Storage as Transmission

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1. Introduction

Large battery energy storage systems (BESS) are not really generation systems, but they can strongly optimize many generation systems including intermittent renewables like photovoltaic (PV) and wind turbines. It is also not transmission, but can also optimize, and in some cases defer transmission upgrades.

I recently came across the following article regarding my home state (California).

The California Public Utilities Commission is pushing forward two proposed battery energy storage facilities in Central California instead of upgrading existing nearby transmission lines, citing a lower cost for the battery storage projects.[1]

In a Dec. 22 proposed decision, the CPUC asked Pacific Gas & Electric to submit an advice letter with plans for a 50-MW and a 95-MW energy storage facility in the utility's territory.

The 95-MW storage facility would be located on PG&E's Kern-Lamont 115-kV system near Bakersfield, and the 50-MW storage facility would be located at PG&E's Mesa 115-kV substation near San Luis Obispo. Both projects would use four-hour batteries.

The California Independent System Operator previously approved transmission projects for these locations as part of the agency's transmission planning process. However, CAISO representatives later determined that the two locations could be potential sites for energy storage facilities, rather than upgraded transmission equipment, the proposed decision says.

The two facilities appear to be the first storage projects that CAISO has identified as acceptable non-transmission alternatives within the agency's transmission planning process, the proposed decision says. The storage facilities would improve grid reliability and cost less than upgrading transmission lines, the ISO said in comments to the proposed decision. If the storage facilities are not built, CAISO will move forward with the planned transmission projects.

CAISO does not currently have a method for counting storage resources as transmission assets in a way that enables developers to recover costs through a transmission access charge, the proposed decision says. In the agency's transmission planning process, storage projects are assumed to receive market revenues through a power-purchase agreement.

For the 50-MW storage facility at the Mesa 115-kV substation, CAISO should consider additional potential reliability issues outside of reliability criteria minimums, PG&E representatives said in comments to the proposed decision. Additionally, CAISO should

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[1] David Krause, California Energy Markets, "CPUC Pushes Forward Battery Storage in Lieu of Transmission Upgrades," Jan 7, 2022, https://www.newsdata.com/california_energy_markets/regulation_status/cpuc-pushes-forward-battery-storage-in-lieu-of-transmission-upgrades/article_e4f6525e-6f57-11ec-a64f-772fd16063db.html#

still move forward with its approved transmission project at the site because it is possible that the storage project alone will not be able to meet reliability needs, the utility's representatives said.

During reliability assessments in 2020 and 2021, CAISO identified severe thermal overloads on the power lines that are served by the Mesa Substation, the grid operator said in its 2020-2021 Transmission Planning Process (TPP). Furthermore, the region's load profile does not allow maintenance periods for the affected facilities, meaning an issue could result in load loss in the area, the TPP says…

Since PG&E is not fully on board with the above applications, this issue has not been fully resolved, however, BESS in lieu of transmission line upgrades have two major advantages (over cost), their bid-to-commission time is probably much lower than the time required to upgrade the transmission line. Furthermore, if required in the future, their capacity and/or duration can be easily upgraded.

I researched the title issue, and came across a really good DOE document on this issue, and the main subject of this post is a summary of that document.

2. BESS as Transmission and a Market Asset

Because the electric grid is a real-time delivery system, it must be large enough to meet the highest levels of demand and withstand any reasonably foreseeable contingencies, even if that demand only occurs for a few hours per year and those contingencies never manifest. The result is that the transmission system is much larger than what is needed under average conditions, and it has significant excess capacity most of the time.[2]

Recognizing this, the Federal Energy Regulatory Commission (FERC) issued a policy statement in 2017 supporting the deployment of energy storage for the dual uses of regulated transmission service and competitive market service. By allowing this usage model, FERC reasoned, revenue earned through market operations when the storage asset isn't needed for transmission could be shared with customers and system costs could be reduced. This type of use is becoming increasingly relevant amid growing calls for significant new investments in the transmission system to incorporate new renewable generation.

