Storage as a Transmission Asset:

Enabling storage assets providing regulated cost-of-service-based transmission service to access market revenues

Second Revised Straw Proposal

October 16, 2018

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1. Executive Summary

In light of advances incorporating storage and other preferred resources into the transmission planning process, the California Independent System Operator Corporation ("ISO") is evaluating the circumstances and conditions when storage facilities the ISO finds through the transmission planning process to be needed to provide a reliability service can also provide market-based services. Developments at both the state and federal levels are driving a more comprehensive and integrated view of storage as a resource that can provide both transmission and market services. In the past, the ISO has considered numerous proposals for storage devices to provide cost-of-service based transmission services in the transmission planning process ("TPP"), and the ISO approved two such proposals in the 2017-2018 TPP. Enabling storage facilities that provide transmission service under a cost-of-service framework, to also participate in the energy and ancillary services markets, can generate additional ratepayer benefits relative to a solely regulated asset. However, this type of hybrid resource introduces unique challenges that must be carefully considered in the policy development process.

The scope of this initiative is to enable storage providing cost-based transmission services to also participate in ISO markets and receive market revenues to provide additional ratepayer benefits and provide greater flexibility to the grid. The idea is market-based revenues generated from delivering market-based services can reduce the costs of the asset recovered under a cost-of-service contract, reducing the burden on rate-paying consumers. Specific issues that are beyond the scope of the current stakeholder initiative include:

- Storage resources procured or contracted for reasons beyond meeting a specific transmission system need identified by the ISO in the TPP;
- The TPP evaluation methodologies;
- The framework for competitive solicitation and the applicability of the ISO's current competitive solicitation framework for transmission solutions;
- Cost allocation of the cost-based revenue requirements for rate-based assets;
- Resource adequacy value.

The February 6, 2017 FERC policy statement maintains that Storage as Transmission Assets ("SATA")[1] resources could access both cost-of-service and market revenues, but the ISO needs to be able to demonstrate that the following issues would not arise:

1) The potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in the wholesale electricity markets to the detriment of other competitors who do not receive such cost-based recovery;

[1] SATA is an ISO term, but aligns with the types of resources contemplated in the FERC policy statement.

2) The level of ISO control over the operation of an electric storage resource could jeopardize its independence as the market operator; and

3) The potential for combined cost-based and market-based rate recovery to result in double recovery of costs by the electric storage resource owner or operator to the detriment of the ratepayer.

The ISO is considering three options that rely on maintaining cost recovery through Transmission Access Charge ("TAC") for SATA resources. Specifically, the ISO is exploring the following options:

1) Full cost-of-service based cost recovery and energy market crediting back to ratepayers;

2) Partial cost-of-service based cost recovery and no energy market crediting; and

3) Full cost-of-service based cost recovery with partial market revenue sharing between owner and ratepayers.

Under the full cost-of-service based cost recovery option all market revenues earned by the resource would reduce the costs recovered through the TAC. The ISO envisions two scenarios in which the SATA project sponsor could be selected under this cost recovery option: direct assigned projects and projects subject to the completive solicitation process. These two options will have slightly different contractual provisions. These options are described in section 5.2.1. Alternatively, under the partial cost-of-service based cost recovery option the resource would only have some portion of its Transmission Revenue Requirement ("TRR") guaranteed or have an increase in the entity's Transmission Revenue Credit, with the remainder recovered through market revenues. The SATA resource will bear some risk – both upside and downside risk – of recovering a portion of its costs (and return) from market services. This option is described in section 5.2.2. Finally, the full cost-of-service with partial market revenue sharing option is designed to provide incentives for market participation not present in the full cost-of-service with full energy market crediting option, while mitigating some of the financial uncertainties that exist in the partial cost of service option. This option is described in section 5.2.3.

Although the ISO has not experienced any shortage of participation in the TPP phase 3 competitive solicitation process, the ISO proposes that at least three qualified project sponsors are required for the partial cost-of-service or full cost of service with revenue sharing to be options for consideration.

The ISO has determined that a new *pro forma* agreement will be developed for the SATA resources that includes provisions from various existing agreements, including the TCA, APSA, PGA, PLA, RMR, MSA, etc., depending upon the final policy determined for this initiative. However, the CAISO received significant support from stakeholders on the concept of developing a pro forma agreement common to all SATA resources and continues to pursue this avenue in its policy development. Following substantial stakeholder comments on this issue on the revised straw proposal, the CAISO is introducing two new concepts, detailed in section 5.4, for further discussion and development with stakeholders, namely:

1) A contractual alternative to the TRR credit mechanism; and

2) Multiple variants of contract terms for SATA resources.

While they appreciate the problem that the CAISO was trying to address via the TRR credit mechanism in the revised straw proposal, several stakeholders including CESA, CRI, Next Era, ORA, PG&E and SDG&E, commented that the CAISO and stakeholders would be better served by including maintenance and replacement obligations in the SATA agreement in place of the TRR credit mechanism proposed by the CAISO. Stakeholders pointed out that SATA resources can vary greatly in terms of technology and degradation factors, and a one size fits all formula rate may not be practical.

Stakeholders including CESA, CRI, Six Cities and ORA, commented that the CAISO and stakeholders would be better served to tailor the term of the agreement based on the SATA resource technology. For example, certain stakeholders suggested that it may be more appropriate to provide long term contracts to resources with longer life cycles such as flow batteries and pumped storage, and shorter term contracts to resources with shorter lifecycles. The CAISO has considered these comments and proposes three variants of the pro forma SATA agreement with different term lengths, i.e. 10 years, 20 years and 40 years. While this provides SATA owners and the CAISO the flexibility of tailoring the agreement to better fit the lifecycle of the asset, it also minimizes the expected variation in terms and conditions by limiting the term option to three (3) types.

The ISO proposes to provide a SATA notification to indicate to SATA resource owners when a SATA resource will be permitted to participate in the market. Once notified that the resource will be allowed to participate in the market, the owner of the SATA resource will be responsible for the bidding and market participation of the resource, not the ISO. The ISO will also notify all market participants of the designation of SATA resources as transmission assets in the same manner as transmission constraint activations are currently noticed.

The ISO proposes to use a load based notification test to determine if the resource will be needed for transmission or can be released for market participation in real time. The proposed notification procedure would determine if the forecasted load levels for the following day, accounting for the import capability and available resource mix in the identified load pocket area. In contrast to some feedback and concerns expressed by stakeholders regarding previous notification process proposals, the ISO believes the proposed load based notification test would reflect the needs to be met by the SATA resource. SATA designations will be made for an entire calendar day, i.e. 24 hours. The ISO has also included a 10% operational reliability margin to this proposed load based notification test to protect against potential inaccuracies related to load forecast error, uncertainty, and resource availability.

SATA resources may be interconnected at a level that differs from the transmission issue it has been identified to resolve. The ISO plans to maintain the current practice of allocating costs to high or low voltage TAC based on the point of interconnection. Once a transmission asset is put in place, it is not practical to track what other uses it might be serving in the future as other changes occur on the system – and revisiting the cost allocation – as to what issues would have otherwise emerged without the asset.

Although the focus of this initiative is relatively straightforward, the interplay between planning activities and processes can be complex. Over the course of this process, the ISO has received numerous stakeholder comments seeking clarifications about the planning process and the flexibility or limitations of that process to address these issues. This paper, therefore, includes a much more comprehensive description of the ISO's TPP, and discussion of how a number of stakeholder issues may be considered in that process in the Appendix.

For this initiative, the ISO plans to seek approval from the ISO Board only. The ISO believes this initiative falls outside the scope of the EIM Governing Body's advisory role, because the initiative does not propose changes to either real-time market rules or rules that govern all ISO markets.

2. Stakeholder Comments on Straw Proposal and Working Group

The ISO received 23 sets of stakeholder comments on the revised straw proposal. The ISO provides a brief description of relevant comments on the revised straw proposal below, with more detailed discussion contained in section 5, as well. Most comments are generally supportive of the ISO approach, however, stakeholders expressed a few areas of general concern. Stakeholder comments typically addressed three topics:

1) The ISO proposed TRR capital credit;
2) Notification timing and process; and
3) Constancy with the FERC Policy Statement.

The ISO also addresses select other stakeholder comments

Additionally, FERC recently issued a decision in Nevada Hydro's Request for Declaratory Order, EL18-131-000. Section 4 has been updated to include the relevant language from FERC's decision on this matter.

2.1. The ISO proposed TRR capital credit

In the previous iteration of this stakeholder process, the ISO proposed a "TRR crediting mechanism" designed to serve two purposes: (1) protect ratepayers from early degradation of SATA resources operational capabilities due to dispatches from ISO market participation and potential for reduced useful lifespan for a SATA resource's ability to meet the identified transmission need(s) and, (2) ensure the SATA resource owner considers all marginal costs when bidding into the market. While most stakeholders support the principle behind the TRR crediting mechanism, they expressed concerns regarding its complexity, accuracy, and feasibility. Most stakeholders support use of the contracts to manage potential resource depletion risks and cost recovery. The ISO has explored this option further and believes contractual requirements can achieve similar outcomes to the TRR crediting mechanism. Additional details are provided in sections 5.2 and 5.4, below.

2.2. Market participation notification

In the revised straw proposal, the ISO put forward two options for when a SATA resource would be notified that it is not needed for transmission services and, therefore, free to participate in the ISO market: prior to the day-ahead market and prior to the real-time market. Almost unanimously, stakeholders supported notifying and releasing the storage device to participate in the market prior to the day-ahead market, facilitating its participation in the ISO's day-market for energy and ancillary services. As a result, the ISO further examined its initial proposal to determine how well it would support pre-day-ahead market notification. This deeper review resulted in the ISO identifying some challenges with its initial proposal, learning that the pre-day-ahead notification would not be appropriate due to operational reliability concerns. The ISO's considerations on this subject are outlined in section 5.5. In addition to the notification timing, numerous parties expressed concerns about how the ISO provides the notification.

The ISO is proposing a load based notification test that would be conducted in the day-ahead timeframe to notify SATA resources for either transmission service or market participation. This notification proposal is described in section 5.5. The ISO is also proposing to notify all market participants via the CAISO market results interface ("CMRI"), similar to the current procedure when transmission constraints are activated and notified through CMRI. The ISO believes the current proposed solution to the SATA notification process will address stakeholder concerns regarding the effectiveness and accuracy of the process to identify, designate, and appropriately. The ISO seeks additional stakeholder feedback on its latest proposed notification procedure. The ISO will address any outstanding issues and concerns in the upcoming draft final proposal.

2.3. FERC Policy Statement

While most commenters agree that the ISO's straw proposal was consistent with the FERC policy statement, some commenters still had questions. Specifically, Calpine and Boston Energy question the impact SATA resources could have on market prices. In response, the ISO has made additional enhancements to its proposal to ensure SATA resources do not inappropriately suppress market prices. While the ISO is proposing to eliminate the TRR capital crediting mechanism from the straw proposal, the contract provisions provided in section 5.4 will provide similar assurances that the SATA resource will be responsible for ensuring any resource owner/operator is responsible for degradation attributable to the resource's voluntary market participation. This proposal is discussed below in sections 0 and 5.4.

2.4. Additional Comments

This section provides a brief description of other comments the ISO has incorporated into this revised straw proposal:

- Many stakeholder urged the ISO to take additional time on this stakeholder process, deferring to later than the originally scheduled November Board of Governors meeting. Given stakeholder comments and the question regarding market participation notification described in section 5.5, the ISO is issuing this second revised straw proposal, not a draft final proposal, and is extending this initiative to Q1 2019. The revised timeline is detailed in section 3.

- There appears to be sufficient stakeholder support for maintaining the “Partial cost-of-service based cost recovery and no energy market crediting” option. While certain opposition remains, the opposition is focused primarily on the idea that this option would never be selected or that a project sponsor could not get the necessary financing for the project. However, stakeholders did not demonstrate any potential harm from maintaining this option. As such, this option is presented in section 5.2.2.
- Numerous parties, including CESA, CRI, Six Cities and ORA, requested the ISO not try to require project life cycles consistent with traditional transmission projects. These stakeholders have made persuasive arguments. As a result, the ISO will allow for three project duration options: 10 years, 20 years, and 40 years. Additional details regarding contract terms is provided in section 5.4.

3. Stakeholder Engagement Plan

Date	Milestone
Mar 30	Issue paper
Apr 6	Stakeholder call on issue paper
Apr 20	Stakeholder comments on issue paper due
May 17	Straw proposal
May 24	Hold stakeholder meeting on Straw proposal
Jun 7	Stakeholder comments on straw proposal due
Jun 21	Working group meeting
Jul 9	Stakeholder comments on working group meeting due
Aug 14	Revised straw proposal
Aug 21	Hold stakeholder meeting on revised straw proposal
Sep 4	Stakeholder comments on revised straw proposal due
Oct 16	Second revised straw proposal
Oct 23	Hold stakeholder meeting on second revised straw proposal
Nov 6	Stakeholder comments on second revised straw proposal due
Dec 10	Draft final proposal
Dec 17	Hold stakeholder meeting on draft final proposal
Jan 4	Stakeholder comments due
Feb 6-7	**Present proposal to ISO Board**

4. Introduction and Background

In this initiative, the ISO is evaluating the circumstances and conditions when storage facilities the ISO finds to be needed to provide a transmission service can also provide market-based services, thereby lowering costs and providing greater flexibility for the benefit of ratepayers.

