Compensation Mechanisms for Long-Duration Energy Storage

August 2022

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HydroWIRES

The U.S. electricity system is changing rapidly with the large-scale addition of variable renewables, and the flexible capabilities of hydropower (including pumped storage hydropower) make it well-positioned to aid in integrating these variable resources while supporting grid reliability and resilience. Recognizing these challenges and opportunities, WPTO has launched a new initiative known as HydroWIRES: Water Innovation for a Resilient Electricity System. HydroWIRES is principally focused on understanding and supporting the changing role of hydropower in the evolving U.S. electricity system. Through the HydroWIRES initiative, WPTO seeks to understand and drive utilization of the full potential of hydropower resources to contribute to electricity system reliability and resilience, now and into the future.

HydroWIRES is distinguished in its close engagement with the DOE National Laboratories. Five National Laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the DOE portfolio that add significant value to the HydroWIRES initiative.

HydroWIRES operates in conjunction with the Grid Modernization Initiative, which focuses on the development of new architectural concepts, tools, and technologies that measure, analyze, predict, protect, and control the grid of the future, and on enabling the institutional conditions that allow for quicker development and widespread adoption of these tools and technologies.

Connections with the HydroWIRES Roadmap

This report on the Compensation Mechanisms for Long-Duration Energy Storage focuses primarily on addressing HydroWIRES Objective 1.3: Valuation Methodologies. It is informed by the techno-economic evaluation research conducted under the HydroWIRES Initiative, and results from it will feed into future valuation efforts, especially of long-duration energy storage technologies. Other relevant DOE efforts include the Energy Storage Grand Challenge, as they address similar challenges of valuing grid services for long duration energy storage resources.

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Executive Summary

Rapidly changing power system conditions, driven by decarbonization goals, are leading to significant growth in renewable energy sources, which can be both variable and uncertain. This has been accompanied with increased reliance on and rapid growth in deployment of energy storage technologies. Currently, approximately 90% of installed, utility-scale energy storage capacity in the United States comes from pumped storage hydropower (PSH). However, development of new PSH has been limited and all recent growth in energy storage has come from batteries, , especially as technology costs have decreased over the years. Most of the current deployment still remains in the form of short-duration (<6 hours) energy storage technologies; the average duration of new storage was 3.7 hours for projects deployed in the first half of 2021 (Wood Mackenzie and Energy Storage Association 2021).

There is growing recognition that longer duration energy storage technologies (more than 6 hours of storage capacity) will be needed in the future to ensure grid operational reliability and resilience (NREL 2022). These needs will be driven by a combination of factors: 1) extreme weather events; 2) decommissioning of conventional generation resources; and 3) increased electrical load from transportation and other sectors. However, the current regulatory, policy, and market-driven compensation and business models are not well suited for incentivizing development of new long-duration energy storage (LDES) assets. For example, the most recent major pumped storage project, arguably the most mature LDES technology, was installed in the U.S. in 1995. There are three projects that have passed the Federal Energy Regulatory Commission (FERC) licensing process, but are not yet built: the Eagle Mountain Pumped Storage facility in California, the Swan Lake North Pumped Storage Facility in Oregon, and the Gordon Butte Pumped Storage facility in Montana (FERC 2022).The reasons range from lack of off-taker agreements, and financing options. There are another three projects in final licensing, and 70 more in various stages of the FERC licensing process. All are likely to face similar challenges (Greenhalgh 2021) to get built.

In this white paper, we use descriptive statistics characterizing extended periods of renewable energy unavailability—wind and solar "droughts"—as potential indicators for requirement of LDES. We then present a review of emerging compensation and business models from around the world, drawing insights for the United States in terms of regulatory, policy, and market design implications. The key findings are as follows:

1. The growing incidences of extended periods of renewable generation unavailability, expected or unexpected, can be a potential indicator for the requirement of LDES technologies. It should be noted, however, that the additional generation, coupled with short-duration storage and transmission, can serve as potential alternatives to LDES, and the trade-offs between these options will need to be considered.
2. The current, market-based business case for LDES is primarily prevailing *arbitrage* opportunities, i.e., price spreads between peak and off-peak periods. Evidence from U.S. and outside markets suggests that price spreads are shrinking, resulting in reduced revenue opportunities. Further, arbitrage opportunities are presently based on intraday price spreads, and hence do not incentivize energy to be stored beyond a day because of the lack of long-term price signals (i.e., beyond a 24-hour period). Therefore, current market-based incentive signals may not provide adequate investment incentives in the future.
3. In recognition of future needs for LDES, regulatory and policy changes are being introduced in different parts of the United States:
   – In 2020, the California Public Utilities Commission released a decision on long-term planning frameworks that identified a minimum 1 GW of LDES needed by 2026 to maintain reliability.

Stakeholder studies as part of the commission's analysis suggest that longer term, up to 55 GW of LDES (10 hours and longer), will be needed by 2045.

   - PJM, in its compliance filing for Federal Energy Regulatory Commission Order 841, indicated that energy storage assets participating in capacity markets would have to have at least 10 hours of duration to receive full credit (PJM Interconnection 2021).

4. There are potential lessons to be learned from capacity market design changes in other countries. For instance, Colombia's Energy and Gas Regulatory Commission, driven by weather-related energy supply shortfalls, changed its generation expansion market from one based on installed capacity (capacity market) to one based on available energy (firm energy) over periods of times.
   - Reliability Charge Colombia provides incentives to ensure energy adequacy; assuring the energy supply even during periods of drought, by making sure adequate generation is procured ahead of time. This mechanism guarantees that power plants can supply the demand for extended periods, even during peak hours, through a mechanism based on penalties.
   - Capacity market and resource adequacy constructs in the United States are presently designed to ensure that sufficient generation capacity is available to meet power demands during peak hours. However, as we encounter greater incidences of energy deficits, i.e., generation nonavailability over extended periods of time, then the U.S. markets will need to consider changes to capacity market designs that function to ensure energy sufficiency.
5. New forms of compensation mechanisms are emerging around the world, mostly backed by long-term revenue guarantees through regulated returns, long-term power purchase agreements, etc. New agreement structures include multipart payment schemes based on capacity availability, energy delivery, and performance. Such structures help off-takers to hedge against market, technology, and renewable energy generation risks, while providing revenue guarantees and sufficiency (contingent on meeting performance requirements) to the project developers.
6. New business models, such as the storage-as-a-service model, are also being discussed. These models offer a paradigm change via the introduction of a new energy storage asset class, which will require compensation for storing energy rather than generating energy. These models can be implemented by third-party resource owners or follow multiutility ownership structures with precedents from multiparty transmission ownership. The regulatory changes needed to accommodate such business models are not known yet and will require development.

Acronyms and Abbreviations

BPA	Bonneville Power Administration
C&I	commercial and industrial
CAISO	California Independent System Operator
CCA	community choice aggregator
CPUC	California Public Utilities Commission
EIA	U.S. Energy Information Administration
ELCC	effective load-carrying capability
ERCOT	Electric Reliability Council of Texas
ESAAS	energy storage as a service
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
ITC	Investment Tax Credit
LDES	long-duration energy storage
MISO	Midcontinent Independent System Operator
PGE	Portland General Electric
PHS	pumped storage hydropower
PPA	power purchase agreement
RTO	regional transmission organization
VRE	variable renewable energy

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1.0 Introduction

About 90% of installed, utility-scale energy storage capacity in the United States comes from pumped storage hydropower (PSH).[1] The remaining 10% largely comes from battery storage systems that in recent years, with cost declines, tax credits, and state government targets and mandates, have seen accelerated development. Battery storage projects continue to be widely deployed, even though they are, in nearly all cases, limited to 4 hours of energy storage. Thus far, this duration has been sufficient for grid needs and, accordingly, despite some PSH projects progressing through the Federal Energy Regulatory Commission's (FERC's) licensing processes, there have been no new PSH projects put in operation in the United States over the last 30 years, nor any other energy storage deployments beyond 4 hours of storage.

In the past few years, however, there has been a growing recognition that to meet clean energy targets and goals, clean and dispatchable capacity will be needed to support the variability of the dominant renewable energy technologies, that is wind and solar. This capacity need is likely to exceed the 4-hour duration provided by battery storage, as preliminarily identified by the California Public Utilities Commission (CPUC), and absent new longer term clean dispatchable capacity, meeting load while maintaining reliability is likely to require a significant overbuild of resources. Further contributing to this need for clean dispatchable capacity will be the drive toward electrification of transportation and industry, increasing electricity demands that require even more variable renewable energy (VRE) resources to be built and more variability that needs to be managed. At the same time, impacts from climate change are becoming more pronounced, resulting not only in more frequent extreme weather events but also impacting the output of existing clean dispatchable capacity like hydropower to support grids.