But this approach represents a significant change in electric grid operations, which have historically separated transmission and generation functions into distinct siloes. To deploy dual-use storage, the differences between how transmission and generation systems are planned, expanded, and compensated will need to be resolved. Implementation of the policy statement creates a significant opportunity for pumped storage hydropower (PSH) facilities in particular, given that their scale is well aligned with transmission applications and that a proposed dual-use PSH facility was a key motivating factor for the policy statement.

Author's comment: Although pumped storage is heavily used and continues to be deployed in California, it is also heavily constrained by the financial considerations, specific location and topography required and time required to deploy a major project, whereas BESS is very much less expensive, quickly deployed and easily upgraded. It

[2] JB Twitchell, SE Barrows, D Bhatnagar & K Mongird, DOE, PNNL, "Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset," Feb 2022, https://www.osti.gov/biblio/1846604

can also be deployed, in general, much lower in the transmission system (lower power/voltage applications). Although reference 2 is focused on pumped storage, many of the applications are also applicable to BESS.

This paper reviews the technical barriers in transmission planning practices and energy market design that prevent the realization of dual-use energy storage projects, describes the principles that a dual-use project must satisfy to meet both functions, and identifies policy options that abide by those principles. Its purpose is to objectively inform subsequent proceedings on dual-use energy storage by framing the issue and identifying options available to regional market operators, utilities, developers, regulators, policymakers, and other stakeholders as they collectively work on this complex issue. The principles identified are technologically neutral and adaptable to PSH, batteries, or any other bi-directional energy storage technology.

Where transmission assets are identified through extensive planning processes and subject to regulatory review, competitive energy and ancillary service markets are designed to create comparatively fewer barriers to entry for generation assets. Because of these disparate paths to entry, a dual-use asset would need to be first identified through a transmission plan, and then provide market services on an as-available basis.

Traditional transmission planning processes, however, create at least five barriers that prevent the identification of energy storage alternatives:

- *Lack of clarity for how and when storage will be considered*
- *Difficulty representing storage in power flow models*
- *Weak links between transmission and generation planning processes*
- *Financial disincentive for utilities to consider lower-cost options*
- *Lack of regulatory review*

A review of current transmission planning practices reveals that two regions have begun addressing these barriers by establishing clear processes regarding how and when storage options will be considered.

These regions took different approaches—one creating an expectation for planners to proactively identify storage alternatives and the other creating a mechanism for stakeholders to propose storage alternatives—that illustrate the options available to regional transmission planning coordinators for improving the representation of energy storage in the planning process.

Accurately valuing a dual-use storage asset in the transmission planning process also requires clarity around how the asset may participate in the market, to facilitate accurate forecasts of market revenue and how much revenue will be credited back to customers. Accounting for these credits during the planning process improves the accuracy of cost comparisons between storage and traditional infrastructure alternatives and increases the potential for identifying cost-effective storage alternatives.

Allowing an energy storage device deployed as a transmission asset to also access wholesale energy markets creates several competing priorities. Market participation creates offsetting revenue to be shared with customers, but excessive participation may also reduce the useful life of the asset and ultimately increase costs to customers if the device must be repaired or replaced ahead of schedule. A storage asset that is oversized relative to the transmission need it is meeting creates headroom to provide *more market services, but also creates inequities for other market participants. A dual-use participation framework must walk a fine line that balances these competing priorities while ensuring that market participation does not jeopardize the asset's ability to serve the transmission function for which it initially selected.*

Because existing policies and regulations vary across regions, developing a universal participation model would not be practical. To maximize flexibility and adaptability across multiple regions, this paper identifies the principles that a participation framework must satisfy and the options available to policymakers in satisfying them. Those principles can be summarized in three key questions that a dual-use participation model must answer:

- *When will the asset participate in the market? Establishing boundaries for market participation, either in temporal terms or operational terms based on the storage asset's state of charge, allows the owner to make informed bids into day-ahead markets.*
- *How will the asset participate in the market? Market products and resource definitions need to recognize the unique nature of dual-use assets by allowing them to simultaneously bid into multiple services and be dispatched in real time as grid conditions require.*
- *Where will the asset recover its costs? Cost recovery mechanisms must balance the revenues earned from transmission rates and market participation to incent reasonable levels of market participation and ensure that customers realize the financial benefits of dual-use energy storage.*

These principles will be incorporated into a techno-economic analysis that will quantify the economic benefits of dual-use energy storage to the grid and to customers, using a theoretical PSH facility. Project partners at Argonne National Laboratory will publish that analysis in a subsequent report.

