Storage as a Transmission Asset:

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

Straw Proposal

May 18, 2018

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1. Executive Summary

In light of advances in 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 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 in the transmission planning process ("TPP") numerous proposals for storage devices to provide cost-of-service based transmission services, and recently the ISO approved two such proposals. Enabling storage facilities to provide transmission service under a cost-of-service framework, while also participating 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 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 <u>issues that are beyond the scope</u> of the current stakeholder initiative are 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

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 seeking clarity regarding 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.

Storage as a transmission asset ("SATA") resources[1] that can access market revenues do not fit precisely into any current ISO contract structure. As a result, the ISO will develop a new agreement that will combine Transmission Control Agreement ("TCA") provisions – if the owner is not already a Participating Transmission Owner ("PTO") – and provisions that cover how the

[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.

ISO will compensate a storage resource and when it can participate in the market, including the impact market revenues have on the total costs to be recovered under the agreement. In the final agreement the ISO will identify the terms and conditions that apply to market participation and the treatment of market participation revenues.

The ISO believes that there are three potential market participation scenarios for a SATA resource: 1) unpredictable, 2) reasonably predictable months, and 3) reasonably predictable hours. If the reliability need is unpredictable, the ISO will affirmatively state that market participation is precluded and market revenues will not be considered when identifying the preferred solution. If the need is reasonably predictable, then market participation would be allowable, subject to recall provisions. However, the terms of market participation may be subject to changes in system needs. 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 need as determined in the ISO's TPP. Once a resource is permitted to provide market services, then the resource, not the ISO, will be responsible for the bidding of the resource into the ISO markets.

The ISO proposes two cost recovery mechanisms:

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

Under the full cost-of-service 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 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 then be at risk – both upside and downside risk – of recovering a portion of its costs (and return) from market services.

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.

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 Issue Paper

The ISO received 21 sets of stakeholder comments on the issue paper. Most comments were generally supportive of the ISO initial proposed scope. Stakeholder comments typically fell into four topics:

1) Scope;
2) The contractual relationship between the ISO and the resources owner;
3) Market participation rules; and
4) Cost recovery options.

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

2.1. Scope

Many stakeholders, including CESA, CRI, ITC, LS Power, NextEra, and Sempra requested that the ISO expand the scope of the initiative to also include economic and policy driven needs. The ISO acknowledges that it may be possible for storage to facilitate transmission access to lower cost resources. However, the bulk of the Transmission Economic Analysis Methodology ("TEAM") economic benefits identified to date for storage projects in stakeholder submissions into the TPP focused on market resource benefits rather than improving transmission system capacity and providing benefits *"resulting from improved access to cost-efficient resources."*[2] Similarly, storage has not aligned with the needs triggered by policy direction that has formed the basis for policy-driven approvals in the past. However unlikely, the ISO acknowledges that such opportunities may be identified in the future. This distinction will be clarified in this straw proposal. The ISO economic-driven and policy-driven transmission planning processes are not meant to be duplicative of the CPUC resource planning processes.

Sempra, SDG&E, and Six Cities all supported the ISO proposal to limit the scope to transmission connected resources. Other stakeholders, such as LS Power and CESA express support for additional consideration of distributed connected resources. The ISO acknowledges that distribution connected resources may also provide transmission services, but these resources bring additional and unique challenges in implementation and should be procured through local capacity procurement processes unless absolutely necessary. However, such projects would be considered in the transmission planning process on a case-by-case basis, not arbitrarily through this initiative.

IEP and DMM requested clarification on why the proposal is only limited to storage, specifically asking if other technologies would be considered. Six Cities noted that the scope should be limited to storage resources and that thermal resources should not be eligible. Alternatively, CRI requested that the ISO use broader language to be consistent with EPAct 2005. The ISO's proposed scope focuses on storage technologies, consistent with the Federal Energy Regulatory Commission's ("FERC") policy statement.

Finally, numerous parties requested additional detail regarding the scope of the present initiative and what tariff authority and flexibility the ISO has to address under its current TPP. The ISO has provided additional detail regarding what can and will be addressed through the

[2] ISO Tariff Section 24.4.6.7

TPP in section 4.1. This initiative's focus is the specific issue of: ***If*** a resource is providing transmission service on a cost-of-service basis, then how can market revenues be accessed to lower the cost-of-service cost to ratepayers? The ISO will not explore any changes to the TPP Phase 3 competitive solicitation process as part of this initiative.