New resources will be needed to balance the system and ensure reliability and resiliency of operations. Demand response, shorter duration batteries, and other technologies will help meet grid needs at shorter timescales, but they will be unable to support capacity needs beyond 4 hours. These needs (NREL 2022) may be daylong (8–12 hours), multiday (24–72 hours), or may even be seasonal (weeks or months). Grids are already seeing such needs, and despite acknowledgments by grid operators and system regulators, resources are not being built to meet these needs.

There is not a clear definition of long-duration energy storage (LDES) resources. The CPUC has identified 8 hours as a minimum, while others, including the Department of Energy, use 10 hours as a minimum, and discuss possible durations at the multiday level (24–72 hours), at the weekly level (100 hours), or even at the seasonal level (CPUC 2020; EERE 2021; Silicon Valley Clean Energy 2020; Dowling et al. 2020).

PSH is the most mature clean capacity resource from both a technology perspective and utility and system operator familiarity. But despite the ever clearer need for clean capacity and several projects that have completed licensing and have even obtained financing, PSH is not being built. There persists a lack of understanding about PSH's ability to provide cost-effective grid services, especially compared to significantly smaller and lower upfront cost battery storage technologies. Similarly, this lack of understanding persists for other LDES technologies (e.g., compressed air energy storage or the use of hydrogen as a storage mechanism). This lack of understanding manifests within electricity markets and regulated utility frameworks in the form of compensation mechanisms that do not adequately renumerate PSH and other LDES resources. Without adequate renumeration, developers cannot prove a business case to obtain financing, a reason no PSH is being built. Power systems that want to reap the benefits of LDES

[1] U.S. Energy Information Administration (EIA) Preliminary Monthly Electric Generator Inventory (Based on Form EIA-860M as a supplement to Form EIA-860) for May 2021.

at high penetrations of VRE will need to reconsider their compensation structures to incentivize the services provided by LDES assets.

This situation is not limited to the United States. The LDES industry, which is at the moment largely the PSH industry, has identified limitations with compensation for LDES resources across the world. The recently completed International Forum on Pumped Storage Hydropower, a government-led multistakeholder initiative to shape and enhance the role of PSH in future power systems, broadly identified a lack of sufficient compensation for PSH in world power systems. The Forum identified that PSH projects should be better acknowledged for all the services they bring to the electric system, including the flexibility and ancillary services needed to develop VRE resources. There was argument for development of new market designs to integrate LDES facilities, given a wide recognition that PSH specifically, and LDES more broadly, will be a key enabler of the energy transition. The following are takeaways from the Forum:

- Many markets lack long-term modeling or targets for LDES needs.
- Where models are used, they often have outdated assumptions about technical capabilities and may not take account of key discriminating factors.
- Long-term electricity and ancillary service prices are difficult to forecast and subject to wider government policies. Without risk mitigation mechanisms, investors are reluctant to invest in assets with long-term payback periods such as PSH.
- In many markets not all services provide by PSH are remunerated.
- In some markets existing PSH plant margins are being squeezed by carbon-intensive gas.
- Rules on transmission assets can create barriers to efficient deployment of PSH. Hybrid assets that can serve both transmission and generation markets may lower overall system costs.
- Licensing and permitting requirements for PSH are often lengthy; where feasible, these should be shortened and best practices introduced with robust yet timely processes.

The Australian government nationalized and pushed the development of large-scale hydro assets in the country, with the Snowy 2.0 project having 8 GW of hydroelectric and PSH capacity. Absent government intervention it is unclear whether the project would have succeeded, particularly as storage to deliver ancillary services is not renumerated in the market, and the long-duration nature of LDES is not incentivized nor rewarded. (NHA 2021)

Similar findings and arguments have been expressed in other, non-PSH specific forums as well. At a special roundtable for the United Nations Climate Conference in 2021 (COP26), high-level attendees discussed some of the policy, regulatory, and market challenges to developing PSH specifically and LDES more broadly:

- The discussion focused on challenges to development, particularly the long route to market and revenue stability: LDES assets have long timelines, are capital intensive, and predicting the future is difficult. Business needs a return on this investment while decisions on LDES need to be made soon to meet net-zero targets ("Experts Call for Market Certainty to Deliver Long-Duration Energy Storage" 2021).
- The United Kingdom will have surplus variable renewables generation that requires storage (or curtailment or transmission) by 2025. National Grid suggests a lack of market certainty is limiting LDES technologies coming to market and argues that mechanisms like cap and floor can have near-term impacts ("Experts Call for Market Certainty to Deliver Long-Duration Energy Storage" 2021).

As PSH is the most mature and deployed LDES technology, much attention is paid to it. But there is recognition that other existing and emerging technologies face the same challenges, including compressed air energy storage, larger scale batteries, and hydrogen for energy storage (P. K.A. Verdonck and M. Kammoun 2020; IRENA 2019; Faunce et al. 2018; Hammann, Madlener, and Hilgers 2017).

1.1 Indicators for Requirements of LDES: Wind Drought Statistics

The need for LDES can be exemplified by analyzing extended periods of renewable power generation below a certain threshold. It should be noted that the forecastability of low levels of generation does not impact the assessment because alternative generation resources or LDES will be needed to fill the deficit regardless of whether the generation shortage is predictable or not. For this study we are using wind power generation in different parts of the country as an illustrative example of the need for LDES in the resource mix, particularly as dispatchable fossil units retire (the analysis could be extended to solar and other non-dispatchable resources as well).

Table 1 presents wind power output statistics by balancing authority over the 3-year period from 2018 to 2020. As is evident in this table, there is a wide variance between average and peak output across the year in each of the regions considered, with a starker variance in particular seasons. These variances, although expected considering the nature of the wind resource, require balancing resources to ensure load is met reliably. For example, in the summer months of June through August, the average and peak output drop significantly relative to the yearly average in Midcontinent Independent System Operator (MISO), PJM, and ISO New England (ISO-NE), with the average output dropping nearly in half. This drop coincides with increased air conditioner loads in these summer months. These shortfalls are currently met by natural gas resources, but in a clean energy future, natural gas will not be available.

Table 1. Wind Generation Output Statistics for Selected Regions/Markets 2018-2020

	Year		Dec-Feb		Mar-May		Jun-Aug		Sep-Nov	
Region	**Peak**	**Average**	**Peak**	**Average**	**Peak**	**Average**	**Peak**	**Average**	**Peak**	**Average**
BPA	3,777	742	2,706	592	2,663	773	3,777	953	2,787	647
ERCOT	22,144	8,879	22,144	9,253	21,034	9,558	21,212	8,529	20,370	8,178
ISO-NE	1,207	400	1,180	479	1,168	452	1,064	259	1,207	412
MISO	19,967	6,798	19,967	7,611	17,832	7,115	15,750	4,852	18,548	7,636
PJM	9,118	2,734	9,118	3,522	8,549	3,108	7,153	1,545	8,416	2,775

All values in MW.

We have developed a metric to quantify wind drought events (i.e., wind generation output below a certain threshold) across selected independent system operators (ISOs)/regional transmission organizations (RTOs) and the Bonneville Power Administration (BPA) balancing area. In this metric, a wind drought event is a continuous period where the average hourly output is less than 10% of the average hourly output across the same month. Here we evaluate such events across the 3-year period from 2018–2020. Drought events are counted over a continuous period, that is as a rolling average in each hour over the next 8–72 hours. Continuous events may be adjacent.[2] This is represented by the following equation:

[2] *For example:* hour 1 = average(h1, h2, h3, h4, h5, h6, h7, h8), hour 2 = average(h2, h3, h4, h5, h6, h7, h8, h9) and so on.

$$Wind\ Drought\ Event = \frac{\sum^{Hours} Wind\ Output}{Hours} < 10\% \ \frac{\sum^{30*24} Wind\ Output}{30*24} \quad (1)$$

where Hours = 8,12, 16, 24, 48, 72;
Wind Drought Event = Avg. (hourly wind output over 8–72 hour period) < 10% (30-day average hourly wind);

or represented another way in Figure 1. The average wind output in each period of length (8, 12, 24, 48, and 72 hours) is compared to the average wind output across the 30-day period (month) in which the period occurs. A wind drought event is counted for each period that has an hourly average output below 10% of the month's hourly average output.