3. Regulatory Consideration

In order to keep this paper to a reasonable length, below I will excerpt some content from Reference 2 that might be applicable to storage being used for transmission functions in California.

3.1. FERC Ruling

FERC's next landmark action on energy storage as a transmission asset came in 2017, when the commission issued a policy statement to clarify its views on the topic after a pair of similar, high-profile cases had different outcomes.

In the first case, initially filed in 2005, developer Nevada Hydro proposed a 500 MW PSH facility in Southern California. Nevada Hydro requested a declaratory order from FERC recognizing the project as a transmission asset eligible for regulated rate recovery through the California Independent System Operator's (CAISO) transmission tariff, arguing that such treatment would be consistent with the Energy Policy Act of 2005's designation of energy storage as an advanced transmission technology. However, Nevada Hydro proposed to give full operational control of the facility to CAISO and have CAISO operate it to provide transmission or generation services at the grid operator's discretion.[3]

[3] Order on Rate Incentives and Compliance Filings. Docket ER06-278 (March 24, 2008). 122

After a lengthy proceeding that included a procedural break while CAISO conducted a FERC-ordered stakeholder initiative to explore the implications of Nevada Hydro's proposal, FERC ruled that the PSH facility was not eligible for rate treatment as a transmission asset. FERC's rejection was rooted in two conclusions: that the proposal did not clearly establish how the PSH facility would be operated in a distinct manner from existing PSH facilities that operate as generators, and that turning over operational control of the facility to CAISO would jeopardize the grid operator's independence.

Informed by the outcome of the Nevada Hydro proceeding, developer Western Grid proposed a different approach to using storage as a transmission asset in 2009. Western Grid's proposal consisted of deploying several sodium sulfur batteries at various locations within CAISO, ranging in size from 10 to 50 MW. The proposal stated that the batteries would be used exclusively on the transmission system to provide voltage support and relieve thermal overloading. Western Grid would own and operate the devices at CAISO's direction as a registered transmission provider, and the batteries would not participate in CAISO's energy markets. Western Grid would purchase retail energy to charge the devices and receive retail compensation when discharging them, with any net proceeds returned to customers.[4]

FERC granted Western Grid's request for a declaratory order, determining that Western Grid had clearly demonstrated that the assets would be operated in support of the transmission system and that CAISO would not be required play an active role in managing them.

In both cases, CAISO and other parties argued that it was premature for FERC to make any determinations on proposed projects before those projects had been analyzed and selected in resource planning processes operated by the State of California and CAISO. FERC agreed that the projects would ultimately need to be selected on their own merits in a planning process, but indicated in the Western Grid order that determining whether a proposed storage asset would qualify for transmission rate treatment would accurately inform planning processes about the costs and operation of that asset.

Table 2 summarizes differences between Nevada Hydro and Western Grid proposals:

Table 2: Summary of Nevada Hydro and Western Grid FERC Applications

	Nevada Hydro	Western Grid
Technology	Pumped Storage Hydro	Sodium Sulfur Batteries
Operator	CAISO	Western Grid
Proposed Grid Services	Any (Transmission and Generation)	Voltage Support, Thermal Management (Transmission Only)
FERC Outcome	Rejected	Approved

In the 2017 policy statement, FERC repeated its rationale for rejecting the Nevada Hydro petition and approving the Western Grid petition. Commissioners then went on to clarify an important point: While the Western Grid petition was approved as a transmission-only project, FERC conceptually supported Nevada Hydro's idea of using storage for both

FERC ¶ 61,272.