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

Most parties sought additional details regarding the contractual relationship between the ISO and the SATA resource. For example, PG&E expressed concerns about SATA resources that do not also become a PTO might not have similar obligations serve as does a PTO. Similarly, ORA was unclear about how the ISO could exercise adequate operational control if the resource's owner was not a PTO. Stakeholders differ regarding the feasibility of modifying the existing PTO agreement – CESA recommended utilizing the existing agreement as a starting point, while SDG&E states that modifications may not be feasible. The ISO agrees that the TCA as currently structured is not adequate to cover all aspects of SATA resources also providing market services. In section 5.2, the ISO details enhancements that must be made to several existing agreements, including the TCA and Participating Generator Agreement ("PGA"), to facilitate SATA resources also providing market services and to ensure treatment and maintenance comparable to other transmission assets.

2.3. Market Participation Rules

Most stakeholder sought additional details about how and when resources would be permitted to provide market services and access market revenues. In section 5.3, the ISO clarifies that it will identify both the reliability need and, to the extent the timing of the need is reasonably predictable, the opportunities for market participation in Phase 2 of the TPP. If the reliability need is unpredictable, the ISO will affirmatively state that market participation is precluded and market revenues will not be considered when identifying the preferred solution. It is important to note, that predictability is likely not a binary condition and that the ISO cannot predict future needs years in advance. There will be variable probabilities and predictability that may change over time and increased probabilities in some months but not others that will need to be examined on a case by case basis. The ISO will examine these probabilities when determining market participation eligibility. If market participation is deemed acceptable, the ISO will work with stakeholders in Phase 2 to estimate potential market revenues as a factor in determining preferred solutions. However, the ISO also notes that there may be circumstances beyond those initially identified that could result in the ISO recalling the resource to provide transmission service or modifying the ability for the resource to provide market services.

2.4. Cost Recovery Options

Stakeholders where generally supportive of the two rate recovery options provided by the ISO in the issue paper. However, many stakeholders sought additional clarity about how and when a project sponsor needed to select an option. Additionally, SDCWAC proposed a "blended" option of that allows a resource to shift from one approach to the other over time. ITC recommends that the ISO contemplate how a market resource can access transmission revenues. The ISO clarifies here that this stakeholder process focuses on facilitating access to market revenues for resources found to be needed for a transmission need.

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

The ISO is evaluating the circumstances and conditions when storage facilities identified during the ISO transmission planning process that are necessary to provide transmission services, and receive a cost-of-service based cost recovery, can also provide market-based services and access market revenues, thereby lowering costs and providing greater flexibility for the benefit of ratepayers. This may include options such as providing additional market-based services, with the resulting market-based revenues ultimately reducing the cost burden placed on 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 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 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 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, and discussion of how a number of stakeholder issues may be considered in that process.

4.1. 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.

4.1.1. 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.

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.

4.1.2. 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,[3] 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;

[3] 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.

- 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 the plan that require Board approval.[4] 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.[5]

4.1.3. 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

[4] 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.
[5] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

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 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.

4.1.4. 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[6] 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[7] 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

[6] "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.

[7] 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.

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.[8] The ISO has also developed a methodology for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – 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.[9]

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

[8] *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.
[9] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

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 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.[10] 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).

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[10] 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.

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;[11]
- 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;
- 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.

[11] 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.

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

As noted above, the ISO's recent history has been to generally consider energy storage as either (1) a market resource, 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."* [12]

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.

4.2.1. Consideration of economic-driven energy storage transmission solutions

To date, the ISO's consideration of storage devices as a transmission assets 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 in the resource adequacy framework:
- Reducing market costs, in which case storage as a "transmission" asset would introduce the market interference that FERC's Policy Statement seeks to avoid;

[12] *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 with other market resources.

4.2.2. 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 the necessity of 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 planning. This will require careful consideration on a case-by-case basis through the course of the annual TPP in Phase 2.

4.2.3. 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;[13] (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.

