Storage as a Transmission Asset:

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

Revised Straw Proposal

August 15, 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 to be needed to provide a transmission 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 recently the ISO approved two such proposals. 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 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.

Storage as a transmission asset ("SATA") resources[1] that can access market revenues do not fit precisely into any current ISO contract structure. Based on stakeholder comments, the ISO has determined that a new *pro forma* agreement will be developed for SATA resources, which include provisions from other agreements such as 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 not limited to, is provided in the table under in Appendix 8.1**.**

The FERC policy statement maintains 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 term "storage acting as transmission assets" used to refer to storage resources that are guaranteed cost recovery through TAC or some other predetermined source for providing a regulated transmission service.

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;

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 addition of more supply resources may impact market prices depending on the marginal cost of the additional resources. To the extent that market prices are lower due to including additional capacity from SATA resources, the question is whether prices are lower because a subsidized resource is participating in the market, or simply because the resource has lower marginal costs. In order to ensure SATA resources providing market service do not inappropriately suppress market prices, the ISO must design incentives for SATA resources to bid at marginal costs. The ISO, therefore, proposes to develop a Transmission Revenue Requirement (TRR) crediting structure based the expected useful life of the resource to incentivize the efficient use of these resources for both their transmission and market services, ensuring that ratepayers covering the cost of these assets receive the expected benefits. Specifically, the ISO proposes to calculate an energy storage system's capital cost based on a "use credit," which is applied against the resource's overall TRR for each instance of market based dispatch.

The ISO continues to explore options for how and when it will notify SATA projects about market opportunities. Initially, the ISO thought it could possibly identify specific time (hours, months, or seasons) when a resource would be permitted to provide market services. However, based on additional analysis and sensitivity studies, the ISO has determined that it is not possible to provide resources such specific information with certainty during phase 2 of the TPP. As a result, the ISO is now exploring two new notification options, both of which ensure the ISO maintains its independence and ensure that transmission services take primacy over market participation. These two options, including a day-ahead option and a two-days prior to the operating day (D+2) option.

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 and energy market crediting;

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 ratepayer.

Under the full cost-of-service based cost recovery option all market revenues earned by the resource would reduce the costs recovered through the Transmission Access Charge ("TAC").

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, 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. The full cost-of-service option is designed to provide incentives for market participation not present in the full cost-of-service option defined in section 5.3.1, while mitigating some of the financial uncertainties that exist in the partial cost of service described above in section 5.3.2.

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. The ISO received numerous stakeholder comments in response to its issue paper and straw proposal 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 18 sets of stakeholder comments on the straw proposal. The ISO's presentation materials addressed many of these comments. Specifically, the ISO provided additional explanations regarding the connection between the TPP, additional details regarding the contractual relationship between the ISO and the SATA resource owner, and consideration of additional cost recovery options (this included options provided by CRI and SDG&E). Subsequently, the ISO received an additional 14 sets of stakeholder comments in response to the June 29, 2018 working group meeting. Because the ISO previously addressed most of the comments submitted in response to the straw proposal, the following summary focuses on comments submitted in response to the working group meeting. However, any relevant comments on the straw proposal not addressed as part of the working group meeting discussion are addressed below as well. Most comments were generally supportive of the ISO initial proposed scope. Stakeholder comments typically addressed four topics:

1) Connection between the TPP and SATA;

2) The contractual arrangement between the ISO and the resource owner;

3) Consistency with the FERC Policy statement; and

4) Cost recovery mechanisms and market participation rules.

Each topic is addressed briefly in this section, with additional details provided in sections 4 and 5, below.

2.1. Connection between TPP and SATA

Based on stakeholder comments on the straw proposal, the ISO provided supplemental materials to further explain the ISO's TPP process and how various types of projects would be considered in the TPP. While numerous stakeholders have requested additional and specific use-cases, the ISO believes addressing every use-case as part of this initiative is not practical or feasible. As such, the ISO has supplemented its supporting materials (attached in the appendix at section 8.2) based on the materials provided in the working group, but cannot explore the many and specific use cases requested in comments in this stakeholder process.

2.2. The Contractual Arrangement between the ISO and the Storage Resource

With the clarifications at the June 29, 2018 working group meeting, the ISO provided additional detail on the SATA agreement and the potential structure. However, until the policy is finalized, the "meat" of the contract cannot be developed. Nonetheless, in the interest of facilitating a better understanding and discussion of the contract proposal, the ISO is including a table outlining proposed contractual provisions in Appendix 8.1, including a listing of the components that are likely to be in the agreement. Thus the question of options, market rules, revenue recovery, transfer from transmission asset to market asset and back, etc. must first be determined prior to the discussion of how those issues are integrated into an agreement. In section 5.2, the ISO details stakeholder comments solely with respect to the form of the contractual arrangement and leaves the balance of the paper to discuss the relevant policy issues in this initiative.

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 to these comments, the ISO has made additional enhancements to its proposal to ensure SATA resources do not inappropriately suppress market prices. Specifically, the ISO proposes to develop a TRR crediting mechanism based on the expected useful life of the resource. This TRR crediting mechanism will help incentivize and balance the efficient use of these resources for both transmission and market services, and it will help ensure the ratepayers supporting the asset receive the expected benefits and that all marginal costs are considered in market bids. This proposal is discussed below in section 5.3.2.

Many stakeholders, including CRI, LS Power, ORA, and SDG&E note the importance of the ISO's notification process for market participation for some of the proposed cost recovery options. In response, the ISO conducted several use-cases, attached in the section 8.2 of the Appendix, to determine how predictable market participation could be over the life of the asset. These use-cases show that long-term assurances of market participation cannot be guaranteed. The ISO notes that there may be circumstances beyond those initially identified that could result in a markedly different outcome than originally projected in the Phase 2 planning stage for the resource to provide market services. Therefore, the ISO is now exploring two alternative options focused on notification closer to real-time. These options are discussed below in section 5.3.3.