[4] Order on Petition for Declaratory Order. Docket EL10-19 (January 21, 2010). 130 FERC ¶ 61,056.

regulated transmission and competitive market purposes, given the potential for market revenues to be shared with customers in a way that would reduce system costs.[5] *However, commissioners explained, such projects must adhere to three principles:*

1. *Double recovery of the asset's costs must be avoided. FERC's overriding objective in the policy statement was to increase the efficiency of the grid and reduce its cost by maximizing the use of energy storage. Allowing an asset owner to recover their full investment through cost-based transmission rates and then additional revenue in the market would not accomplish that goal, so FERC indicated that dual-use energy storage mechanisms would need to balance the two revenue streams to ensure that customers do not overpay for the asset.*

2. *Adverse market impacts of dual-use assets must be minimized. In the proceeding that led to the policy statement, several participants expressed concern that energy storage selected for transmission purposes would not have to pay for its interconnection costs and, given its ability to recover most of its costs from regulated services, would not enter the market with the same cost structure as other market assets. Stakeholders worried that these unfair advantages could lead the dual-use asset to submit artificially low bids that suppress prices for other market participants. FERC acknowledged this concern but indicated that mechanisms to prevent double-recovery of costs would likely balance out any advantages that dual-use storage assets might have.*

3. *ISO/RTO independence must be maintained. Objective and fair operation of regional transmission systems and wholesale markets require ISOs and RTOs to be independent entities, FERC stated. Therefore, the policy statement indicated that the ISO/RTO should only have operational control of a dual-use storage asset when it is being used for transmission functions, and control should revert to the asset owner when it is being used for market functions. In practical terms, this means that the asset is operated by the grid operator as needed in transmission mode, and then dispatched based on bids submitted by the asset owner in market mode.*

3.2. Storage as Transmission vs. Storage in Place of Transmission

There are two ways in which a need for energy storage could manifest in a transmission plan: as a transmission asset or in place of a transmission asset.

Within the U.S. energy regulatory structure, there is a significant difference between a regulated storage asset that provides service to the transmission system and a competitive storage asset that provides service to energy markets in a manner that reduces or eliminates the need for transmission infrastructure. CAISO's 2018 Transmission Plan provides contrasting case studies that illustrate the difference.

3.2.1. Storage as Transmission: Dinuba, CA

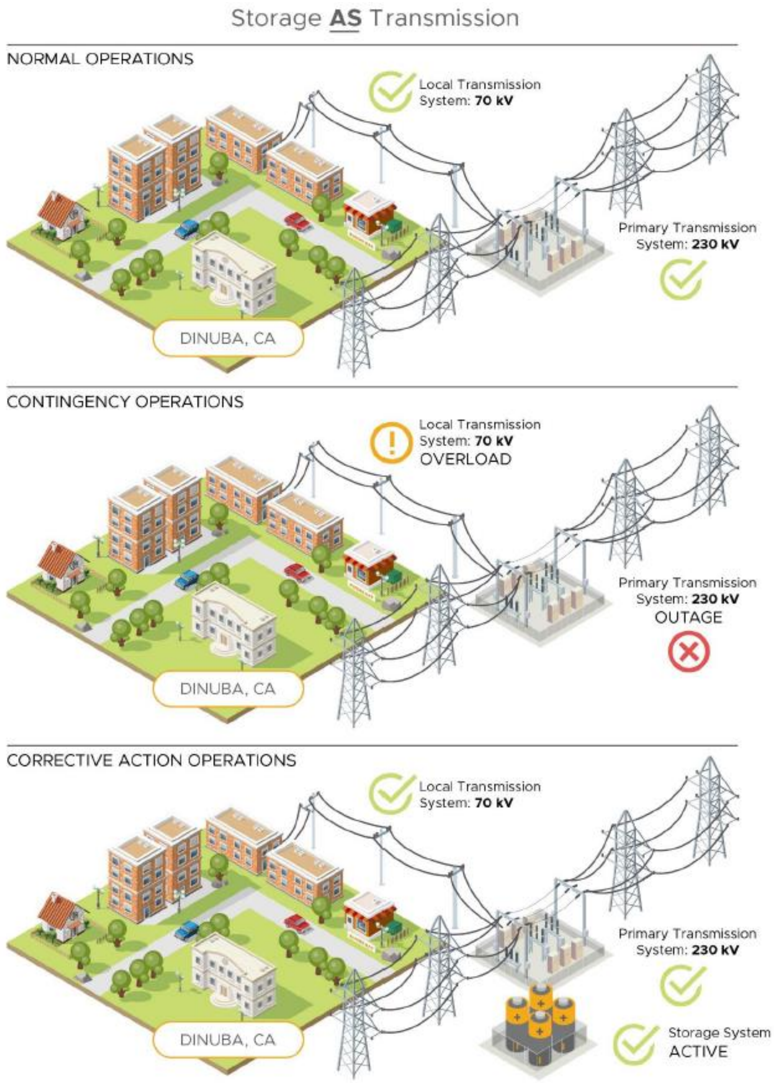
Dinuba is a small town in central California served by a 70 kilovolt (kV) transmission system. In its 2010 Transmission Plan, CAISO identified a contingency scenario in which an outage on a nearby, larger transmission line would overload the line serving Dinuba. The 2010 plan called for several minor investments in the local system to temporarily