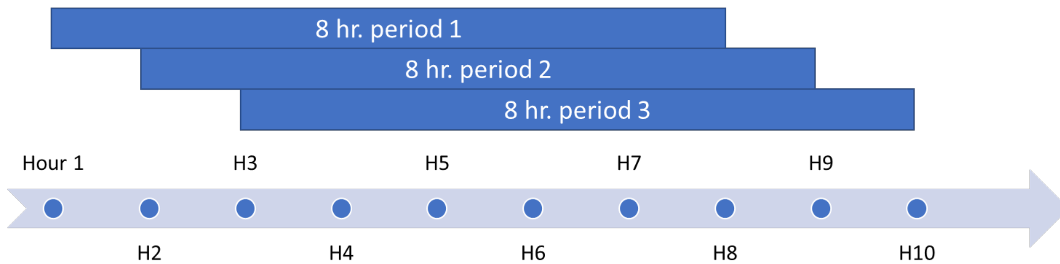


Figure 1. Graphic representation of the wind drought metric used here. Each period (from 8–72 hours) is a rolling average of hours through the 3-year period. Average period wind output is compared to the monthly average wind output (averaged to hourly output) in the month the period occurs.

Figure 2 identifies these events for each ISO/RTO and BPA for the 3-year timeframe of 2018–2020. Depending on the region or market and the characteristics of the wind resource in each, these numbers vary widely but can represent significant occurrences of drought, which must be compensated for to maintain system reliability.

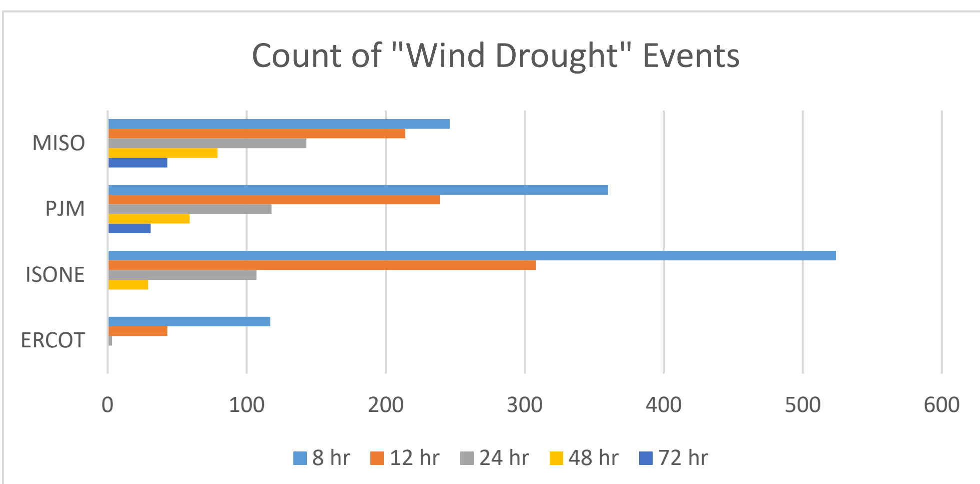


Figure 2. Events of wind drought over identified periods (hours) and the percentage of time represented relative to total number of such periods, across 2018-2020 for selected ISOs/RTOs and BPA.

This metric illustrates the frequency and occurrence of wind drought events across the different ISOs/RTOs and BPA. Although currently these droughts have been covered by existing resources, as the levels of renewables deployment increases to meet clean energy targets, long new duration (as evidenced by the length of these droughts) clean energy and capacity will be needed.

LDES is likely to be one of or the primary resource to address the renewable output gaps identified here. Of course, we have not explicitly considered the addition of solar, offshore wind, or other resources to add diversity to the generation portfolio, nor have we explicitly evaluated the geographic diversity of the existing wind resource. While those can and should be further follow-on work to better identify future clean energy and capacity needs, the examples presented here illustrate the need for a level of dispatchable and clean LDES resources. Despite added diversity from different types of resources and additional load flexibility (i.e., demand response), regulators, system operators, and reliability organizations have recognized the challenges that increased variable renewables and retiring dispatchable resources will present, specifically in the form of additional clean capacity needs:

- In 2020, the CPUC released a decision on long-term planning frameworks that identified a minimum 1 GW of long-duration storage needed by 2026 to maintain reliability. Long duration was defined as an 8-hour storage resource. Stakeholder studies as part of CPUC's analysis suggest that longer term, up to 55 GW of LDES (10 hours and longer), will be needed by 2045 (NHA 2021; CPUC 2020).
- In August and September 2020, extreme heatwaves hit California that caused a rise in demand and led to rolling blackouts. These blackouts were a result of higher than expected demand, lower than expected solar output, lower than expected wind output, low availability of hydropower from the Pacific Northwest due to its own heat wave, and some limits to importing capability due to wildfire disruption of transmission operations (Penn 2020).
- In February 2021, Texas suffered severe winter storms that resulted in a power blackout crisis. Although this was largely caused by unavailable fossil units due to inadequate winterization, wind resources were also unavailable (Englund, Will 2021). In this situation, as well as a future where fossil units are not available, large-scale capacity resources such as large-scale LDES may have prevented or reduced the severity of the situation.

1.2 Compensation for Long-Duration Energy Storage

Arbitrage opportunities have provided the primary revenue source for PSH resources operating in organized wholesale markets. PSH plants have conventionally operated in day-night arbitrage patterns (i.e., resources typically pump during nighttime hours in concurrence with low energy prices and generate during evening peak-load hours in concurrence with high energy prices). Figure 3 shows that the PSH units in MISO continue to pump primarily during the nighttime hours. However, Figure 4 shows that the price spread between peak and off-peak energy prices has been decreasing over the years, reducing the revenue opportunity for PSH resources. Hence, alternative revenue mechanisms will need to be designed and implemented to compensate LDES resources, including PSH.

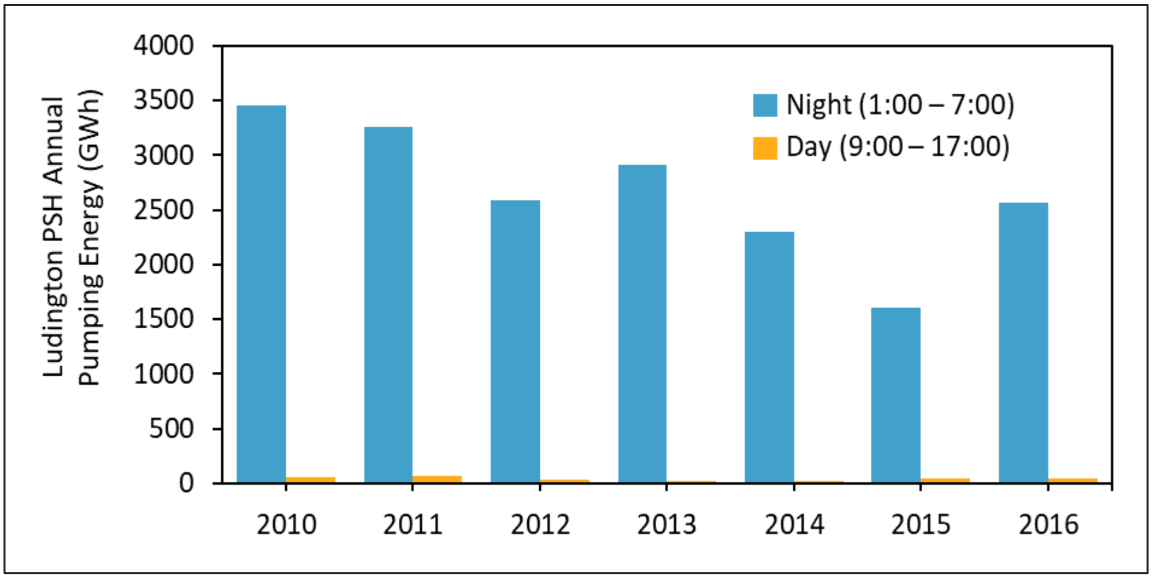


Figure 3. Pumping operations of PSH plants in MISO over the years. (Source: [Hydropower Value Study, January 2021]())

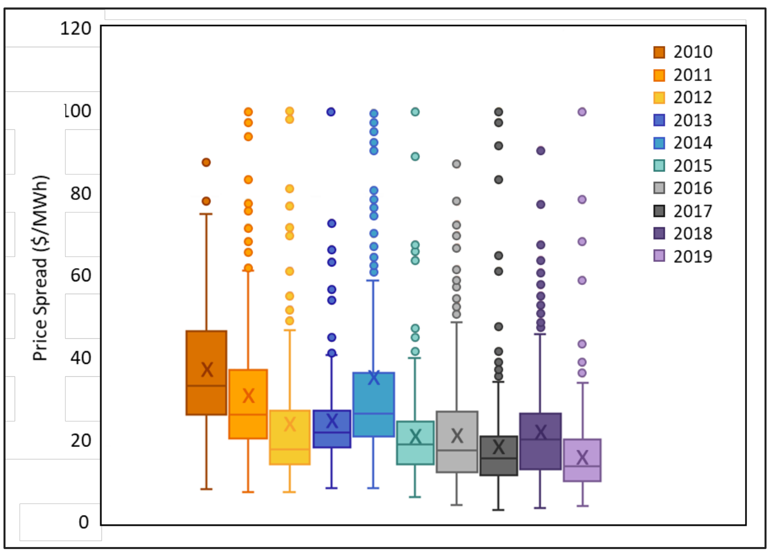


Figure 4. The location marginal pricing spread between peak and off-peak hours in MISO shows a decreasing arbitrage spread. (Source: [Hydropower Value Study, January 2021]())