Developments at both the state and federal levels are driving a more comprehensive and integrated view of storage as a resource that can provide both transmission and market services. The ISO has considered numerous proposals for storage devices to provide cost-of-service based transmission services through the Transmission Planning Process (TPP), recently approving two such proposals in the 2017-2018 TPP. Enabling storage facilities to provide transmission service under a cost-of-service framework, while also participating in the energy and ancillary services markets, may generate additional ratepayer benefits relative to a solely regulated cost-of-service asset. However, this type of hybrid resource introduces unique challenges that must be carefully considered in the policy development process.

The overarching objective of this initiative is to determine a pathway for storage assets that are selected in the ISO's TPP to provide regulated cost-of-service transmission service to also provide market-based services during periods when the resource is not needed to provide transmission services.

Although the focus of this initiative is relatively straightforward, the interplay between planning activities and processes can be complex. The ISO received numerous stakeholder comments throughout this process seeking clarity regarding the planning process and the flexibility or limitations of that process in managing a number of these issues. This paper therefore includes a much more comprehensive description of the ISO's TPP in the appendix in section 9.1.

The remainder of the section provides a discussion of how a number of stakeholder issues may be considered in that process.

4.1. Future Consideration of Energy Storage in the Transmission Planning Process

Historically, the ISO considered energy storage as either (1) a market resource potentially providing local resource adequacy capacity, approved through a CPUC or other local regulatory authority procurement process and compensated through bilateral contracts and/or market revenues, or (2) as a transmission asset, approved through the ISO transmission planning process and compensated through cost-of-service rates established based on a regulated revenue requirement. In both cases, transmission needs are being met. In the case of energy storage operating as a market resource, its procurement may be through competition with other market resources, including preferred resources.

FERC provided additional direction on January 19, 2017, when it issued its policy statement regarding "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" (Policy Statement). The purpose of the policy statement is to:

> *"provide guidance and clarification regarding the ability of electric storage resources to receive cost-based rate recovery for certain services (such as transmission or grid support services or to address other needs identified by an RTO/ISO) while also receiving market-based revenues for providing separate market-based services."*[2]

The policy statement also sets out a number of concerns that would need to be addressed to enable this outcome. Further, with respect to the policy statement, FERC provided additional direction in EL18-131-000. Specifically, FERC states

[T]he *Storage Policy Statement* does not provide guidance for determining whether a particular electric storage resource is a transmission facility eligible for cost recovery through transmission rates. Rather, the *Storage Policy Statement* provides guidance only with respect to issues that must be addressed if an electric storage resource seeks to receive cost-based rate recovery for certain services, whether through transmission rates or any other cost-based rate, while also receiving market-based revenues for providing separate market-based services."[3]

A more complete regulatory background and history of FERC's guidance on storage as a transmission asset is discussed in more detail in the Appendix.

This initiative contemplates that energy storage may be approved through the ISO TPP with either revenue requirements offset by market revenues or partial compensation through market revenues. This section provides details regarding how the ISO's consideration of energy storage as a transmission asset may evolve through the existing TPP.

4.1.1. Need for energy storage as a transmission asset

To consider energy storage as a transmission asset, e.g. providing transmission service under cost-of-service rates, the energy storage unit must:

1) Meet the requirements of providing transmission service - not just "meeting a need"; and

2) There must be a reason to move to cost-of-service transmission rates rather than meeting the need with a market resource – which could be storage, preferred resources, or even conventional resources.

Regarding (1), the ISO interprets FERC guidance to require the energy storage to be the more efficient or cost effective solution to an ISO-identified need by providing services such as

[2] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

[3] FERC docket No. EL18-131-000 Issued September 20, 2018. Paragraph 24, page 10,

voltage support or thermal overload mitigation, and in doing so increase the capacity, efficiency, or reliability of an existing or new transmission facility.

Regarding (2), to justify approval of energy storage as a transmission asset, there should be compelling technical, operational, or contractual considerations that preclude procurement by a load serving entity as a market resource under local regulatory authority rules. Compelling technical, operational, or contractual reasons for considering storage as a transmission asset include:

(1) ISO visibility in real-time operations, including a complete and unencumbered path to the operation of that storage device in real-time;[4]

(2) Anticipated constrained or restricted operation of the energy storage resource due to the nature of the transmission need identified in phase 2 of the TPP study process;

(3) The infeasibility of procurement through normal bilateral contracting processes;

(4) Inconsistency between resource adequacy must-offer obligations and transmission system needs; and

(5) Overly complex interconnection processes as a market resource that would impede development of the resource.

The ISO notes that a transmission asset directly connected to the ISO-controlled grid avoids many of these complications by providing direct operational line of sight from the grid to the storage device, as opposed to a distribution-connected resource that is connected to the transmission system through facilities the ISO does not have visibility to, or operational control over. A distribution-connected resource could also be terminated to different substations depending on the current configuration of the distribution gird, or be unavailable without ISO knowledge due to distribution limitations. An ISO controlled grid connected device also provides clarity on cost allocation – regional or local TAC – based on voltage level the storage is interconnected to (greater than 200 kV or less than 200 kV). Lastly, an asset directly connected to the ISO-controlled grid avoids conflict with CPUC-jurisdictional distribution resource planning, including planning for distributed generation and behind-the-meter resources.

Subject to the above conditions, the practical consequence of the ISO relying on an energy storage device to provide transmission service consists of being able to call upon the energy storage device at a particular point in time – possibly with no notice but during some particular period of risk – to rapidly change its output to meet a reliability need on this ISO controlled grid. This also requires the ISO and energy storage to manage the state of charge of the energy storage device while leading into the particular period of risk. While this could be considered somewhat analogous to managing the startup time of a gas-fired generator functioning as a local capacity resource, it goes a step further by requiring drawing energy from the grid in order to charge – which must be managed well ahead of the risk period. Further, and somewhat

[4] The ISO notes that this would hold for all components of the resource, including any resources with multiple locations on the distribution system.

analogous to transmission lines, the ISO relies on all transmission assets to meet future operating and planning transmission needs, not just the needs upon which the transmission asset was originally approved and constructed.

4.1.2. Consideration of economic-driven energy storage transmission solutions

To date, the ISO's consideration of storage as a transmission asset has been based predominantly on whether the proposed storage solution meets an ISO-identified reliability need, as opposed to economic need as defined in the ISO tariff. This is because existing ISO tariff provisions for economic-driven transmission primarily relate to market-based benefits, including:

- Reducing local capacity needs, in which case the storage should compete under the resource adequacy framework; and
- Reducing market costs, in which case the conditions in section 4.1.1 are not met, and storage as a "transmission" asset would introduce the market interference that FERC's Policy Statement seeks to avoid.

FERC's prior guidance in *Western Grid* also supported the position that energy storage should be considered for reliability purposes by noting that transmission assets should provide transmission services, *e.g.*, address thermal loading and provide voltage support, as noted in section 4.1.1.

The policy statement indicates that storage may also be identified as a transmission solution to meet an economic-driven transmission need, when the storage resource is part of a solution that provides transmission service to alleviate a constraint and/or reduce congestion, thereby allowing access to lower cost energy or capacity. The policy statement does not support approving energy storage as a transmission asset when providing market-based services as a competing energy resource inside a constrained area. FERC further clarifies this point in its decision in EL18-131-000 as noted above. The ISO will consider energy storage to meet economic-driven transmission needs when the solution reduces congestion, but the ISO notes that the majority of the economic benefits for storage projects appear to occur when acting as resources competing against other market resources.

4.1.3. Considering market revenues in approving transmission solutions

To date, the ISO has not considered potential market revenues attributable to energy storage resources when deciding the best transmission solution due to FERC guidance in the *Nevada Hydro* and *Western Grid* orders precluding storage from also accessing market revenues. The FERC policy statement opened the door to a cost-of-service based transmission service resource also accessing market revenues, but it cited numerous issues the ISO would need to address prior to implementing such a framework. The ISO notes that over reliance on market revenues to justify an energy storage resource as a transmission asset runs the risk of looking like a market resource and encroaching on local regulatory authority jurisdiction over resource adequacy and planning. This will require careful consideration on a case-by-case basis through the course of the annual TPP in Phase 2.

5. Proposal

5.1. Scope of Policy Examination

As noted above, developments at both the state and federal levels are driving a more integrated view of storage resources providing both transmission and market services. These developments include:

1) Recently approved battery storage projects being advanced as transmission assets in the ISO's most recent TPP,
2) The FERC Policy Statement issued on February 6, 2017 and clarification in its decision in EL18-131-000, and
3) Expansion of market resources largely put in place through California state procurement processes under the CPUC.

Accordingly, the ISO is re-examining its consideration of storage in the TPP.

5.1.1. Proposed scope

The scope of this initiative is to enable storage providing cost-based transmission services to also participate in ISO markets and receive market revenues to provide ratepayer benefits and provide greater flexibility to the grid. The idea is market-based revenues generated from market-based services can reduce the costs of the asset to be recovered under a cost-of-service contract, reducing the burden on rate-paying consumers.

In its policy statement, FERC refers to "cost-based services" and "cost-based rate recovery" as being separate and distinct from "market-based services" and "market based revenues." Further, cost-based services examples provided in the policy statement include "transmission or grid support services or to address <u>other needs identified by an RTO/ISO.</u>" In light of this general consideration, the scope of this initiative focuses specifically on storage resources the ISO identifies through the TPP as needed to provide transmission services.[5] Although a resource may be eligible to access market-based revenue streams, the ISO must first determine that the resource is needed to address a specified transmission need as determined in the ISO's TPP.

To achieve this objective, the ISO will specifically address the following:

[5] This is includes storage resources providing reliability-based transmission services, economic, and policy projects. The ISO is indifferent to transmission or distribution connection, provided all other required visibility and control needs are also met.

- The cost recovery mechanism,
- The contractual arrangement with the SATA resource and the ISO, and
- The determination of how a SATA resource may access market revenues.

This paper explores the framework and requirements - and allowable mechanisms - for those resources to also access market revenues by providing market services that do not conflict with the fundamental transmission purpose for which the resource was selected in the TPP.

Additionally, the January 19, 2017 FERC policy statement states that SATA resources could access both cost-of-service and market revenues, but the ISO needs to be able to demonstrate that the following issues would not arise:

1) The potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in the wholesale electric markets to the detriment of other competitors who do not receive such cost-based recovery;
2) The level of ISO control over the operation of an electric storage resource could jeopardize its independence as the market operator; and
3) The potential for combined cost-based and market-based rate recovery to result in double recovery of costs by the electric storage resource owner or operator to the detriment of the ratepayer.

The manner in which each of these objective is achieved is also within the scope of the current initiative. As noted above, FERC provided additional clarity on the policy statement in EL18-131-000.

5.1.2. Issues that are beyond the scope

Specific issues that are beyond the scope of the current stakeholder initiative are:

- **Storage resources procured or contracted for reasons beyond meeting a specific transmission system need identified by the ISO in the TPP**. This includes following storage resource use/procurement cases:
    - Other state and FERC initiatives considering other storage options,
    - Exclusively providing market-based services, and
    - Storage procured, in whole or in part, through a CPUC-mandated capacity procurement process.
- **The TPP evaluation methodologies**. The ISO is not reexamining its TPP, which identifies needs and selects the optimal solution(s) to meet identified needs. These issues are appropriately considered in the ISO's annual TPP. If additional

clarification of the evaluation process is needed in the future, the ISO will address it on a case-by-case basis within the annual TPP.

- **The framework for competitive solicitation and the applicability of the ISO's current competitive solicitation framework**. The ISO's current competitive solicitation tariff provisions apply to regional storage facilities just as they apply to other regional transmission facilities such as reactive support devices. Specifically, projects connected at 200 kV or higher will be subject to competitive solicitation unless the project constitutes an upgrade to an existing transmission facility. Incumbent PTOs are responsible for projects connected at less than 200 kV.
- **Cost allocation of the cost-based revenue requirements for rate-based assets.** The ISO's current tariff provisions that address cost allocation apply to storage just as they apply to other transmission facilities such as reactive support devices.
- **Resource adequacy value**. The ISO will not consider cost-of-service based storage resources procured through the TPP to count as resource adequacy resources as these resources are already taken into account when determining local capacity area needs.[6]

5.2. Transmission Cost Recovery Options

The ISO identifies reliability needs in the TPP, then it examines numerous possible alternatives, including non-transmission options, to determine the more cost-effective and efficient solution to address the identified need. The cost recovery for transmission assets currently comes solely through the TAC. Allowing storage to act as both a transmission asset and a market resource means that additional cost recovery mechanisms may now enter the equation. If the ISO facilitates storage resources acting as both a transmission asset and a market resource, then the ISO must establish rules and policies to determine how to appropriately reconcile multiple revenue streams against the cost of the storage resource.