[5] Utilization of Electric Storage Resources for Multiple Services While Receiving Cost-Based Recovery, January 19, 2017. 158 FERC ¶ 61,051.

manage the contingency, with a future rebuild of the Dinuba line to increase its thermal rating.[6]

In the 2018 Transmission Plan, CAISO compared the rebuild option to an alternative plan that would deploy a battery at the Dinuba substation to absorb and manage excess flows during the contingency. CAISO selected the battery alternative after determining that it could be deployed for $14 million, while the line rebuild would cost $16 million.

Figure 3 illustrates how the energy storage option will protect the existing Dinuba system during a contingency event by regulating power flows and preventing thermal overloading, making it a transmission asset subject to cost-based rates.



3.2.2. Storage in Place of Transmission: Oakland, CA

Elsewhere in their 2018 Transmission Plan, CAISO planners faced the challenge of preserving reliable service in the Oakland area after determining that the imminent

[6] CAISO. 2018a. 2017-2018 Transmission Plan. March 22, 2018. http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

retirement of an aging, 165 MW peaker plant in the downtown area would create contingency scenarios in which the transmission lines serving the city would not have sufficient capacity to meet local demand.

CAISO considered four proposals, including a major overhaul of existing transmission lines in the area, construction of a larger new line, and placing a 200 MW generator in the area. Estimated costs for those alternatives were between $367 million and $574 million. But the successful proposal came jointly from the transmission-owning utility in the area and the community choice aggregator that procures generation resources to serve the Oakland area: a $102 million initiative to conduct minor upgrades on the existing lines, then site energy storage and distributed solar within the Oakland area to preserve reliable service during a contingency event.

Figure 4 (next page) illustrates how the locally sited energy storage systems would act as generation assets within CAISO markets to maintain service in a contingency event. While the presence of the storage reduces the transmission infrastructure investments necessary to ensure reliable service, the storage would not directly affect power flows or transmission system operations, and would recover its costs by participating in energy markets. It is therefore a competitive asset subject to market-based rates.

As Figures 3 and 4 demonstrate, energy storage can benefit the grid in multiple ways. But regulatory structures affect how those benefits are realized and compensated: either fixed operations and cost recovery as a transmission asset, or market-driven operations and cost recovery as a generation asset. These disparate regulatory structures create incompatibility in how each function plans for its needs, operates its assets, and recovers the costs of those assets. That incompatibility creates a formidable barrier for dual-use energy storage technologies, one that FERC's policy statement encouraged grid operators to reduce.