Similarly, PSH units in Europe, particularly those in Spain, Germany, Austria, and Switzerland, were designed and then built with the expectation of significant arbitrage revenues, with arbitrage being the primary driver, or compensation mechanism, for profitability. Several of these plants were located in the Alps with natural elevation differences and in between major national electricity markets. Developers intended to leverage price differentials between these markets, particularly with the emergence of renewables driving both high and low prices. However, as with the example from MISO, the significant drop in demand in 2008 followed by low natural gas prices has seen these price spreads drop. In Switzerland, Alpiq has seen the business case for its PSH assets evaporate as dropping prices and price spreads have fallen below breakeven revenue and even operating costs (International Forum on Pumped Storage Hydropower 2021), see Figure 5. Hence, alternative revenue mechanism will need to be designed to compensate LDES resources, including PSH.

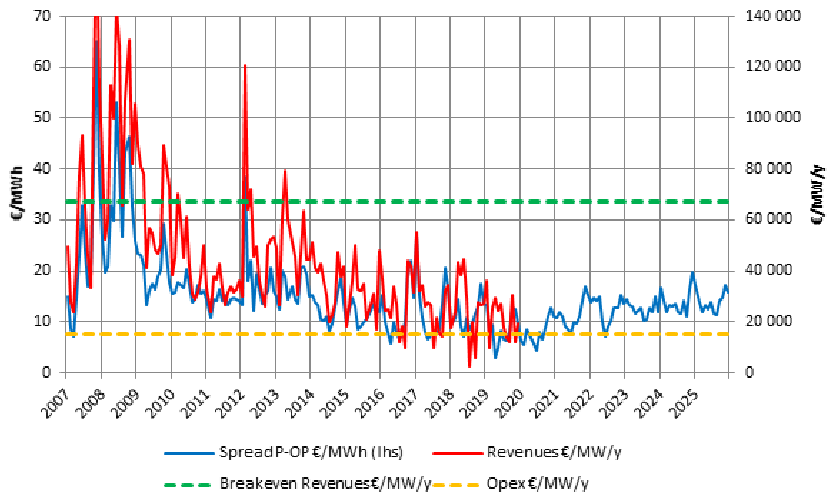


Figure 5. PSH operations and performance, and breakeven revenue in the Swiss market as reported by Alpiq for its PSH units (Source: Alpiq). Spread P-OP indicates peak and off-peak price spreads. Opex is operating costs.

Much of the value from PSH and other energy storage resources comes from their flexibility to deliver various grid services on demand, which requires the resources to have a certain amount of stored energy available at different times. For resource owners, storing energy comes at the cost of foregone revenue from generating/discharging energy. Hence, the opportunity cost of storing energy needs to be compensated commensurately with the reliability benefits provided to the grid, such as discharging and generating during wind drought events. Conventional power purchase agreements (PPAs), including those for wind and solar, typically provide compensation for *generating* energy and not for stored or available energy. Capacity market/resource adequacy mechanisms have been used to provide compensation for available capacity, but the existing constructs are typically limited to short-duration capacity needs, typically 4 hours or less, and only provide guaranteed compensation in short terms (e.g., 1-year capacity markets in many ISOs/RTOs). Newer constructs are being discussed that recognize the need beyond diurnal/short-term (>4 hours) reliability requirements, but they are not yet implemented and discussion is limited to a few regions of the country (CPUC 2021; NARUC 2021; CAISO 2021).

Although there has been no recent PSH development in the United States, worldwide PSH projects have been built (e.g., Australia, Israel and China). In many instances these are a result of government utilities dictating development, but even then, there are some insights that may be applicable for the U.S. context, particularly involving the contracting mechanisms being used. What is common across these contracts and market constructs is a change in how resources are remunerated. Specifically, they get away from the traditional "pay for energy as you go" framework that has been commonplace with development of conventional energy projects and, arguably, has stalled recent PSH projects in the United States and worldwide. Instead, they compensate resources for a combination of 1) stored energy (capacity available over a period of time); 2) energy generation; and 3) performance, include accuracy of response, switching operations from pumping to generation modes (and vice versa), etc. These provisions, especially the guaranteed payments for available capacity (stored energy), ensure developers have a revenue stream to help recover capital costs.

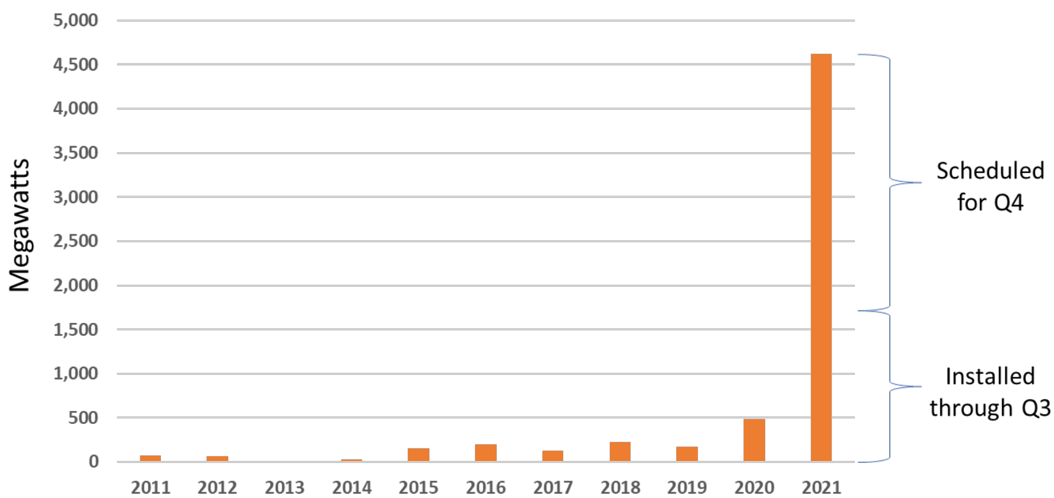
This paper will provide an in-depth discussion of the recent trends in deployment of energy storage resources, regulatory and policy initiatives, and contracting mechanisms in Section 2. The high capital costs associated with LDES assets may warrant alternative ownership and operational structures, such as joint ownership by multiple utilities. The alternative ownership structures are discussed in Sections 3 and 4 of this paper.

2.0 Recent Trends in the Energy Storage Market

Energy storage deployments have accelerated in the U.S. in recent years, supported by falling system costs and supportive policies at the federal and state levels. As these policies create new markets for energy storage, the average duration of new projects has increased to meet the needs of these markets. This section will explore the relationships between energy storage policies and deployment, and how they are moving toward longer duration storage technologies.

2.1 Energy Storage Deployment Trends

Utility-scale energy storage deployments in the United States dramatically increased in 2021, when the nation installed more front-of-the-meter energy storage in just the first three-quarters (1,736 MW) than it had in the previous decade. With another 3 GW scheduled to enter service in the fourth quarter, the United States is on pace to quadruple the amount of battery energy storage connected to the grid in 2021. Figure 6 illustrates sheer scale of increased storage deployments in 2021.



EIA 2021

Figure 6. U.S. front-of-the-meter energy storage deployments, 2011-2021.

As the overall scale of storage deployment increased in 2021, so did the scale of individual projects as developers and utilities took a significant step away from smaller, demonstration-scale projects toward larger, grid-scale projects. From 2012–2020, the average storage project was 6.5 MW. But in 2020, the average size increased to 30 MW, and 18 projects scheduled to enter service in 2021 were 100 MW or larger (EIA 2021). The average duration of new projects also significantly increased in 2021, from 1.5 hours over the period 2013–2020 to 3.7 hours for projects deployed in the first half of 2021 (Wood Mackenzie and Energy Storage Association 2021).