Historically, the lines between a transmission asset and generating resource where clearly defined. As a result, cost recovery for transmission assets versus market-based resources was clear and fairly well defined. As shown in Figure 1, the PTO of a transmission asset has traditionally recovered the transmission facility costs through the ISO's TAC. Alternatively,

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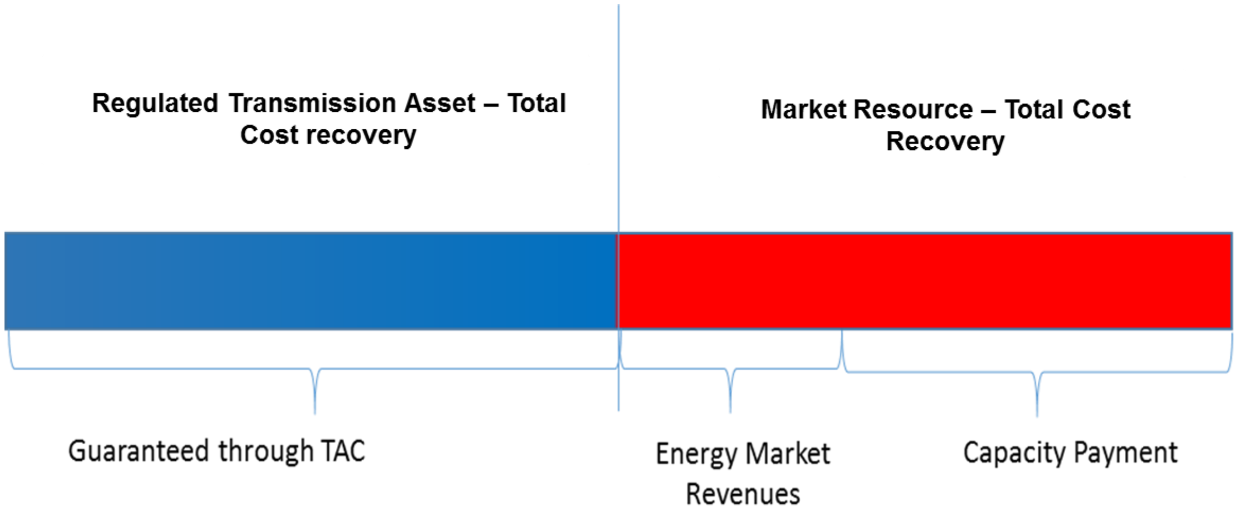
[6] In comments, PG&E asserts that "all resources that contribute to or reduce the local capacity requirement have a must offer obligation such as Capacity Procurement Mechanism (CPM) designations." This statement is not completely correct. Not all resources that reduce the local capacity requirement have a must-offer obligation. PG&E goes on to assert "[a]llowing a SATA resource to reduce the local capacity requirement in a similar way as a deliverable resource without a must offer obligation, assumes that the reliability need of the SATA resource will coincide with the same contingency event that establishes the minimum local capacity requirement." The ISO notes that the market participation and notification will consider contingency conditions and the SATA resources would have been studied and approved to address contingency event. If any such event is possible, then the resource would not be permitted to participate in the market.

market-based resources have received cost recovery through a variety of sources, including revenues from capacity and energy payments.

Figure 1: Traditional separation between transmission and market resources



The ISO selects specific detailed preferred solutions though the TPP. This means that preferred solutions are "right-sized" to address a specific need. In other words, SATA resources would not have additional capability in excess of that which is needed to address the identified need; the TPP would not specify capabilities beyond what is needed. This means that any network and interconnection upgrades for the resource will be covered under the TRR. It also means that large SATA projects may be selected as the preferred solution in the TPP and be eligible for cost recovery.[7] This is similar to approving a traditional transmission line where the size of the line is "blocky" and may not fit the identified need precisely. Additionally, the ISO is not saying that a SATA project that exceeds the minimum size needed to address the transmission need could not be selected as the preferred solution in phase 2 of the TPP. However, as noted below, the ISO proposes to only cover the network and interconnection upgrades needed for the approved solution.

The ISO notes that some project sponsors may seek to include opportunities to add additional market based resources or capability. In comments on the straw proposal, PG&E stated "[t]he incremental capital cost, interconnection facilities, reliability network upgrades, local delivery network upgrades and other incremental facilities costs triggered by the excess capacity would be determined during ISO's generation interconnection process."[8] The ISO agrees. While the ISO is not expressly foreclosing these opportunities,[9] it notes that any incremental cost for interconnection facilities and generation beyond the ISO's preferred solution will not be covered by the TRR.

[7] In comments, NextEra noted that this issues required additional clarity.
[8] PG&E straw proposal comments at p. 3.
[9] EDF-R and NextEra both support the ISO allowing SATA resources as potential options.

In comments on the revised straw proposal, SDG&E noted that "a prospective storage owner that desires to size its facility larger than what the CAISO's identified reliability need requires, or which could be operating during non-reliability periods (which is likely most SATA facilities), be obligated to enter the CAISO queue for the entire amount of its installed capacity."[10] The resources and costs for the approved, right-sized project are authorized in the TPP, therefore the ISO will not require the project sponsor to enter to the interconnection queue for the entire capacity of the resource. However, any incremental capacity must complete the generation interconnection process and will not be permitted to jump the interconnection queue.

LS Power also challenges the ISO's determination that a project need not go through the interconnection process, stating "[a]llowing a SATA resource to participate in the market after receiving discriminatory access will negatively impact the market for storage services." The ISO reiterates that, in most instances, storage should be procured through LSE procurement as market resources, and will be assessed to provide transmission services under the limited circumstances considered in section 4, above. As a result, the ISO does not believe that SATA resources and the fact that the TPP has assessed there interconnection will have any impact on the market for storage services.

Cost Recovery Options

As part of this stakeholder process, the ISO is considering three options that rely on maintaining cost recovery through TAC for SATA resources. Specifically, the ISO is exploring the following options:

1. **Full cost-of-service based cost recovery with energy market crediting.** In this context, any revenue received from market services would be treated as a revenue offset, thus reducing the revenues otherwise required through TAC (high or low voltage) to provide cost-of-service based compensation to the PTO.
2. **Partial cost-of-service based cost recovery with no energy market crediting.** The asset is in rate base, but only a portion of the cost recovery is guaranteed through cost-of-service provisions, and the owner bears both the upside and downside risk of recovering a portion of its costs (and return) from market services.
3. **Full cost-of-service based cost recovery with partial market revenue sharing between owner and ratepayer.** This option mitigates financial risks associated with option 2 and provides incentives that do not exist under option 1. More specifically, this option would provide incentives for the owner to participate in the market by allowing the resource owner to retain some percentage of the market revenue. However, resources will not be subject to the risk of not being able to at least recover the full cost of the resource.

[10] SDG&E comments on straw proposal at p. 5.

Prior to providing additional details about each of these options, it is important to clarify that each is designed to avoid double recovery of costs. Each option will allow market participation and provide the resources with a TRR. However, each option provides distinct differences in terms of what costs are recoverable under the TRR and which costs would the responsibility of the resource owner. In comments, Calpine and Boston Energy remain concerned that SATA resources will be permitted to participate in energy markets even though they are able to recover costs through the TAC. The ISO notes that, in its policy statement, FERC cites numerous instances where a resources receiving both cost based and market based revenues at the same time. The ISO's options will look to establish how the TRR is determined. Once determined, market revenue adjustments can be applied through the Transmission Revenue Balancing Account Adjustment. Since the market revenues are separate from the TRR determination and received for providing a separate service, they do not constitute double recovery cost so long as the resource owner bears any additional maintenance costs incurred from voluntary market participation.

In the previous iteration of this stakeholder process, the ISO proposed a "TRR crediting mechanism" designed to serve two purposes: (1) protect ratepayers from early degradation of SATA resources operational capabilities due to dispatches from ISO market participation and potential for reduced useful lifespan for a SATA resource's ability to meet the identified transmission need(s) and, (2) ensure the SATA resource owner considers all marginal costs when bidding into the market. While most stakeholders support the principles behind the Transmission Revenue Balancing Account crediting mechanism, they also expressed concerns regarding its complexity, accuracy, and feasibility. The ISO has continued to review its original proposed methodology and determined that the concerns expressed by stakeholder are reasonable. As a result, the ISO is exploring other options to manage the above risks.

Most stakeholders supported using the procurement contract to manage potential resource depletion risks and cost recovery. The ISO explored this option further and believes contractual requirements can achieve similar outcomes to the TRR crediting mechanism. Although the contractual treatment for each option may vary slightly, all options will require strict performance and maintenance provisions that ensure the resource owner will be responsible for the resource's upkeep and availability, regardless of the frequency or volume of market participation. These provisions ensure that the resource owner internalizes any depreciation of the resource from its voluntary market participation. This should also ensure that SATA resources participating in the market are doing so at prices not lower than the resources marginal cost.[11]

To provide all stakeholders with a common understanding of the terms used by the ISO, the ISO provides the following:

Rate Base (total actual cost for transmission, general & intangible) = addition of:

[11] If resources do bid at marginal cost, then any market price reductions should be seen as appropriate.

1. Net Plant in Service = Gross Plant in Service – Accumulated Depreciation & Amortization
2. Adjustments to Rate Base = Accumulated Deferred Income Taxes (ADIT) + Construction work in Progress
3. Land held for future use
4. Working Capital = % of (O&M – amortization) + Materials & Supplies + Prepayments

Annual Revenue Requirement = O&M (fixed and variable) + A&G (Regulatory Commission Expense) + Depreciation Expense + Taxes (Payroll + Property + gross Receipts) + Income Taxes (Amortized Investment Tax Credit + ITC Adjustment + AFUDC +Income tax + Tax adjustment) + Return (Rate Base * Rate of Return)

Annual Revenue Credit* = Standby Revenue + Wheeling Access Charge + Existing Contract Revenue + Net Positive Annual Market Revenues from CAISO

Net positive market revenues from CAISO = Monthly sum of all revenues received by the resource owner for any market based services provided to the ISO, limited to positive values to limit recovery of poor bidding strategies

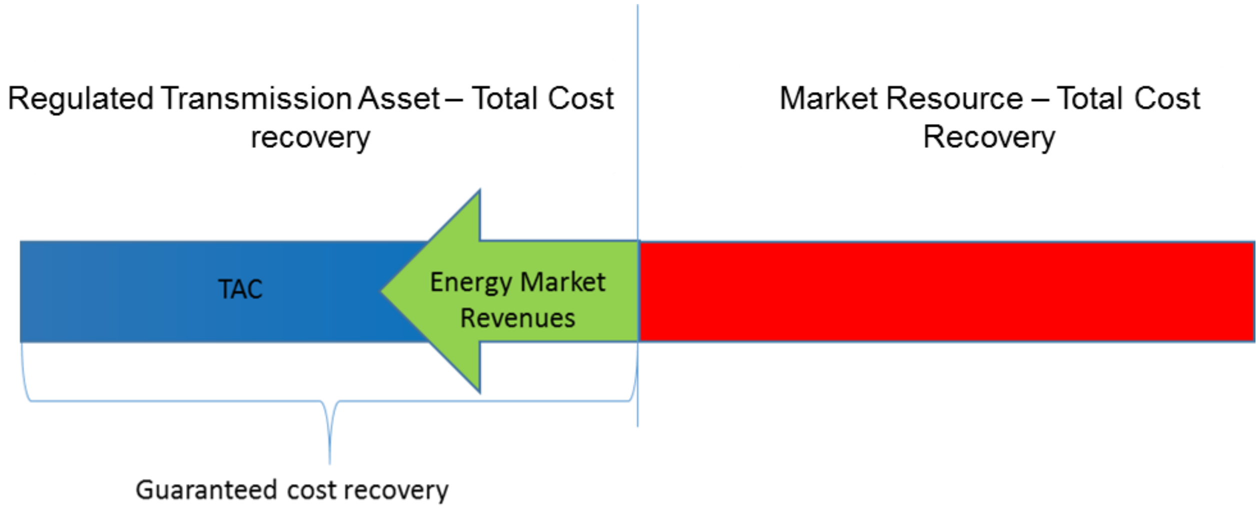
* Not all credits will apply to SATA resources

The remainder of this section provides greater details for each option.

5.2.1. Full cost-of-service based cost recovery and energy market revenue crediting

As shown in **Error! Reference source not found.**, below, the full cost-of-service based cost recovery and energy market revenue crediting option relies on maintaining the clear delineation between transmission and market-based assets, at least as it pertains to cost recovery for SATA resources. It ensures that a resource's total TRR is covered, but any additional market revenues would reduce the overall TRR recovered through TAC. Establishing a cost recovery framework that ensures all of resources prudent costs are fully covered is that it facilitates an apples-to-apples comparison across all other bids into a request for offers ("RFO") solicitation. Additionally, the ISO will have to establish any necessary settlements protocols to ensure these net revenues are properly captured and settled against the cost of the resource.