[13] 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 be re-terminated to multiple substations through adjusted normally-open points, or unavailable without ISO knowledge due to distribution limitations. A directly connected device also provides clarity on cost allocation – regional or local TAC – based on voltage 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 other needs identified by an RTO/ISO." 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. 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 relationship 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 aspecific 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
    - Storage procured, in whole or in part, through a CPUC-mandated capacity procurement process
- **The TPP evaluation methodologies**. The ISO is not reexamining its TPP, which identifies needs and selects the optimal solution(s) to meet identified needs. These issues are appropriately considered in the ISO's annual TPP. If additional clarification of the evaluation process is needed in the future, the ISO will address it on a case-by-case basis within the annual TPP.
- **The framework for competitive solicitation and the applicability of the ISO's current competitive solicitation framework**. The ISO's current competitive solicitation tariff provisions apply to regional storage facilities just as they apply to other regional transmission facilities such as reactive support devices. Specifically, projects connected at 200 kV or higher will be subject to competitive solicitation unless the project constitutes an upgrade to an existing transmission facility. Incumbent PTOs are responsible for projects connected at less than 200 kV.
- **Cost allocation of the cost-based revenue requirements for rate-based assets.** The ISO's current tariff provisions that address cost allocation apply to storage just as they apply to other transmission facilities such as reactive support devices.

- **Resource adequacy value**. The ISO will not consider cost-of-service based storage resources procured through the TPP to count as resource adequacy resources as these resources are already taken into account when determining local capacity area needs.

5.2. Contractual Arrangements between ISO and SATA Accessing Market Revenues

SATA resources that can access market revenues do not fit precisely into any current ISO contract structure. For example, a SATA resource would likely be subject to the provisions of maintenance and upkeep of the facility as a participating transmission owner signing a transmission control agreement. At other times, the SATA resource may be acting as a generator and subject to the requirements detailed in the participating generator agreement when they discharge, as a load subject to the requirements detailed in the participating load agreement when they are charging. As a result, the ISO will develop a new agreement that would be a combination of the needed transmission control agreement provisions – if the owner is not already a participating transmission owner – and provisions that cover how the ISO will compensate a storage resource and when it can participate in the market, including the impact of the market revenues on the total cost of the agreement. The ISO proposes to develop compensation provisions of the new agreement using concepts similar to those used in RMR agreements where a resource is compensated by the ISO for all or some portion of its fixed costs and also provides that the resource can participate in the ISO market under certain conditions.

The ISO proposes creating a new agreement and not have the owner of SATA resources accessing market revenues execute a PGA, PLA, RMR or new TCA Agreement. Attempting to use those agreements would require significant edits to include storage resources. A separate agreement makes more sense so that it is tailored for storage resources and storage resources' cost recovery mechanisms through the transmission access charge. The ISO would likely take certain language out of the various agreements, but not all of the terms and conditions. Examples of the provisions that would be included within the new agreement from the TCA are transfer of operational control, system operation and maintenance, critical protective systems that support the ISO controlled grid, system emergencies, access and interconnection, expansion of facilities, use and administration of ISO grid, and maintenance standards. The new agreement would also cover the PGA, PLA, and RMR concepts so it is all contained in one agreement and all of the obligations and benefits are in the same agreement.

In the final agreement the ISO will also identify the terms and conditions that apply to market participation. The details regarding how the ISO will determine market participation eligibility is described in section 5.3. The specific times in which a resource is able to participate in the market will be defined through Phase 2 of the TPP and those times will be laid out in the final agreement. Although the ISO would approve market participation during certain times, it should be noted that the ISO will have a right to recall the resource to serve its primary function – as a transmission asset – at any time. The resource owner will be responsible for ensuring the resource can accept ISO dispatch instructions at all times. The specifics of market revenues in determining overall cost recovery and ensuring resources are not receiving double payments for the same services are detailed in section 5.4.

5.3. Market Participation Rules

This stakeholder process focuses on enabling electric storage resources providing transmission services (*i.e.*, filling a specific ISO identified transmission system need) to potentially access market revenues. These needs include, but may not be limited to, mitigating contingency driven thermal overloads and/or providing transmission system voltage support. As a primary determination, the ISO must make a determination if a SATA resource is eligible to access market revenues. Once a resource is permitted to provide market services, then the resource, not the ISO, will be responsible for the bidding of the resource into the ISO markets.