3.3. Energy Storage and Transmission System Planning

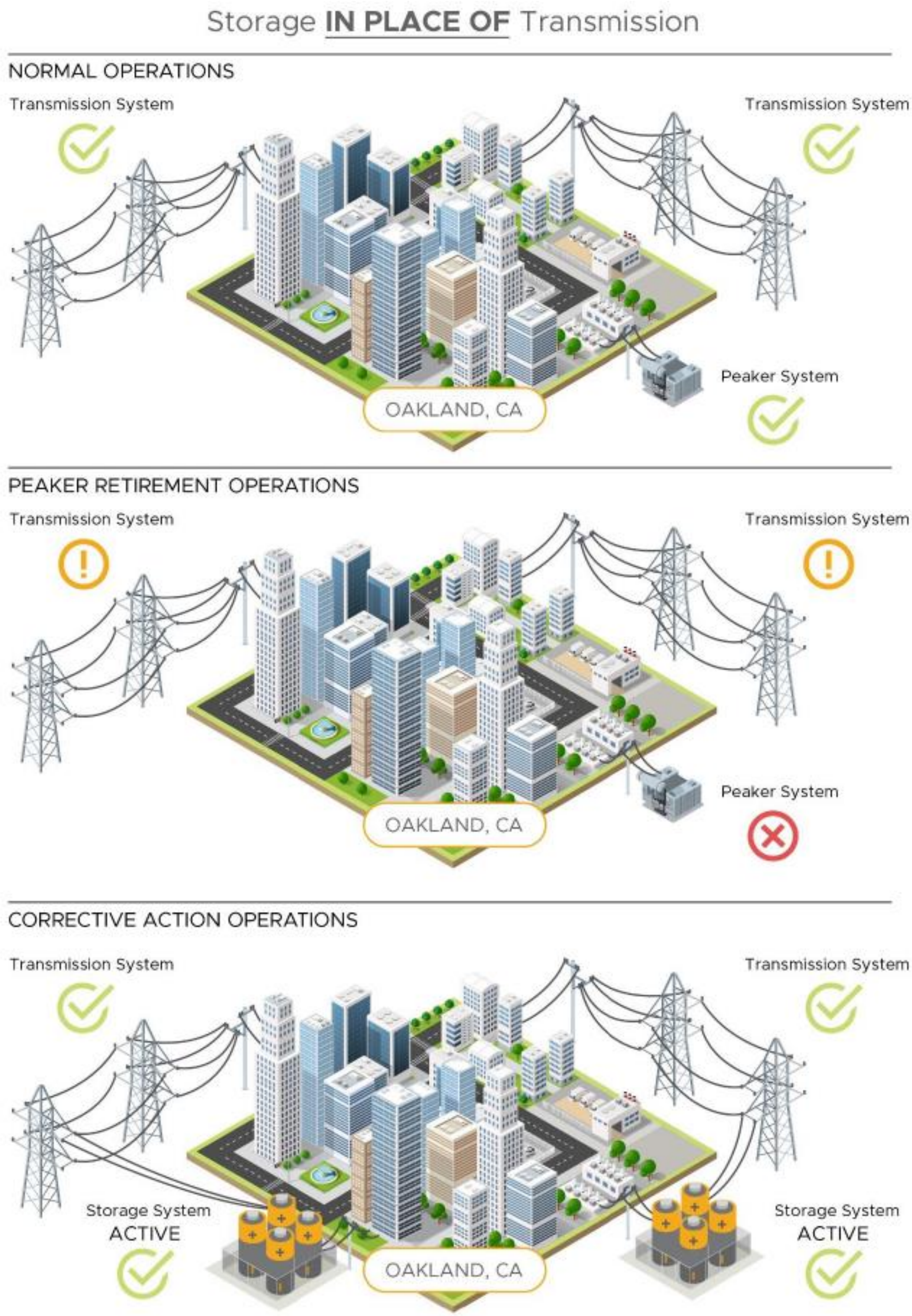
Near the end of the policy statement, FERC makes an understated but crucial point:

> *"We also provide guidance that, when the circumstances leading to the need for the service compensated through cost-based rates arise, RTO/ISO dispatch of the electric storage resource to address that need should receive priority over the electric storage resource's provision of market-based rate services. Performance penalties could be imposed on the electric storage resource owner or operator for failure to perform at these times."*

This guidance forms a key principle of this project: that the reliability function performed by a dual-use storage resource in its transmission role always takes priority, and that market services may only be provided in a manner that does not compromise the asset's ability to meet its transmission obligations. Grid operators are subject to dozens of mandatory reliability standards. Failure to meet them subjects the operator to severe fines, may expose customers to service interruptions, and may damage grid infrastructure.

As explained earlier, transmission investments are identified through extensive planning processes, then subject to regulatory review and approval before they can be eligible for cost-based rate recovery. Energy and ancillary service markets do not share those hurdles; minimal barriers to entry are a key element of a competitive market.

