlisted for a power purchase agreement under this GIDAP, the agreement must meet the following criteria:

(1) the agreement has a term of no less than five (5) years. Interconnection Customers with multiple, short-term agreements for the same capacity may meet this criterion where the combined terms are five (5) years or more; and

(2) the counterparty must:

(a) be a Load Serving Entity procuring the capacity to meet its own Resource Adequacy obligation; or
(b) demonstrate it has a contract to provide the capacity for at least one (1) year to a Load Serving Entity for a Resource Adequacy obligation.

Interconnection Customers may seek a TP Deliverability allocation under Groups A or B if they meet all tariff criteria except the counterparty criterion (2); however, within thirty (30) days of receiving a TP Deliverability allocation, they must demonstrate they meet the counterparty criterion or provide a deposit of $10,000 per MW of allocated TP Deliverability, but in no case less than $500,000. The CAISO will deposit these funds in an interest-bearing account at a bank or financial institution designated by the CAISO. The CAISO will refund the deposit when the Generating Facility begins Commercial Operation or meets the counterparty criterion, whichever is earlier. To the extent the Interconnection Customer withdraws, is deemed withdrawn, converts to Energy Only, or otherwise downsizes or eliminates the capacity allocated TP Deliverability, the deposit or commensurate portion thereof will be non-refundable, and the CAISO will process it and any accrued interest pursuant to Section 7.6.

Interconnection Customers that received and retained TP Deliverability allocations before the 2023-2024 cycle are not subject to the minimum term or counterparty requirements for those allocations, including under Section 6.7.4 and this Section 8.9. If they re-seek TP Deliverability for any reason during or after the 2023-2024 cycle, they would be subject to these requirements in seeking a new allocation or retaining a new allocation.

For all TP Deliverability allocations based upon having, negotiating, or being shortlisted for power purchase agreements, the CAISO will allocate TP Deliverability up to the amount of deliverable MW capacity procured by the power purchase agreement. All Load Serving Entities building Generating Facilities to serve their own Load must be doing so to fulfill a regulatory requirement that warrants Deliverability. Load Serving Entities acting as Interconnection Customers are otherwise eligible for all other attestations.

Notwithstanding any other provision, all refunds pursuant to this Appendix DD will be processed in accordance with the CAISO's generally accepted accounting practices, including monthly batched deposit refund disbursements. Any CAISO deadline will be tolled to the extent the Interconnection Customer has not provided the CAISO with the appropriate documents to facilitate the Interconnection Customer's refund, or if the Interconnection Customer has any outstanding invoice balance due to the CAISO on another project owned by the same Interconnection Customer.

* * * * *

14.4 Special Provisions for Affected Systems, Other Affected PTOs

The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected Participating TO(s), as applicable. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected Participating TO(s). If the affected entity is another Participating TO, the initial form of agreement will be the GIA, as appropriately modified.

* * * * *

14.5 CAISO as an Affected System

An interconnection customer in Balancing Authority Areas that may affect the reliability of the CAISO Controlled Grid will execute the CAISO as an Affected System Study Agreement, Appendix B.23 to the CAISO Tariff, to allow the CAISO and affected Participating TO(s) to study the impact of the interconnection. The agreement will specify the terms governing the study. In performing the study, the CAISO and Participating TO will use the Base Case effective upon execution of the Affected System Study Agreement.

14.5.1 Cost Allocation and Interconnection Financial Security

Affected system studies will list separate cost estimates for facilities and Network Upgrades required in the CAISO Balancing Authority Area. These separate sums may be adjusted over time based on actual costs incurred. The interconnection customer will post financial security with the impacted Participating TO(s) for facilities and Network Upgrades. The interconnection customer will be eligible for repayment of amounts advanced for Network Upgrades consistent with Section 14.3.2.1 for Interconnection Customers in Queue Cluster 6 and later.

* * * * *

Section 16. Cluster 14 Unique Procedures

The CAISO tariff and the GIDAP will apply to Queue Cluster 14 with the following exceptions:

16.1 Study Procedures and Timelines

a) The CAISO will validate Cluster 14 Interconnection Requests by September 26, 2021. Interconnection Requests with deficiencies after that date will be deemed invalid and will not be included in Cluster 14.

b) GIDAP provisions stating when the CAISO and Participating TOs must initiate Interconnection Studies will not apply.

c) The CAISO will publish Phase I Interconnection Studies no later than September 15, 2022. The Phase I Interconnection Study will not include system-level stability analyses.

d) Interconnection Customers may submit, in writing, additional comments on the final Phase I Interconnection Study report up to (5) Business Days following the Results Meeting. Based on any discussion at the Results Meeting and any comments received, the CAISO (in consultation with the applicable Participating TO(s)) will determine, in accordance with Section 6.8, whether it is necessary to follow the final Phase I Interconnection Study report with a revised study report or an addendum. The CAISO will issue any such revised report or addendum to the Interconnection Customer no later than thirty (30) calendar days following the Results Meeting.

e) No later than the earlier of (1) ninety (90) days after the publication of the Phase I Interconnection Study or (2) January 13, 2023, Interconnection Customers must (1) submit an updated, valid dynamic model to the CAISO, and (2) post their initial Interconnection Financial Security.

f) The CAISO will publish Phase II Interconnection Studies no later than November 24, 2023.

g) Phase I and Phase II Interconnection Study Results meetings will occur with ninety (90) days of publication.

h) The CAISO will publish the results of the TP Deliverability allocation process no later than March 23, 2024.

i) Interconnection Customers must post their second Interconnection Financial Security no later than May 4, 2024.

j) Unless the CAISO issues a Market Notice stating otherwise, the CAISO will not open the Queue Cluster 15 Cluster Application Window in 2022. The CAISO will open the Queue Cluster 15 Cluster Application Window in 2023 pursuant to Section 3.3.

k) Deadlines related to Interconnection Customers that elect to park their Interconnection Requests will be extended consistent with this Section, including for Interconnection Financial Security postings.

(l) If an Interconnection Customer withdraws after posting its initial Interconnection Financial Security but before demonstrating Site Exclusivity, its Site Exclusivity Deposit will not be refunded, and will be processed with non-refundable funds described in Section 7.6.

(m) On or before their initial Interconnection Financial Security posting, Interconnection Customers proposing to use third-party Interconnection Facilities must provide documentation to the CAISO demonstrating they are negotiating or have secured rights on those Interconnection Facilities. On or before their second Interconnection Financial Security posting, such Interconnection Customers must provide documentation to the CAISO demonstrating they have secured rights on those Interconnection Facilities through their Commercial Operation Date.

The CAISO and Participating TOs will use Reasonable Efforts to meet all deadlines in the GIDAP and this Section 16, and may publish study results early or otherwise accelerate the interconnection process where possible. The CAISO will publish Interconnection Studies simultaneously for all the Participating TOs.

* * * * *

Appendix B.23

CAISO AS AN AFFECTED SYSTEM STUDY AGREEMENT (CASSA)

* * * * *

2.6 Network Upgrades Agreement. If the CAISO determines that network upgrades are required to mitigate the Generation Project Owner's interconnection, the Parties will negotiate and enter into a separate agreement that sets forth the provisions for the construction timeline and estimated costs provisions for those network upgrades. A modified version of Appendix EE to the CAISO Tariff ("LGIA") will serve as the template for this separate agreement.

2.7 Repayment of Network Upgrades. The interconnection customer will be eligible for repayment of amounts advanced for Network Upgrades consistent with Section 14.3.2 for Interconnection Customers in Queue Cluster 6 and later. To the extent that such repayment does not cover all of the costs of Generation Project Owner's Network Upgrades, the Generation Project Owner will be eligible to receive Merchant Transmission Congestion Revenue Rights in accordance with CAISO Tariff Section 36.11 associated with those Network Upgrades, or portions thereof that were funded by the Generation Project Owner. The Participating TO will own and operate the Network Upgrades regardless of repayment eligibility.

* * * * *

Attachment B – Marked Tariff

Tariff Amendment – Interconnection Process Enhancements – Phase 2

California Independent System Operator Corporation

January 26, 2023

Appendix DD

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6.7.4 Commercial Viability Criteria for Retention of Deliverability beyond Seven Years in Queue

The CAISO's agreement to modifications requested by the Interconnection Customer pursuant to Section 6.7.2.3 for a Generating Facility with a Commercial Operation Date that has exceeded or will exceed seven (7) years from the date the Interconnection Request is received by the CAISO with retention of TP Deliverability will be predicated upon the Interconnection Customer's ability to meet and maintain the following commercial viability criteria:

a) Providing proof of having, at a minimum, applied for the necessary governmental permits or authorizations, and that the permitting authority has deemed such documentation as data adequate for the authority to initiate its review process;

b) Providing proof of having an executed ~~and regulator-approved~~ power purchase agreement. Power purchase agreements must have the point of interconnection, capacity, fuel type, technology, and site location in common with the Interconnection Customer and GIA;

c) Demonstrating Site Exclusivity for 100% of the property necessary to construct the facility through the Commercial Operation Date requested in the modification request. A Site Exclusivity Deposit does not satisfy this criterion;

d) Having an executed Generator Interconnection Agreement ("GIA"); and

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

Interconnection Customers that satisfied these commercial viability criteria before November 27, 2018 on the basis of balance-sheet or binding financing may continue to do so in their annual review. The CAISO's agreement to an extension of the proposed Commercial Operation Date does not relieve the Interconnection Customer from compliance with the requirements of any of the criteria in Section 8.9.3 to retain TP Deliverability. The CAISO will not consider the addition of energy storage; changes to the type, number, or manufacturer of inverters; or insubstantial changes to the Generating Facility as modifications under this Section. Interconnection Customers may request such modifications pursuant to this GIDAP.

If the Interconnection Customer fails to meet all of the commercial viability criteria but informs the CAISO that it intends to proceed with the modified Commercial Operation Date, the Generating Facility's Deliverability Status will become Energy Only Deliverability Status. Interconnection Customers that become Energy Only for failure to meet these criteria may not reduce their cost responsibility or Interconnection Financial Security for any assigned Delivery Network Upgrades as a result of converting to Energy Only unless the CAISO and Participating TO(s) determine that the Interconnection Customer's assigned Delivery Network Upgrade(s) is no longer needed for current Interconnection Customers.

If an Interconnection Customer satisfies all the commercial viability criteria except criterion (b), the CAISO will postpone converting the Generating Facility to Energy-Only Deliverability Status for one year from the day the Interconnection Customer submits the modification request, or eight years after the CAISO received the Interconnection Request, whichever occurs later. Interconnection Customers exercising this provision must continue to meet all other commercial viability criteria.

If an Interconnection Customer has declared Commercial Operation for a portion of a Generating Facility, or one or more Phases of a Phased Generating Facility, the CAISO will not convert to Energy-Only the portion of the Generating Facility that is in service and operating in the CAISO markets. Instead, the portion of the Generating Facility that has not been developed will be converted to Energy-Only Deliverability Status, resulting in Partial Capacity Deliverability Status for the Generating Facility. However, where the Generating Facility has multiple Resource IDs for the Generating Facility, each Resource ID will have its own Deliverability Status independent from the Generating Facility. Any individual Resource ID may have Full Capacity Deliverability Status where the Generating Facility as a whole would have Partial Capacity Deliverability Status. If the Generating Facility downsizes to the amount in service and operating in the CAISO markets, it will revert to Full Capacity Deliverability Status.

Interconnection Customers in Queue Cluster 7 and beyond whose Phase II Interconnection Study reports require a timeline beyond the seven-year threshold are exempt from the commercial viability criteria in this section provided that they modify their Commercial Operation Dates within six (6) months of the CAISO's publishing the Phase II Interconnection Study report. This exemption is inapplicable to report addenda or revisions required by a request from an Interconnection Customer for any reason.

6.7.4.1 Annual Review

For Interconnection Customers extending their Commercial Operation Date beyond the seven-year threshold and retaining their TP Deliverability pursuant to Section 6.7.4, the CAISO will perform an annual review of commercial viability. If any Interconnection Customer fails to maintain its level of commercial viability, the Deliverability Status of the Generating Facility corresponding to the Interconnection Request will convert to Energy-Only Deliverability Status.

6.7.5 Alignment with Power Purchase Agreements

An Interconnection Customer with an executed GIA and an executed~~, regulator-approved~~ power purchase agreement may request to automatically extend the GIA Commercial Operation Date to align with its power purchase agreement for that Generating Facility, including any extension or amendment. Interconnection Customers requesting alignment must (1) provide a copy of the power purchase agreement~~ and evidence of regulatory approval~~, and (2) confirm the power purchase agreement's standing and details in the annual TP Deliverability affidavit process. Requests to align the Commercial Operation Date with power purchase agreements are not exempt from the commercial viability criteria provisions in Section 6.7.4, where applicable.