5.3.1. Eligibility based on predictability of transmission need

The ISO will identify both the need and the opportunities for market participation, to the extent the timing of the need is reasonably predictable, in Phase 2 of the TPP. If the reliability need is unpredictable, the ISO will affirmatively state that market participation is precluded and market revenues will not be considered when identifying the preferred solution.[14] It is important to note, that predictability is likely not a binary condition and that the ISO cannot predict future needs years in advance. There will be variable probabilities and predictability that may change over time and increased probabilities in some months but not others that will need to be examined on a case by case basis. The ISO will examine these probabilities when determining market participation eligibility.

The ISO believes that there are three potential market participation scenarios: 1) unpredictable, 2) reasonably predictable months, and 3) reasonably predictable hours. Figure 1, shows an example to illustrate when transmission needs are fairly unpredictable. The red areas show when the ISO is most likely to need the resources to act purely as a transmission asset, with orange, yellow, and green representing times of decreasing likelihood of need. Figure 2, below, shows examples to illustrate when the need for a transmission asset is reasonable predictable. As noted above, these probabilities must be analyzed on a case by case basis and similar probabilities may result in different market eligibility in different locations.

[14] This is consistent with the FERC policy statement which states at paragraph 25
We recognize that this assignment of responsibility is premised on the need for the service compensated through cost-based rates being predictable enough to allow the appropriate charge management structure to be implemented. In situations where this premise does not hold, and the need for the service for which cost-based rates are provided is not reasonably predictable as to size or the time it will arise each day, the cost-based rate service may be the only service that the electric storage resource could provide.

Figure 1: Example of unpredictable transmission needs

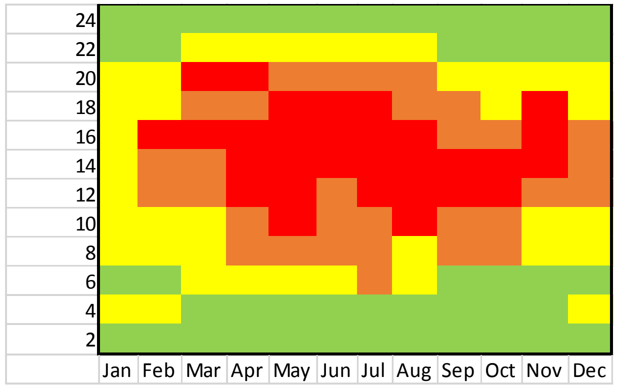
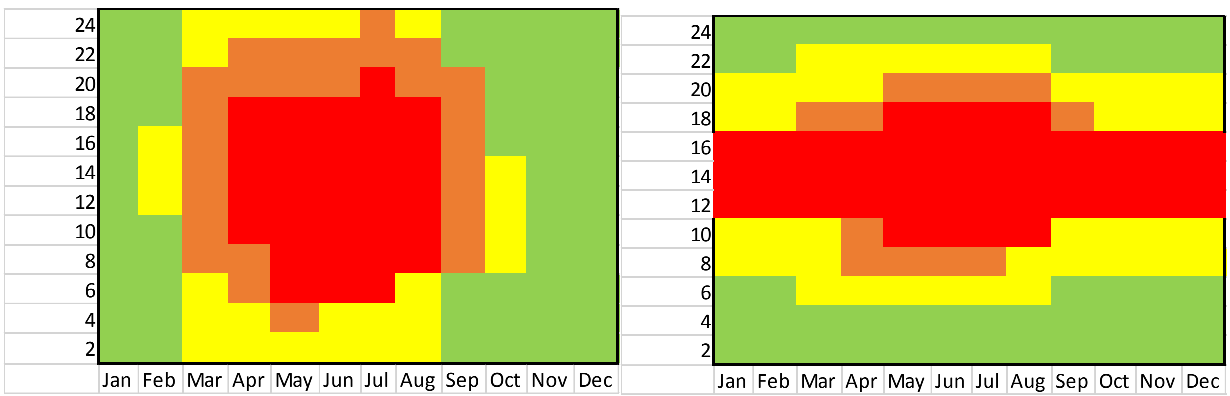


Figure 2: Examples of reasonably predictable transmission needs, including (a) months and (b) hours



The FERC policy statement contemplates predictability of size of a need. The ISO does not believe this is a viable option. As noted above, 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. Any capacity that a project sponsor seeks to add beyond that which is need to resolve the identified need will be required to utilize the ISO's generation interconnection process and would not be eligible for cost-of-service rate recovery. Resources selected in Phase 3 of the TPP would proceed as transmission projects and not be required to request interconnection through the ISO's generator interconnection process. However, the ISO notes that even requiring additional capacity to use the ISO's interconnection process creates questions regarding the use of common facilities between the portion of the facility used for transmission services and the portion used for additional market participation by excess capacity interconnecting at the same point. The ISO, therefore, seeks stakeholder comments about how such concerns can be resolved.