2.4. Cost Recovery Options

In the June 29, 2018 working group meeting, the ISO introduced a third cost recovery option to the two options that previous existed. Specifically, the ISO expressed a willingness to explore:

1. Full cost-of-service based cost recovery with complete energy market crediting to ratepayer;
2. Partial cost-of-service based cost recovery and retain energy market revenues; and
3. Full cost-of-service based cost recovery with partial market revenue sharing between owner and ratepayer.

Stakeholders are generally supportive of the first option, there is also general support for the third option. ORA is the only party that expressed opposition to the third option, noting that the resource is receiving guaranteed cost recovery, therefore ratepayers should receive the benefit of market participation. However, as the ISO notes in section 5.4, absent the type of incentive provided by option 3, there are no guarantees of market participation since there is no up-side to the participant. Therefore, the ISO has added option 3 to the proposal as a potential choice for SATA project sponsors. Additionally, SCE and SDG&E raised significant concerns regarding the viability of option 2. Further, the ISO as determined it is not able to provide certainty for market opportunities for the life of the project. As a result, the ISO has not eliminated this as a potential option, but seeks stakeholder input to determine if it should remain an option.

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
Sep 24	Draft final proposal
Oct 4	Hold stakeholder meeting on draft final proposal
Oct 15	Stakeholder comments due
Nov 14-15	**Present proposal to ISO Board**

4. Introduction and Background

In this initiative, the California Independent System Operator Corporation ("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 in response to its issue paper and straw proposal 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 8.1.

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.

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 in order to enable this outcome. 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. Consideration of economic-driven energy storage transmission solutions

To date, the ISO's consideration of storage as a transmission asset has been based 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 storage as a "transmission" asset would introduce the market interference that FERC's Policy Statement seeks to avoid.

[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.

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

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. 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.

4.1.2. Considering market revenues in approving transmission solutions

To date, the ISO has not considering 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.

4.1.3. Need for energy storage as a transmission asset

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;[3] (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, (5) overly complex interconnection processes as a market resource that would impede development of the resource.

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

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.

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
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.[4] 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:

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

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.

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

[4] 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.

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.

5.2. 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 8.1**.**

Understanding that the ultimate contractual terms for this initiative will be determined based on the policy that is developed. Solely with respect to the contractual arrangement, BAMx, EDF-R, National Grid, NextEra Energy, NWHA, San Diego County Water Authority and City of San Diego, SDG&E, and SCE supports the development of a new agreement specific to storage as a transmission asset. Six Cities does not oppose developing a pro forma agreement for SATA resources but believes the rates, terms, and conditions may be different for each SATA and, therefore, a pro forma agreement would not work since each agreement would need to be filed separately with FERC.

Calpine and SDG&E commented that if the storage resource will be participating in the market it should go through the standard generator interconnection process to identify network upgrades that may be needed and not "jump the queue". ITC commented that the transfer from market participation to CAISO operational control should also be established.

CRI disagrees that the SATA contract must be 40 years and suggests a 10 year base contract with the option to renew for each of the 3 successive 10 years and given the disconnect in life expectancies of a transmission line versus a storage asset the ISO should consider an annual net present value or replacement chain method analysis to determine the least cost solution. In addition CRI recommends that a 10-year contract with the ability to possible renegotiate the terms of the agreement each time would allow the ISO to reassess the load growth and load profile. In contrast, NextEra Energy commented that modifications to agreements increase uncertainty regarding the expected level of market revenues likely resulting in higher project costs.

PG&E believes that the SATA resource owner must be a Participating Transmission Owner (PTO), or become a PTO. Six Cities questioned if the SATA resource would have a SATA PTO status if it weren't a PTO. SCE and SDG&E both commented that the SATA resource must ensure the reliability of the grid. NRG raised concerns that development of a SATA agreement will be complex and contentious, and is likely to be difficult and lengthy endeavor.

Comments regarding influence over market prices and outcomes; frequency of cycling and compensation; reporting requirements to determine financial strength; dispatching requirements including emergency dispatch; and cost recovery options are being covered by other sections of this Revised Straw Proposal and once determined will be incorporated into the SATA agreement.

The ISO disagrees with Six Cities' assertion that each SATA agreement is going to be different. The proposed formula rate will take care of financial differences, however, the terms and conditions of how and when the SATA resource operates and the reliability obligations must be the same to ensure consistent treatment of similarly situated resources and transparency for the market.

With respect to the question of whether the storage unit goes through the interconnection queue or a modification process is moot because the need for the SATA resource is determined in the transmission planning process which is in advance of the generator interconnection process. In addition, where possible the SATA resource will be subject to competitive solicitation. Thus it is through these two processes that the SATA resource transmission needs and the ratepayer cost for the resource are determined.

The ISO agrees with ITC's concerns that the transfer from market participation to CAISO operational control should also be established and once that determination is made in the policy development we will be able to determine whether the transition from market to transmission asset and back to market asset is in the agreement or in the business practice manuals.

The ISO agrees with NextEra with respect to the certainty and a shorter-term agreement as proposed by CRI is incompatible with the ISO's identified needs. The transmission planning process looks at transmission requirements 10 years out and a transmission line has a life of 40 years. If the ISO were to change the life of the SATA resource to 10 years, then in the next study year we would have to choose another SATA resource for the same transmission overload issue. This is not a workable solution. However, if the SATA resource is paid to recover the cost of the initial unit and three replacement units, under the one agreement then the ISO can have the stability it needs to ensure that the SATA resource will be available for the same term as the competing solution – a new transmission line – and the reliability of the grid will be maintained. However, the ISO also understands the challenges for a project sponsor to forecast costs, for example, over three project cycles. <u>Therefore, the ISO is seeking stakeholder comments about how to balance the burden of the planning study needed for the TPP with the difficulty of projecting cost out three to four project cycles.</u>