The evolutionary steps of the energy storage market in 2021 can largely be explained by the market opportunities available. Initially, ancillary service markets provided a viable opportunity for shorter duration battery systems. From frequency regulation products, which require a duration of just seconds, to spinning reserve products, which require up to an hour, ancillary service markets supported the deployment of fast-responding, short-duration battery systems. However, ancillary service markets are much shallower than capacity and energy markets and were quickly saturated. Moving into the deeper energy and capacity markets requires longer duration storage technologies that can ensure reliable operation of the grid during periods of peak demand. The significant increases in both size and duration of energy storage projects deployed in 2021 are indicative of the industry's pivot toward using storage as a capacity asset.

Considering these trends, the simplest explanation for why long-duration storage technologies have not been built in recent years is because they have not yet been needed. The demand for energy storage created by existing grid conditions and market products could be satisfied by technologies with 4 hours of storage or less. It should also be mentioned that PSH is the only commercially available form of LDES and is significantly larger in scale than the projects that utilities and grid operators have been willing to accept. It was not until 2021 that utilities began deploying storage projects at scales approximating a PSH asset.

However, as the following section will discuss, the trend toward larger and longer duration storage is being reinforced by policy and regulatory changes made by utilities, states, and the federal government. As the grid transitions toward a more variable generation fleet, these actions are creating nascent market signals for longer duration technologies.

2.2 Regulatory and Policy Shifts

As the amount of VRE on the grid increases, there is growing recognition of the need for long-duration storage resources that can capture variable generation and shape it to customer demand. This recognition is showing up in utility planning and procurement activities, in state policy development, in regional market design, and in federal government research priorities.

2.2.1 Utility Planning and Procurement

Incorporating energy storage technologies of any duration into planning and procurement activities is still a developing practice for many utilities. However, in regions with aggressive decarbonization goals, some utilities have begun contemplating the role of LDES specifically. A group of eight community choice aggregators (CCAs) serving more than 2.3 million customers in central and northern California issued a joint request in October 2020 for up to 500 MW of energy storage resources capable of providing at least 8 hours of storage. In a factsheet issued with the request, the CCAs indicated that their request was driven by a need to capture low-cost solar generation during the middle of the day and use it to maintain reliable service throughout the evening (Silicon Valley Clean Energy 2020). The CCAs shortlisted several proposals in May 2021 and final contract announcements are pending.

In Oregon, utility Portland General Electric (PGE) prepared an integrated resource plan (IRP) in 2019 that was the first of its kind in explicitly identifying a need for LDES, selecting 200 MW of PSH and 37 MW of 6-hour battery storage. PGE's landmark findings were the results of changes the utility made to its IRP model that enabled a more granular study of its system's flexibility and resource adequacy needs. The changes resulted in two key findings: PGE needed more flexible resources to enable renewable resource integration by quickly responding to changes in renewable output, but it also needed resources that could support the system on cold winter mornings when customer demand is at its highest and renewable generation is at its lowest. The combination of these two needs led the utility to select long-duration resources that could provide both system flexibility and multi-hour support during periods of low generation.

2.2.2 State Policy Activity

Connecticut, Maine, and Illinois adopted energy storage mandates in 2021, bringing the number of states with such mandates to 10 and increasing the collective total of mandated storage in the United States to more than 13.5 GW by 2035.[3] Long-duration technologies are not directly mentioned as an asset class in any state's mandate. However, many policies specifically address PSH, which provides a useful analog for how states view the need for LDES in their policy development. California, the first state to adopt a storage target in 2013, made PSH ineligible because the policy was intended to drive market transformation in support of new storage technologies. At the other end of the spectrum, Virginia's target authorizes and encourages utilities to include PSH in their target compliance. Most states fall somewhere in between, with PSH included in the definition of energy storage technologies, though two of the states have targets that are too small for PSH to play a role. Table 2 summarizes each state's target and the status of PSH:

Table 1. State Energy Storage Mandates

State	Target	Terminus	Status of PSH
California	1,825 MW	2020	Excluded
Connecticut	1,000 MW	2030	Eligible
Illinois	Pending	2032	Uncertain[4]
Maine	400 MW	2030	Eligible, but likely not viable due to target size and carveouts for customer-sited storage
Massachusetts	1,200 MW	2025	Eligible
Nevada	1,000 MW	2030	Eligible
New Jersey	2,000 MW	2030	Eligible
New York	3,000 MW	2030	Eligible
Oregon	10 MWh	2020	Categorically excluded by target size
Virginia	3,100 MW	2035	Eligible and encouraged in legislation

Although California's initial storage mandate excluded PSH and did not expressly consider long-duration storage, the state's changing resource mix is driving policy activity in support of the technology. California's statewide IRP process, which is managed by the CPUC, determined in its 2020 planning cycle that the state would need at least 1 GW of long-duration storage within the next decade (CPUC 2020). In June 2021, the CPUC followed up by directing the state's utilities to procure 1 GW of LDES (defined as at least 8 hours) by 2026 (CPUC 2021). Additionally in 2021, Gov. Gavin Newsome proposed a $350M fund to support the commercialization of nascent long-duration storage technologies. The proposal was tabled for consideration in the state's 2022 budget planning.

2.2.3 Regional Market Reforms

Changing resource mixes has also led regional market operators to reevaluate how they define their capacity needs and compensate the resources that meet them. Recent and upcoming proceedings in the California Independent System Operator (CAISO), PJM, and ISO-NE have explored this matter and made changes that will affect the way energy storage participates in their capacity products going forward.

[3] Illinois' target has been authorized but not yet set.

[4] The Illinois legislation does not define the term "energy storage." Other language in the legislation precludes hydropower involving new water impoundments from being eligible for the state's clean energy standard; it is unclear whether that prohibition would apply to PSH.

While the details of these proceedings vary, the common thread is a growing recognition of the importance of long-duration storage in managing an increasingly variable generation fleet, and a move toward compensation mechanisms that provide clearer price signals for longer duration technologies.

CAISO. CAISO's Resource Adequacy Program is the process by which the grid operator assures that there is sufficient generation capacity on the system to maintain reliable service. In 2018, CAISO initiated a proceeding to enhance the Resource Adequacy Program to facilitate the "rapid transformation of resources to a cleaner, variable and energy limited fleet" (CAISO 2021). Phase 1 of the proceeding concluded in early 2021 and resulted in four changes that FERC approved in June 2021 and allowed to take immediate effect:

1. Requiring a minimum state of charge for storage resources that participate in the Resource Adequacy Program[5]
2. Requiring, with some narrow exceptions, that generators requesting a maintenance outage provide substitute capacity (previously optional)
3. Requiring generators seeking to increase the size or duration of maintenance outage to submit a second outage request rather than simply extending the initial request
4. Refining the local capacity study process to evaluate local capacity needs under emergency conditions, consider the duration and availability of energy-limited resources providing local capacity, and allow CAISO to procure additional resources through its capacity procurement mechanism if it identifies a resource inadequacy (FERC 2021).

In its order accepting CAISO's modifications, FERC noted that some addressed problems that CAISO identified in its root cause analysis of the rolling blackouts that affected the state in August 2020. Two of the changes directly affect how energy storage assets will provide capacity in CAISO. The first change ensures that a storage asset that successfully bids into the capacity market will have enough stored energy to meet its obligations when the capacity period begins by constraining the asset's participation in other market products subject to the minimum charge requirement. This prevents storage assets from jeopardizing their ability to meet their capacity obligations by overcommitting to other market products, such as frequency regulation or spinning reserves.

The fourth change, which refines the way CAISO determines its local capacity requirements, will likely increase opportunities for long-duration storage assets to provide resource adequacy in CAISO. In its filings with FERC, CAISO noted that under its previous approach to local capacity, any resource capable of providing at least 4 hours of energy was treated equally, even if a resource could provide much more than 4 hours. But given changing grid conditions and other risks present in the state, such as wildfires and public safety power shutoffs, CAISO is beginning to identify situations in which 4 hours of capacity is not enough to maintain reliable service.

Under the changes, CAISO will study local capacity areas under emergency conditions to identify situations in which longer durations of capacity will be needed, compensate resources based on their ability to meet those needs, and procure additional resources if necessary to maintain reliability. In considering duration requirements when studying local capacity options, CAISO will be able to identify specific instances in which longer duration technologies are necessary, thereby creating tangible investment opportunities.

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[5] CAISO indicated that it intends to replace the minimum charge mechanism with a more holistic approach to integrating energy storage into market operations within the next two years.

In approving the change, FERC noted that "as storage and other types of limited availability resources begin to comprise a larger portion of the resource adequacy fleet, we find it reasonable that the energy production capability of local resource adequacy resources should be considered in addition to the MW capacity" (*id.*). Phase two of CAISO's Resource Adequacy Program Enhancements Initiative will focus on how the ISO identifies capacity needs and determines capacity credits for different resources at the system level. It was scheduled to begin in November 2021.