Figure 2: Illustration of full cost-of-service based cost recovery and energy market crediting



The ISO envisions two scenarios in which the SATA project sponsor could be selected under this cost recovery option. The first scenario is when the project is directly assigned to the incumbent PTO. The second scenario is when the project sponsor bids into TPP phase 3 competitive solicitation process, selecting this option.

5.2.1.1. Direct Assigned projects

All transmission projects that are connected at 200 kV or lower are directly assigned to the incumbent PTO. The same assignment process will hold for SATA projects. More specifically, these are SATA projects that are approved by the ISO Board of Governors as the preferred solution, but are not subject to the TPP phase 3 competitive solicitation process. In these instances, the incumbent PTO will not be subject to competitive forces that would mitigate the ability of the incumbent PTO to keep all potential market revenues. As a result, the ISO proposes that direct assigned SATA projects will only be permitted to utilize the full cost-of-service based cost recovery and energy market crediting option.

Specifically the ISO will credit all net market revenues against the annual TRR. Further, the ISO clarifies that net market revenues will be limited to positive net market revenues on a monthly basis. This is designed to ensure the resource is not operating inefficiently in the market at the expense of captive ratepayers.

Example 1: TAC treatment for Direct Assigned projects

Total cost of service = Annual TAC = Annual Revenue Requirement – Annual Revenue Credits

Annual Revenue Credit to rate payers from net market revenues = 100% Net market revenues

Rate of Return/Equity – Based on existing Rate of Return/Equity

Bidding – Required, as permitted by CAISO

The most significant challenge with this model is that it provides little incentive for the resource to participate in the market. However, to ensure ratepayers are able to benefit from market participation from direct assigned projects, the ISO is exploring establishing a must offer obligation that ensures direct assigned SATA resources that are permitted to participate in the market do so. As a starting point, the ISO is considering establishing a must offer obligation ("MOO") that either sets the discharge price at the energy price cap or at the 95 percent level at a given location. This MOO ensures the resource is not suppressing market prices and ensures the ISO remains independent. Additionally, the ISO is still considering if a MOO for charging is needed or if it sufficient to specify only the MOO for the discharge of the resource and allow the resource owner to manage the charging portion. <u>The ISO is seeking stakeholder feedback regarding what a MOO should look like for direct assigned SATA resources.</u> Because the ISO is considering a MOO for direct assigned resources, the ISO also proposes that all maintenance costs, including those incurred due to market participation will be eligible for recovery under the TRR.

5.2.1.2. Competitive procurement option

A project sponsor may propose a project into phase 3 of the TPP presenting assumptions of market revenues in an effort to be selected. However, absent additional obligations, there is no assurance that the resource sponsor would follow through on pursuing those market revenues. This differs from the direct assigned projects in that the incumbent PTO has no option about what cost recovery option available to them in those circumstances. For competitive procurement, the project sponsor has other options available to it (see below). The ISO has explored various options to provide additional incentives for SATA resources selecting this option to participate in the market, but concluded that no additional incentive is required. In phase 3 of the TPP, the ISO will assess resources selecting this option based on the overall cost-of-service and will not assume any market revenues. However, the <u>ISO is also considering if projects subject to competitive solicitation process should be allowed to elect to be subject to the same provisions as the direct assigned projects. The ISO seeks stakeholder input regarding whether it should make the same provisions available to both direct assigned projects and to the projects subject to competitive solicitation process</u>.

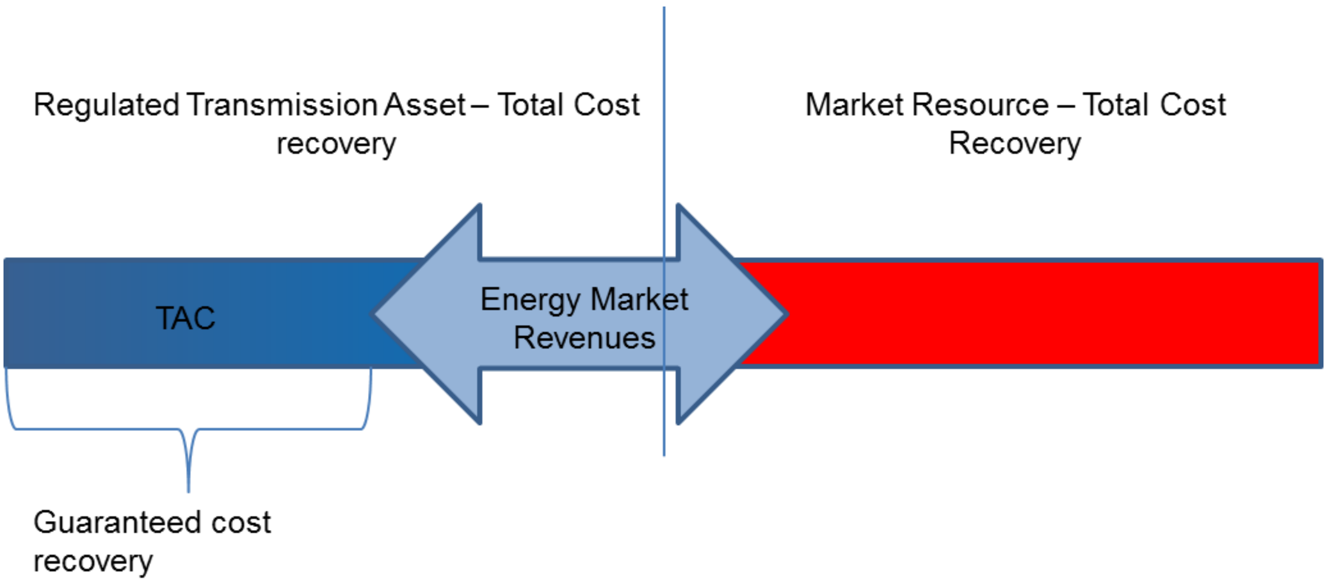
5.2.2. Partial cost-of-service based cost recovery and no energy market crediting

The partial cost-of service option relies on moving away from clearly defined or guaranteed cost recovery for SATA resources. In this model, the resource would only have a portion of its TRR guaranteed, with the remainder recovered through market revenues.[12] The partial cost-of service option is depicted in **Error! Reference source not found.**, below. Although this option guarantees less of the SATA resource's transmission revenue requirement may be recovered through the TAC, it provides for additional potential upside in that it would not be required to

[12] Only ISO market revenues could be considered. The ISO will not assess projects seeking funding through both the CPUC procurement and approval in the ISO's TPP.

credit all ISO market revenues against its' TRR. This means that although the project sponsor accepts the risk that it may not fully recover its TRR in a given year, it potentially could receive market revenues that, when combined with the specified level of guaranteed TRR recovery, are greater than a fully guaranteed TRR. This would be a completely new model for transmission assets.

Figure 3: Illustration of Partial cost-of-service based cost recovery and no energy market crediting



Because this model allows a resource owner to forecast how much cost could be recovered through markets, it also adds complexities in assessing the resources financial risk, which can impact its ability to participate in competitive solicitations. For example, the current evaluation method for assessing projects to resolve an identified reliability need considers two things (1) does the project address the identified need, and (2) what is the cost of the project compared to other alternatives. As a result, in Phase 3 competitive solicitation, the ISO will evaluate each bid to determine if it assumes reasonable levels of expected market revenues and/or if the project sponsor is able to accept the risks that all costs may not be recovered.

Under this model, any changes to the time or frequency a resource can provide market services will also impact the resource's ability to recover costs. However, the ISO has determined that is not feasible to provide a firm schedule that identifies market opportunities for SATA resources over the life of the project. It is not clear if the notification processes currently under consideration (detailed below in section 5.5) provides sufficient and or comparable information to facilitate financing under this option. In the revised straw proposal, the ISO considered eliminating this options. Numerous stakeholders, including CESA, CRI, LS Power,[13]

[13] LS Power also details concerns it has with the other options presented by the ISO, indicating that this option is the only viable option. The ISO has reviewed these and does not share LS Power's concerns about independence or a subsidized resource.

ORA, and TransCanyon supported the ISO maintaining this option. Alternatively, Calpine, NextEra, NWHA, SCE, SDG&E, and SWDCA[14] recommended the ISO eliminate the option. While opposition remains, the opposition focused primarily on the idea that this option would never be selected or that a project sponsor could not get necessary financing for the project. They did not demonstrate any potential harm from maintaining the option. Although the likelihood that a project sponsor would select this option and be able to finance its project given the uncertainty regarding the level of uncertainty for market participation remains unclear, there seems to be sufficient support to maintain this option.

Example 2: SATA seeking less than total cost of service through TRR

Total cost of service > Annual TAC = Annual Revenue Requirement – Annual Revenue Credits

Annual Revenue Credit to rate payers from net market revenues = 0

Rate of Return/Equity – Based on competitive solicitation

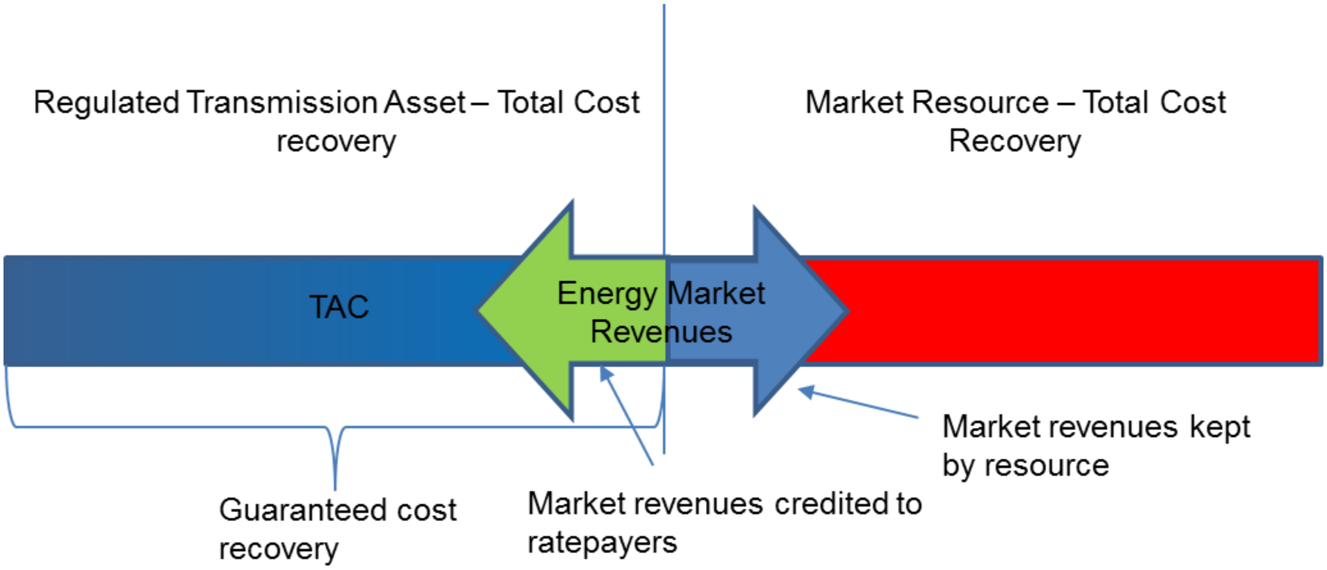
Bidding – As permitted by CAISO, but not required

5.2.3. Full cost-of-service recovery with partial market revenue sharing between owner and ratepayer

This option is designed to provide incentives for market participation not present in the full cost-of-service option defined in section 0, while mitigating some of the financial uncertainties that exist in the partial cost of service described above in section 5.2.2. Specifically, this option would allow a project sponsor to submit a bid into Phase 3 of the TPP for full cost-of-service. In order to incentivize market participation, the project sponsor would be permitted to retain some portion of the market revenues with the remainder being credited to the ratepayers in the form of a lower TRR for the resource.

[14] Cogentrix does not suggest this option should be eliminated, but does state that it is inconsistent with the FERC policy statement.

Figure 4: Illustration of full cost-of-service recovery with partial market revenue sharing between owner and ratepayer



In comments to the working group there were two basic means by which this option could be administered. The first option is simply that *any* market revenues would be split, the second option is that the resource would have to first surpass a given amount of market revenues before it would be permitted to retain some portion of market revenues. Under either scenario, the ratepayer benefits. Based on stakeholder feedback and an assessment of the administrative challenges associated with tracking whether a resource has reached a particular net market revenue threshold, the ISO proposes to apply the market revenue split to all market revenues. In comments, SCE suggested that "wear and tear" reduce the net market revenues prior to making the split. While ISO understands the principle behind this suggestion is similar to the ISO's previous capital crediting mechanism, it is also subject to many of the same shortcomings with respect to how to determine a specific "wear and tear" adjustment. As such, the ISO will defer such adjustments, relying on the contractual provisions, below in section 5.4, instead. Additionally, the requiring a minimum net market revenue threshold can potentially reduce the efficiency of the bidding and market participation. For example, the resource owner may look to participate in the market too aggressively to exceed the threshold. Finally, the ISO will not propose a fixed split for market revenue sharing. Instead, the ISO will assess each proposed split within the TPP phase 3 process for the preferred solution.