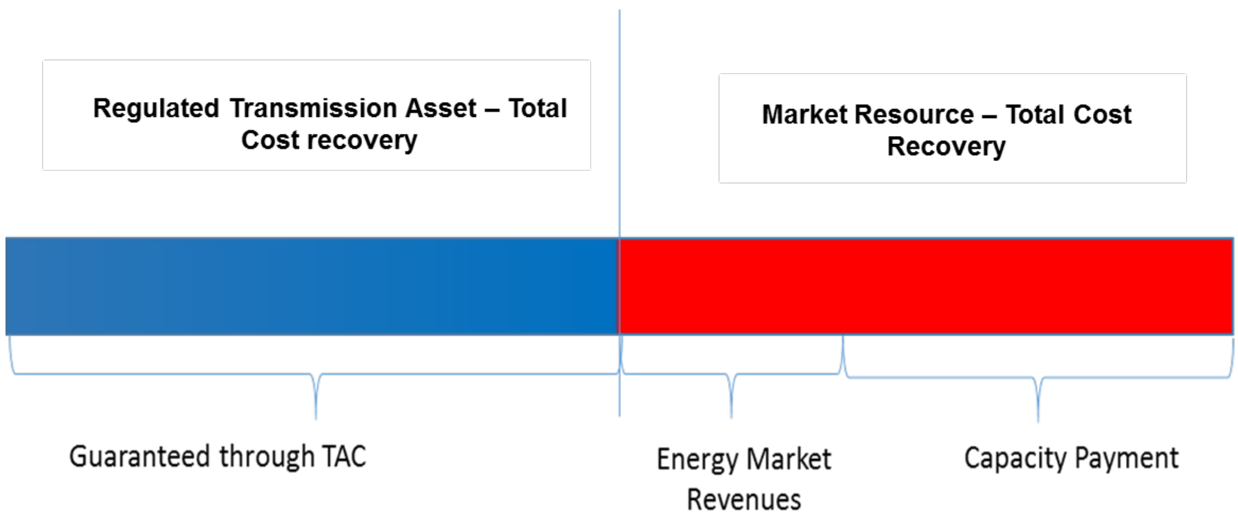
With respect to whether the SATA is a PTO or becomes a special "SATA PTO" will need to be worked out as the policy is further developed. However, the SATA resource will need to be one or the other to recover its costs through the ISO's transmission access charge. While the ISO acknowledges NRG's comment that the SATA agreement will be complex, the benefits of having the entire relationship in one agreement outweighs the impracticality of multiple agreements controlling one resource.

5.3. Transmission Cost Recovery and the FERC Policy Statement

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 3, The PTO of a transmission asset has traditionally recovered the transmission facility costs through the ISO's TAC. Alternatively, 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



This paper discusses only those SATA resources that provide transmission service the ISO has identified as a needed in the TPP to meet a transmission need.

5.3.1. FERC policy statement

The 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 remainder of this section addresses each of the elements and how the ISO will plans to address them.

5.3.2. Impact on market prices

The addition of more supply resources may impact market prices depending on the marginal cost of the additional resources. Lower marginal cost resources will lower market prices while higher marginal cost resources will not since they will not clear the market. To the extent that market prices are lower due to including additional capacity from SATA resources, the question is whether prices are lower because a subsidized resource is participating in the market or simply because the resource has a lower marginal cost.[5] In order to ensure SATA resources providing market service do not inappropriately suppress market prices, the ISO must design incentives for SATA resources to bid at their marginal cost. If resources do bid at marginal cost, then any market price reductions should be seen as appropriate. Additionally, as identified by BAMX, ITC, and LS Power, market participation and resulting dispatches may have an impact on the longevity of the lifecycle of resources. The ISO must establish a means of assuring that market participation does not negatively impact the life cycle of the transmission asset that has been procured at ratepayer expense.

The ISO, therefore, proposes to develop a TRR crediting mechanism based on the expected useful life of the resource. This TRR crediting mechanism will help incentivize and balance the efficient use of these resources for both transmission and market services, and it will help ensure the ratepayers supporting the asset receive the expected benefits and that all marginal costs are considered in market bids. Specifically, the ISO proposes to calculate an energy storage system capital cost based "use credit" to be applied against the resources overall TRR

[5] In comments on the working group meeting, Calpine had concerns regarding the ISO's conclusion that additional capacity would not affect market prices. Boston Energy also voiced these concerns in comments to the straw proposal. The ISO has clarified this position.

for each instance of market based dispatch.[6] The proposed TRR credit will reduce the resource's TRR in proportion to the reduction in the useful life of the asset. This incentive mechanism is necessary and intended 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.

This means that SATA resources would have an incentive to bid into the market while understanding the potential negative capital cost implications of providing market service. This reduction to the TRR effectively eliminates any subsidization of market services from transmission service cost recovery. As a result, the ISO asserts that SATA resources will not inappropriately suppress market prices.

The number of cycles or the total designed MWh capacity of a battery storage device[7] over its useful lifecycle can be forecasted.[8] This provision insulates and protects ratepayers from subsidizing a transmission asset that is used primarily as a market resource. As such, the ISO believes this proposal provides the correct incentives to mitigate over use of SATA resources in the ISO markets.

The ISO will calculate this capital cost TRR credit based on the overall TRR resulting from the project's overall capital costs and the SATA resource's number of expected cycles or discharges over its full lifecycle. This credit would be assessed against the SATA resource's TRR each instance the ISO dispatches the resource based on the resource owner's bids into the market when not providing transmission service.[9] Each MWh of discharge will be assessed a capital cost TRR credit, reducing the resource's TRR recovery by this credit to reflect the reduced lifecycle of the resource based on its use as a market based resource (non-SATA/transmission service dispatches). This credit would be fixed for all MWh's of a resource's discharges due to market participation awards (but not discharges due to ISO dispatches for transmission service). It would therefore be a marginal cost that any SATA owner would include in any market service bid. This means that SATA resources would have an incentive to bid into the market with full consideration of the potential negative capital cost implications of providing market service. This reduction to the TRR effectively eliminates any cross subsidization of market services from transmission service cost recovery. The following formulas describe this

[6] Because not all installed facilities will degrade quickly based on discharge cycle, the credit calculated will be based on the cost of the batteries, not other balance of system (i.e. inverters, control systems, switches, relays, etc) or interconnection components.