PJM. When PJM made its compliance filing for Order 841, FERC's landmark order requiring regional market operators to incorporate energy storage into their markets, the grid operator indicated that energy storage assets participating in capacity markets would have to have at least 10 hours of duration to receive full credit (PJM Interconnection 2021). While this had been PJM's standard for evaluating capacity resources for years, the energy storage community argued that it was an unreasonable and unfair standard to apply to storage resources.

FERC approved the substance of PJM's filing but set aside the question of duration requirements and opened a separate proceeding to evaluate it. That proceeding was held in abeyance at PJM's request while the grid operator worked with its stakeholders to develop an alternate approach, which FERC approved in July 2021.

PJM's proposal uses an effective load-carrying capability (ELCC) methodology, which studies variable and energy-limited resources on a case-by-case basis to determine how much capacity they provide to the system during scenarios in which the grid is stressed, such as generation shortages and high-demand periods, and then authorizes the resource to bid that amount of capacity into the market (PJM Interconnection 2021). Rather than prorating a resource's capacity based on an arbitrary duration standard, the ELCC approach would prorate based on its modeled performance. This technology-neutral approach allows energy storage of any duration to participate in the capacity market, but because long-duration storage technologies will be able to sustain higher levels of output across more scenarios, they will see less of a capacity derate and therefore be more valuable in the capacity market.

PJM completed its most recent ELCC analysis in December 2021, which set capacity values for resource types ahead of the next Base Residual Auction for 2024-2025. The analysis found a 100% capacity rating for 8-hour storage and above, while prorating 6-hour storage assets at 97% of their nameplate capacity and 4-hour storage assets at 82% of their nameplate capacity (PJM Interconnection 2021).

ISO-NE. Citing capacity valuation proceedings in its neighboring ISOs, in particular the ELCC approach developed by PJM, ISO-NE initiated a new proceeding in October 2021, "Resource Capacity Accreditation in the Forward Capacity Market." ISO-NE plans to complete the proceeding and make a filing with FERC by the end of 2022.

2.3 Contracts and Market Constructs for Longer Duration Capacity and Hybrid Resources

Although there has been no recent PSH (or LDES) development in the United States, worldwide, countries have seen PSH projects built. In many instances these are a result of government utilities dictating development, but even then, there are some insights that may be applicable for the U.S. context, particularly involving the contracting mechanisms being put in place. Further, contract designs for hybrid energy systems, such as PV+storage, have seen recent evolution, accounting for the flexibility, dispatchability, and ability of such projects to store energy over different durations. This section will highlight examples from different parts of the United States and the world where innovative contracting mechanisms have been instantiated and led to project development. These examples can provide insights into the contracting mechanisms or other market constructs that may be needed to incentivize investments in long-duration storage resources.

What is common across these contracts and market constructs is a change in how resources are remunerated. As discussed in Section 1, they get away from the traditional "pay for energy as you go" framework that has been commonplace with energy development. For generation-only resources, such contracts have worked well, paying for the energy generated. Project developers can estimate the amount of energy their project will produce and then negotiate pricing for the delivery of that energy. With PSH and energy storage more generally, however, their use is less predictable and changes with grid conditions. An energy-only payment does not guarantee a developer a clear revenue stream over the timeframe needed to recover PSH costs, nor the costs of other high-capital, long-life grid assets. Further, much of the value for PSH and other energy storage resources comes from their flexibility and ability to deliver different grid services. Most energy resource contracts do not pay for these services. In unorganized markets, a utility's existing resources often cover such services without explicit renumeration. In organized markets, developers of battery storage technologies have been successful in installing projects in and profiting on ancillary service markets. While it appears feasible to successfully develop battery projects for ancillary service market participation, their capital costs relative to PSH per unit are much lower and the timeframe needed to recover costs much smaller. It is difficult for a potential PSH developer to estimate both energy and ancillary service revenues over the timeframe of the project.

The contracts and market constructs discussed here move away from the current market paradigm and toward some form of longer term guarantee associated with resource output that incentivizes the need: dispatchable clean capacity and energy in the case of Hawaii and Nevada; long-term capacity and energy in the case of Israel; large balancing needs in the case of Australia; revenue certainty for transmission development in the UK; or a different capacity market construct that creates incentives for energy availability over the long term in Colombia.

Hawaii and Nevada. Hawaiian Electric Company's PPA for Renewable Dispatchable Generation contracts are intended to solicit development of firm renewable energy capacity in the form of solar and energy storage or wind and energy storage. As a policy, the Hawaii Public Utilities Commission has required the company to contract for new resources rather than self-build. Therefore, Hawaiian Electric worked extensively with industry to develop contracts that would deliver clean energy resources, whose output could be controlled by the company while paying for curtailed energy. This ensured developer interest and competitive participation in resource solicitations. After much back and forth, Hawaiian Electric successfully contracted solar and storage projects through its first procurement round and has continued to add new projects in subsequent rounds.

The contracts enable guaranteed payment for facility availability and net energy potential to be delivered, in addition to or in place of the standard delivered energy payment. This is similar to both operational reserve requirements (i.e., spinning and non-spinning reserves) and capacity markets in organized markets: renumeration for availability to deliver energy over a term. However, the term in this case is 20–25 years, whereas operational reserves are day ahead at most, and capacity markets cover a year. This payment construct provides a developer guaranteed revenue that is less subject to curtailment and provides the utility and its ratepayers a lower cost firm and dispatchable renewable energy resource. In this model, the vertically integrated Hawaiian Electric will dispatch these plants as one of its system resources, again like an RTO or ISO in an organized market.

Traditionally the utility has signed expensive PPA contracts with developers for intermittent renewables, and recently more firm solar contracts supported by energy storage. However, in both situations the developer is subject to resource curtailment and the utility operates the resources as must-take rather than dispatchable. Accordingly, the developer would either price its energy at a higher rate to compensate for potential curtailment, or the utility would have to pay for the energy that could have been generated despite curtailing output to maintain system reliability. Based on the results of these procurements, this contract structure has been successful. In the first round Hawaiian Electric received regulatory approval for seven solar and energy storage contracts worth 252 MW at prices near $0.10/kWh, the lowest prices the state has seen for such development.[6] Subsequent procurements have seen even lower prices.

Nevada Energy took a similar approach with a recent procurement of hybrid solar and storage capacity. The contract structure pays a price during system peak hours (4–9 p.m.) that is 6.5 times higher than the price paid for output during other hours. This PPA ensures that the projects will provide capacity value in addition to energy value. Nevada Energy additionally has the flexibility to dispatch the plant during nonpeak hours to minimize system costs.[7]

It is possible to imagine a utility procuring a LDES development tied to a solar or wind farm following a similar contract structure. The contract would guarantee revenue for the developer through availability and stored energy payments, while allowing a vertically integrated utility to dispatch the resource to meet system needs, providing clean, firm capacity. This would deliver clean capacity to a utility without it having to develop its own project and potentially reducing ratepayer burdens. In a market environment, such a project could be a part of a bilateral contract for firm renewable generation service.

Australia. In 2018, Snowy Hydro signed eight wind and solar contracts totaling 888 MW, which are firmed with Snowy Hydro's existing PSH assets, enabling the company to deliver competitive prices to customers.[8] More recently, Snowy Hydro started exploring a new 'super-peak' contract that is designed to cover demand during the high-priced morning and evening periods, when solar output is low.[9] This new hedging product enables participants to manage the risk of very high prices. Such firming products will be an important revenue stream for the Snowy 2.0 PSH currently under construction. In 2017, the federal government identified the value and need for large-scale LDES as a necessary system resource in light of the increasing penetration of VRE across the National Electricity Market and imminent closure of significant coal-fired capacity. In response, the government aggressively supported the development of the 2,000 MW (175 hours) pumped storage project in the state of New South Wales by becoming the sole shareholder of the project's developer, Snowy Hydro Limited, as well making an AU$ 1.4 billion equity investment in the project. Further in 2019, Snowy Hydro signed a $5.1 billion contract to build the Snowy 2.0 PSH project. It is expected to be fully operational in 2025.

Also in Australia, Hydro Tasmania recently announced the signing of a "virtual storage" contract with Macquarie and ERM Power. Under the contract, Hydro Tasmania will sell the rights to power stored in their hydro system during the highest priced parts of the day and buy energy to charge their plants when prices are low. This allows Hydro Tasmania to take advantage of the swings in daytime prices due to weather-dependent renewable energy. The novel component of this contract is that Hydro Tasmania, rather than relying on market pricing, locks in a price spread by establish both purchase prices and sale prices. The benefits to offtakers are similarly in guaranteed pricing. This virtual storage contract could provide part of the much-needed revenue certainty to support future PSH and LDES investment.