Example 3: SATA seeking full cost-of-service recovery with partial market revenue sharing between owner and ratepayer cost of service through TRR

Total cost of service = Annual TAC = Annual Revenue Requirement – Annual Revenue Credits

Annual Revenue Credit to rate payers from net market revenues = net market revenues * X%

X% = Percent to credited back to ratepayers

Rate of Return/Equity – Based on competitive solicitation

Bidding – As permitted by CAISO, but not required

5.3. Option in the event of insufficient qualified project sponsors

Under the ISO's current tariff, if there is only one qualified project sponsor for regional transmission projects, the ISO awards the project to that project sponsor.[15] However, under the current proposal, this could result in allowing a project sponsor to submitting bids, for example, for 99.99 percent of total cost to be recovered through cost-of-service and the ability to keep 100 percent of all market revenues (*i.e.*, under the partial cost-of-service option described above in section 5.2.2). As noted in DMM's comments, SATA projects can provide benefits to ratepayers when there is sufficient competition. In order to mitigate such scenarios, the ISO is currently exploring options to either ensure competitive solutions or mitigate costs to ratepayers. Although the ISO has not experienced any shortage of participation in the TPP phase 3 competitive solicitation process, the ISO proposes that at least three qualifies project sponsors are required for the partial cost-of-service or full cost of service with revenue sharing to be options for consideration. Additionally, all project sponsors would be required to also submit a full cost-of-service bid as described in section 5.2.1 as a contingency option. The ISO will only consider this option if there is an insufficient number of qualified project sponsors.

5.4. Contractual Arrangements between ISO and SATA Accessing Market Revenues

Based on stakeholder comments, the ISO has determined that a new *pro forma* agreement will be developed for the SATA resources that includes provisions from various existing agreements, including the TCA, APSA, PGA, PLA, RMR, MSA, etc., depending upon the final policy determined for this initiative. An example of potential terms and conditions that may be included, but are not limited to, provided in the table under in Appendix 9.1**Error! Reference source not found.**

Understanding that the ultimate contractual terms for this initiative will be determined based on the policy that is developed. The CAISO received significant support from stakeholders on the concept of developing a pro forma agreement common to all SATA resources and continues to pursue this avenue in its policy development. Following substantial stakeholder comments on this issue following the revised straw proposal, the CAISO is introducing two new concepts for further discussion and development with stakeholders, namely;

3) A contractual alternative to the TRR credit mechanism, and

4) Multiple variants of contract terms for SATA resources.

Several stakeholders including CESA, CRI, Next Era, ORA, PG&E and SDG&E, commented that the CAISO and stakeholders would be better served in including maintenance and replacement obligations in the SATA agreement in place of the TRR credit mechanism

[15] See tariff section 24.5.3.4.

proposed by the CAISO. Stakeholders pointed out that SATA resources can vary greatly in terms of technology and degradation factors, and a one size fits all formula rate may not be practical. While they appreciate the problem that the CAISO is trying to address via the TRR credit mechanism, i.e. protecting transmission ratepayers from the undue burden of bearing replacement costs of a SATA asset due to degradation from market participation, they consider contractual terms and conditions to be more appropriate. This will also allow CAISO and the SATA owner to negotiate terms and conditions specific to the SATA resource allowing for a more appropriate oversight of potential ratepayer burdens.

The CAISO recognizes these concerns and proposes to include these terms and conditions in the SATA pro forma agreement. The CAISO also raises the issue of cost sharing between transmission ratepayers and SATA owners (e.g. the balance of revenue sharing versus the increased degradation to the energy storage unit) through the SATA agreement and recognizes this as an additional issue to be resolved in the development of the pro forma agreement. <u>The CAISO invites stakeholders to provide additional comments on this issue to further develop this concept.</u>

Stakeholders including CESA, CRI, Six Cities and ORA, commented that the CAISO and stakeholders would be better served to tailor the term of the agreement based on the SATA resource technology. For example, certain stakeholders suggested that it may be more appropriate to provide long term contracts to resources with longer life cycles such as flow batteries and pumped storage, and shorter term contracts to resources with shorter lifecycles.

The CAISO has considered these comments and agrees that there are certain benefits to this idea and proposes to structure the pro forma SATA agreement around this framework. But the CAISO is also reluctant to leave the term of the contract completely open-ended to be resolved during contract negotiations, and instead proposes three variants of the pro forma SATA agreement with different term lengths, i.e. 10 years, 20 years and 40 years. While this provides SATA owners and the CAISO the flexibility of tailoring the agreement to better fit the transmission need and the lifecycle of the asset, it also minimizes the expected variation in terms and conditions by limiting the term option to three (3) types. For e.g. the CAISO believes that there may be significant differences in certain terms and conditions based on the term length of the contract, such as escalation factors, market participation conditions, maintenance obligations, capital additions and repairs, testing and monitoring, among others. <u>The CAISO invites stakeholders to provide comments on this issue to better develop this concept into the various pro forma agreements</u>.

The CAISO notes that certain parties such as PG&E, SCE, and SDG&E, provided comments for adding provisions into the pro forma agreement in addition to the table provided in Section 8.1. These provisions included but weren't limited to defining SATA operator, confidential data sharing, change in law, permitting, market revenues, return to service etc. The CAISO duly recognizes these comments and will consider them in the development of the pro forma agreements.

5.5. SATA market participation notification process

The ISO proposes to provide a SATA notification to indicate to SATA resource owners when a SATA resource will be permitted to participate in the market. All notifications allowing for market participation will be made prior to the relevant market runs. Once notified that the resource will be allowed to participate in the market, the owner of the SATA resource will be responsible for the bidding and market participation of the resource, not the ISO. The ISO will also notify all market participants of the designation of SATA resources as transmission assets through the CAISO Market Results Interface (CMRI) in the same manner as transmission constraint activations are currently noticed through CMRI.

The ISO continues to explore options for how and when it will notify SATA projects about market participation opportunities. Initially, the ISO attempted to identify specific time (hours, months, or seasons) when a resource would be permitted to provide market services. Many stakeholders, including CRI, LS Power, ORA, and SDG&E, have commented on the need for this type of upfront information to facilitate project financing. However, based on additional analysis and sensitivity studies, the ISO determined that it is not possible to provide resources such information with certainty during the TPP phase 2.[16] These additional use-cases are provided in the appendix at section 9.2.

The ISO also previously explored two potential notification timeframe options, either; 1) Day Ahead market option, or 2) D+2 option timeframes. The ISO provided these options for stakeholder consideration, and both were intended to ensure that transmission services take primacy over market participation.[17] After further review, the ISO believes that the D+2 timeframe option is not a viable option due operational concerns over the limitation of available forecast and resource bid availability in the D+2 process and timeframe. Further details on the additional notification options that were considered and new options for stakeholder feedback are included below.

Previously, the proposed Day-Ahead Market Option approach for the notification of SATA resources for market participation opportunities through the Day-Ahead market process was to utilize the DAM RUC process. The ISO received stakeholder feedback indicating some concern over the proposed approach to use the DAM RUC market run to determine if SATA resources would be needed for transmission service or could be released for market participation opportunities because they believe that the ISO's DAM process model does not capture the level of detailed constraints that are utilized in the ISO TPP studies. The ISO has considered the stakeholder feedback and had further discussion on the possible options. The resulting direction is to provide further background on the needs and drivers that SATA resources would

[16] It should also be noted, that this likely forecloses the opportunity to bilaterally contract SATA resources as proposed by CRI in its presentation at the June 29, 2018 working group meeting.

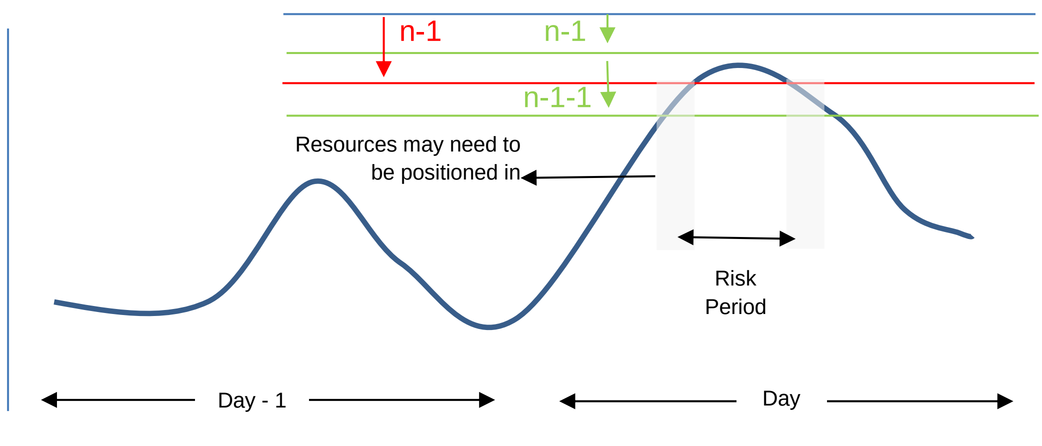
[17] San Diego County Water Authority and City of San Diego notes that the ISO should allow for market participation unless recalled. The ISO believes this puts market participation as the primary objective of the resource. Such resources should look to be procured a funded as market resources, not transmission resources.

be identified and selected to address, provided below, as well as to propose a new, load based SATA notification option.

The planning needs that result in preferred resources or storage devices being selected in areas is generally driven by load pocket concerns – either voltage or thermal limitations – where these resources can be an alternative to transmission upgrades or conventional generation.

A common theme among these transmission needs is for non-wire alternatives to be properly positioned at the start of a risk period – generally based on load levels in the area and the specific characteristics of the resources available in the area. The following figure helps illustrate this need for resources to be properly positioned prior to a forecast period of need.

Figure 5: Scenarios that would be identified as a transmission "need"



Note that for an n-1 limitation, being "positioned" may mean producing power at the start of the risk period, or just being capable of quickly ramping up depending the emergency rating should that contingency occur. For n-1-1 contingencies, it may mean being capable of producing power quickly at any time in the risk period, but only after the first contingency occurs. For batteries, this means being fully charged at the beginning of the risk period and ready to discharge or actually discharging when instructed.

The ISO is already addressing similar circumstances for local area needs on a limited basis with relatively comparable overall requirements, but with slightly different circumstances. The ISO believes the SATA notification process should build off existing and understood operational practices to the greatest extent possible rather than coming up with new and untested operational approaches for SATA resources. Thus, the ISO proposes to explore the applicability of a local area load forecast based test for SATA resource notifications.

Load based SATA notification test option

Considering stakeholder feedback, the ISO proposes to develop a load based notification test process to determine if a SATA resource will be needed for transmission service or can be released to the market for real time market participation. The proposed notification process would determine if the forecasted load levels for the following day, studied in the Day-Ahead timeframe, would indicate a need for a SATA resource as a transmission asset in a local load pocket for the following day. The proposed load based notification test process would also consider the import capability and available resource mix for the identified load pocket area. In contrast to some of the feedback and concerns expressed by stakeholders regarding previous notification process proposals, this test would determine if the needs in a local area require a SATA resource be exclusively a transmission asset dedicated to providing transmission services the following day.

This proposed load based SATA notification process is provided at a high level for initial consideration and is described as follows:

- In the Day-Ahead time frame, the ISO will perform the proposed load based notification test to identify when SATA resource(s) are needed based upon the load forecast for the local load pocket area, the available capacity from other local area resources, and the import capability into the load pocket.
- If the load forecast for the local area (<u>including an additional 10% operational reliability margin</u>) exceeds the level identified as a reliability concern, considering the import capability and capacity resource availability in the local load pocket areas, the SATA resource(s) in the local area will be designated as a transmission asset the following day.
    - The SATA resource(s) would need to be fully charged starting at 12AM of the delivery day and would not be allowed to participate in the Real-Time market for that following calendar day, i.e. 24 hour period.
- If the proposed load based notification test did not indicate the following day's load forecast (<u>including an additional 10% operational reliability margin</u>) would exceed critical load levels, considering the import capability and capacity resource availability in the local load pocket areas, then the SATA resource(s) would be deemed unneeded as a transmission asset and allowed to participate in the Real-Time market the following day.

Assessments as to whether or not a SATA resource will be deemed a transmission asset the following day will be made for an entire calendar day, i.e. a 24 hour period. It is prudent to make these reliability determinations at a daily granularity due to potential for forecast errors that may result in transmission needs at times that differ from the initial projection, when the resource may not be fully charged. The ISO has also included the 10% operational reliability margin adder to this proposed local load based notification test to protect against potential load forecast errors, uncertainty, and resource availability.

The ISO understands that some stakeholders may believe that other circumstances should be considered, including potential flow based needs, which may go beyond the more straightforward load based SATA notification process that is proposed here. The ISO understands this perspective, however, as a result of the additional complexity of a flow-based analysis, the ISO declines to propose a flow based notification test at this time. This could have negative implications on the ISO's market computational timeline and would also be limiting for the number of potential situations that could be studied due the added complexity and computation timing. The ISO may be able to reconsider the potential for some type of flow based SATA notification process to be developed in the future if advancements are made and the necessary computational complexity and timing are improved.