[7] The total designed MWH capacity is essentially the number of discharge hours multiplied by the capacity of the battery. This allows the ISO assess battery degradation values that are time based and will be included in the ultimate sizing of the resource.

[8] There are numerous sources that can be used to derive these estimates, including OEM vendor warranties, and industry standards.

[9] This includes exceptional dispatches for the resource when it has been notified it can participate in the market and has submitted a bid into the ISO market.

capital cost TRR credit for market based participation and the credit for shared ISO market revenues:

Without shared energy market TRR credit:

- TRR = (Capital Costs – (Cap Cost Credit Multiplier x MWh discharge) x ROE) + Variable O&M + A&G

With shared energy market TRR credit:

- TRR = (Capital Costs – (Cap Cost Credit Multiplier x MWh discharge) x ROE) + ((Variable O&M – Ratepayer Share of ISO Market Revenues Credit) + A&G)

The ISO believes these adjustments to the TRR are appropriate given the nature of these resources intended use and optionality to participate in the ISO markets. By developing incentives to include foregone TRR in their bids, the ISO believes that allowing SATA resources to access market revenues when they are not needed for transmission services will not inappropriately suppress competitive wholesale electricity prices. Resource owners have the proper incentive to reflect any marginal costs of its foregone TRR in their market bids. The hours in which the resource will be most needed for transmission service will be the same hours in which the resource would most likely have the ability to significantly impact energy market prices, therefore the ISO believes there should not be significant energy market power concerns. The hours a SATA resource would be able to access market revenues would be intervals that are already competitive and, with the proposed reduction to the SATA resource's TRR, the addition of SATA resources would have little to no impact on market prices, let alone inappropriately suppressing them. Additionally, to the extent that SATA resources may lower energy prices in some intervals while discharging, conversely, they would increase the price in other hours when the resource is charging. Finally, DMM notes that resources procured through a competitive process "could enhance market efficiency."[10]

5.3.3. Maintaining ISO independence through notification practices

The ISO proposes to ensure its independence is not jeopardized though the use of effective notification practices about 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, the owner of the SATA resource will be responsible for the bidding and market participation of the resource, not the ISO.

The ISO continues to explore options for how and when it will notify SATA projects about market 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

[10] See DMM's comments at p. 4. Available at http://www.caiso.com/Documents/DMMComments-StorageasaTransmissionAsset-IssuePaper.pdf

sensitivity studies, the ISO has determined that it is not possible to provide resources such information with certainty during the TPP phase 2.[11] These additional use-cases are provided in the appendix at section 8.2. As a result, the ISO is now exploring two new notification options, both of which ensure the ISO maintains its independence and ensure that transmission services take primacy over market participation.[12] While these options provide less upfront/long-term certainty, they likely provide more frequent opportunities to provide market services. These two options, including the relative pros and cons of each are as follows:

Option 1: The Day-Ahead Market Option

- The ISO will evaluate the needs for SATA resources to be used as transmission asset in the Day-Ahead Market.
- CAISO will generate a bid right below the transmission relaxation penalty in Day-Ahead Market RUC run.
- If DAM clears the SATA resources, then SATA resources will be deemed as "Transmission Service Asset" and will not be allowed for market based participation.
- If DAM does not clear the SATA resources, then SATA resources will be allowed to bid in the Real-Time Market.

Pros: The DAM clears with sufficient bids and the ISO is able to use an accurate load forecast to determine how the resource should be utilized. A complete bid stack is assessed.

Cons: SATA resources will not be able to participant in the Day-Ahead Market, and will only be allowed to participant in the Real-Time Market limiting their opportunity provide certain market services.

Option 2: The D+2 Option

- The ISO will evaluate the needs for SATA resources to be used as transmission asset two days prior to the operating day, at D+2.
- Similarly, CAISO will generate a bid right below the transmission relaxation penalty for SATA resources in D+2 RUC run.
- If SATA resources are cleared in this process, then SATA resources will be deemed as a "Transmission Service Asset" and will not be allowed for market based participation.

[11] 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.
[12] San Diego County Water Authority and City of San Diego notes that the ISO should allow for market participation unless recalled. The ISO believes 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.

- If SATA resources do not clear in the D+2 process, then SATA resources will be allowed to bid in both Day-Ahead and Real-Time Market.

Pros: SATA resources can participant in both the Day-Ahead and the Real-Time Markets.

Cons: RUC run with bids and load forecast data available in D+2 which could be less accurate.

All of the determinations will be made for an entire day. 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 seeks additional input from stakeholder on these options as continues to explore effective options for notifying SATA resources about when they can provide market services.

5.3.4. Ensuring there is no double payments for providing the same service

Although allowing a SATA resource to participate in the market may allow a resource owner to earn combined revenues in excess of its total cost-of-service, the revenues earned through the energy market are earned by providing market services, not transmission services. This is further supported by the fact that the energy market revenues will only occur at times when the ISO has stated that resource is not expected to be needed to provide transmission services and thus, does not constitute double recovery for the same services. Given the TRR reduction discussed in section 5.3.2 and the notification processes being considered in 5.3.3, the ISO asserts there are not opportunities for SATA resource to receive double compensation for providing transmission services.