* * * * *

8.9.2 Second Component: Allocating TP Deliverability

Following the process set forth in Section 8.9.1, the CAISO will allocate any remaining TP Deliverability in the following order.

The CAISO shall allocate available TP Deliverability to all or a portion of the full MW capacity of the Generating Facility as specified in the Interconnection Request. Where a criterion is met by a portion of the full MW generating capacity of the Generating Facility, the eligibility score associated with that criterion shall apply to the portion that meets the criterion. The demonstration must relate to the same proposed Generating Facility as described in the Interconnection Request.

(A) To Interconnection Customers that have executed power purchase agreements~~.~~, and to Interconnection Customers in the current Queue Cluster that are Load Serving Entities serving their own Load.

(B) To Interconnection Customers that are actively negotiating a power purchase agreement or on an active short list to receive a power purchase agreement.

(C) To Interconnection Customers that have achieved Commercial Operation for the capacity seeking TP Deliverability.

(D) To Interconnection Customers electing to be subject to Section 8.9.2.3.

Energy Only capacity seeking TP Deliverability may not trigger the construction of Delivery Network Upgrades pursuant to Section 6.3.2. This includes, without limitation, capacity expansions effected through modification requests and capacity converted to Energy Only after failing to receive or retain a TP Deliverability allocation. The CAISO will allocate TP Deliverability to Energy Only Interconnection Customers requesting Deliverability after FCDS and PCDS Interconnection Customers within its allocation group and solely based on TP Deliverability available from existing transmission facilities, from already planned upgrades in the CAISO Transmission Planning Process, or upgrades assigned to an interconnection project that has an executed GIA and currently has a TP Deliverability allocation.

Interconnection Customers requesting Deliverability for Energy Only capacity must submit to the CAISO a $60,000 study deposit for each Interconnection Request seeking TP Deliverability. The CAISO will deposit these funds in an interest-bearing account at a bank or financial institution designated by the CAISO. The funds will be applied to pay for prudent costs incurred by the CAISO, the Participating TO(s), and/or third parties at the direction of the CAISO or applicable Participating TO(s), as applicable, to perform and administer the TP Deliverability studies for the Energy Only Interconnection Customers. Any and all costs of the Energy Only TP Deliverability study will be borne by the Interconnection Customer. The CAISO will coordinate the study with the Participating TO(s). The Participating TO(s) will invoice the CAISO for any work within seventy-five (75) calendar days of completion of the study, and, within thirty (30) days thereafter, the CAISO will issue an invoice or refund to the Interconnection Customer, as applicable, based upon such submitted Participating TO invoices and the CAISO's own costs for the study. If the actual costs of the study are greater than the deposit provided by the Interconnection Customer, the Interconnection Customer will pay the balance within thirty (30) days of being invoiced.

~~All power purchase agreements in this Section 8.9 must require Deliverability for the~~Beginning with new awards in the 2023-2024 TP Deliverability allocation cycle, for an Interconnection Customer seeking to receive or retain TP Deliverability to represent that it has, is negotiating, or is shortlisted for a power purchase agreement under this GIDAP, the agreement must meet the following criteria:~~.~~

(1) the agreement has a term of no less than five (5) years. Interconnection Customers with multiple, short-term agreements for the same capacity may meet this criterion where the combined terms are five (5) years or more; and

(2) the counterparty must:

(a) be a Load Serving Entity procuring the capacity to meet its own Resource Adequacy obligation; or

(b) demonstrate it has a contract to provide the capacity for at least one (1) year to a Load Serving Entity for a Resource Adequacy obligation.

Interconnection Customers may seek a TP Deliverability allocation under Groups A or B if they meet all tariff criteria except the counterparty criterion (2); however, within thirty (30) days of receiving a TP Deliverability allocation, they must demonstrate they meet the counterparty criterion or provide a deposit of $10,000 per MW of allocated TP Deliverability, but in no case less than $500,000. The CAISO will deposit these funds in an interest-bearing account at a bank or financial institution designated by the CAISO. The CAISO will refund the deposit when the Generating Facility begins Commercial Operation or meets the counterparty criterion, whichever is earlier. To the extent the Interconnection Customer withdraws, is deemed withdrawn, converts to Energy Only, or otherwise downsizes or eliminates the capacity allocated TP Deliverability, the deposit or commensurate portion thereof will be non-refundable, and the CAISO will process it and any accrued interest pursuant to Section 7.6.

Interconnection Customers that received and retained TP Deliverability allocations before the 2023-2024 cycle are not subject to the minimum term or counterparty requirements for those allocations, including under Section 6.7.4 and this Section 8.9. If they re-seek TP Deliverability for any reason during or after the 2023-2024 cycle, they would be subject to these requirements in seeking a new allocation or retaining a new allocation.

For all TP Deliverability allocations based upon having, negotiating, or being shortlisted for power purchase agreements, the CAISO will allocate TP Deliverability up to the amount of deliverable MW capacity procured by the power purchase agreement. All Load Serving Entities building Generating Facilities to serve their own Load must be doing so to fulfill a regulatory requirement that warrants Deliverability. Load Serving Entities acting as Interconnection Customers are otherwise eligible for all other attestations.

Notwithstanding any other provision, all refunds pursuant to this Appendix DD will be processed in accordance with the CAISO's generally accepted accounting practices, including monthly batched deposit refund disbursements. Any CAISO deadline will be tolled to the extent the Interconnection Customer has not provided the CAISO with the appropriate documents to facilitate the Interconnection Customer's refund, or if the Interconnection Customer has any outstanding invoice balance due to the CAISO on another project owned by the same Interconnection Customer.

* * * * *

14.4 Special Provisions for Affected Systems, Other Affected PTOs

The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected Participating TO(s), as applicable. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected Participating TO(s) ~~as well as the repayment by the owner of the Affected System and/or other affected Participating TO(s)~~. If the affected entity is another Participating TO, the initial form of agreement will be the GIA, as appropriately modified.

~~Any repayment by the owner of the Affected System shall be in accordance with FERC Order No. 2003-B (109 FERC ¶ 61,287).~~

* * * * *

14.5 CAISO as an Affected System

An interconnection customer in Balancing Authority Areas that may affect the reliability of the CAISO Controlled Grid will execute the CAISO as an Affected System Study Agreement, Appendix B.23 to the CAISO Tariff, to allow the CAISO and affected Participating TO(s) to study the impact of the interconnection. The agreement will specify the terms governing the study. <u>In performing the study, the CAISO and Participating TO will use the Base Case effective upon execution of the Affected System Study Agreement.</u>

14.5.1 Cost Allocation and Interconnection Financial Security

Affected system studies will list separate cost estimates for facilities and Network Upgrades required in the CAISO Balancing Authority Area. These separate sums may be adjusted over time based on actual costs incurred. The interconnection customer will post financial security with the impacted Participating TO(s) for facilities and Network Upgrades. <u>The interconnection customer will be eligible for repayment of amounts advanced for Network Upgrades consistent with Section 14.3.2.1 for Interconnection Customers in Queue Cluster 6 and later.</u>

* * * * *

Section 16. Cluster 14 Unique Procedures

The CAISO tariff and the GIDAP will apply to Queue Cluster 14 with the following exceptions:

16.1 Study Procedures and Timelines

a) The CAISO will validate Cluster 14 Interconnection Requests by September 26, 2021. Interconnection Requests with deficiencies after that date will be deemed invalid and will not be included in Cluster 14.

b) GIDAP provisions stating when the CAISO and Participating TOs must initiate Interconnection Studies will not apply.

c) The CAISO will publish Phase I Interconnection Studies no later than September 15, 2022. The Phase I Interconnection Study will not include system-level stability analyses.

d) Interconnection Customers may submit, in writing, additional comments on the final Phase I Interconnection Study report up to (5) Business Days following the Results Meeting. Based on any discussion at the Results Meeting and any comments received, the CAISO (in consultation with the applicable Participating TO(s)) will determine, in accordance with Section 6.8, whether it is necessary to follow the final Phase I Interconnection Study report with a revised study report or an addendum. The CAISO will issue any such revised report or addendum to the Interconnection Customer no later than thirty (30) calendar days following the Results Meeting.

e) No later than the earlier of (1) ninety (90) days after the publication of the Phase I Interconnection Study or (2) January 13, 2023, Interconnection Customers must (1) submit an updated, valid dynamic model to the CAISO, and (2) post their initial Interconnection Financial Security.

f) The CAISO will publish Phase II Interconnection Studies no later than November 24, 2023.

g) Phase I and Phase II Interconnection Study Results meetings will occur with ninety (90) days of publication.

h) The CAISO will publish the results of the TP Deliverability allocation process no later than March 23, 2024.

i) Interconnection Customers must post their second Interconnection Financial Security no later than ~~the earlier of (1) ninety (90) days after the publication of the Phase II Interconnection Study or (2)~~ May 4, 2024.

j) Unless the CAISO issues a Market Notice stating otherwise, the CAISO will not open the Queue Cluster 15 Cluster Application Window in 2022. The CAISO will open the Queue Cluster 15 Cluster Application Window in 2023 pursuant to Section 3.3.

k) Deadlines related to Interconnection Customers that elect to park their Interconnection Requests will be extended consistent with this Section, including for Interconnection Financial Security postings.

(l) If an Interconnection Customer withdraws after posting its initial Interconnection Financial Security but before demonstrating Site Exclusivity, its Site Exclusivity Deposit will not be refunded, and will be processed with non-refundable funds described in Section 7.6.

(m) On or before their initial Interconnection Financial Security posting, Interconnection Customers proposing to use third-party Interconnection Facilities must provide documentation to the CAISO demonstrating they are negotiating or have secured rights on those Interconnection Facilities. On or before their second Interconnection Financial Security posting, such Interconnection Customers must provide documentation to the CAISO demonstrating they have secured rights on those Interconnection Facilities through their Commercial Operation Date.

The CAISO and Participating TOs will use Reasonable Efforts to meet all deadlines in the GIDAP and this Section 16, and may publish study results early or otherwise accelerate the interconnection process where possible. The CAISO will publish Interconnection Studies simultaneously for all the Participating TOs.

* * * * *

Appendix B.23

CAISO AS AN AFFECTED SYSTEM STUDY AGREEMENT (CASSA)

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2.6 Network Upgrades Agreement. If the CAISO determines that network upgrades are required to mitigate the Generation Project Owner's interconnection, the Parties will negotiate and enter into a separate agreement that sets forth the provisions for the construction timeline and estimated costs provisions for those network upgrades. A modified version of Appendix EE to the CAISO Tariff ("LGIA") will serve as the template for this separate agreement.

2.7 Repayment of Network Upgrades. The interconnection customer will be eligible for repayment of amounts advanced for Network Upgrades consistent with Section 14.3.2 for Interconnection Customers in Queue Cluster 6 and later. To the extent that such repayment does not cover all of the costs of Generation Project Owner's Network Upgrades, the Generation Project Owner will be eligible to receive Merchant Transmission Congestion Revenue Rights in accordance with CAISO Tariff Section 36.11 associated with those Network Upgrades, or portions thereof that were funded by the Generation Project Owner. The Participating TO will own and operate the Network Upgrades regardless of repayment eligibility.

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Attachment C – Final Policy Papers

Tariff Amendment – Interconnection Process Enhancements – Phase 2

California Independent System Operator Corporation

January 26, 2023

Interconnection Process Enhancements 2021

Phase 2: Longer Term Enhancements
Final Proposal

September 13, 2022

Prepared by:
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Steve Rutty
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California Independent System Operator

Table of Contents

1 Introduction

This Phase 2 Final Proposal is the next step in the 2021 Interconnection Process Enhancements (IPE) Initiative, one aspect of the ISO's ongoing commitment to improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve.

The 2021 IPE initiative was launched at a particularly critical inflection point in resource development in California, and in the ISO footprint in particular, as current circumstances have led to a confluence of issues that need consideration in the ISO's interconnection processes, related transmission and resource planning occurring at the ISO and state agencies, the procurement activities of load serving entities, and state policy development. While the accelerating pace of needed resource development called for examination of opportunities for process improvement, the timing of this initiative was also heavily influenced by the circumstances of the April 2021 Cluster 14 interconnection application window.