Because of this disparity in how transmission and generation assets enter service in an ISO/RTO, a dual-use energy storage asset would logically need to be identified as a transmission asset first, and then provide market services on an as-available basis…



3.4. Reliability Standards Governing Transmission Planning

In the Energy Policy Act of 2005, Congress created a new entity, an Electricity Reliability Organization, which would be a single organization responsible for developing and enforcing industrywide standards to ensure electric grid reliability, and directed FERC to establish the organization. In 2006, FERC selected the North American Electric Reliability Corporation (NERC) to fulfill that role. Through consensus-based processes, NERC has since led the development of almost 100 mandatory reliability standards and more than 400 voluntary standards.

From a transmission planning perspective, NERC standards serve two primary purposes. First, they provide a practical framework for transmission planning. While Congress and FERC have collectively developed policies requiring transparent, regionally coordinated transmission planning practices that consider a wide range of technology options, NERC standards establish the metrics that those plans must meet to ensure a reliable electric grid and identify the tools, processes, and plan structure that system planners should utilize.

Second, NERC standards ensure consistent industry practices in regions outside of traditional FERC jurisdiction. Because its footprint is located entirely within the state of Texas and it has no interconnections with any other U.S. regions, the Electric Reliability Council of Texas region is not subject to FERC rate jurisdiction, which is rooted in the interstate transmission of electricity. The Texas region is, however, subject to NERC standards. Canada has also agreed to abide by NERC standards, which ensures that energy transacted between the two countries is done on compatible systems meeting the same reliability requirements.

NERC's regulations governing transmission system planning are found in Standard TPL-001-5, Transmission System Planning Performance Requirements, which places eight specific requirements on transmission planners.[7]

1. ***Modeling:*** *Planners must maintain robust models of their respective transmission systems capable of performing the required modeling exercises.*
2. ***Annual planning:*** *Planners must conduct annual studies that include near-term and long-term sensitivity analyses and a corrective action plan for remedying any identified shortcomings.*
3. ***Steady-state analysis:*** *Plans must analyze the system's ability to regain normal operation after minor disturbances and under multiple contingencies.*
4. ***Stability analysis:*** *Plans must analyze the system's ability to manage grid fluctuations arising from major disturbances and regain normal operations under multiple contingencies.*
5. ***Voltage requirements:*** *Planners shall establish standards to ensure proper voltage levels are maintained on the system.*

[7] North American Electric Reliability Corporation (NERC). 2020. Standard TPL-001-5: Transmission System Planning Performance Requirements. Accessed February 2020. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf

6. ***Instability criteria:*** *Planners shall develop criteria by which system instability events will be identified.*

7. ***Internal coordination:*** *The planning coordinator shall ensure that all participating entities with planning responsibilities understand their individual and joint responsibilities.*

8. ***External coordination:*** *Planners shall share studies and other relevant information with planners from other regions (NERC 2020).*[8]

… While NERC standards do not explicitly address the role of non-transmission alternatives in the planning process, they do grant wide latitude to system planners in identifying corrective actions. NERC's required contingency analyses therefore are the primary entry point for energy storage in transmission planning. Energy storage cannot move electricity through space like a transmission line, but because it can move electricity through time, it can be a viable alternative for managing power flows or preserving service to customers in the event of an outage, which are the services required in many contingency scenarios. Used in this manner, energy storage can enhance and protect existing transmission infrastructure, giving it greater flexibility and extending its useful life while deferring or eliminating the need for additional infrastructure…

Final author's comment: I believe the above is a useful excerpt from Reference 2. Although I'm reasonably sure this document might yield additional useful content, I am approaching the preferred maximum length for this post, and will terminate it. If you wish to drill into this reference for additional information, go through the link in Reference 2, and start on with section 2.2 on page 13.

Also, we have taken a deep dive into utilities, RTOs and ISOs planning process, but I believe this will be useful to readers in a larger context.

[8] Mandatory NERC standards are subject to FERC approval; FERC approved TPL-001-5 in January 2020, replacing the previous standard (TPL-001-4). The new standard requires additional reliability analyses of protection systems and potential long-term equipment outages, though those requirements will not be enforced until January 2023.