5.4. Cost Recovery Options

As part of this stakeholder process, the ISO 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 risk – both 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

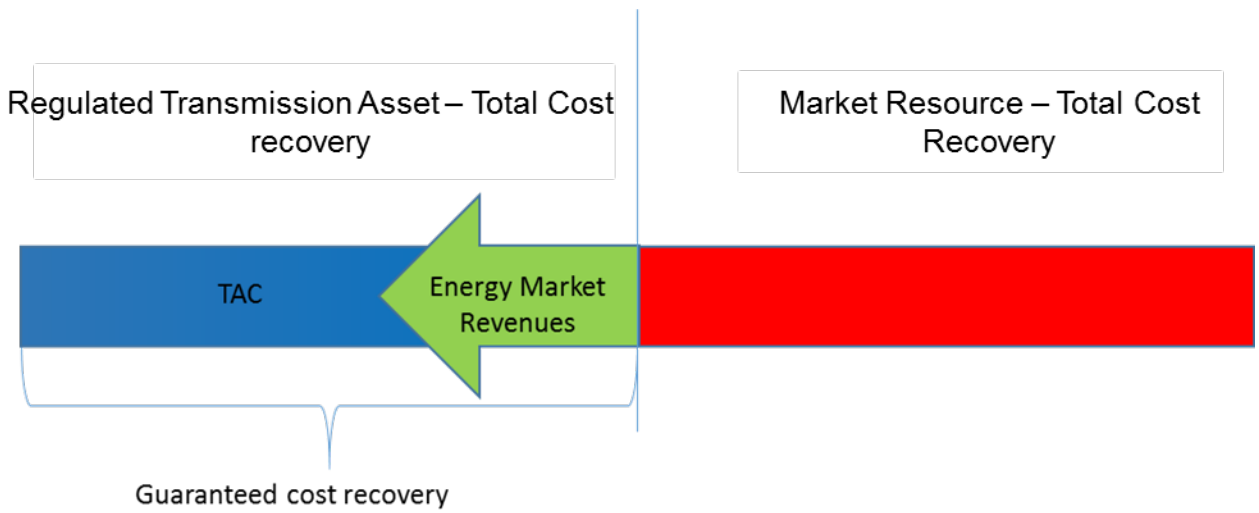
with option 2 and provides incentives that do not exist under option 1. More specifically, this option would provide incentives for the owner to participate in the market by allowing the resource owner to retain some percentage of the market revenue. However, resources will not be subject to the risk of not being able to at least recover the full cost of the resource.

This section provides greater details for each option.

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

As shown in Figure 4, 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 Transmission Revenue Requirement ("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

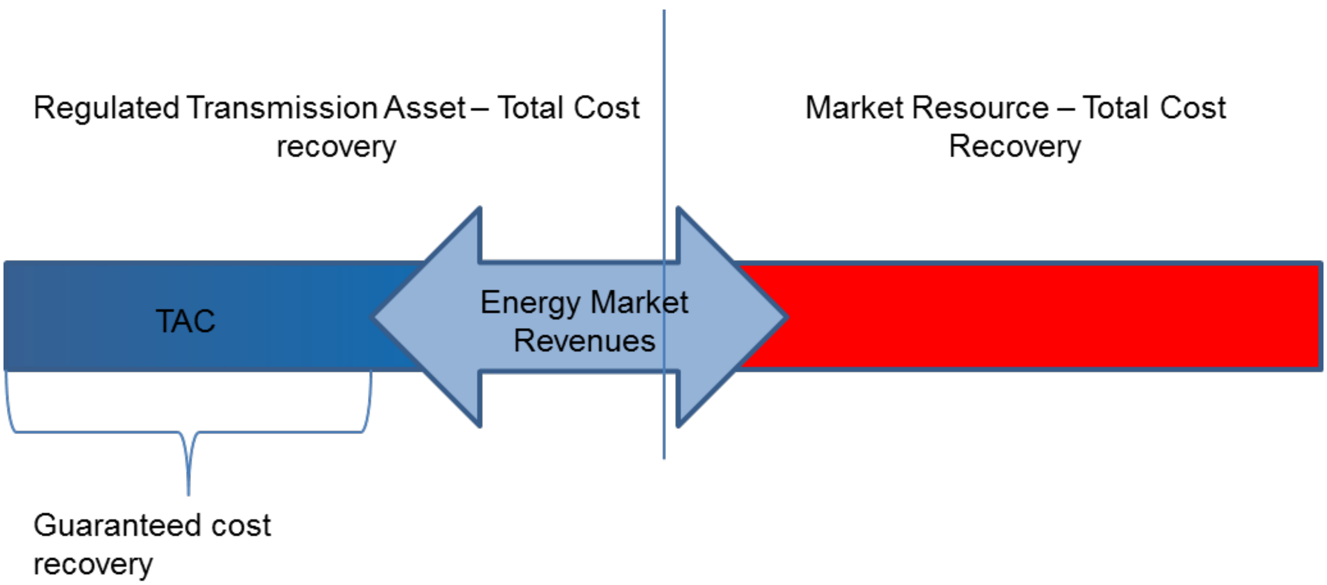


The most significant challenge with this model is that it provides little incentive for the resource to participate in the market. A project sponsor may propose a project into Phase 3 presenting assumptions of market revenues in an effort to be selected. However, absent additional obligations, there is no assurance that the resource sponsor would follow through on pursuing those market revenues. 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.[13] However, 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.

5.4.2. 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.[14] The partial cost-of service option is depicted in Figure 5, 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 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)

[13] This is consistent with comments from ITC.
[14] 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.

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.