During the Cluster 14 open window, the ISO received 373 interconnection requests, creating an overload of industry resources which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[1]. The supercluster initiative focused specifically on addressing the immediate timing issues associated with the unprecedented number of interconnection applications to ensure parties were well informed of the timing impacts and that an effective plan could be put in place to deal with the situation. In the supercluster initiative, the ISO committed to continue to discuss topics that were not resolved in the time available within that initiative that could affect the Cluster 14 supercluster Phase II processes[2]. In addition to the issues related to the broader need for reforms, both in the short term and longer term, the ISO also identified a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

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

[1] For more information on the Supercluster Interconnection Procedures initiative please refer to the initiative webpage at: [FinalProposal-SuperclusterInterconnectionProcedures.pdf (caiso.com)]
[2] The supercluster initiative needed to produce a filing to FERC quickly to receive a FERC order in a time frame that would allowed Cluster 14 to move forward as expeditiously as possible under a revised schedule.
[3] Phase 1 tariff amendment filing is available at http://www.caiso.com/Documents/Jun2-2022-TariffAmendment-InterconnectionProcessEnhancements-ER22-2018.pdf.

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

Another impact of the Cluster 14 supercluster was the recognition that the current GIDAP may need to be modified to be more adept at dealing with the current significant generation expansion and to better accommodate interconnecting significant amounts of new generation expeditiously to meet near-term reliability challenges. Phase 2 focuses on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities along with some additional issues that have arisen. It also addresses several residual issues that related to Phase 1 enhancements that were not fully resolved in the Phase 1 process. The ISO is targeting the ISO Board of Governors October 2022 meeting for approval of Phase 2.

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

2 Background

Meeting the challenges facing timely, effective, reliable and economic resource and transmission development over the next decade and beyond will require enhancements and improved coordination across all fronts, and progress on each front must be considered in the context of improvements occurring in other parallel paths as well.

The impact of the drive towards higher levels of year over year resource development cannot be overstated. The ISO's 2021-2022 transmission plan approved by the ISO Board of Governors in March, 2022 was based on resource portfolios developed through CPUC processes that are more than double the previous plan's forecast for additions. The draft forecast requirements to be used in the 2022-2023 cycle indicate potentially a four-fold increase in new resource requirements over the forecast relied upon in the approved 2020-2021 plan[4]. At the same time, the CPUC authorized more midterm procurement in its June 24, 2021 decision than last year's 10 year plan was based on, which was the largest single procurement authorization by the CPUC.[5] Responding to these signals and previously approved authorizations, the resource development industry submitted a record-setting number of new interconnections

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

requests in April 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[6] The 596 projects totaling 236,175 MW, 162,237 net MW at the Point of Interconnection (POI), currently in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates distractions and commandeers precious planning, engineering and project management resources from the ISO and Participating TOs. Developing interconnection proposals for 10 to 15 times the volume of resources needed in that time frame challenges the procurement activities being smoothly aligned with transmission planning and state policy needs (including for resource diversity) when procurement responsibility is spread over more than 40 load serving entities.

The ISO's interconnection queue and transmission planning process (TPP) has to this point been very successful in meeting emerging needs and challenges as it evolved over the last ten to fifteen years. However, the volume of requirements, pace of development, and intensity of competition clearly call for additional reforms to current processes designed around more measured pace of planning, procurement and resource development. A broader spectrum of reform considerations is needed than adjustments to any one process in isolation, and reforms and enhancements must be considered holistically. To aid the ISO in its own considerations, the ISO commissioned a review of other practices in the US, looking not only at other ISOs and RTOs but also other FERC-jurisdictional and non-jurisdictional organizations to explore other practices that may prove helpful. This review, conducted by Grid Strategies LLC,[7] was posted to the ISO website on December 13, 2021. Additionally, the ISO has reviewed FERC's more recent Notice of Proposed Rulemaking ("FERC NOPR"),[8] and notes the ISO's current processes already incorporate many of the reforms set out in this NOPR. While the ISO anticipates participating in the comment process, ISO staff have made an effort to align some existing proposals with those included in the FERC NOPR in cases where there may be direct overlap.[9]

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative therefore focused on the interconnection process and

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

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

[8] *Notice of Proposed Rulemaking: Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022).

[9] This is *not* to say that the ISO may conduct a stakeholder initiative to comply with any final rule FERC issues. The ISO generally does not do so because it can only make tariff revisions consistent with the final rule, and no other.

enhancements specifically, and other tracks of process improvement will proceed through other efforts.

Accordingly, the 2021 IPE initiative was established to discuss and address interconnection-related issues the ISO and stakeholders have identified given current circumstances, and to resolve concerns that have surfaced since the last IPE initiative in 2018.[10] The ISO proposes changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

This Phase 2 Final Proposal is intended to present proposed solutions that focus on long-term process enhancements based on comments received from stakeholders from the July 26th Draft Final Proposal.

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

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

The ISO's transmission planning process includes a framework for developing policy-driven transmission associated with state (and federal, although that has not yet been relevant) policy needs and direction. However, that policy direction in the transmission planning process is not coordinated with interconnection requests seeking to utilize that capacity as it is being developed, nor with the procurement activities of the large number of load serving entities now having procurement obligations. The ISO has proposed a number of measures relating to this overall objective in this initiative, including several measures approved in Phase 1 and continuing the discussion of others in this Phase 2 paper. The Phase 1 effort in this regard focused primarily on revisiting the deliverability allocation framework, and aspects of that have been carried

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

over for further review in Phase 2. Phase 2 discussions also touch on the consideration of how policy-driven transmission should be made available for allocation (Section 3.2).

There were two topics originally addressed in the 2021 IPE initiative moved to other more appropriate forums.

1. Coordination among the transmission planning process—and policy-driven transmission in particular—the interconnection process, and load serving entities' procurement processes. The ISO has concluded that this topic is more appropriately considered in the context of the ISO's transmission planning process where policy-driven transmission needs are coordinated with state input.
2. Consideration of a solicitation model for key location and constraints not addressed in portfolio development, where commercial interest is the primary driver. The ISO concluded this topic is more appropriate in a separate stakeholder process associated with the 2021-2022 Transmission Plan.

3.1 Transparency enhancements

- Background

  In the July 26th Draft Final Proposal the ISO proposed to make the following project information public to stakeholders, likely through RIMS – PUB similar to the existing Queue Report:

    - PTO study area and sub-area by cluster;
    - TPD allocation group and percentage allocation (or MW amount allocated) for the project. From this information stakeholders could deduce whether a project has a PPA;
    - Resource ID(s);
    - Status of suspension and parking (yes/no);
    - Phase data: Generation and fuel type, MW, hybrid or co-located, synchronization date and COMX or COD date.

  The remaining data items requested were not strongly supported by the responding stakeholders. However, if the Interconnection Customers would like the ISO to put together a list of developers to be posted on the ISO website, that is possible. At this time, the ISO believes posting this data does not require a tariff change, and once the reports are developed, the ISO will add them to the BPM including a description of the data fields. The ISO requested comments on this section.

- Stakeholder Feedback

The ISO receive comments from 13 stakeholders. AES, CESA, Cal Advocates, CalWEA, EDF-R, Hanwha Q Cells USA Corp., MRP, SEIA, and Vistra support the ISO's proposal. REV does not oppose the ISO's proposal. EDF-R requests that the ISO rush publishing of this data so that cluster 15 project can be better informed.

AES, CESA, LSA also encourages the ISO to further consider and implement as soon as possible the creation of a heat map or other data visualization tools to help Interconnection Customers identify viable POIs prior to entering the queue. It is AES's belief that until the ISO provides more information on the best places to interconnect, the ISO will continue to experience overheated interconnection queues. As discussed at the August 1st stakeholder meeting, the ISO is going to wait for the FERC NOPR process to provide additional information before agreeing to produce a heat map.

CalCCA wants the ISO to publicize the PPA status and MW, rather than require entities to deduce whether a project has a PPA from its TPD allocation group. The ISO took the route, as suggested by the CPUC, because the ISO does not have the PPA status of the projects. The only time the ISO knows the PPA status of a project is if it needs to meet commercial viability criteria, or retention of deliverability. That pool of projects does not encompass all of the projects in the queue. It is the CPUC that tracks that information and has it readily available on its website. The ISO is not in a position to provide this information.

CESA requests that the ISO produce site exclusivity documentation and status; project milestones; construction status; and Affected System status. CESA further states that it believes that there may be alternative means to make this information available, which would support smart and rational decision-making by Interconnection Customers in entering, proceeding through, or withdrawing from the queue, thereby addressing the ISO's intent of better managing the overheated interconnection queue. They note that if the information is too commercially sensitive to provide at an individual level, CESA recommends that the ISO provide these data categories in an aggregate form, perhaps by transmission planning or local areas. CESA pointed to the Phase 1 Revised Straw Proposal, where the ISO provided helpful site exclusivity information for the ISO system as a whole in making the case for site exclusivity as a pre-requisite to enter Phase II studies, however that data was determined manually as a one-off process with the Participating TOs that took weeks to determine the information. In this process, the ISO is striving to provide data that it has easily accessible to market participants and can be consistently produced.

With respect to CESA's request for project milestone information, there are generally 36 milestones in a GIA, which the ISO currently monitors manually from the project quarterly status reports. The construction status is also monitored manually based on the status reports. Again, this is not data that is easily accessible for the reporting function being discussed. The Affected System information, while currently accessible in RIMS would be very voluminous to report out on, and to date, all affected system issues have been resolved to allow the project to synchronize to the grid, and therefore, the ISO sees no benefit in producing this information.

LSA continues to urge the ISO to clean up and update the data in the queue, at least for projects currently active. For example, projects in the active queue are listed with CODs that have already passed, the fuel data should be standardized by column, and POI substation and other names should be standardized. Each of LSA's suggestions have merit but are a challenge to implement. As an example, the ISO cannot change a project's COD unilaterally; the project must submit a modification request to change the COD. While the ISO contacts these projects on a regular basis requesting them to submit the MMA, to date the ISO has not exercised the breach of contract mechanism to require them to submit an MMA, but the ISO may move in that direction to enforce GIAs.

LSA also proposes the ISO, to the extent possible, add all of the new information requested to the existing queue report and delete columns that are no longer needed – Interconnection Request Date, Application Status, Feasibility or Supplemental Review and Optional Study. The ISO's concern with deleting this information is that it is applicable for projects that are completed and withdrawn and the queue report is a report that was ordered by FERC for the ISO to publish monthly. The ISO intends to add items to the queue report where appropriate and only have additional reports if it makes sense to do so.

Vistra also requested the that the ISO update its existing Queue Report to include repowering requests, emergency fast track process, and Qualifying Facility Conversions. The Queue Report was specifically ordered by FERC to reflect the projects in the ISO's queue. The additional projects requested by Vistra are not part of the generator interconnection process and therefore do not belong in the queue report unless they do not meet the requirements of Section 25.1 of the ISO tariff. In that case, they would have to submit an interconnection request to make the changes identified, then they would enter the cluster process and be on the Queue Report.

- Final Proposal

  The ISO proposes to implement the Draft Final Proposal and make the following project information public to stakeholders, likely through RIMS – PUB similar to the existing Queue Report:

    - PTO study area and sub-area by cluster;

- TPD allocation group and percentage allocation (or MW amount allocated) for the project. From this information stakeholders could deduce whether a project has a PPA;
- Resource ID(s);
- Status of suspension and parking (yes/no);
- Phase data: Generation and fuel type, MW, hybrid or co-located, synchronization date and COMX or COD date.

The ISO believes posting this data does not require a tariff change, and once the report forms are developed, the ISO will add them to the BPM including a description of the data fields.

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

- Background

In the July 26, 2022, IPE Phase 2 Draft Final Proposal, section 3.2, the ISO proposed eligibility criteria for a power purchase agreement (PPA) to be eligible to seek an allocation of TPD. Also addressed was the proposed eligibility criteria for PPAs with a non-LSE to seek an allocation of TPD. A summary of the proposals for these two items in the Draft Final Proposal were:

1. Beginning with the 2023-2024 TPD allocation cycle and thereafter, a PPA must procure the deliverable capacity for a minimum of five years to be eligible. In other words, the minimum term will apply to allocation groups A and B, including the retention requirements for group B, and the retention requirements for group D.
2. To allow TPD be allocated to Interconnection Customers with PPAs with non-LSEs. These PPAs will be subject to the 5-year minimum term requirement. The non-LSE procurement entity must demonstrate at the time the seeking affidavit is due that it has a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year. If the non-LSE procurement entity cannot demonstrate such a contract it must provide a deposit in-lieu of a contract. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.