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[6] See Hawaii PUC Docket Management System, Dockets 2018-0430 to 2018-0436.

[7] R. Hledik, R. Lueken, J. Chang, H. Pfeifenberger, J. Cohen, and J. I. Pedtke, "Solar-Plus-Storage: The Future Market for Hybrid Resources," December 2019.

[8] Snowy Hydro. "Snowy Hydro signs game-changing deals - Snowy Hydro." https:/www.snowyhydro.com.au/news/shl_deals/ (accessed June 16, 2020).

[9] M. Maisch. "'Super-peak' firming contracts open up new opportunities for battery storage." PV Magazine Australia. https://www.pv-magazine-australia.com/2020/04/15/super-peak-firming-contracts-open-up-new-opportunities-for-battery-storage/ (accessed July 9, 2020).

In both cases, the PSH developer/operator is a government utility, but in establishing these mechanisms it provides a market transparent revenue stream for PSH and other assets. Such similar market products or contracts could be considered in U.S. markets, particularly as renewable development continues to increase while dispatchable fossil units are shut down, but markets must still to compensate for the variability of renewables. The need for such products has already materialized, for example, with CAISO's refined flexible ramping product that incentivizes fast ramping resources to compensate solar drop-off in evening hours on particularly high-demand days.[10]

Israel. In 2018, the Israel Electric Corporation determined that the country's grid required a significant deployment of long-duration storage to integrate its planned development of solar resources while also reducing reliance on natural gas generation. Accordingly, the government corporation developed a payment mechanism with a renumeration structure intended to ensure private financing and development. Based on this structure, two major pumped storage projects have progressed: the 344 MW Kokhav Hayarden project owned by Star Pumped Storage under development and the 300 MW Gilboa pumped storage project which is already operational.

The contract structure guarantees revenue over an 18–20-year timeframe, the long-term nature of which, as discussed above, is traditionally not available to resources in organized electric markets. This approach mimics, in some form, an asset in a vertically integrated market with a guaranteed level of payment to ensure development, but at the same time includes delivery and performance requirements to promote efficiency and a high level of resource performance. The three-part payment scheme consists of the following revenue streams:

- An availability payment that forms the bulk of revenue and requires the plant to be available for a minimum time during a year. In addition, an availability requirement is passed on to the equipment manufacturer, supplying plant availability guarantees through a long-term operations and maintenance contract. This payment also includes bonus payments for dynamic benefits including ramp rates, pumping to generation switching timeframes, star-up and shutdown speeds, etc.
- Payment for energy.
- Startup and shutdown payments based on how often the plant is operated.

The project developers have indicated their support of this mechanism as it mitigates market and regulatory risks for the projects' business case. The grid operator bears long-term development risk while the developer bears the plant's performance risk, which is also shared by equipment suppliers. This allows for risk allocation and sharing among all the involved parties. Similar contracts could be developed in the United States, building on the hybrid contract design from Hawaii and Nevada, with additional risk sharing and mitigating elements with equipment suppliers and a more incentive-laden approach to performance rather than the harsher penalty approach taken by the Hawaii contracts.

UK – Cap and Floor. In the United Kingdom, to be responsive to agreement in industry that there was a need for merchant transmission development to enable large-scale imports and exports of mainland Europe energy, the market regulator, Ofgem, developed the cap-and-floor mechanism. In simple terms, the mechanism provides a revenue floor for transmission development in an environment where merchant transmission development could not be financed due to long-term revenue uncertainty. In some ways, this is like a contract for differences used to support renewable development across Europe for decades and more recently in the United States. As expected from the name, the mechanism establishes a rate recovery floor, that is a minimum return, that transmission projects are guaranteed to receive from all customers

[10] "Initiative: Flexible ramping product refinements." California Independent System Operator. https://stakeholdercenter.caiso.com/StakeholderInitiatives/Flexible-ramping-product-refinements

through regulated transmission rates. It also establishes a cap, or a maximum return, that projects can receive in the market. This cap is intended to permit market participation while limiting operators from exercising market power and to ensure ratepayers are not subsidizing projects that result in windfalls for developers. This is often a reason cited, as to why pumped storage resources should not be guaranteed rate recovery while being permitted to participate in markets.

Since the scheme was implemented in 2012, there are five installed and operating transmission projects. Review of these projects have indicated that the scheme is operating as intended with quantifiable benefits for ratepayers.[11] As a result of this success, SSE and ScottishPower have both suggested that a similar scheme should be expanded to pumped storage projects. Thus far Ofgem has not acted.[12]

A cap-and-floor mechanism could be a viable approach in the United States to permitting pumped storage projects or other large energy system projects to be funded for development, ensuring a revenue guarantee sufficient for capital financing, but limiting the potential for market power and revenue windfalls. California in its Storage as a Transmission Asset efforts highlighted potential pathways for dual-use storage assets but considered undue revenue from market participation coupled with transmission returns a significant issue. This could be a solution and enable vertically integrated utilities in market regions to procure pumped storage services while limiting ratepayer burdens by allowing market participation for developers, or in nonorganized market regions, allow a developer to sell some capacity to other utilities or off-takers.

Colombia. The Colombian firm energy market, known as Reliability Charge, is a case study for compensation of LDES. Colombian power system is comprised mostly of hydro power plants, complemented by thermal units fueled by gas, coal, and fuel oil. In 2020, approximately 64% of the total installed capacity (Figure 7) came from hydro power resources. However, total energy supply from hydro sources varies from 48–78% depending on hydrological conditions. As expected, the high dependency on hydro sources can introduce challenges to the operation of the power system, especially during extreme and extended dry weather periods (or wet) derived from high (or low) temperatures along the "*Pacific Ring of Fire*" triggering a climate event known as "*El Niño Phenomena*" (or *La Niña*).

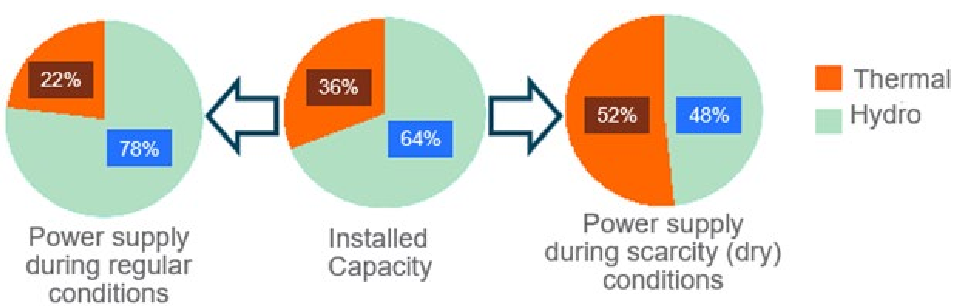

Figure 7. Installed capacity and hydro-thermal energy production during regular and scarcity conditions.[13]

Figure 8 presents electricity energy production by source for the last 12 months. During a dry period in May 2020, nonhydro resources supplied near 40% of the total demand, while during regular conditions

[11] "Guidance on the cap and floor conditions in National Grid North Sea Link Limited's electricity interconnector licence " Ofgem, Guidance 2018.; Cap and floor regime: unlocking investment in electricity interconnectors. (2016). Ofgem.
[12] M. Dickie. "Hydro power operators press for UK rules rethink." Financial Times. https://www.ft.com/content/fed7a1bc-5477-11e9-91f9-b6515a54c5b1 (accessed July 16, 2019).
[13] "https://www.xm.com.co/Presentaciones%20Cargo%20por%20Confiabilidad/Forms/AllItems.aspx"

(May 2021) hydro resources supplied nearly 75% of the demand. Additional metrics are included in Table 3, including installed capacity, annual energy production, and CO_2 emissions. Current gap between installed capacity and peak demand shows a security margin of 64%.

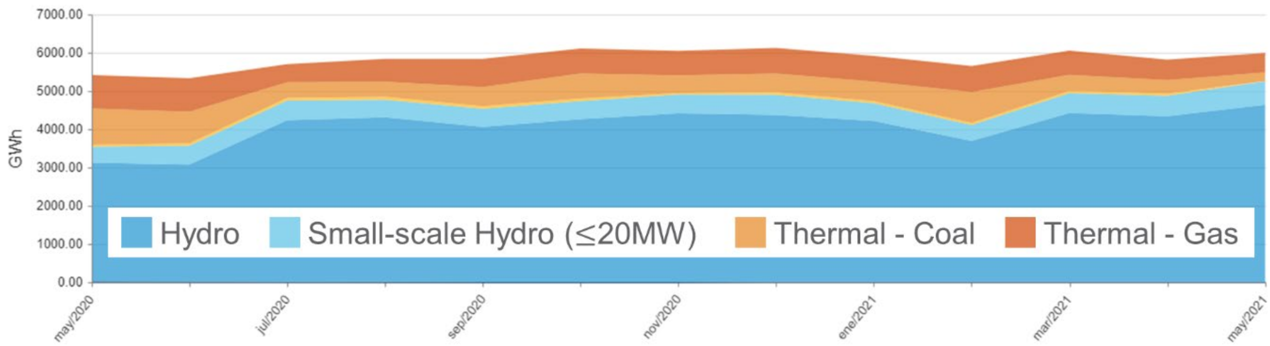

Figure 8. Monthly electricity generation in Colombia by source.