<u>The ISO seeks additional input from stakeholder on the proposed load based SATA notification process.</u>

6. Allocation to High or Low Voltage

The ISO currently has two levels of TAC: high and low voltage. High voltage transmission assets are those that are 200 kV and above resources, while low voltage resources are those that are below 200 kV. SATA resources may be interconnected at a level that differs from the transmission issue it has been identified to resolve. For example, the ISO may identify a Regional need, but identify a SATA resource connecting at a Local level as the best solution to meet the need. The ISO plans to maintain the current practice of allocating costs to high or low voltage TAC based on the point of interconnection.

In addition, stakeholder comments have suggested that the cost of storage receiving cost-of-service revenue streams providing transmission service should be allocated to regional or local transmission access charge recovery based on the issue the storage is addressing, rather than the voltage of interconnection. The ISO notes that today, regional (greater than 200 kV) reinforcements can be planned to address local (less than 200 kV) issues, and vice versa, and the assets are allocated to the level of the transmission system associated with their point of interconnection, not the level of the identified need. Also, contingencies on regional facilities can cause potential overloads on local facilities, and vice versa. In addition, once a transmission asset is put in place, it is not practical to track what other uses it might be serving in the future as other changes occur on the system – and revisiting the cost allocation – as to what issues would have otherwise emerged without the asset.

In short, this is consistent with current practices that have been found by FERC to be just and reasonable.

7. EIM Governing Body Role

For this initiative, the ISO plans to seek approval from the ISO Board only. The ISO believes this initiative falls outside the scope of the EIM Governing Body’s advisory role, because the initiative does not propose changes to either real-time market rules or rules that govern all ISO markets. This initiative is focused on ISO transmission planning process. This process applies only to ISO controlled transmission, and does not apply to transmission outside the ISO balancing authority area. The ISO seeks stakeholder feedback on this proposed decisional classification for the initiative.

8. Next Steps

The ISO will discuss this second revised straw proposal with stakeholders during a stakeholder meeting on October 23, 2018. Stakeholders are asked to submit written comments by November 6, 2018 to initiativecomments@caiso.com.

9. Appendix

9.1. Contractual provisions

Provision type	Description
Term of agreement, extension	Describes the term of the agreement and any extension provisions allowed.
Amendment rights	Describes the amendment rights of the parties under this agreement. May allocate 205 rights for certain sections to each party, e.g. CAISO right to amend section on market participation. Section will also describe how future amendments or rate schedule revisions will be done for life cycle replacements, capital additions etc.
Termination rights	Provides termination rights under different scenarios- default, force majeure, "no harm" termination by CAISO, change in law, sale of asset, termination by owner on notice- and associated cost recovery options. Will describe applicable cost recovery for SATA owner under different scenarios.
Default provisions	Identifies the different provisions for default: performance, maintenance, implementation, default on payment(CAISO/PTO) etc.
Change of ownership	Describes change of ownership process and any approval steps required: FERC order, CAISO approval etc.
Insurance and credit rating	Describes the insurance and credit rating requirements for the SATA owner.
CAISO tariff vs agreement	Describes when the agreement holds when in conflict with CAISO Tariff and when it does not.
Applicability to TAC	Describes how the annual revenue requirements of the agreement will be recovered through TAC, by referencing appropriate tariff sections. Will also discuss any crediting of market revenues through the TRBA to TAC.
Interconnection requirements	Describes interconnection requirements and facilities for the SATA resource, and responsibilities of parties to maintain interconnection facilities.
Applicable reliability criteria	Generic provision referring to applicable reliability criteria for the SATA.
Implementation schedule obligations	Describes the implementation schedule for the resource in the form of a milestone table including commencement date and in service date.

	Will also include periodic reporting and progress monitoring for the project.
Metering/telemetry requirements	Identifies the metering and telemetry requirements for the SATA resource.
Maintenance obligation	Broad section detailing all maintenance obligations for SATA resource: reliability standards, CAISO standards, other industry standards, good utility practice, etc.
Performance/operational obligation	Details performance obligations of SATA as a transmission resource Describes how SATA resource will respond to ISO dispatch instructions and perform on those instructions. Will address how the resource will be able to participate in the market, as applicable.
Performance and characteristics-Schedule	Schedule to the agreement that will detail the performance requirements and electrical characteristics such as MWh, ramp rates, SOC maintenance, MVAR, min/max load, etc.
Performance/availability testing	Describes how CAISO or SATA owner can periodically test unit for ability to meet the performance requirements. The details of the testing can be in CAISO operating procedures and the agreement can refer to the CAISO operating procedure.
Ancillary services	Describes which Ancillary Service products this resource is eligible for providing under market participation mode. May also describe use of AS for out of market dispatch.
Training/compliance requirements	Describes the reliability standard driven training and compliance requirements on this SATA resource.
Emergency operations	Describes the obligations of the unit to operate under system emergencies and respond to CAISO dispatch instructions. This is more relevant on the SATA resource as a market resource than a transmission resource.
Outage of service reporting	Describes the outage reporting process for the SATA resource- may describe specific outage reporting for periods where it is a transmission resource vs market resource.
Service availability	Describes the resource available process to meet the requirements to be a CAISO transmission resource. May specify a minimum service availability requirement and link payment of fixed cost to availability.

Monitoring for compliance	CAISO will describe processes for monitoring the SATA resource's compliance with performance obligations. May describe a periodic reporting process for monitoring compliance.
Non-performance penalties	Describes the calculation and types of penalties applicable for non-performance. Non-performance against dispatch instruction, missing operating target, being unavailable during transmission resource periods, etc.
Market participation obligation/restriction	Describes how and when this SATA resource can participate in the market. Will describe how ISO will notify SATA resource of market participation and how SATA resource shall respond to such instruction. CAISO will also retain right to pull SATA resource out of market participation if needed for reliability. May also describe any restrictions around bidding of the resource.
Dispatch and scheduling rights	Describes the CAISO's scheduling and dispatch right over the SATA resource owner's dispatch right. A CAISO transmission dispatch will override a market dispatch or bid by the SATA owner. The CAISO will have dispatch right over entire resource. Requires SATA owner to have an active Scheduling Coordinator.
CAISO dispatch process	Describes the process the CAISO shall follow for dispatching SATA resource as a transmission resource. Will describe the manual and/or automated dispatch process.
Invoicing of cost-process	Describes the invoicing process for paying fixed cost under agreement. This will also define the process for crediting market revenues, and sharing any market revenues, as applicable.
Cost schedule	Describes annual fixed revenue requirement in a schedule attached to the agreement. CAISO will include all necessary cost accounts to be included in the rate schedule. It should also describe any revenue sharing we are contemplating in the agreement, if applicable. The cost schedule may vary based on the term of the agreement.
Capital additions	Describes the entire process for requesting, approving and implementing any capital additions required for this project. Capital additions could include lifecycle replacements, unplanned capital items and repairs. Will also define the cost obligations of the parties involved for funding these capital additions. The capital addition costs may also vary based on the term of the agreement.
Contacts and notices	Generic provision for capturing all contacts and notices. We should have the right to revise this section without having to amend the agreement.

9.2. Use-cases demonstrating the impact of input uncertainties on predictability of constraints mitigated by SATA

In the straw proposal for this initiative, the ISO contemplated evaluating the predictability of transmission needs based on the nature of the transmission constraints. In response to stakeholder feedback about considering some use cases for SATA and the viability of various options, the ISO further examined how predictably the transmission needs could be defined, how far in advance these predictions can be made, and with what certainty they can be made. These factors have become pivotal to the discussion of potential cost recovery mechanisms. As explained below, the ISO has concluded that while short term operational projections may be viable, long term projections such that the resource owner can rely on ISO commitments of market participation opportunities in assessing market revenue potential over the life of an asset are infeasible.

The ISO reviewed a set of transmission constraints and, in the process, identified several drivers that result an unacceptable level of uncertainty in the predictability of transmission need precluding the ISO making long term commitments regarding the timing of the transmission need and the resulting opportunities for market participation.

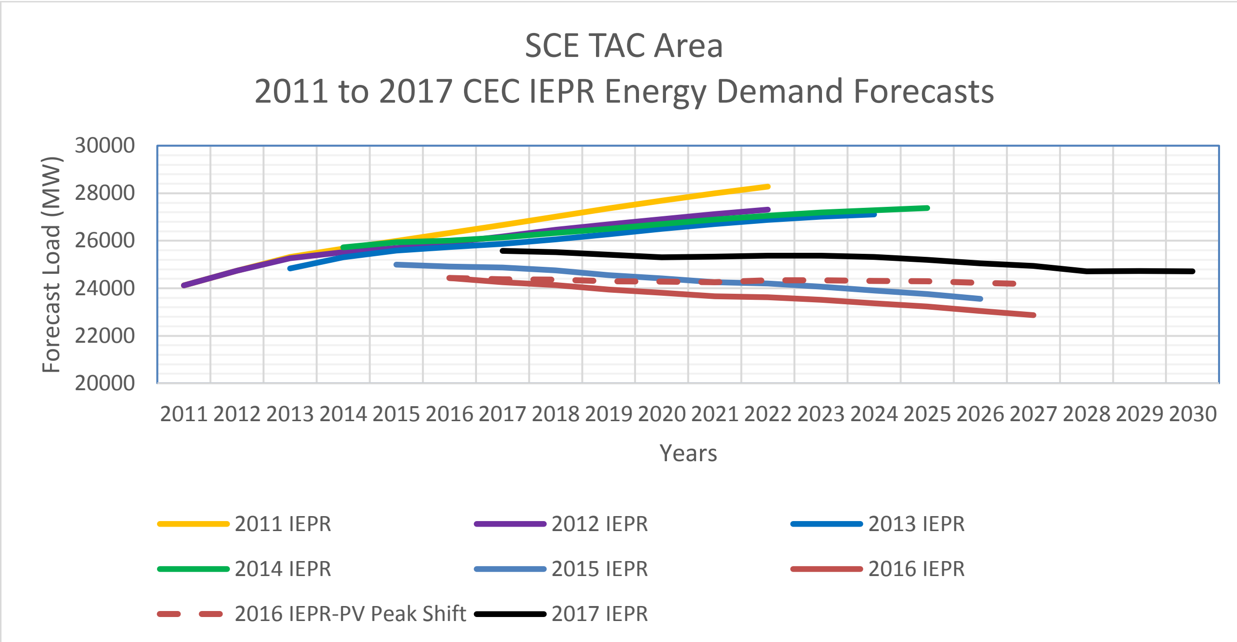
ISO's transmission need assessment depends on several continuously evolving input assumptions from state agencies and utilities, including:

- CEC: Forecasts of gross consumption, behind the meter generation, energy efficiency, demand response, etc.

- Utilities: Distribution of loads and load modifiers across their service areas

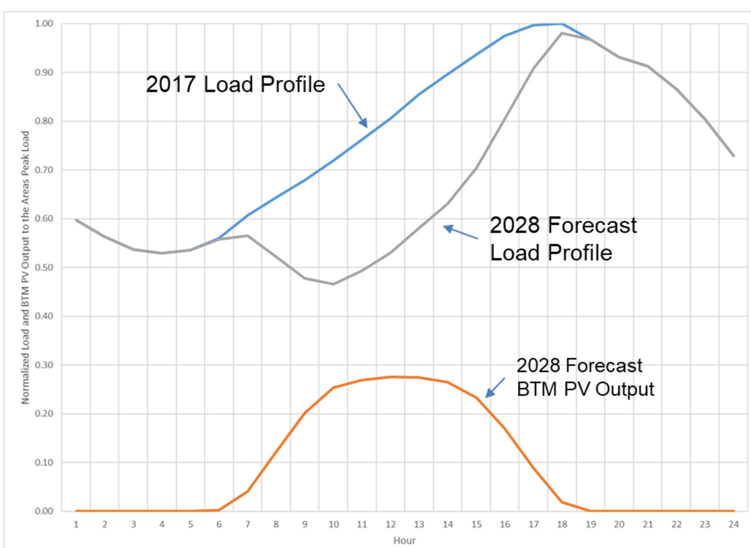
Load forecasts from CEC have been varying – both at the system level and at the local level as shown in Figure 6, below.

Figure 6: SCE TAC area IEPR Demand Forecasts



The forecasted peak demand and daily load shapes are also going through major shifts as demonstrated in the actual 2017 and forecasted 2028 greater bay area load profile in Figure 7. BTM PV has a major impact as shown in the 2028 peak normalized forecasted BTM PV output.