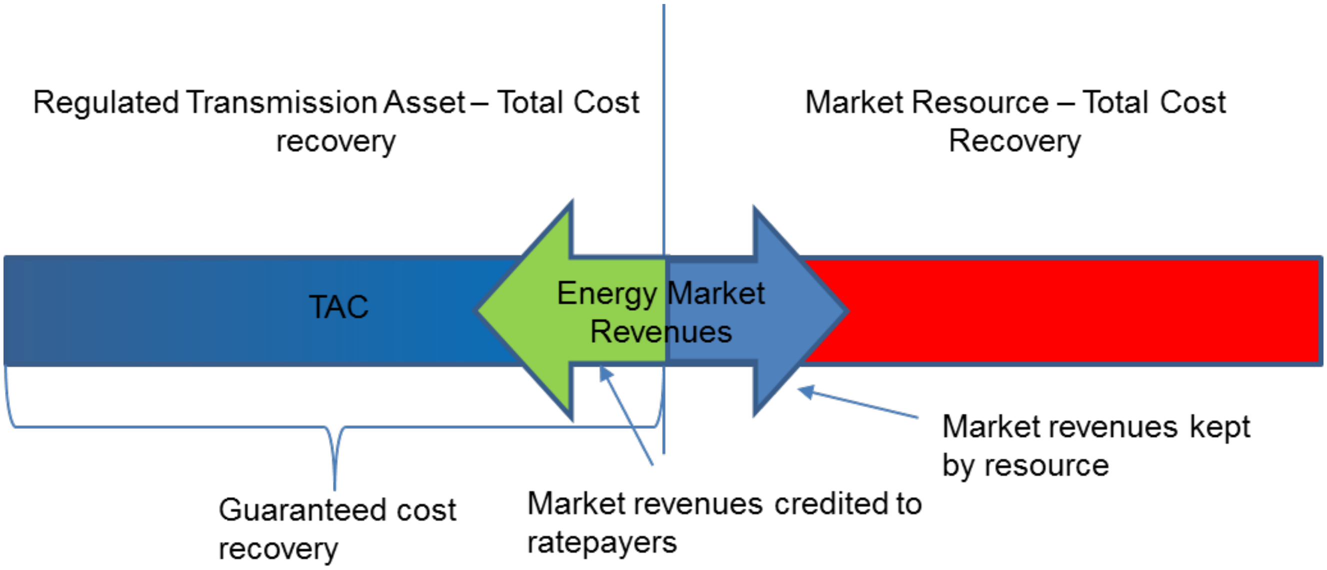
Under this model, any changes to the time or frequency a resource can provide market services will also impact the resource's ability to recover costs. However, is explained above, the ISO has determined that is not feasible to provide a firm schedule that identifies market opportunities for SATA resources over the life of the project. It is not clear if the notification processes currently under consideration (detailed above in section 5.3.1.2) provide sufficient and or comparable information to facilitate financing under this option. Therefore, the ISO is seeking stakeholder input to determine if this option remains viable or should be eliminated.[15]

5.4.3. 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 5.3.1, while mitigating some of the financial uncertainties that exist in the partial cost of service described above in section 5.3.2. 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.

[15] It should be noted that SCE and SDG&E have recommended that the ISO remove this as a potential option. While LS Power states that is "the only Option that guarantees more saving to ratepayers while still providing same benefits."

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.[16] 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.[17] Under either scenario, the ratepayer benefits. The ISO is seeking stakeholder comments on two aspects of this option. First, is to determine if a threshold of market revenue necessary or desirable before a SATA resources is allowed to retain a portion of market revenues is appropriate. Second, the ISO must determine if the split of market revenues should be fixed or allowed to vary across projects and/or bids. Variable splits will make it very difficult for the ISO to create and apples-to-apples comparison in Phase 3 of the TPP, while allowing resources to bid splits may result in greater ratepayer benefit.

5.4.4. 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.[18] 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 5.3.2). 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

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[16] It should also be noted that ORA opposed this option, stating "[i]f a SATA is receiving 100% cost recovery through the TAC, then its market participation revenues should be credited towards ratepayers' TAC obligation."
[17] SCE supported the first option, while SDG&E put forward the second option.
[18] Need tariff citation.

currently exploring options to either ensure competitive solutions or mitigate costs to ratepayers. Current options that ISO is exploring include the following:

1) Requiring at least three qualifies project sponsors 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 a contingency option.

2) Only in cases of too few qualified sponsors, requiring a set percent of total TRR be recovered before any market revenues be could be retained by the project sponsor.

3) Limiting the total allowable market revenue retention be limited to a fixed percent of the total annual TRR, or limiting the revenue split to no more than 50-50.

The ISO seeks stakeholder feedback regarding which of these options, or any other offered by stakeholders, will ensure ratepayers are able to benefit from SATA projects.

5.4.5. Shared facilities

The ISO approves 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.

The ISO notes that some project sponsors may seek to include opportunities to add additional market based resources or capability. In comments of 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."[19] The ISO agrees. While the ISO is not expressly foreclosing these opportunities,[20] it notes that any incremental cost for interconnection facilities and generation beyond the ISO's preferred solution will not be covered by the TRR.

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."[21] As noted above, 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.

[19] PG&E straw proposal comments at p. 3.
[20] EDF-R and NextEra both support the ISO allowing SATA resources as potential options.
[21] SDG&E comments on straw proposal at p. 5.

5.5. Market Participation and Bidding Rules SATA Resources

Market participation by SATA resources is the primary driver for the modifications being considered under this initiative. In order to allow for market based participation of SATA resources the ISO must outline the requirements for these resources ability to participate when not designated for use as a transmission asset to meet the identified needs, namely the intended bidding rules.

The ISO proposes that SATA resources may bid like any other non-RA resource when participating as a market resource.[22] Specifically, these SATA resources would be able to bid similarly to other storage resources when participating in the ISO markets. The ISO believes this aspect of the proposal treats these resources in a fair and equitable manner compared to other market resources by maintaining similar bidding requirements and parameters.

5.6. 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.

6. 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

[22] ORA requested that the ISO clarify that SATA resources will be required to pay transmission charges when participating in the market. At this time, non-generating resources, which the ISO expects SATA resources would be when participating in the market, do not pay Transmission Costs. Non-generating resources are considered negative Generation and thus excluded from TAC Allocations.

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.

7. Next Steps

The ISO will discuss this revised straw proposal with stakeholders during a stakeholder meeting on August 21, 2018. Stakeholders are asked to submit written comments by September 4, 2018 to initiativecomments@caiso.com.

8. Appendix

8.1. 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 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 hours and time periods this resource is available to the CAISO as a 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.
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.
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.

8.2. 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.