5.3.2. Emergency system needs

The ability to provide market services and to access market revenues will be made based on an ISO assessment of the probability that a SATA resource is not needed during certain times. However, emergency conditions may arise at any hour. As a result, the ISO reserves the right to recall any SATA resource from market participation to transmission service. The ISO will provide notice to the resource owner regarding the nature of the need and the expected duration of the need. The resource owner will then be responsible for ensuring that the resource is able to provide transmission services at the time and for the duration determined by the ISO.

5.3.3. Adjusting long-term system needs

An initial determination that a SATA resource has the ability to access market revenues in a given month is not a guarantee that the resource will be able to access those market revenues for the entire life of the resource. The ISO proposes to make determinations that facilitate access to market revenues for SATA resources using the TPP Phase 1 input assumptions. However, the ISO notes that, over time, the needs for a SATA resource may change. For example, the ISO's initial studies may show that the greatest transmission needs for a SATA resource exists from July through September, allowing a SATA resource to access market revenues from October through June. However, due to load growth, the ISO determines in subsequent studies that additional transmission needs exist in May and June. As a result, the ISO reserves that right to build in additional limitations and make necessary modifications regarding market participation over time. Absent the ability to account for changing system conditions, the ISO would be forced to identify new costly system additions that can already be addressed by existing resources. Details regarding the impact on cost-recovery for various resources is provided in section 5.4, below.

5.3.4. 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 ISO does not believe that allowing SATA resources to access market revenues when the resource is not needed for transmission services will impact competitive wholesale electricity prices. The hours in which the resource will be most needed for transmission will be the same hours in which the resource would most likely have the ability to significantly impact energy market prices. The hours a SATA resource would be able to access market revenues would be intervals that are already competitive and the addition of SATA resources would have little to no impact on market prices. Additionally, to the extent that SATA resources may lower energy prices in some intervals while discharging, they would increase the price in other hours when the resource is charging. Finally, DMM notes that resources procured through a competitive "could enhance market efficiency."[15]

The ISO also believes that the above proposed structure ensures the ISO's independence is not jeopardized. Specifically, the ISO will not be responsible for the bidding and market participation of the resource. Additionally, the opportunities for market participation are made known well in advance of any energy market optimization, creating an additional layer of separation.

Item (3) is addressed in greater detail in section 5.4, below.