Figure 7: 2017 and 2028 (Forecasted) Load Profile with Peak normalized BTM PV Output profile

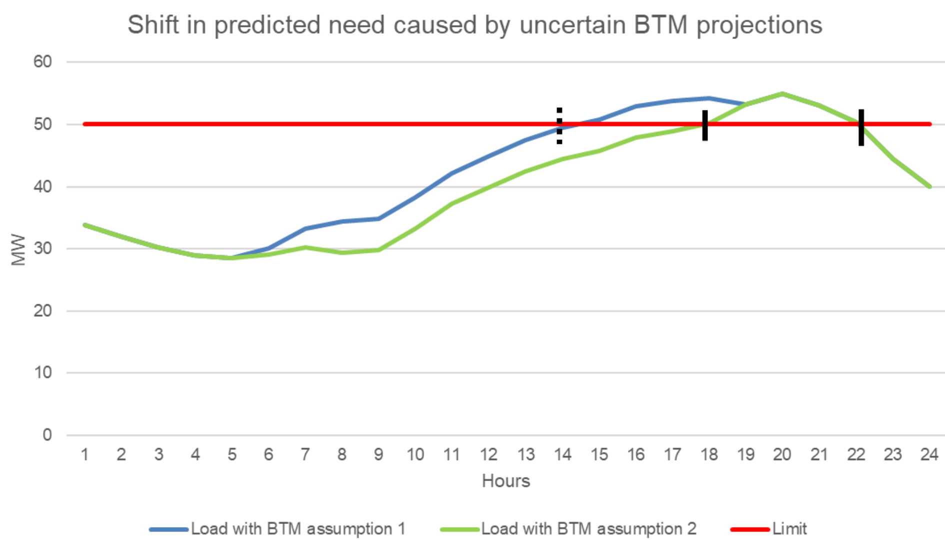


Several examples below further demonstrate the challenge of providing long term commitments as to the precise timing and duration of transmission needs.

1. *Variation in behind-the-meter resource projections*

Predictability of the timing and duration of transmission constraints is extremely sensitive to behind-the-meter (BTM) projections. As shown in Figure 7, a slight change in BTM projections would result in a considerable shift in the predicted transmission need window. In some locations, for example, a 10% variation in BTM prediction could potentially reduce market revenues by more than 50%. This level of uncertainty in predicting the window available for SATA device to access market revenues is not acceptable for purposes of long term commitments regarding the use of a resource.

Figure 7: Impact of BTM projections on the predicted transmission need window



2. *Variation in assumptions/forecasts about transmission connected generation (e.g. gas generation retirement at a short notice)*

Uncertainty about the future of the existing gas fleet can also yield vastly different determinations of constraint predictability. Figures 7 and 8 demonstrate how gas-fired generation exiting the market on short notice due to economic reasons would dramatically change the prediction about market revenue accessibility for a SATA device.

Figure 8 shows a transmission constraint which frequently relies on local gas generation dispatch as a mitigation. If the ISO were to predict the transmission need window today, it would be approximately June through September. Based on this assessment, the SATA device could access market revenues during rest of the year. But Figure 8 demonstrates how sensitive this determination is to a sudden change in generation mix behind the constraint – a change predominantly driven by the high likelihood of gas generation retirement with very short lead times.

Figure 8: Transmission need window prediction with availability of gas generation

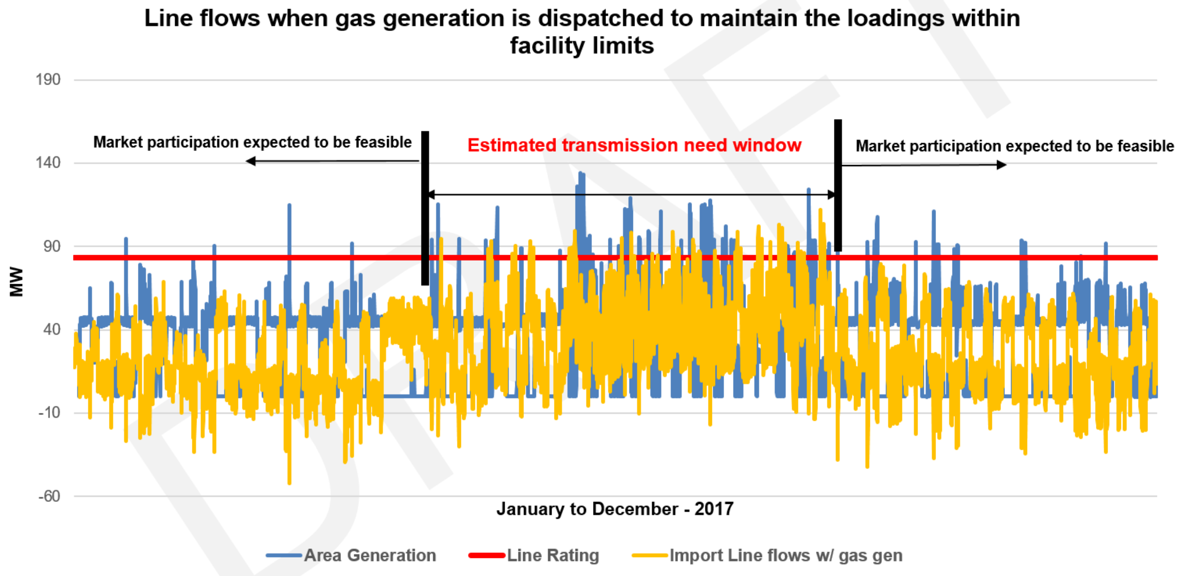
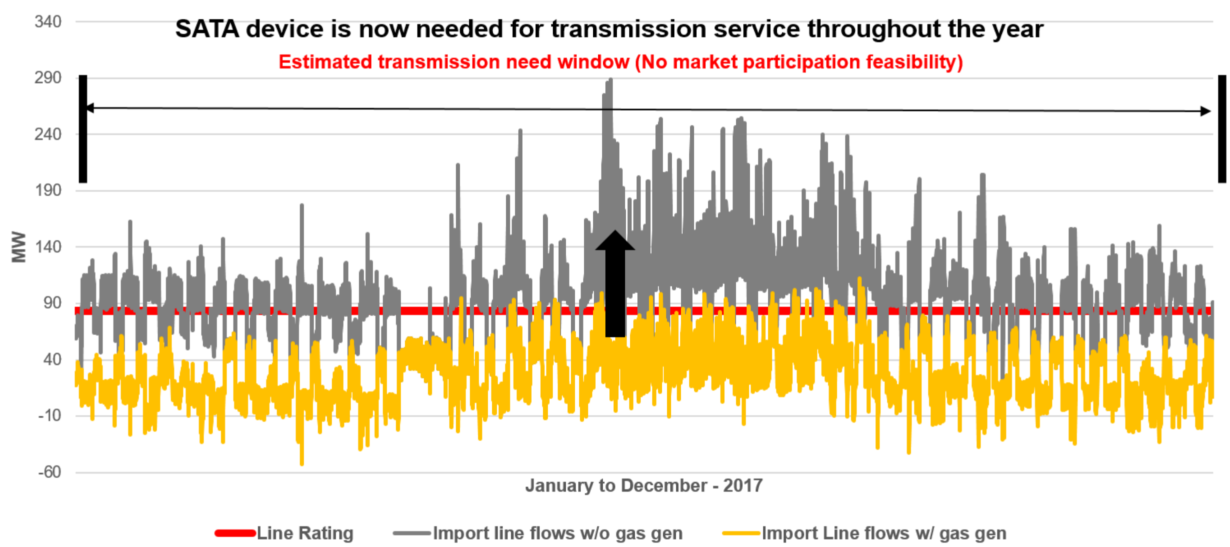


Figure 8: Transmission need window prediction under gas retirement scenario with a short notice



9.3. Structure of the Transmission Planning Process

The annual transmission planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2017-2018 planning cycle began in January 2017 and concluded in March 2018.

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months, typically from January through March of the first year in the cycle.

In Phase 2, the ISO performs studies to identify transmission needs and subsequent studies of potential solutions to address those needs. Phase 2 culminates in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, Phases 1 and 2 take approximately 15 months to complete. During this timeframe, the ISO also identifies non-transmission alternatives that it will rely on in lieu of transmission solutions. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

Phase 3 includes the ISO's competitive solicitation process to select developers to build and own new regional transmission facilities identified in the Board-approved plan. In any given planning cycle, Phase 3 may or may not be needed depending on whether the final plan includes regional transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

Each of these TPP phases are discussed in more detail below.

9.3.1. Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan. The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO performs in Phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other pertinent information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions, the ISO also specifies the public policy requirements and directives that it will consider in assessing the need for new transmission infrastructure.

Developing the unified planning assumptions benefits from coordination efforts between the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the ISO, building on the staff-level, inter-agency process alignment to improve infrastructure planning coordination between the three core electricity planning and procurement processes:

- The CEC's long-term forecast of energy demand produced the biennial Integrated Energy Policy Report (IEPR);
- The CPUC's integrated resource plan (IRP) proceeding; and
- The ISO's annual transmission planning process (TPP).

This coordination results in improved alignment of the three core processes by establishing consistent planning assumptions and scenarios considered in infrastructure planning activities. The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios. This inter-agency process alignment continues to evolve as the ISO, CPUC, and CEC processes are adapted to meet rapidly changing system needs and legislative mandates.

The ISO produces a study plan during each TPP cycle that describes the computer models and methodologies used in each technical study, provides a list of the studies to be performed as well as the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment. Stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then selects high priority studies from these requests and includes them in the study plan published at the end of Phase 1. The ISO may modify the list of high priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

9.3.2. Phase 2

In Phase 2, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO controlled grid. The comprehensive transmission plan specifies the transmission solutions required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. In Phase 2, the ISO conducts the following major activities:

- Performs technical planning studies described in the Phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the ISO's technical studies; demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs; Location Constrained Resource Interconnection Facilities project proposals; and merchant transmission facility project proposals;
- Coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC long-term procurement proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);

- Reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;

- Performs a "least regrets" analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[18] which is intended to minimize the risk of constructing under-utilized transmission capacity and ensure that transmission needed to meet policy goals is built in a timely manner;

- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;

- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;

- Performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;

- Conducts stakeholder meetings and provides public comment opportunities at key points during Phase 2; and,

- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of Phase 2 in March.

Board approval of the comprehensive transmission plan at the end of Phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through ISO transmission rates of those transmission projects included in

[18] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

the plan that require Board approval.[19] As indicated above, the ISO solicits and accepts proposals in next phase of the TPP, Phase 3, from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

As noted earlier, Phases 1 and 2 of the TPP encompass a 15-month period. Thus, the last three months of Phase 2 of one planning cycle will overlap Phase 1 of the subsequent cycle.

At the conclusion of Phase 2 of the TPP, any eligible regional transmission facilities identified in the final Board approved transmission plan as eligible for competitive solicitation will proceed to Phase 3.[20]

9.3.3. Phase 3

Phase 3 projects have detailed project descriptions and functional specifications included in the final approved transmission plan. These functional specifications define the identified solutions' technical requirements, as well as all alternative transmission assets that would be considered for evaluation by the ISO. Although the ISO typically identifies a single preferred solution, the ISO's transmission planning process is sufficiently flexible to identify multiple transmission alternatives that could meet the ISO-identified needs. For example, in Phase 2, the ISO could seek approval of either of a new transmission line and a new storage facility as alternative solutions to meet an ISO-identified need and provide functional specifications for both alternatives. Developers could pursue either option during the Phase 3 competitive solicitation. This would potentially allow for wire and non-wire solutions to compete in Phase 3 of the TPP for Regional Transmission projects, with the determination then based on the criteria established in the ISO's tariff for approved project sponsor selection.

Phase 3 takes place after the ISO Board approves a plan that includes projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional reliability-driven, category 1 policy-driven, or economic-driven transmission solutions, except for regional transmission solutions that are upgrades to existing facilities. Where the ISO selects a regional transmission solution to meet an identified need that constitutes an upgrade to or addition to an existing participating transmission owner facility, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner upon approval of the transmission plan. Local transmission facilities – whether upgrades or not – are also not subject to competitive solicitation.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO commences Phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The ISO then evaluates the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the ISO selects an approved project sponsor by evaluating all of the qualified

[19] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. The ISO includes such projects in the comprehensive plan as pre-approved by ISO management and not requiring Board approval.
[20] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

project sponsors based on the tariff selection criteria and compliance with the technical requirements identified by the ISO in the associated functional specifications. Where there is only one qualified project sponsor, the ISO will authorize that sponsor to move forward to project permitting and siting.

In the case of the ISO identifying a "hybrid" solution that consists of some level of transmission as well as preferred resources, the assignment of upgrades or the competitive procurement of eligible upgrades or new facilities applies only to the transmission assets – including storage if so designated in the plan. The procurement of the non-transmission preferred resources is coordinated with the load serving entity.

9.3.4. Current process for evaluating non-transmission alternatives and preferred resources

The ISO's transmission planning process, also facilitates the use of non-transmission alternatives and preferred resources to meet transmission system needs. The ISO focuses on specific area analysis and resource testing. The analysis is based on information provided by the market for utility procurement processes as they relate to preferred resources and their potential to mitigate reliability concerns. The ISO developed the methodology it uses during the initial phase of the transmission planning process to support these considerations and presented it in a paper issued on September 4, 2013[21] as part of the 2013-2014 transmission planning cycle. In this paper, the ISO demonstrated how it was supporting California's policies that emphasized the use of preferred resources[22] by considering how such resources could constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation. In addition to developing a methodology the ISO could apply annually in each transmission planning cycle, the ISO also described how it would apply the proposed methodology in future transmission planning cycles.