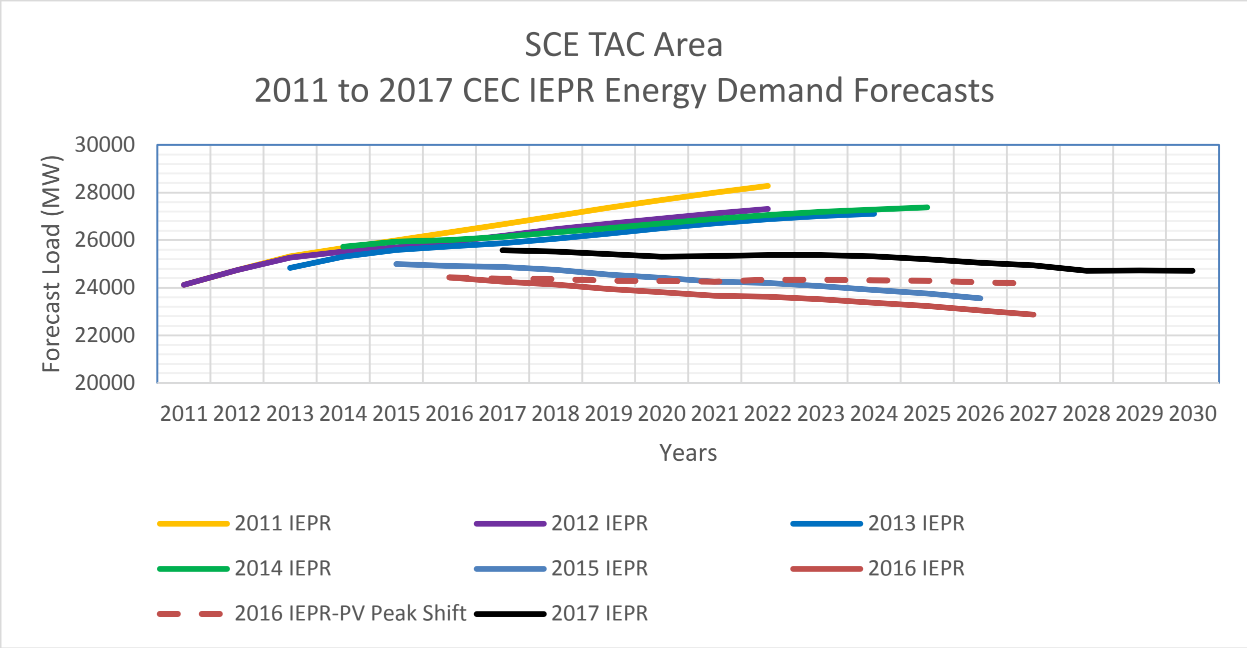
The ISO reviewed a set of transmission constraints and, in the process, identified several drivers that result an unacceptable level of uncertainty in the predictability of transmission need precluding the ISO making long term commitments regarding the timing of the transmission need and the resulting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

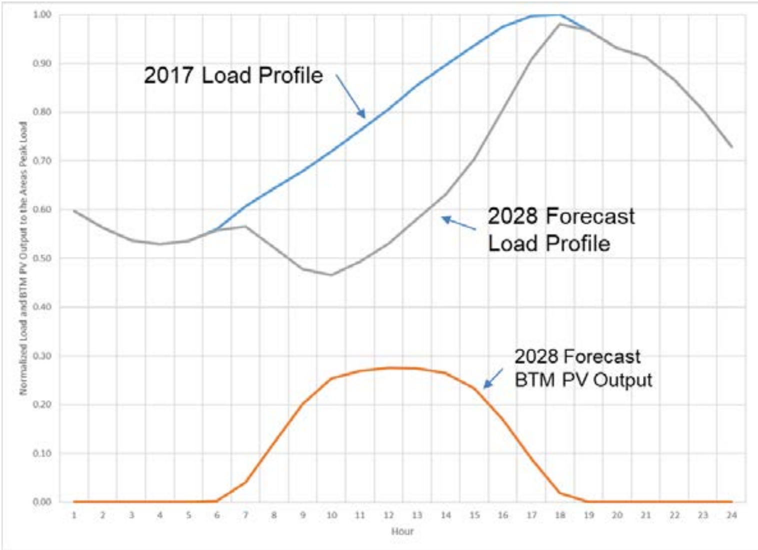
Load forecasts from CEC have been varying – both at the system level and at the local level as shown in Figure 5, below.

Figure 5: 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 6. BTM PV has a major impact as shown in the 2028 peak normalized forecasted BTM PV output.

Figure 6: 2017 and 2028 (Forecasted) Load Profile with Peak normalized BTM PV Output profile

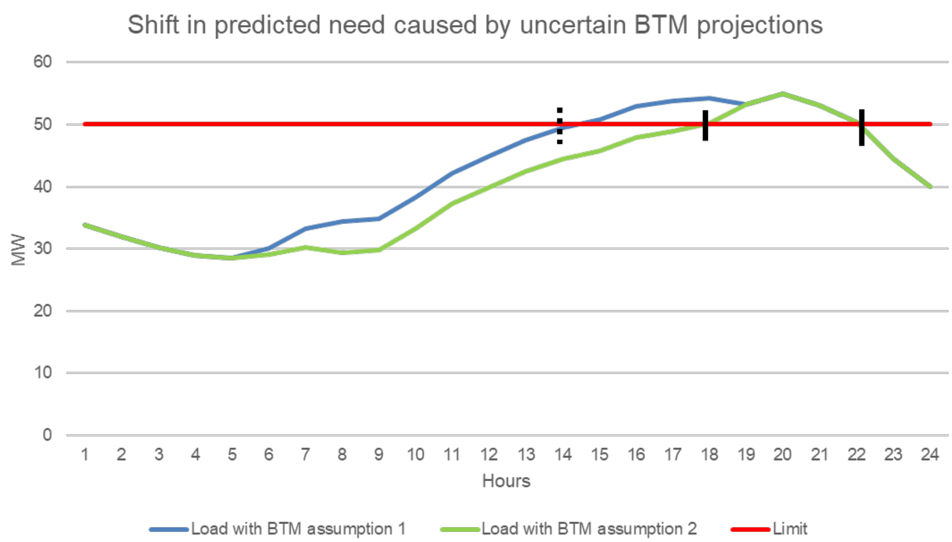


Several examples below further demonstrate the challenge of providing long term commitments as to the precise timing and duration of transmission needs.