- Stakeholder Feedback

1. TPD item 1 – the minimum required term for an eligible PPA.

Fourteen stakeholders provided specific input on the PPA eligibility criteria. The following are summaries of stakeholder comments.

	Minimum Term				
Entity (Name)	**No Min Term**	**1 Year**	**3 Years**	**5 Years**	**10 Years**
AReM		1			
California Community Choice Association					1
California Energy Storage Alliance			1		
CPUC - Public Advocates Office				1	
California Wind Energy Association				1	
Calpine		1			
Direct Energy		1			
EDF-Renewables					
Golden State Clean Energy			1		
Intersect Power		1			
Large-scale Solar Association/ LSA		1			
Middle River Power				1	
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California				1	
Southern California Edison				1	
Vistra Corp.				1	
Sum of Comment Categories	**0**	**5**	**2**	**6**	**1**

- Stakeholder Comments Summarized

<u>**Do Not Support a minimum term of more than one-year (5 commenters)**</u>

AReM does not support any change to the requirement for a one-year PPA for new projects and state that the proposal is not needed and could result in unintended consequences.

Intersect Power stated “Contracting the RA attributes of a project does not mean the project is fully contracted” (which assumes the proposed term is only for the RA capacity). They contend that year ahead RA could come from greenfield projects and that assuming long-term contracts make a project more viable than short-term contracts is subjective. They state that the manner in which Interconnection Customers elect to structure their offtake contracts should not be dictated by the ISO and that the optimization of <u>contract tenor is a risk</u> management decision that should be left to the Interconnection Customer.

LSA opposes the ISO’s proposal for a minimum PPA term to qualify for TPD allocations that exceeds one year, stating the proposal fails to justify a five-year minimum PPA term, on the merits. Their comments focus on LSEs using short-term contracts (one month to a few years) relative to LSEs meeting short-term RA obligations. They state that revenue from RECs and energy can be relatively more significant, and those attributes can be contracted on a long-term basis to buttress short-term RA contracts and support project financeability and that long term contracts have greater risk in current environment of inflation and uncertainty. They recommend that if the ISO proceeds with the five-year minimum PPA requirement, the proposal should include an in-lieu deposit option where a project has secured a PPA of at least one year but less than an otherwise-applicable minimum term.

Calpine supports a minimum term of one year – in line with annual RA commitments. They state that upgrades to existing resources are smaller in size, frequently faster to market, less expensive than new builds and contracting for these upgrades takes many forms.

Direct Energy (NRG) would support a minimum one year term and that longer terms discriminate against legitimate projects with shorter term PPAs which do not require a long term PPA for financing. They state that the proposal would harm the ability of LSEs to meet their procurement needs.

Supports a 3-year minimum (2 commenters)

California Energy Storage Alliance urges for the ISO to return to the 3-year minimum contract term requirement, stating there are reasonable cases where short-term contracts are rational risk mitigation measures in the face of regulatory uncertainty about RA resource counting rules. They state the FERC NOPR 5-year minimum term as part of the commercial readiness demonstration has yet to receive comments, making the proposal potentially subject to change.

Golden State Clean Energy stated that a 3-year minimum term requirement would be reasonable given it is only needed to support the resource adequacy program, which is a short-term compliance regime of no more than 3 years. They do not agree with the assertion that new greenfield projects or project expansions require a contract of at least ten years. Their experience has shown that using a portfolio approach to contracting, including layering in short-term contracts, contracts for RECs and contracts for RA, renders a project viable for obtaining financing. They state that the focus on a long-term contract is outdated and should not be a threshold for how deliverability is allocated and retained and that setting a minimum term requirement for contracts to receive and retain TPD needlessly interferes with commercial negotiations and financing strategies.

Supports (7 commenters)

California Community Choice Association supported 10-year minimum and agree that 5-year is a reasonable compromise. Their members' experience is no entity has procured capacity from new greenfield projects or an expansion of an existing project for less than ten years and the proposal is consistent with CPUC's 2019 and 2021 procurement orders.

California Public Utilities Commission - Public Advocates Office supports a term of five or more years. They state that the term aligns with the ISO Tariff where Interconnection Customer investment in network upgrades is reimbursement over a five-year period.

California Wind Energy Association, Middle River Power, Six Cities, Southern California Edison and Vistra Corp generally support the Draft Final Proposal.

- **ISO Response to Stakeholder Comments**

The ISO maintains that it is imperative to require a minimum term for PPAs that align with LSE procurement practices and the requirements of the CPUC, which accounts for the majority of the LSE procurement requirements. The ISO must ensure that the TPD allocation process ensures the most viable and ready projects have an opportunity for an allocation before less viable and ready projects, and to ensure entities are seeking allocations in good faith, especially as the availability of deliverability decreases. The majority of new capacity procurement falls under mandates of the CPUC,[11] which require LSEs to enter into agreements with new resources for terms of at least ten years in duration. Six Cities, a group of non-CPUC jurisdictional LSEs supports the ISO's proposed term of five year. No LSE has stated that they procure capacity from new greenfield projects or an expansion of an existing project for less than ten years.

The ISO believes a longer term contract supports the use of the TPD as soon and fully as possible by allocating TPD to projects that are positioned to come online as soon as possible. Giving the highest TPD allocation priority to projects that have long term contracts in place, facilitating their expeditious progression into construction, accomplishes that. The ISO continues to maintain that the viability and readiness of projects with PPAs of terms less than five years are of a lesser readiness than those with PPAs with terms of five or more years. Any exceptions are rare. Moreover, providing allocations to less viable and ready projects on an equal footing as those with long term PPAs puts LSEs at a greater risk of not receiving an allocation. A condition that would hinder the ability of LSEs to bring new capacity online to meet their mandated timelines for new capacity and would put reliability of the ISO system at greater risk.

While comments for the FERC interconnection NOPR are not yet due, the NOPR proposes to include a commercial readiness framework that includes the establishment of the defined terms "Commercial Readiness Demonstration." One criterion of that framework is:

[11] Decision 21-06-035: Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF#page=50&zoom=100,96,703; Decision 19-11-016: Decision Requiring Electric System Reliability Procurement For 2021-2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

> "Executed contract (as opposed to term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale *is not less than five years*."[12]

This demonstrates that many transmission providers have already instituted PPA term requirements, and FERC agrees that a PPA for a minimum term 5 or more years demonstrates commercial readiness.

The ISO believes the merits of a five year PPA term are fully justified and the option proposed by LSA to include an in-lieu deposit alternative for projects that have secured a PPA of at least one year but less than an the required five year term is imprudent.

- Final Proposal for PPA eligibility remains unchanged from the proposal in the Draft Final Proposal.

  Beginning with the 2023-2024 TPD allocation cycle, any tariff deliverability requirement for a PPA will require a term of five or more years. In other words, the minimum term will apply to allocation groups A and B, including the retention requirements for group B, and the retention requirements for group D. Projects that received an allocation prior to the 2023-2024 TPD allocation cycle will not be subject to the new minimum term requirements at this time.

  Clarifications

  - The requirement that RA capacity be procured for a minimum term is intended for all projects to either obtain or retain deliverability in all allocation groups (except group C, which has no such requirements). The minimum term would be required for all projects seeking an allocation in group A, for all shortlisted projects seeking an allocation in group B, group B projects seeking to retain their allocation, and for group D projects seeking to retain their allocation through either the shortlist for a PPA or the executed PPA.
  - A number of sequential PPAs with a specific project where the sum of the terms of the individual contracts meets the minimum requirement would qualify.
  - The PPA requirements for the 2022-2023 allocation cycle will be the same as for the 2021-2022 allocation cycle.
  - The PPA requirements for the retention of an allocation received prior to the 2023-2024 TPD allocation cycle, for projects requesting a COD extension and

[12] *Notice of Proposed Rulemaking: Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) at P 129.

projects required to demonstrate Commercial Viability will be the same requirements that were in place when a project received its allocation of TPD.

2. **TPD item 2 – the ISO proposed requirements to allow TPD be allocated to Interconnection Customers with PPAs with non-LSEs.**

Thirteen stakeholders provided input on eligibility criteria for PPAs with non-LSEs. The following is a summary of stakeholder comments.

Entity (Name)	Supports	Comments for Different Approach	Comments on Deposit Amount
AEE and AEBG	1		
California Community Choice Association	1	Does to not support giving a non-LSE procuring entity extra time to secure a contract with an LSE with a RA compliance obligation.	
California Energy Storage Alliance	1		
CPUC - Public Advocates Office	1		
California Wind Energy Association	1		
Direct Energy,	1		
EDF-Renewables	1		Requests logic and empirical justification
Hanwha Q Cells USA	1		
Large-scale Solar Association/ LSA	1		Proposes a $5K/MW, w/$250K minimum and $1 million cap
Middle River Power, LLC	1		
Solar Energy Industries Association/SEIA	1		Deposit amount Needs to be adequately justified
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California	1	RA sale term should be 5 yrs, same as PPA term	
Vistra Corp.	1	Allow long-term RA contracts between counterparties, regardless of affiliation	
Sum of Comment Categories	13	3	3

ISO Response to Stakeholder Comments

The ISO believes that the extra time provided to the non-LSE offtaker to obtain a contract to sell the RA capacity to an LSE with an RA obligation is appropriate because this process is an additional step in the procurement process for a non-LSE. Projects working towards PPAs with LSEs with RA obligations and with non-LSEs offtakers should be on the same timeline for executing their PPAs in time to submit seeking allocation affidavits by the affidavit due date. The requirement for the non-LSE to complete the sale of the RA capacity could take time, particularly with projects that have longer lead-times to COD.

The ISO believes it is likely that contracting for the RA capacity from a project with a non-LSE long term PPA will resemble the contracting with existing generators versus new greenfield projects, which are often shorter term contracts in the one to three year range. It would not be appropriate to put a potential barrier on this contracting process by requiring a five year agreement, which could result in RA capacity failing to obtain an agreement and be left unused.

The deposit in-lieu of an RA contract amount was designed to create a sufficient incentive for the non-LSE to perform on the requirement to enter into an agreement with an LSE with an RA obligation as quickly as possible to help to ensure the RA capacity is utilized to support system reliability. The $500,000 minimum amount is needed to accomplish this for smaller projects. It is important not to establish a maximum amount, or cap, as an incentive against large amounts of TPD being tied up in projects that seek to essentially “buy” TPD capacity, which could result in significant amounts of TPD being unused for a significant period of time and unavailable to projects that could use it sooner. Furthermore, offtakers with RA obligations do not have to ability to buy TPD in a similar manner.

The ISO does not support allowing long-term RA contracts between counterparties, regardless of affiliation. The ISO is concerned about the risk that Interconnection Customers may offer illegitimate or sham PPAs to qualify for deliverability and then seek a legitimate PPA. The ISO clarifies that it views PPAs with affiliates (marketing houses, holding companies, etc.) as an attempt to circumvent tariff requirements.[13] The ISO has rejected and will continue to reject such PPAs and others it views as shams or workarounds to obtain deliverability.

- Final Proposal for PPAs with a non-LSE remains unchanged from the proposal in the Draft Final Proposal.

The ISO proposes to allow TPD be allocated to Interconnection Customers with PPAs with non-LSEs. These PPAs will be subject to the 5-year minimum term requirements described above. Non-LSE PPAs will also be subject to the following

[13] The exception being between LSEs with RA requirements and their generation affiliates (such as the IOUs).

requirements depending on which group the Interconnection Customer seeks to qualify for:

- Seeking an allocation in group A
    - The non-LSE procurement entity must demonstrate at the time the seeking affidavit is due that it has a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year.[14]
    - If the non-LSE procurement entity cannot demonstrate that it has a contract to sell the RA capacity to an LSE with a RA obligation for a term on at least one year, it must provide a deposit in-lieu of such a contract. The deposit would only be required if the project obtains an allocation of TPD. If the project receives an allocation, the deposit will be due within 30 days of the ISO notifying the Interconnection Customer that the project has received an allocation. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.
- Seeking an allocation in group B
    - Consistent with all projects receiving an allocation in group B, the Interconnection Customer must demonstrate by the next allocation retention affidavit due date that it has executed a PPA with a non-LSE offtaker that requires deliverability for a term or five or more years. Furthermore, the offtaker must demonstrate a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year, and if unable to do so, must provide a deposit in-lieu of such a contract. The deposit would be required by the retention affidavit due date. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.
- Retaining an allocation in group D
    - Consistent with all projects receiving an allocation in group D, the Interconnection Customer must demonstrate by the next allocation retention affidavit due date that it has executed a PPA or is shortlisted or actively negotiating a PPA with a non-LSE offtaker that requires deliverability for a term or five or more years. In the allocation retention cycle that a project demonstrates an executed PPA with a non-LSE, the offtaker must demonstrate a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year, and if unable to do so,

[14] The contracts must provide sufficient MW procurement and match technology; however, they do not have to be 1:1. For example, a non-LSE could execute PPAs with six 200 MW projects. If the non-LSE then had a contract with an LSE to supply 1,000 MW of RA, five of the non-LSE's six projects could immediately qualify for group A, and the other could qualify for group B.

must provide a deposit in-lieu of such a contract. The deposit would be required by the retention affidavit due date. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.