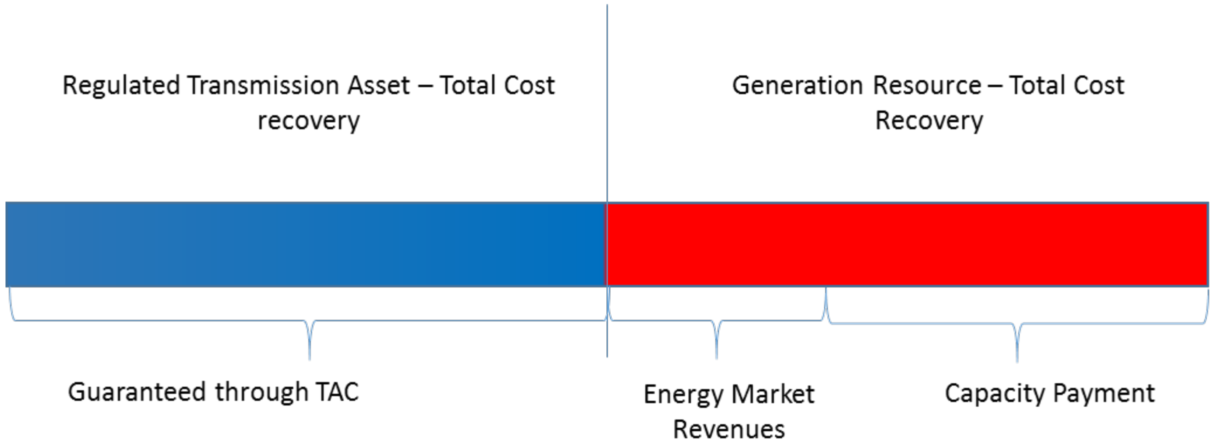
5.4. Cost Recovery Mechanisms

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 comes solely through the TAC. Allowing storage to act as both as 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, generation resources have received cost recovery through a variety of sources, including revenues from capacity and energy payments.

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

Figure 3: 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.

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

a. 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.

b. 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 is at risk – both upside and downside risk – of recovering a portion of its costs (and return) from market services.

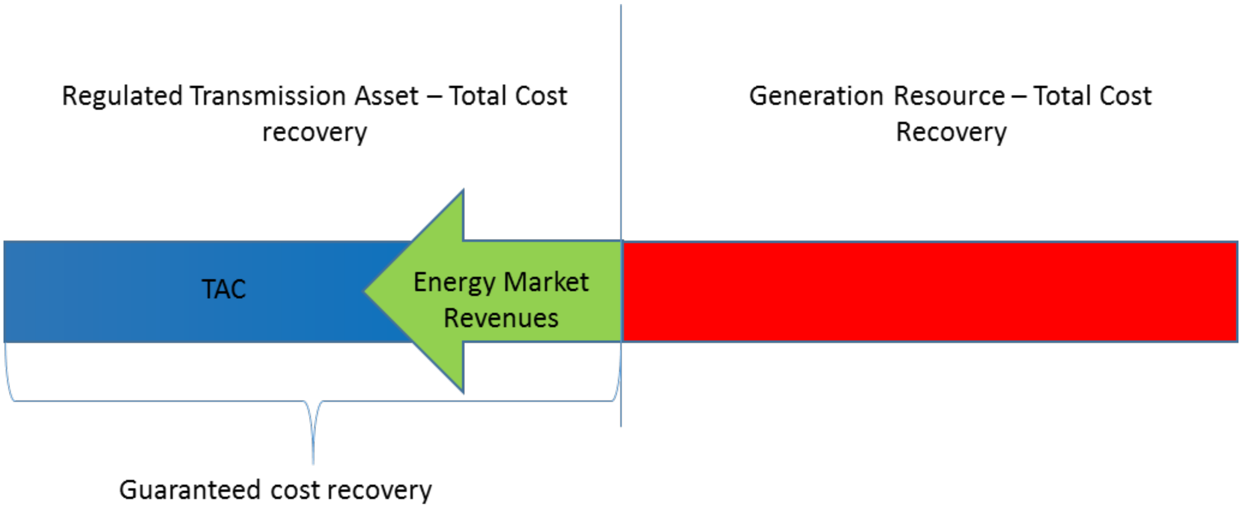
The SATA resource would have the opportunity to select one of these options as part of their bid submission into the competitive solicitation process of Phase 3 of the TPP.

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

5.4.1.1. Description

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 generation 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 4: Illustration of full cost-of-service based cost recovery and energy market crediting



As noted above, the ISO reserves the right to adjust the time windows in which a resource could provide market services. While under this model that could reduce the overall TRR credits, it will not impact the SATA resource's ability to recover its costs. As such, the ISO does not need to provide any additional compensation to the SATA resource for this change.

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 is exploring options to further ensure SATA resources receiving full cost-of-service based cost recovery and energy market based revenues will make reasonable efforts to earn market revenues and seeks stakeholder comments on this matter.