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

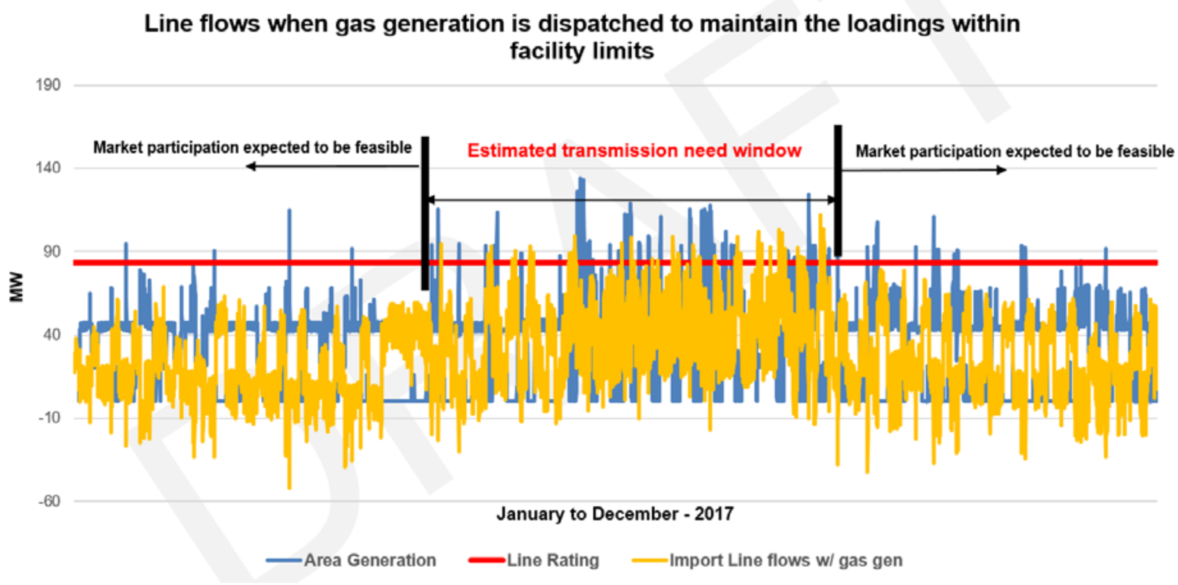
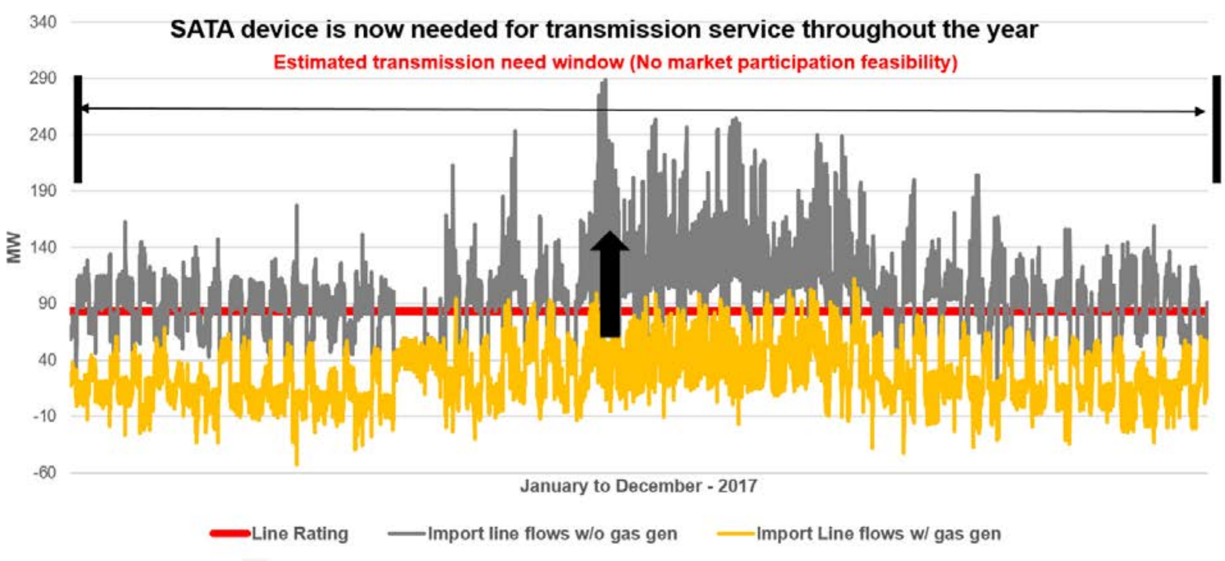


Figure 7: Transmission need window prediction under gas retirement scenario with a short notice



8.3. 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.

8.3.1. 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.

8.3.2. 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,[23] 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

[23] 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.[24] 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.[25]

8.3.3. 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

[24] 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.
[25] 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.

8.3.4. 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[26] 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[27] 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.[28] The ISO has also developed a methodology for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources –

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[26] "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.

[27] 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.

[28] *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.[29]

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

[29] 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.[30] 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;[31]
- 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;

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[30] 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.

[31] 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.

8.4. 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.[32]

[32] *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.[33] 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.[34]

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."[35] 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."[36]

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.[37] 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.[38] 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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33 *The Nev. Hydro Co. Inc*., 122 FERC ¶ 61,272 (2008).

34 *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).

35 *Id*.

36 *Id*.

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

38 *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."[39]

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.[40]

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.[41] 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."[42] 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."[43] 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
- Cannot jeopardize ISO/RTO independence.

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39 *Id.* at P 53.

40 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.

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

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

43 *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."

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.

The ISO acknowledges there may be instances where a dedicated solution is necessary to support local transmission needs with limited or no alternatives, in which case the ISO would consider the storage (as transmission only) option in its planning process. In these instances, the ISO may need to constrain or define narrowly the operation of the electric storage resource, for example, by requiring it to abstain from market participation and remain fully charged so it is solely available to meet a potential transmission contingency need.