Deposits in-lieu of RA contracts will be held by the ISO and refunded to the entity providing the deposit after a demonstration of a contract to sell the RA capacity to an LSE with a RA obligation for a term on at least one year, or after the project achieves its COD. If the project withdraws without meeting these requirement,[15] the entire deposit will be non-refundable and will be processed with non-refundable interconnection financial security, as described in Appendix DD, Section 7.6 (to offset still-needed upgrades or transmission revenue requirements).

Clarification

Notwithstanding the requirements described above, all of the PPA requirements listed in Section 3.2, TPD item 1 – the minimum required term for an eligible PPA, apply to PPAs with non-LSEs. The qualifying PPA with non-LSE procurement entities must require deliverability for the portion of the project procured.

The ISO believes its proposal represents a workable paradigm for developers to execute PPAs with non-LSEs and obtain deliverability. The ISO's proposal provides off-takers with the opportunity to market the energy they have procured, while still protecting ratepayers from financing delivery network upgrades without receiving the benefit of their bargain. The ISO's proposal also recognizes that non-LSE procurement is new and could provide a viable path for different customer classes to receive the various benefits new projects provide. The ISO's deposit requirements align with FERC's NOPR and help ensure that only committed, viable projects can retain deliverability, thereby minimizing churn in the queue.

4 Phase 2 topics on managing the overheated queue

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

- Background

In the September 30, 2021 preliminary issue paper, section 4.1, the ISO sought stakeholder input on whether the bar for entry into the interconnection process should be raised to discourage numerous and perhaps excessive interconnection

[15] Unless the project withdraws due to an error or omission that allows the project to receive a full refund of its interconnection financial security posting.

request submissions by a single developer, such as requiring higher fees or deposits for submitting an interconnection request, or imposing other requirements. Stakeholders were generally supportive for higher fees or imposing other requirements. Site exclusivity deposit requirements were addressed in Phase 1, and are not being revisited in Phase 2.

In the July 26th Draft Final Proposal the ISO significantly revised its proposal on this topic based on stakeholder feedback and also that on June 16, 2022 FERC issued a Notice of Proposed Rulemaking (NOPR) on 'Improvements to Generator Interconnection Procedures and Agreements'. The revised proposal attempted to integrate a number of FERC's proposals while maintaining key aspects of the ISO cluster study process. Some of the notable proposed changes included revising the allocation of study costs, setting study deposit amounts that are based on project MW size, requiring demonstration of commercial readiness or in lieu deposits, and imposing withdrawal penalties that increase as the Interconnection Customer moves through the study process. The ISO requested stakeholders provide feedback on whether the ISO should wait for the FERC NOPR process to be completed, or if the ISO should move forward with its own revised proposal as detailed in the July 26th final draft proposal, making the changes applicable for cluster 15.

- Stakeholder feedback

There are 4 stakeholders that fully support the ISO proposal. The CPUC Cal Advocates supports these revisions, stating they are consistent with the FERC NOPR reforms and with these changes the ISO should be able to effectively manage the overheated queue by raising the bar for entry into the interconnection process. NRG supports the flexible approach outlined which allows different options to show commercial viability and increased deposits for larger contracts. SCE supports the ISO integrating several of FERC's Generator Interconnection NOPR proposals – revised allocation of study costs, study deposits that are based on project MW size, required demonstration of commercial readiness or in lieu deposits, and withdrawal penalties that increase as the Interconnection Customer moves through the study process – while maintaining key aspects of the ISO cluster study process. SCE states the ISO should clarify if commercial readiness must be tied to a site or could only be used for one active interconnection request. SCE does not see a need to wait until the final FERC determination to proceed with the ISO proposed tariff revisions as it will benefit Interconnection Customers, ISO, and PTOs to focus resources on fewer projects that are ready to proceed. PG&E is supportive of ISO's revisions to the proposal to align it with FERC's recently issued Notice of Proposed Rulemaking on interconnection issues. Even though FERC's action is a proposal at this time and not a final order, aligning with the direction FERC seems to be going is reasonable. Aligning with FERC's proposal, even though what eventually may be adopted could be somewhat different, makes sense as it will reduce impacts of making changes in the future to the interconnection request requirements.

There are 5 stakeholders that do not support any provisions of the ISO proposal. EDF Renewables strongly opposes moving forward with this proposal as it is not mature and not appropriate for the ISO unique interconnection and deliverability procedures. EDF is also advocating for a transparent stakeholder discussion of any FERC order compliance proposals before it goes to the ISO Board for approval. LSA states ISO proposals go far beyond providing criteria for "submitting and IR" to encompass Interconnection Study cost allocation, new readiness criteria for entering both Phase I and Phase II Studies, and Study Deposit retention far beyond completion of Interconnection Studies. LSA states the proposed cost-allocation and study deposits bear no relationship to ISO costs, the commercial readiness criteria are vague and inconsistent with ISO-area PPA contracting practices, and the study deposit refund proposals are unjust and unreasonable. Hanwha Q Cells believes the ISO must delay the start of C15 or the rollout of IPE Phase 2 to allow additional debate on the FERC NOPR, and believes that having the option of providing a financial deposit in lieu of commercial readiness is essential. Also, until a developer receives a system impact study, meeting the commercial readiness criteria is not feasible. Intersect Power opposes the proposals for: (1) revised cost allocation and Study Deposit structures that do not reflect ISO costs, (2) Study Deposit amounts that far exceed ISO costs, (3) Commercial Readiness criteria, which are vague at this time and inconsistent with ISO-area contracting practices, and (4) Study Deposit retention for years after study completion. Vistra recommends deferring action on the allocation of study cost and study deposit proposals and opposes the commercial readiness proposals.

There are 9 stakeholders that support some but not all of the provisions of the ISO proposal.

Allocation of study costs – CalWEA supports the proposed study cost allocation. REV Renewables supports the proposed cost allocation of study costs. California CCA states the ISO should allocate study fees in a way that reflects the drivers for the costs incurred by the study. If the ISO incurs more costs for studying larger MW projects than it does for studying smaller MW project, then the ISO's proposal to allocate costs primarily based on requested MW is reasonable. If the costs are the same to study a larger project and a smaller project, then the ISO should revisit its proposal and provide this feedback to the FERC in response to the NOPR such that the ISO's allocation of study fees can align with the way different projects impact the costs of the study. AES Clean Energy does not oppose the 90/10 study cost allocation proposal. However, it was unclear from the proposal when any unspent study deposits would be refunded to customers, it would be unjust and unreasonable to retain the deposit once all study activities have been completed.

Study costs based on project MW size – SEIA supports implementing elements of the FERC NOPR, like study deposits, recognizing that these enhancements will likely comply with any FERC interconnection rulemaking. Middle River Power supports the ISO Proposal with regards to fees and deposits. CalWEA supports the study deposit structure and urges the ISO to move forward without waiting until FERC NOPR process is completed. REV Renewables supports the proposed study deposit revisions that will create an additional financial liability on the Interconnection Customer thus creating an incentive to submit viable projects. Six Cities are not categorically opposed to the ISO's proposed revisions to study fees and deposit structures proposed by the ISO, however it may be that the ISO footprint requires a different approach or alternative weighting, as compared with the FERC NOPR. CESA supports the adoption of a combined study deposit as proposed as reasonable and aligns with the thresholds in the NOPR. Golden State Clean Energy supports the proposal to base study deposits on a megawatt amount rather than the number of interconnection requests. This makes ISO's proposal directionally consistent with the NOPR while increasing study deposit amounts to create better incentives for projects entering the queue. The proposed increase in study deposits warrants a reexamination of the use of funds in excess of actual study costs given the study deposit is now also being used as a deterrent to projects entering the queue rather than increasing to cover study costs. AES Clean Energy supports the new study deposit structure being based on project size and finds the proposed fee structure in line with study deposit requirements in MISO and PJM.

Commercial Readiness – SEIA opposes the commercial readiness requirements and the ISO should delay implementation until FERC issues final rulemaking. Middle River Power states it is not realistic to require parties to furnish a binding, executed term sheet before moving into Phase I studies and that there is no guarantee that the studies, let alone the upgrades required will be completed on time so developers will be unwilling to take on the risk associated with a binding schedule. CalWEA believes the commercial readiness deposit to enter Phase II studies is too high and recommends reducing it to 2.5 times study deposit. REV Renewables strongly opposes the commercial readiness proposal. CESA opposes the commercial readiness requirements proposal and notes it is problematic because it provides no way for projects to meet this requirement through a merchant development strategy. CESA states the structure for commercial readiness requirements, if maintained, would represent excessively high amounts of capital at risk that would deter market participation. CESA requests that the ISO clarify whether the study deposits must be provided in cash or could be provided via other means. Golden State Clean Energy supports some form of commercial readiness demonstration and increased fees to submit an interconnection request, but the eligibility criteria should be expanded to more accurately reflect readiness early in project development. Readiness demonstrations should be expanded and include site exclusivity, permitting, procurement of major equipment, or an early financial commitment to interconnection facilities to support multiple projects. AES Clean Energy opposes the commercial readiness requirements as currently outlined in the DFP

Withdrawal Penalties – SEIA supports implementing elements of the FERC NOPR, like withdrawal penalties recognizing that these enhancements will likely comply with any FERC interconnection rulemaking, however the ISO should be incentivizing earlier withdrawals with no penalties prior to entering Phase I studies. CalWEA recommends reducing the maximum withdrawal penalty to 1.5 times the study deposit. REV opposes the proposed withdrawal penalties that are tied to commercial readiness criteria. CESA is opposed to the adoption of withdrawal penalties, which are unnecessary given the withdrawal penalties already in place associated with the initial financial security (IFS) posted after Phase I and Phase II studies. AES Clean Energy opposes the withdrawal penalties proposal as written in the draft final proposal. AES believes that the withdrawal penalty framework should be revised to incentivize early withdrawal and increase as projects move through the process.

Site Exclusivity – Middle River Power believes site control should be demonstrated before moving into the study process.

- Final Proposal

  Based on stakeholder input, it is apparent that reaching consensus on any proposal for this topic in time for approval of the ISO Board at their scheduled October meeting, which would be necessary to have any proposal apply to Cluster 15, is not feasible. The ISO has decided not to move forward with a final proposal on this topic within IPE Phase 2. The ISO will refocus its efforts on this topic by participating within the framework of the FERC NOPR on 'Improvements to Generator Interconnection Procedures and Agreements'[16].

[16] *Notice of Proposed Rulemaking: Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022).

5 Phase 2 Topics - Other Issues

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

- Background

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

The ISO addressed this issue with stakeholders and filed a narrowly focused proposal to FERC in 2017. FERC ultimately found that the ISO failed to support its proposal as just and reasonable and not unduly discriminatory and rejected the ISO’s filing without prejudice, which allows the ISO to refile a proposal.[17]

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.1, the ISO proposed that the addition of the capital costs for low voltage (<200kV) network upgrades driven by generation interconnections to the LTRR of a Participating TO will not cause the aggregate of the net investment for all low voltage network upgrades driven by generation interconnections included in the LTRR to exceed fifteen (15) percent of the aggregate of the net investment for all low voltage transmission facilities of that Participating TO reflected in their LTRR in effect at the time of the in-service date of the network upgrade. Any costs for low voltage network upgrades in excess of the 15 percent threshold will be financed by Interconnection Customers without cash reimbursement.

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

In the June 7, 2022 Revised Straw Proposal, section 5.1, the ISO did not propose any changes to the December 6, 2021 straw proposal, however the ISO did provide additional data and responses to stakeholder initial concerns.