5.4.1.2. Consistency with FERC Policy Statement

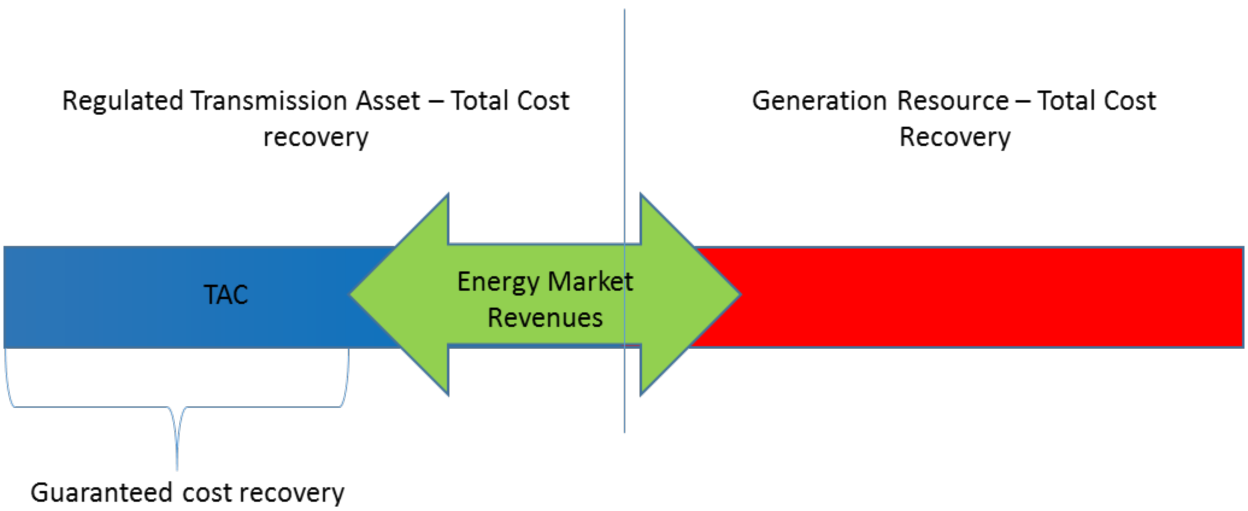
As noted above, the ISO believes that allowing SATA resources to participate in competitive markets during time periods known well in advance of any ISO market timeframes ensures the ISO will maintain its independence and the limited opportunities for market participation mitigate any potential to suppress energy market prices. Additionally, FERC stated that the ISO must also demonstrate that resources will not receive double compensation for a particular service. The ISO believes the proposed full cost-of-service recovery mechanism with associated energy market revenues credits is consistent with this requirement. Any market revenues are credited against the resource's transmission revenue requirement. As such, the resource will actually be using revenues from providing a separate and distinct service that will also reduce its TRR, and will not receive duplicative revenues from providing transmission services.

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

5.4.2.1. Description

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.[16] 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 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 5: Illustration of Partial cost-of-service based cost recovery and no energy market crediting



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. Therefore, if for any reason the ISO determines that the opportunities to provide market services change, the ISO proposes to work with the resource to determine appropriate compensation to ensure the resource is justly

[16] 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.

compensated for any changes. It is important to note, the SATA resource may not request a change to the opportunities to provide market services. For example, if the expected market revenues are not reaching forecasted levels, the resource cannot seek to revise the agreement to increase the portion of costs covered under cost-of-service rates.

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

5.4.2.2. Consistency with FERC Policy Statement

Similar to the full cost-of service option, under the partial cost-of-service model, the ISO is able to maintain its independence and avoid suppressing competitive market prices. Additionally, this model also ensures that resources will not receive double compensation for providing transmission services. Although the resource owner may be able to earn combined revenues in excess of its total cost-of-service, the revenues earned through the energy market are earned from providing a separate service. This is further supported by the fact that the energy market revenue streams 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.

5.5. 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 again, 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 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 issue paper with stakeholders during a stakeholder call on May 24, 2018. Stakeholders are asked to submit written comments by June 7, 2018 to initiativecomments@caiso.com.

8. Appendix

8.1. 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.[17]

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.[18] 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.[19]

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."[20] 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."[21]

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

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[17] *Utilization of electric Storage Resources for Multiple Services When Receiving Cost-Based Recovery,* 158 FERC ¶61,051 (2017) ("Policy Statement").
[18] *The Nev. Hydro Co. Inc*., 122 FERC ¶ 61,272 (2008).
[19] *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).
[20] *Id*.
[21] *Id*.

transmission facilities eligible for cost-based recovery.[22] 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.[23] 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:

> "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."[24]

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.[25]

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.[26] 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."[27] FERC was careful to note that its Policy

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

23 *Id*. at P 3.

24 *Id.* at P 53.

25 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.

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

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

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."[28] 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.

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.

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[28] *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."