The ISO further refined and advanced methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs through development of the Moorpark Sub-Area Local Capacity Alternative Study, released on August 16, 2017.[23] The ISO has also developed a methodology for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources –

[21] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

[22] To be precise, the term "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

[23] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

which both builds on and expands on the analysis framework of preferred resources, as discussed in section 6.6 of the 2017-2018 Transmission Plan.[24]

If a preferred resource is identified in Phase 1 of the transmission planning process as having the potential to meet a reliability need, the ISO considers the cost effectiveness and other benefits these alternatives provide in Phase 2 and although the Board does not “approve” non-transmission (*e.g.*, preferred resource capacity) solutions, the ISO can identify these solutions as preferred solutions to transmission projects and work with the appropriate load serving entities and local regulatory authorities to support their development. Examples of these efforts include the ISO’s efforts in the SCE LA Basin and Moorpark procurement activities, and the development of the PG&E Oakland Clean Energy Initiative. This approach is particularly viable when there is not an immediate need to initiate a transmission solution. In those cases, time can be set aside to explore the viability of non-conventional alternatives while relying on a more conventional transmission alternative as a backstop.

The ISO relies heavily on preferred resources identified through various resource procurement proceedings, proposals received in the request window, and other stakeholder comment opportunities in the TPP to examine the benefits preferred resources can provide. An issue of particular concern to the ISO and stakeholders is the quality of cost estimates used in considering preferred resources – including storage – in the economic assessment of potential solutions for transmission needs. In Phase 2 of the TPP, any cost estimates provided by stakeholders are informational and not binding, as cost commitments are only made in the competitive solicitation process, or in the load serving entities’ procurement processes.

Given the complex interaction between ISO approval of transmission solutions and procurement of preferred resources under the framework of local regulatory agencies, certain details in the planning process are particularly relevant and discussed below.

Identification of High potential areas

Each year’s transmission plan identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The ISO expects developers interested in developing and proposing preferred resources as mitigations in the TPP to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities’ procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 of each year’s transmission plan contains a section describing the preferred resources that are providing reliability benefits. In addition, the ISO has, in recent years, summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 7.3 of recent transmission plans.

Use-limited resources, including demand response

The ISO continues to support integrating demand response, which includes bifurcating and categorizing the various programs and resources as either supply side or load-modifying resources. Activities such as participating in the CPUC’s demand response related proceedings

[24] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

support identifying the necessary operating characteristics that demand response should have to fulfill in meeting transmission system needs. The study work conducted on the necessary characteristics for “slow response” demand response programs discussed above is an example of the ISO’s efforts. This study was initially undertaken through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[25] The ISO anticipates that there will be more progress for demand response and other use-limited resources in this area.

Energy storage

In addition to considering energy storage under the preferred resource umbrella in transmission planning, the ISO is engaged in a number of parallel activities to facilitate energy storage development overall. These include past efforts to refine the generator interconnection process to better address the needs of energy storage developers and the continued refinement of the benefits analysis of large scale energy storage in addressing flexible capacity needs.

Existing procurement mechanisms can and have supported development of preferred resources through the ISO’s wholesale markets coupled with procurement directed by the CPUC. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs. It also enables the resource to participate in providing value to the market to the greatest extent possible.

In the case of electric storage resources, procurement may also result in distribution-connected resources and behind-the-meter resources that do not participate in the ISO’s wholesale markets. In the case of grid-connected resources, storage resources function primarily as a market resource, with contractual obligations to the off-taker to provide certain services supporting local reliability (*i.e.*, a local capacity resource).

Typically, the CPUC’s local capacity procurement processes have provided the most fruitful procurement efforts for storage and preferred resources. Energy storage procurement as a local capacity resource, rather than a transmission asset, provides the following benefits:

- Access to a full range of market opportunities - at customer sites, on the distribution system, or on the transmission system;[26]
- Operation through available ISO market functions;
- A viable framework for storage and other preferred resource to meet a variety of reliability and resource adequacy needs;

[25] See “Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop,” presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[26] This is critical issue, as storage – and other preferred resources – compete through various procurement processes already in place. The ISO’s intention is not to create a parallel and duplicative procurement process for preferred resources that competes and potentially conflicts with existing procurement processes overseen by local regulatory authorities.

- Must offer obligations and other market mitigations can be managed through existing tariff and contract provisions, thereby requiring minimal ISO intervention in the operation of the resource.

As a result, the ISO's approach has been to facilitate the local capacity resources model in the CPUC or other local regulatory authority procurement processes procuring as much storage as they determined to be cost effective.

Consistency with FERC direction

FERC's guidance is that transmission assets should provide transmission services, focusing on thermal loading and voltage support. In past planning cycles, the ISO relied on the FERC's guidance that transmission assets – and in particular electric storage as a transmission asset – should provide transmission services focused on thermal loading and voltage support. The ISO considered that direction appropriate and particularly helpful in past TPPs. As a result, the ISO has studied numerous potential applications of energy storage as transmission assets, assuming the studied energy storage resource provided only transmission service and did not provide other market services or have access to other market-based revenue streams.

As discussed in section 4.2 below, FERC's additional direction on January 19, 2017, necessitates a reconsideration of a number of these issues, and also sets out concerns that need to be addressed to enable electric storage resources to receive cost-based rate recovery while also receiving market-based revenues for providing separate market-based services.

At the present time, the ISO is continuing to evaluate energy storage as either potential non-transmission alternatives or as transmission assets with full cost recovery through regulated rates. Although the issues associated with multiple revenue streams is addressed through the policy initiative, the specific assessment methodologies for energy storage resources that will be applied in Phase 2 of the transmission planning process will be adapted in future planning cycles.

9.4. FERC Regulatory Background

In past Transmission Planning Processes, the ISO has considered numerous proposals for storage devices to provide cost-of-service based transmission services, and the ISO recently approved two such proposals. Having storage facilities that both provide transmission service under a cost-of-service framework and participate in the various energy markets introduces unique challenges that the ISO must carefully consider in the policy development process. These challenges and the ISO's interpretation of previous FERC rulings dissuaded the ISO from pursuing the concept further. However, FERC opened the door to revisit this issue by issuing its Policy Statement in Docket No, PL17-2-000 regarding the utilization of electric storage resources for multiple services when receiving cost-based rate recovery.[27]

[27] *Utilization of electric Storage Resources for Multiple Services When Receiving Cost-Based Recovery,* 158 FERC ¶61,051 (2017) ("Policy Statement").

Also in 2005, the Nevada Hydro Company filed a request for rate incentives with FERC for its proposed Lake Elsinore Advanced Pump Storage ("LEAPS") project.[28] In its filing, Nevada Hydro proposed that LEAPS should be treated as a transmission facility under the ISO's operational control. According to Nevada Hydro, the ISO would serve its ancillary services needs consistently from LEAPS, and Nevada Hydro would consistently bid LEAPS' stored energy into the market at a price of $0. Nevada Hydro asserted that it had carefully crafted its proposal to avoid market distortions. Specifically, Nevada Hydro proposed to always bid its stored energy at $0 to avoid market distortions. The ISO was nevertheless concerned that its independence could be comprised because it would have to decide (in all instances) when LEAPS would operate, how much energy it would produce and when it would operate the pumps to store water for future generation.[29]

In a 2008 order, FERC denied Nevada Hydro's request. FERC found that "the purpose of CAISO's transmission access charge is to recover the costs of transmission facilities under the control of CAISO, not to recover the costs of bundled services."[30] FERC also shared the ISO's concern that ISO control of a generator participating in the ISO markets would compromise the ISO's independence. Further, FERC found that "allowing LEAPS to receive a guaranteed revenue stream through CAISO's TAC would create an undue preference for LEAPS compared to these other similarly situated pumped hydro generators."[31]

In 2009, Western Grid Development filed a Petition for Declaratory Order with FERC to request a finding that its proposed sodium-sulfur-based energy storage projects were wholesale transmission facilities eligible for cost-based recovery.[32] Western Grid proposed that its storage projects would only exist to provide voltage support and thermal overload protection, and that they could solve existing reliability problems at a lower cost than traditional transmission upgrades.[33] Western Grid argued that—unlike with LEAPS—it would manage the charging of its devices to allow the ISO to maintain independence. Western Grid also notified the Commission that it would not arbitrage wholesale energy market prices, and would credit any market revenues it received from charging and discharging back toward its transmission revenue requirement.

In a 2010 order, FERC found that Western Grid's proposal had resolved the issues presented in *Nevada Hydro*, and that Western Grid's project should be eligible for cost-based recovery. FERC found that Western Grid would operate its devices as transmission facilities only, and therefore should recover costs like a transmission facility. FERC also noted that its order was only limited to the issue of eligibility for cost-based treatment, but that:

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28 *The Nev. Hydro Co. Inc*., 122 FERC ¶ 61,272 (2008).

29 *See Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 82 F.R. 9343 at P 3 (Feb. 6, 2017).

30 *Id*.

31 *Id*.

32 *Western Grid Dev., LLC,* 130 FERC ¶ 61,056 (Western Grid), *reh'g denied,* 133 FERC ¶ 61,029 (2010).

33 *Id*. at P 3.

> "the Projects will be subject to review and approval by the CAISO in its transmission planning process. Pursuant to CAISO Tariff section 24.1.1, the CAISO will not approve the Projects if a superior alternative project is proposed or if the Projects do not pass a cost-benefit analysis. Thus, if the CAISO approves the Projects, they would be paid for by ratepayers because the CAISO had found that they were the most efficient solution proposed."[34]

Ultimately, the ISO never found the Western Grid projects to be needed in the ISO's TPP. Since the *Western Grid* decision, the ISO has studied several potential energy storage projects as reliability solutions, ranging from transmission asset models to local resources participating in markets.[35]

There remained uncertainty between the generator-oriented approach rejected in *Nevada Hydro* and the transmission-only approach approved in *Western Grid*. FERC solicited comments and held a technical conference on this issue in 2016. The ISO submitted written comments and testified at the technical conference.[36] In 2017, FERC issued its Policy Statement. The Policy Statement found "there may be approaches different from *Western Grid*'s approach under which an electric storage resource may receive cost-based recovery, and, if technically capable, provide market-based services."[37] FERC was careful to note that its Policy Statement "is not intended to resolve the detailed implementation issues surrounding how an electric storage resource may concurrently provide services at cost- and market-based rates," which would be decided on a case-by-case basis. Rather, FERC said that the Policy Statement is intended (1) "to clarify that providing services at both cost- and market-based rates is permissible as a matter of policy," and (2) "provide guidance on some of the details and allow entities to address these issues through stakeholder processes and in filings before the Commission."[38] As such, FERC noted that such as a resource's participation likely would be subject to these principles:

- Must be cost competitive with transmission
- Must avoid double recovery for providing the same service
- Cannot suppress market bids, and

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34 *Id.* at P 53.

35 The ISO also published a stand-alone paper presenting its methodology for considering non-transmission alternatives in 2013. http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf. Detailed information on the ISO's most recent consideration of non-transmission alternatives and preferred resources can be found in the ISO's 2015-2016 Transmission Plan, beginning on page 27. http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf.

36 *See* FERC Docket No. AD16-25-000.

37 Policy Statement, 158 FERC ¶61,051 at P 9.

38 *Id*. at P 14. Commission LaFleur dissented from the Policy Statement, noting that she disagreed with "the Policy Statement's sweeping conclusions about the potential impacts of multiple payment streams on pricing in wholesale electric markets," and was "concerned about the broad rationale for this approach put forth in the Policy Statement, which . . . is both flawed in its conclusions and premature in its timing."

- Cannot jeopardize ISO/RTO independence.

Further, with respect to the policy statement, FERC provided additional direction in EL18-131-000. Specifically, FERC states

> [T]he *Storage Policy Statement* does not provide guidance for determining whether a particular electric storage resource is a transmission facility eligible for cost recovery through transmission rates. Rather, the *Storage Policy Statement* provides guidance only with respect to issues that must be addressed if an electric storage resource seeks to receive cost-based rate recovery for certain services, whether through transmission rates or any other cost-based rate, while also receiving market-based revenues for providing separate market-based services."[39]

The TPP includes a comprehensive evaluation of the ISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals, and explore projects that can bring economic benefits to consumers. Although the ISO does not approve non-transmission alternatives in its existing TPP, the ISO promotes opportunities for non-transmission resources such as storage to serve as the preferred solution, and the ISO works to support regulatory approvals for those projects if the TPP identifies them as the preferred alternative. In the context of the TPP, the ISO has studied a number of potential electric storage projects as reliability needs solutions, ranging from transmission asset models to local resources participating in markets. The former approach recently resulted in energy storage assets moving forward, and the latter approach has resulted in a number of energy storage projects providing local capacity. In this context, the ISO's experience reflects that electric storage has more effectively fit within the framework of market resources providing local capacity rather than as transmission assets providing transmission services. Over the past several years, the ISO has studied 27 battery storage proposals and one pumped hydro storage proposal as potential transmission assets. To date only two proposals have resulted in storage projects moving forward, both in the most recent 2017-2018 Transmission Plan.

[39] FERC docket No. EL18-131-000 Issued September 20, 2018. Paragraph 24, page 10,