In the July 26th Draft Final proposal, the ISO refined its latest proposal with two additional enhancements. The first enhancement was for the ISO to maintain up-to-date data on the ISO website on where each PTO's share of interconnection-related low-voltage costs are, and where the ISO projects them to be in the near-term based on queued projects that have executed GIAs. The second enhancement was to allow Interconnection Customers to withdraw at minimum cost—consistent with the IPE Phase I tariff revisions for substantial errors and omissions—if it submits an interconnection request where the PTO would have reimbursed the costs of a low-voltage upgrade, but that changes for the customer while in queue (due to the PTO going over the 15% threshold while the customer is in queue, regardless of whether this was projected). These two enhancements would provide customers with as much transparency as possible while protecting the customer from the risk of merchant-financing low-voltage upgrades where unexpected.

- Stakeholder Feedback

There are 4 stakeholders that support or do not oppose the proposal. The CPUC Cal Advocates supports this proposal, which intends to protect local transmission ratepayers from funding excessively expensive interconnection-related local voltage network upgrades. According to them, this change also moves the ISO closer to a participant funding model used by other regional planning organizations, in which Interconnection Customers pay a fair portion of the cost of required network upgrades to reflect a fair allocation of benefits between the Interconnection Customer and ratepayers. Valley Electric Association (VEA) supports the proposal as a reasonable balancing if the interests involved, and for VEA, it is a significant improvement from the circumstances today. SCE does not oppose the ISO proposal.

There are 7 stakeholders that oppose the ISO's proposal. SEIA believes that the ISO proposal will discourage future resource development on local systems, which could have deleterious effect on California clean energy goals. EDF-R views the proposal as similar proposal rejected at FERC before and believes it is unjust and unreasonable to impose different and discriminatory refundability rules in different ISO area locations. Middle River Power (MRP) states that the impetus for this issue is a reasonable concern that Valley Electric Association (VEA) customers should not incur undue costs related to lower-voltage interconnection of generators that are connecting in the VEA area not for the primary purpose of serving load there but instead to serve load in the ISO. That said, however, MRP is not yet persuaded that the way to address that legitimate concern is to limit generators' cash reimbursement recovery of network upgrade costs. CalWEA opposes requiring Interconnection Customers to finance network upgrade costs exceeding the funding cap. The cost should be borne by all parties that benefit from accessing the generation enabled by the transmission upgrades. LSA continues to believe that the ISO's proposal is not just and reasonable and that the assertion that this proposal would apply to "any PTO" in a "non-discriminatory" fashion is simply not true. LSA also states the proposal would likely have the impact of preventing most future generation development on the VEA system, since the cap is so low that a single project could easily absorb the entire $3.5 million below it. If that is the intent, the ISO should simply say so. LSA is disappointed that ISO did not explain in any detail its reasons for rejecting the SEIA "Net Importer/Net Exporter" proposals, or any of LSA's alternative suggestions. These alternatives included, for example, addressing FERC's problems with the earlier proposal by allocating "excess" LV-TRR costs to other PTO LV-TRRs based on LSE contracting of projects in the VEA area, which would provide the direct connection to beneficiaries required by FERC. LSA is also requesting clarification on the calculation of the cap and the PTO-provided figures, specifically whether the calculation would include LV costs associated only with completed projects, projects under construction or with executed GIAs, or forecasts based on study results for additional projects or clusters. If the ISO proceeds with this framework, it should not apply to project already in the queue as well as projects moving to a higher voltage POI due to application of the cap should qualify for "lower of" Phase I/Phase II cost-cap protection and projects that do not receive full Network Upgrade reimbursement due to the 15% limit should be entitled to additional reimbursements if the target dollar amount increases. REV Renewables states the High and Low voltage transmission in California is configured in a loop arrangement in most locations. Therefore, any network upgrades that get built on the low voltage transmission side provide overall reliability and other benefits to the bulk high voltage transmission as well, similar to upgrades that get built on high voltage transmission. Separating the cost allocation on high and low voltage would not only be cumbersome but would also go against the fundamentals that are in place today. AES Clean Energy opposes this proposal. However, if the ISO adopts this proposal, then they should grandfather all resources currently in queue from this 15% cap and make this policy effective starting with Cluster 15 projects so that developers can better manage the risk of developing projects on lines below 200 KV. While AES appreciates the ISO's proposal to allow project to withdrawal without penalty if the 15% cap is reached, this still will not make developers whole to the investments already made to develop the project.

There are 3 stakeholders that neither support nor oppose but are asking for further clarifications. The Six Cities note that their prior comments included several questions that were not addressed in the Draft Final Proposal, including:

- How is the amount of investment in low voltage network upgrades for each Participating TO being determined? Are these amounts self-reported? How are the proposed amounts validated? Is the basis for the reported investment included in any FERC-filed financial reports? The Six Cities note the ISO's commitment to post relevant amounts on its website. (See Draft Final Proposal at 32.)
  - How will the 15% threshold be applied on a going forward basis, as the value of the plant-in-service associated with the low voltage TRR and low voltage network upgrades depreciates? If the applicable threshold is reached in one year, such that Interconnection Customers are required to fund low voltage network upgrades, and then falls below the 15% threshold in a subsequent year, will Interconnection Customers become eligible for reimbursement until the 15% threshold is again reached?
- How will the 15% threshold apply for Participating TOs that do not have low voltage transmission facilities at this time, but could develop low voltage facilities or network upgrades in the future?
  - The Six Cities request that the ISO confirm, notwithstanding that there will be no reimbursement of network upgrade costs in excess of the proposed threshold, that there will likewise be no restriction on the ability of Interconnection Customer-funded network upgrades to be part of the ISO controlled grid and available for the use of ISO transmission customers just like any other assets that are under the ISO's operational control. The Six Cities request the ISO to provide in its Final Proposal additional information on how it will implement this proposal.

PG&E requests the ISO clarify in any final proposal that the proposed 15% cap on reimbursement for low-voltage network upgrades is not in-lieu of and replacing the current respective PTO structures for NU reimbursements, including which type of network upgrades are eligible for reimbursement and at what rate. PG&E recommends ISO add language making clear that Interconnection Customers are still responsible for certain types of NUs (e.g., area deliverability network upgrades (ADNUs)) irrespective if a PTO has reached the 15% reimbursement threshold and that the proposal is not proposing to require PTOs to reimburse Interconnection Customers for all NUs until it has reached the 15% threshold. SDG&E supports ISO's efforts to ensure that local ratepayers are protected from the cost impact of low voltage (below 200 kV) generation interconnection-driven network upgrades that benefit all customers in the ISO's system. SDG&E also agrees with the ISO that if the current cost allocation structure remains unchanged it might lead to inequitable cost allocation in the future. Under ISO's current proposal, generation interconnection-driven network upgrades will be limited at 15% of the low voltage transmission revenue requirement (LTRR) of a Participating TO. SDG&E is concerned with the 15% limit selected by the ISO and would appreciate if the ISO could provide more data that explains why a 15% limit is just and reasonable compared to a 30% limit or a 10% limit. It is unclear in the current proposal that only 15% of generation interconnection-driven network upgrade costs only benefit local ratepayers. At a minimum, SDG&E believes that the ISO should try to find a clear correlation between a selected limit and the benefits received by local ratepayers. Furthermore, although SDG&E believes the ISO is taking a step in the right direction to protect local ratepayers, SDG&E is also concerned that ISO's proposal does not address the fact that generation interconnection-driven network upgrades benefit all ratepayers irrespective of their location. This essentially means that all ratepayers should share the cost of generation-driven network upgrades that are part of the ISO-controlled grid. The current proposal as it stands, might not be consistent with FERC's cost causation principles and might lead generators to avoiding cost-efficient and feasible point of interconnections for more expensive high-voltage interconnection points.

- Final Proposal

The ISO does not propose to revise or change its proposal substantially; however, the ISO agrees that it should provide constant transparency on where each PTO is in relation to the 15% threshold so developers can understand how costs will fall. The ISO proposes to maintain up-to-date data on the ISO website on where each PTO's share of interconnection-related low-voltage costs are, and where the ISO projects them to be in the near-term based on queued projects that have executed GIAs. The ISO also proposes to allow Interconnection Customers to withdraw at minimum cost—consistent with the IPE Phase I tariff revisions for substantial errors and omissions—if it submits an interconnection request where the PTO would have reimbursed the costs of a low-voltage upgrade, but that changes for the customer while in queue prior to when the customer executes the GIA (due to the PTO going over the 15% threshold prior to the customer executing the GIA, regardless of whether this was projected). These two proposals provide customers with as much transparency as possible while protecting the customer from the risk of merchant-financing low-voltage upgrades where unexpected.

The ISO continues to disagree with stakeholder opposition that would shift costs to the regional TAC. Stakeholder suggestions are not materially different than the ISO's rejected proposal in 2017, and fail to distinguish between the benefits of the network upgrades themselves and the benefits of the generation that triggered them. As FERC reiterated in 2017, "The Commission has found that network upgrades represent improvements to the integrated transmission system and that these benefits to the transmission system are considered independent from any benefits customers may receive as a result of generation that interconnects to the system."[18] As such, proposals that look to the procurement of the generating capacity or the benefits the generation provides are inconsistent with FERC cost allocation precedent. The ISO also believes that examining whether each PTO "imports or exports" is antithetical to the purpose of an integrated grid and ISO/RTO.

The ISO agrees that its proposal may create hurdles to low-voltage interconnections once a PTO has crossed the 15% threshold; however, the ISO believes this result is not imprudent, and should—rightfully—incentivize larger interconnections to the high-voltage grid. The ISO also notes that nothing prevents developers from recouping network upgrade costs through power purchase agreements and ongoing energy sales, a common practice outside of California.

The ISO recognizes that 15% is an arbitrary figure—an unavoidable result for this structure—but that does not mean it is not just and reasonable. As FERC has stated, "It is well established that there can be more than one just and reasonable rate."[19] The ISO based this figure on the tariff's existing LCRIF provisions, and believe it represents a reasonable share of low-voltage network upgrades resulting from generator interconnections. The ISO disagrees with comments arguing it creates unduly discriminatory cost allocation rules. To the contrary, these rules would apply to each PTO equally. The fact that the rules would produce different results for groups of ratepayers based on past and future expenditures is not unduly discriminatory. Few cost allocation rules do otherwise. Moreover, failing to do so would leave ratepayers such as those in VEA paying costs of low-voltage network upgrades disproportionate to their benefits, inconsistent with the Federal Power Act and FERC cost allocation precedent.

As requested by a number of stakeholders, PG&E has provided an estimate of their available low voltage network facilities investment before the 15% cap is reached and is included in the following table:

PTO	(A) Estimated investment for all low voltage network facilities	(B) Estimated investment for low voltage network upgrades driven by generation interconnections	Percentage = B/A	Estimated available investment before the proposed 15% cap is reached
PG&E	$9,645,808,250	$347,586,176*	3.6%	$1,099,285,061
SCE	$387,761,394	$3,532,187	0.9%	$54,632,022

18 *California Independent System Operator Corp.,* 160 FERC ¶ 61,047 at P 34 (2017).
19 *Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,109, at P 20 (2009).

SDGE	$3,387,000,000	$264,480,000	7.8%	$243,570,000
VEA	$23,049,376	$0	0%	$3,457,406

* PG&E's (B) estimate includes all network upgrades driven by generation for all voltage levels. Therefore, the estimated available investment for low voltage network facilities before the proposed 15% cap is reached is conservative.

In response to stakeholder questions, the ISO includes the following clarifications:

- Each PTO determines the share of low voltage network upgrades driven by interconnections by tracking what triggered the upgrades (*e.g.,* an interconnection study, transmission planning, load growth). The PTO will self-report them to the ISO, and the ISO tariff will require each PTO to report them accurately. The ISO is unaware of any FERC reporting requirement or rate case element that requires this specific breakdown.
- Once an Interconnection Customer has executed a GIA, its reimbursement eligibility will not change regardless of any change to the PTO's share of interconnection-driven upgrades due to other interconnection costs (up or down). This will provide the Interconnection Customer a firm cutoff to understand its reimbursement eligibility before proceeding toward a GIA and third posting. Although this may create some float for the transmission owner to manage project to project, the ISO believes this firm, simple rule outweighs the benefits of reimbursement provisions that could change for every customer right up until commercial operation.
- The ISO and each PTO will evaluate the Interconnection Customer's reimbursement eligibility when it tenders its GIA. If the parties agree to extend the negotiation period beyond the 120 days recommended by the tariff, the PTO should update the precise reimbursement eligibility before execution. The PTO's share at the time of the GIA tendering should be based on its current transmission revenue requirement plus any costs for network upgrades by Interconnection Customers that have executed GIAs. Likewise, because reimbursement will not be finalized until a customer has executed a GIA, the PTO should exclude costs from queued projects that have not executed GIAs.
- The 15% threshold will apply to all PTOs, regardless of their current share of interconnection-driven upgrades or if they even have low-voltage facilities at this time. This will protect potential future PTOs that may be concerned over rate shock and current PTOs considering expanding their system. A universal rule for all PTOs also ensures the rule is non-discriminatory.
- All network upgrade costs that do not receive cash reimbursement will be owned by the PTO and considered part of the ISO controlled grid. The Interconnection

Customer will not have any special or unique rights for those upgrades. The ISO will treat non-reimbursable upgrades under this rule just as it treats non-reimbursable upgrades under the Reliability Network Upgrade cap, meaning the Interconnection Customer would receive Merchant Transmission CRRs if additional capacity creates them according to existing Merchant Transmission CRR rules.

- The ISO's proposed rule is iterative on existing cost allocation and reimbursement rules. The ISO does not propose to change how any network upgrades are classified or triggered. Nor does the ISO's proposed rule impact cost cap classifications or rules. As stated above, stakeholders should use the Reliability Network Upgrade reimbursement cap as an analogy for how this rule will work in concert with other cost allocation rules.
- The ISO proposes to make this rule effective in 2023 for all queued customers that have not executed GIAs when the rule goes into effect. Because the ISO intends for this rule to protect ratepayers against costs for which they do not commensurately benefit, the ISO does not believe a drawn-out transition period is appropriate. If an individual Interconnection Customer believes this requirement should not apply to them, the parties may negotiate a non-conforming GIA for FERC approval, or file the GIA unexecuted.

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

- Background

  In the last decade, there have been virtually no instances where a generator's interconnection to a neighboring balancing authority area would affect the reliability of the ISO grid. In interconnection terms, the ISO is almost never an "affected system." However, recently the ISO has received a few notices from neighboring BAAs that a proposed interconnection may affect the ISO, and therefore warrants study. The ISO developed a study process and agreement for such studies in the Contract Management Enhancement initiative. However, that initiative deferred the question to IPE of how any network upgrades required to mitigate reliability impacts would be reimbursed.[20] The ISO also needs to determine what base cases would be used for affected system studies.

  In the June 7, 2022 Phase 2 Revised Straw Proposal, section 5.2, the ISO proposed the base case assumptions for the ISO as an affected system study to be based on previously queued projects as of the affected system study agreement execution

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

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

- It is the ISO's existing policy, and is therefore easy to understand and implement for the ISO and Participating TOs.
- The creation, allocation, and tracking of Merchant Transmission CRRs is complex, presenting a burden that would outweigh the few network upgrades the ISO may ever have to construct as an affected system. Stakeholders should remember that, to date, the ISO has never had to construct network upgrades as an affected system.
- Cash reimbursement from the Participating TO recognizes that although the generator may be elsewhere, the network upgrades themselves are in the Participating TO's service territory, and therefore benefit its ratepayers. FERC explained the drawbacks of non-reimbursement policies at length in its recent ANOPR, indicating a preference for cash reimbursement (or transmission owner financing) in the future.
- Reciprocity agreements or providing reciprocal treatment based on the neighboring BAA's own policy fails to recognize that most neighboring BAAs are not FERC jurisdictional and can operate in completely different paradigms than the ISO. Moreover, most of these affected systems do not only fail to provide cash reimbursement when they are the affected system; they do not provide cash reimbursement to their own Interconnection Customers as well. Like the affected systems, the ISO merely proposes to apply its own policy for RNU reimbursement consistently.
- Tracking and providing different reimbursement rules depending on the offtaker erroneously focuses on the beneficiaries of the generator; not the network upgrades themselves.

- Stakeholder Feedback

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

Six stakeholders, ACP, AES, CalWEA, LSA, SEIA, and Six Cities, support the ISO's proposal to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. LSA and Six Cities also urges the ISO to seek reciprocal arrangements with other jurisdictions. Six Cities asked if the ISO would consider evaluating the value and appropriateness of tracking and reporting the costs of upgrades on the ISO controlled system triggered by affected systems.

PG&E opposed the RNU reimbursement proposal and instead agrees with the cost allocation proposal regarding Affected Systems in the Contract Management "COMA" Enhancements Initiative Draft Final issued September 30, 2021. This paper proposed that Participating TO's would not reimburse external Interconnection Customers for network upgrades, consistent with neighboring utilities' practices.

- Final Proposal

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

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

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

- Background

The July 26 Draft Final Proposal proposed that the ISO does not change the solutions proposed in the Revised Straw Proposal for this issue. The only clarification would be that the ISO would only use the BPM for Generator Management, Section 6.5.2.1, or Section 17 of the LGIA and Article 7.6 of the SGIA where appropriate, taking into account the project specific issues and circumstances. The ISO requested comments on this section.

- Stakeholder Feedback

The ISO received comments from 11 stakeholders for feedback on the following:

CESA, CalWEA, EDF-R, LSA, MRP, PG&E, SEIA, Six Cities, and SCE support the ISO's proposal as a reasonable approach to exercise and enforce the ISO's existing authorities and procedures in order to manage the queue.

Cal Advocates views the ISO's proposal to be more modest than originally proposed and urges the ISO take the additional step of requiring Interconnection Customers to report on an annual basis, the detailed status of its project(s), demonstrate specific issues with engineering, permitting, or construction and, if the Interconnection Customer does not respond, then the ISO could invoke the default clause in the Generation Interconnection Agreement (GIA), Section 17 in the Large Generation Interconnection Agreement (LGIA) and Article 7.6 of the Small Generation Interconnection Agreement (SGIA). The ISO actually requires all projects to provide quarterly reports on the status of their project and to the extent the Interconnection Customer does not respond, the ISO would invoke the default section of the GIAs.

Calpine does not support unilateral termination prior to 7 years. The ISO would not unilaterally terminate an agreement. The project would need to demonstrate that it is not following the terms and conditions of the GIA and if not then the ISO would send a notice of breach to the Interconnection Customer that gives them an opportunity to cure the breach. If the breach is not cured, then the ISO would file at FERC for termination of the GIA. The Interconnection Customers can protest that filing at FERC if they still disagree with the ISO's actions after having ample opportunity to cure the breach.

- Final Proposal

The ISO does not propose to change the solutions proposed in the Draft Final Proposal for this issue.

6 Phase 2 topics - Other Stakeholder Suggested Proposals

6.1 Examining the issue of when a developer issues a notice to proceed to the PTO, requesting the PTO/ISO should start

planning for all upgrades that are required for a project to attain FCDS, including the upgrades that get triggered by a group of projects

- Background

  In the July 26th Draft Final Proposal, the ISO proposed to continue the Transmission Forum stakeholder meetings on a quarterly basis to allow each of the Participating TOs to give a presentation on the status of their transmission upgrade projects. As previously proposed, the ISO encourages the Interconnection Customers to work closely with the Participating TO to ensure that both the generation and transmission portions of the projects are on track to meet the GIA milestone dates.

- Stakeholder Feedback

  The ISO received stakeholder comments from three (3) stakeholders, none of which support the ISO proposal.

  CESA, REV have found that the Transmission Development Forum is ill-suited for the purpose of discussing project-specific questions. CESA recommends that this issue be taken up in the new TPP Enhancements Initiative. Having such a proposal in place will inform procurement and project development activities, as well as ensure accountability on the construction of network upgrades.

  LSA objects to the ISO's removing the item about Interconnection Customers Notices to Proceed from the scope of this initiative. ISO's characterization of this issue has been mischaracterized from the start. Developers are not asking for the Participating TO to start working on "every project's network upgrades when the GIA is executed or the [NTP] is received by the [PTO]." Instead, the Participating TO should be required to begin work on all upgrades in time for the project to achieve its COD and deliverability status. Work on the longest lead-time upgrades should begin first, followed by work on shorter lead-time upgrades, so the Participating TO can fulfill its commitments under the GIA. If developers could just "work closely with the Participating TO" to resolve this problem, it would already be resolved. Instead, Participating TOs frequently delay work on needed upgrades after the Notice to Proceed ("NTP") is provided, delaying project progress toward the milestone dates the Participating TO has committed to in the GIA. LSA asks what is the purpose of an Interconnection Customer "Notice to Proceed" (often accompanied by a third (non-refundable) posting) if the Participating TO does not, in fact, actually proceed? Why should Interconnection Customers make a unilateral commitment when the Participating TO is not doing the same? We again ask the ISO to respond to these questions.

  As the ISO stated in the July 26 Draft Final Proposal and August 1st stakeholder call, while the ISO appreciates that customers believe the ISO has a greater ability to influence the Participating TOs, the milestones in the GIA are set-up to require the Interconnection Customer and the Participating TO to work together to ensure that the project is on track. The ISO believes the Interconnection Customer and the Participating TO need to establish a relationship that addresses the forward progress of the project consistent with the terms and conditions of the GIA.

REV believes it is just and reasonable for the Participating TO to provide a plan for the upgrades and not defer the project until some date unknown by the Interconnection Customer. If needed, Participating TO could require the first project that issues NTP to post security for the entire network upgrade and not just the cost allocated to this project, so a Participating TO has coverage for the financial obligations to build these upgrades. As more projects start executing GIAs and issuing NTPs these projects could reimburse their portion of cost obligation to the first project.

- Final Proposal

The ISO will continue to hold the Transmission Development Forum allowing each of the Participating TOs to give a presentation on the high level status of the transmission upgrade projects which has been well received. As previously proposed and consistent with the terms and conditions in the GIA, the ISO encourages the Interconnection Customers to work closely with the Participating TOs to ensure that both the generation and transmission projects required to interconnect their generating facilities are on track to meet the GIA milestone dates.

7 Stakeholder engagement

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

IPE Phase 2	
Date	**Event**
09/13/22	Publish final proposal
09/20/22	Stakeholder conference call on final proposal
10/04/22	Stakeholder comments due on final proposal
October 26-27 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on Sept 20, 2022 to review the Phase 2 Final Proposal. Stakeholders are encouraged to submit comments on this Final Proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on October 4, 2022. The ISO also will publish draft tariff language and hold a conference call to discuss the draft tariff language well before the Board of Governors meeting.

Attachment D – Board Memoranda

Tariff Amendment – Interconnection Process Enhancements – Phase 2

California Independent System Operator Corporation

January 26, 2023

Memorandum

To: ISO Board of Governors

From: Neil Millar, Vice President of Infrastructure and Operations Planning

Date: October 19, 2022

Re: **Decision on interconnection process enhancements – phase 2**

This memorandum requires ISO Board of Governors action.

EXECUTIVE SUMMARY

The interconnection process enhancement 2021 (IPE) is the California Independent System Operator Corporation's current stakeholder initiative in its ongoing commitment to improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve.

To date, the ISO has processed nearly 2,000 interconnection study requests, providing interconnection customers with the information needed to make decisions on how to proceed with their projects and to compete for a power purchase agreement with California procurement entities. Of that amount, approximately 200 projects (24,000 MW) have gone into commercial operation. With the significant acceleration in procurement targets, numerous generator retirements, load growth, and state mandates for non-carbon emitting generation, the ISO's processes must continue to evolve. The dramatic increase in competition among suppliers has significantly increased the pressure on the GIDAP. With cluster 14, the ISO experienced unseen volumes of projects seeking to position themselves to compete in procurement processes. Across the country and in California, stakeholders and regulators have initiated discussions on methods to better accommodate increasing pressure on interconnection processes.

This IPE initiative consisted of two phases. Phase 1 focused on simpler and near-term enhancements that were needed sooner with broad stakeholder support.[1] Phase 2 focused on long-term and more complex enhancements. During phase 2, the ISO also worked with stakeholders to provide interconnection customers with more data and information to help interconnection customers determine more efficient locations to interconnect.

[1] The Board approved IPE phase 1 on May 12, 2022. FERC approved the enhancements on August 31, 2022.

Phase 2 resulted in three enhancements for which Management seeks approval from the Board:

1. Transmission plan deliverability allocation eligibility requirements;
2. Cost allocation treatment for network upgrades to local systems (< 200 kV); and
3. Network upgrade reimbursement policy when the ISO is an affected system.

Other items implemented in phase 2 that do not require tariff changes or Board approval include:

1. Providing more publicly available and easier access to data to help developers determine the most efficient locations to interconnect new resources and better understand the status of projects in queue.
2. Providing process clarity for developers to work with the participating transmission owner when a developer issues a notice to proceed to construction to the participating transmission owner, allowing developers to provide input into the planning process for required network upgrades.

Management recommends the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed interconnection process enhancements, as described in the memorandum dated October 19, 2022; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

DISCUSSION AND ANALYSIS

The IPE phase 2 enhancements are designed to complete the deliverability allocation process enhancements that were approved by the Board in the phase 1 package of enhancements, propose a new methodology for allocating the cost of network upgrades for the local transmission systems (< 200 kV) of the participating transmission owners, and other process enhancements that have been identified as necessary. Management seeks Board approval of the following enhancements:

1. Transmission plan deliverability allocation eligibility requirements

At its May 12, 2022 meeting, the Board approved enhancements to the transmission plan deliverability allocation process to better align the process with generation procurement and to allocate deliverability to projects most likely to succeed. However, two components of the ISO proposal were deferred to enable further stakeholder discussion in phase 2: (1) implementing criteria for allocating transmission plan deliverability to projects that obtain a power purchase agreement from non-load serving entities that do not have a resource adequacy obligation, and (2) requiring power purchase agreements have a minimum procurement term to be eligible for a high-priority deliverability allocation.

Transmission plan deliverability refers to the transmission capacity needed for a generator to have the ability to deliver its output during peak conditions and be eligible to sell resource adequacy capacity to load serving entities.[2] A resource does not require transmission plan deliverability to interconnect to the ISO system, and can instead elect to interconnect as an "energy only" resource.

Allocation criteria for power purchase agreements with non-load serving entities

In phase 1 stakeholders were concerned the ISO's proposal was overly burdensome for interconnection customers with power purchase agreements with non-load-serving entities to qualify for deliverability. The ISO had proposed to require non-load serving entity offtakers demonstrate a contract to sell any deliverable generation to a load serving entity that has a resource adequacy requirement for a term of three years or more. After more iteration in phase 2, the ISO modified its proposal to allow interconnection customers to qualify for deliverability with power purchase agreements from non-load-serving entity offtakers, so long as the offtaker can provide a resource adequacy contract with a term of at least one year. This proposal reflects (1) that the interconnection customer has a legitimate, long-term contract for its energy and capacity, and (2) that the deliverability will be put to use in resource adequacy portfolios, which include very short-term contracts for resource adequacy where a different offtaker has contracted for the other services. If the non-load serving entity offtaker cannot immediately demonstrate it has a contract to sell the resource adequacy capacity to a load serving entity with a resource adequacy obligation for a term of at least one year, it must provide a deposit in-lieu of such a contract. The deposit would only be required if the project actually obtains an allocation of transmission plan deliverability, with the deposit amount set at $10,000 per MW allocated, with a minimum deposit of $500,000. The deposit is refundable once the project can demonstrate the required one year contract, or the project goes into commercial operation. If the project withdraws without having provided a resource adequacy contract, the ISO processes the

[2] Deliverability does not guarantee any level of transmission capacity or avoided curtailment. All generators are subject to security-constrained economic dispatch, which can be affected by bids, outages, and topology changes.

funds with other non-refundable interconnection charges.

Minimum procurement term for power purchase agreements

The proposal presented to the Board in May was to require power purchase agreements be for a minimum procurement term of three years. Up until the final proposal the proposed minimum term was five years. The ISO reduced the minimum term from five to three years based on stakeholder feedback. When the issue was continued in phase 2, the ISO reintroduced it with a minimum term of five years based on significant feedback from offtakers and local regulators, including the three California investor-owned utilities, the California Community Choice Association, and the California Public Utilities Commission. They informed the ISO they only execute power purchase agreements with greenfield and expansion projects for terms of at least ten years. The California Public Utilities Commission emphasized their most recent procurement orders require terms of at least ten years.[3]

Based on that input and the need to ensure that the most ready projects are given the highest priority within the allocation process, Management proposes a minimum power purchase agreement term of five years. The ISO must ensure that the transmission plan deliverability allocation process ensures the most viable and ready projects have an opportunity for an allocation before less viable and less ready projects, and to ensure entities are seeking allocations in good faith, especially as the availability of deliverability decreases. Moreover, providing allocations to less viable and less ready projects on an equal footing as those with long term power purchase agreements puts load-serving entities at a greater risk of not receiving an allocation. This would hinder their ability to bring new capacity online to meet their mandated timelines and would put reliability of the ISO system at greater risk. Management proposes that this requirement would begin with the 2023-24 TPD allocation cycle.

2. Cost allocation treatment for network upgrades to local systems (< 200 kV)

The ISO tariff requires participating transmission owners to reimburse interconnection customers for the financing costs of reliability and local delivery network upgrades built in their systems and turned over to their control. The participating transmission owners then include those reimbursement costs in their FERC-approved transmission rate bases, requiring ratepayers to pay those costs through either the local or regional transmission access charges. Network upgrades for 200 kV systems and above are considered regional, and their costs are allocated to all measured demand on a per-MW basis system-wide. This is known as a "postage

[3] Decision 21-06-035: Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF#page=50&zoom=100,96,703; Decision 19-11-016: Decision Requiring Electric System Reliability Procurement For 2021-2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

stamp rate." In contrast, local network upgrade costs remain with the participating transmission owner that will own them. Their costs are charged only to customers within the participating transmission owner's service area. This voltage-based cost allocation system is the national practice based on the principles that cost allocation correlate with benefits received, and low-voltage network upgrades do not benefit ratepayers farther away.

There is ongoing concern that the current practice for generator-interconnection-driven local upgrades could unduly impact local ratepayers who solely bear their costs. In other words, certain interconnections could cause ratepayers to bear costs disproportionate to the benefits received for the low-voltage network upgrades. The ISO addressed this issue with stakeholders and filed a narrowly focused proposal to FERC in 2017 that would have assessed certain interconnection-driven low voltage network upgrades on a regional basis. This proposal was premised on the idea that the beneficiaries of the generation were outside of the local transmission owner. FERC ultimately found that the ISO failed to support its proposal as just and reasonable and not unduly discriminatory and rejected the ISO's filing.[4] FERC found that the *generation* benefits were independent and immaterial to the cost allocation issue of the low-voltage *network upgrades*, and the ISO had not demonstrated that regional ratepayers would benefit from the low-voltage upgrades.

Instead of creating different rules for different participating transmission owners, Management proposes to use a cost limiting model similar to the one the ISO uses for funding location constrained resource interconnection facilities. The ISO proposes a revised treatment for the addition of the capital costs for local or low voltage (<200kV) network upgrades driven by generation interconnections to the local transmission revenue requirement of a participating transmission owner. Such upgrades will not cause the aggregate of the net investment for all low voltage network upgrades driven by generation interconnections included in the local transmission revenue requirement to exceed fifteen percent (15%) of the aggregate of the net investment for all low voltage transmission facilities of that participating transmission owner reflected in their local transmission revenue requirement in effect at the time of the in-service date of the network upgrade. Any costs for low voltage network upgrades in excess of the fifteen percent (15%) threshold will be financed by interconnection customers without cash reimbursement, but with merchant transmission congestion revenue rights if created. In addition, the proposal allows interconnection customers to withdraw their project at any time without incurring withdrawal penalties if its interconnection request is in an area where the participating transmission owner would have reimbursed the costs of a low-voltage upgrade, but that changes for the interconnection customer while in queue (due to the participating transmission owner going over the 15% threshold while the customer is in queue, regardless of whether this was projected).

Management believes this proposal ensures equal treatment for all participating

[4] *California Independent System Operator Corp*., 160 FERC ¶ 61,047 (2017).

transmission owners, and protects their local ratepayers from paying for network upgrade costs that likely exceed their benefits. All participating transmission owners are currently well under the 15% threshold; however, current and future participating transmission owners with smaller rate bases face a real risk of rate shock if their systems receive multiple or expensive interconnections disproportionate to the low-voltage system. The ISO proposal protects the participating transmission owners and incentivizes larger interconnections to high-voltage systems.

3. Network upgrade reimbursement policy when the ISO is an affected system

In the last decade, there have been no instances where a generator's interconnection to a neighboring balancing authority area affected the reliability of the ISO grid such that network upgrades were required. In interconnection terms, the ISO is almost never an "affected system," and has only been asked to perform affected system studies a handful of times. Most of these studies were not performed because the project quickly withdrew. However, recently the ISO has received a few notices from neighboring areas that a proposed interconnection potentially may affect the ISO, and could warrant ISO study. Although the probability is very remote that an external interconnection would require network upgrades on the ISO system, Management believes the ISO tariff should have a clear policy on this issue.

To perform the ISO as an affected system study, Management proposes to use the base case assumptions from the most recent cluster study as of the affected system study agreement execution date. In addition, FERC precedent requires the ISO to provide some form of remuneration for network upgrades financed by the interconnection customer, either in the form of cash reimbursement or transmission rights, which would be merchant transmission congestion revenue rights for the ISO. Management proposes to use its existing policy for reliability network upgrade reimbursement for projects interconnecting to the ISO system for reliability network upgrades resulting from an affected system study. Transmission owners would reimburse interconnection customers in cash and include those costs in their transmission revenue requirement. This policy reflects that the transmission ratepayers benefit from the network upgrades, and it incentivizes transmission owners to assign cost-efficient necessary upgrades to the interconnection customer.

POSITIONS OF THE PARTIES

The ISO initiated the IPE 2021 initiative phase 2 with a revised straw proposal on June 7, 2022, which picked up each topic at the point that discussions were suspended within phase 1. Through stakeholder input the topics addressed in phase 2 were reduced to those that had sufficient stakeholder support. In total, five papers were posted associated with phase 1 and three papers were posted associated with phase 2, each with respective stakeholder meeting and comment process. The IPE 2021 Phase 2 Final Proposal was posted on September 13, 2022, followed up with a stakeholder conference call on September 20, 2022.

Section 1 Enhancements

1. Transmission plan deliverability allocation eligibility requirements

Allocation criteria for power purchase agreements with non-load serving entities

The vast majority of stakeholders support this proposal.

- All but one stakeholder either supported or did not comment on the proposal. This includes Amazon, who in an August 25, 2022, letter to the ISO Board of Governors stated they were "very pleased with the current proposal."
- One stakeholder opposed the ISO not allowing contract eligibility for arrangements between the interconnection customer and counterparties that are affiliates of the interconnection customer.

Minimum procurement term for power purchase agreements

- Eight stakeholders provided written comments in support of the proposal.
- Eight stakeholders provided written comments not in support – providing various forms of alternative proposals.

All load serving entities that provided comments, as well as the California Public Utilities Commission, support the proposal as appropriate for their procurement practices for new greenfield generation and generation facility expansions. Management believes that the interests and procurement practices of the load serving entities should guide the decision to approve this proposal.

2. Cost allocation treatment for network upgrades to local systems (< 200 kV)

- Six stakeholders, including San Diego Gas & Electric, oppose the proposal.
- Valley Electric Association and the California Public Utilities Commission - Public Advocates Office support the proposal, and Southern California Edison did not oppose.

Opposing stakeholders argue the ISO should not change its existing policy at all, as doing so could disincentivize development on low-voltage systems. Management agrees that this could happen, but only where local ratepayers would no longer commensurately benefit from network upgrades, and development should be directed to higher-voltage facilities. Other opposing stakeholders argue these rules should not be imposed on already queued customers. Management disagrees because its proposal reflects existing cost allocation principles. Without tariff changes, transmission owners facing rate shock would simply file complaints at FERC arguing their ratepayers should not receive the imminent interconnection costs, and the same result would occur. SDG&E argues costs above the 15% threshold should be allocated regionally.

Management believes FERC already rejected that proposal in 2017, and it would be imprudent to argue that regional ratepayers benefit from low-voltage network upgrades on other systems such that they should pay for them equally.

3. Network upgrade reimbursement policy when ISO is an affected system

- Six stakeholders support the proposal.
- No stakeholders oppose the proposal.

This proposal received broad stakeholder support.

CONCLUSION

Management recommends that the Board approve the three enhancements proposed in this memorandum. Although some enhancements have not received broad support, Management believes the proposals are correct and appropriate for addressing each of the issues in this memorandum. The proposed modifications ensure the most viable and ready projects have an opportunity for an allocation before less viable and ready projects, and gives priority to load serving entities who must procure and bring into operation large amounts of new generation to meet their mandated procurement timelines and to ensure the future reliability of the system. The proposed modifications will also provide a cost allocation structure for transmission upgrades on the local transmission systems to not overwhelm the ratepayers of those local transmission systems. Finally, the proposed modifications will improve the ISO's generator interconnection procedures' ability to manage the projects in the queue and help California and the West obtain the robust capacity levels needed and meet their public policy goals.