Table 2. Installed Capacity, Annual Energy Production, and CO_2 Emissions[14]

Year	Total Installed Capacity – GW	Annual Energy Production TWh-yr	CO_2 Annual Emissions Ton CO_2-yr
2018	17.31	68.94	8.8
2019	17.46	70.11	11.8
2020	17.48	69.32	14.3

The concept of capacity market was first introduced in Colombia in 1995. This mechanism provided incentives to private investors interested in developing generation fleet by guaranteeing a 20-year fixed income as long as the generation projects were commissioned according to the national generation expansion plan. From 1995–2006, generation expansion planning studies were based on ensuring the installed capacity met peak demand. However, despite consistently maintaining a margin of 64% between *installed capacity* and *peak demand*, the Colombian power system was repeatedly challenged by the ability of the generation fleet to serve load, continuously and uninterruptedly. The weather-driven shortfalls in water availability, especially during severe and extended dry periods (i.e., *El Niño* periods), created energy supply deficits.

Consequently, Colombia's Energy and Gas Regulatory Commission changed the generation expansion market from one based on installed capacity (capacity market) to one based on *available energy* (firm energy) over a period of time. This Reliability Charge mechanism provides incentives to ensure *energy adequacy* and ensures the energy supply for the Colombian demand, even during periods of drought such as the *El Niño* phenomena, by ensuring adequate generation is procured ahead of time. This mechanism also guarantees that power plants are able to supply the demand for extended periods, even during peak hours, through a mechanism based on penalties.

[14] http://www.xm.com.co/Paginas/Indicadores/Oferta/Indicador-generacion-sin.aspx.

3.0 Ownership Options

LDES assets are likely to be very capital intensive. Building such an asset may be more than what a single utility could afford or justify from the perspective of rate-based cost recovery. Hence, alternative ownership may need to be explored, such as multiple owners or third-party owners of such assets. These new options for deploying LDES will create new opportunities and challenges for owners of energy assets.

Each of the options discussed below may be best suited to a particular technology or operations strategy. These strategies also have important repercussions for compensation and remuneration. Most energy storage systems operate within an energy market, through bilateral contracts, or receive a regulated rate of return. However, these compensation models are evolving, and ownership strategies will change alongside them. New business models like energy storage as a service (ESaaS) and swing contracts have also emerged to ensure utilities retain resource adequacy while placing more renewables on the system.

3.1 Single Utility Owned

Historically, ownership models for energy storage have been less diverse than traditional generating assets. For example, roughly a third of nuclear and conventional coal-fired plants are jointly owned, whereas Figure 9 illustrates that 85% of pumped hydro storage plants are owed by a single entity (EIA-860, 2020). This trend may be related to historical deployment patterns, as many pumped hydro projects, both conventional and pumped storage, were created by a single utility or government agency. Traditional hydro (as seen in Figure 10) is also a small portion of jointly owned assets, especially when compared with coal and nuclear. However, batteries also have a low rate of joint ownership when compared to other generators, even pumped storage. That said, many battery systems are owned by an entity other than the systems operator, a potential indication that there may be more unorthodox operations strategies for battery energy storage systems, or that large, credit-worthy owners are required to deploy pumped hydro. Battery projects that are jointly owned also see a more diverse group of owners than pumped storage plants. While ownership in pumped heat electrical storage systems is limited to utilities and government agencies, financial institutions, independent power producers, developers, and holding companies all have shares in battery systems.

The benefit of single ownership lies in its simplicity. When a single utility owns a project and receives a regulated rate of return, the utility can operate the project as it wishes, so long as it is compliant with market rules and state, federal, and local regulations. A utility may see an immediate need for energy storage for excess generation from a nuclear plant, or balance increasing renewable generation, and build capacity to suit this need. This process is consistent with integrated resource planning, almost synonymous with rate-of-return-based investments, and illustrative of how most utilities and regulators weighed decisions for capacity expansion prior to deregulation in the 1990s. However, this simplicity can also limit energy storage in higher cost or less straightforward arrangements. These strategies (described in Section 4.0) may require partnerships and cooperation to be achieved at scale. Likewise, for higher capacity (and higher cost) technologies, two or more off-takers may be needed to capture all the benefits of a single system, as is common among conventional generators.

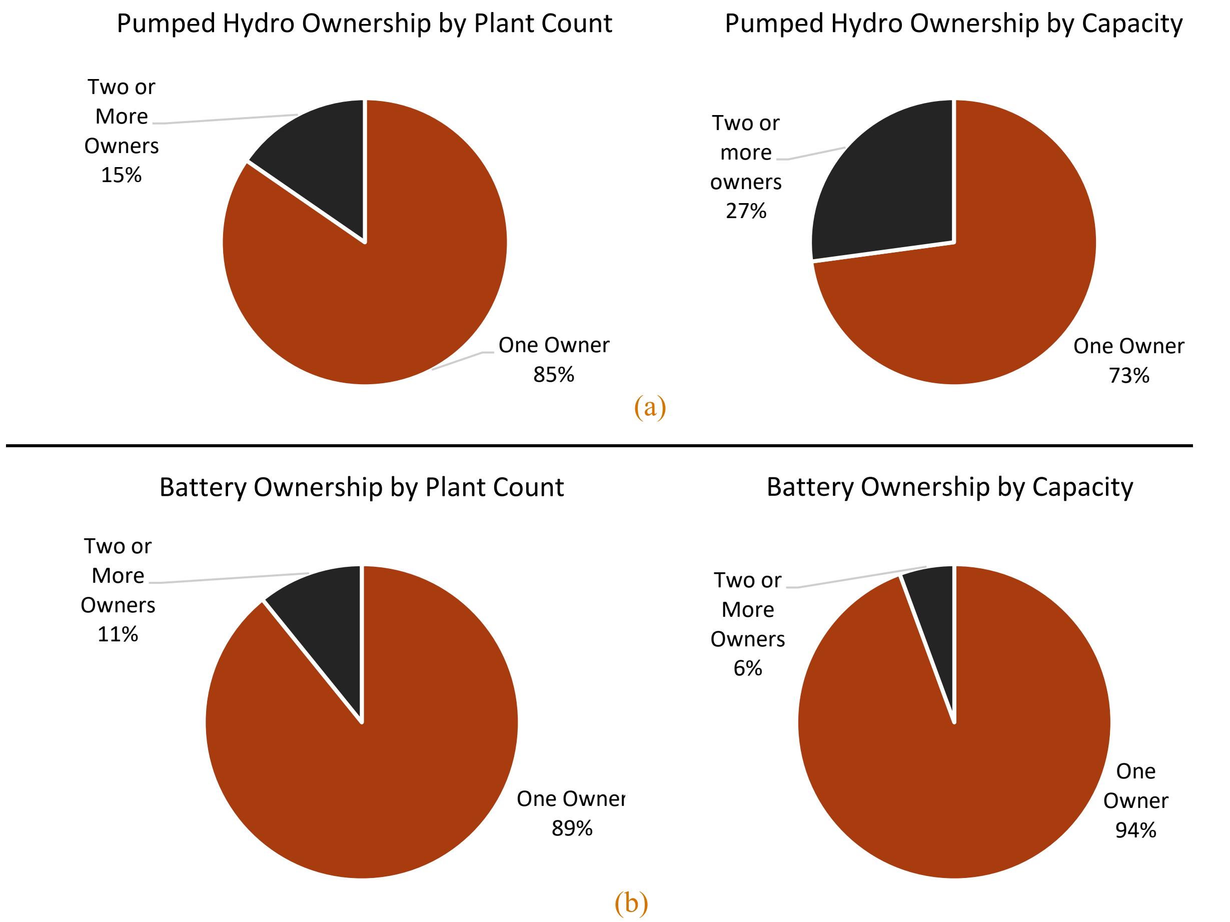

Figure 9. Energy storage ownership by plant count and power capacity for (a) pumped storage and (b) battery storage projects.

3.2 Jointly Owned by Multiple Utilities

Baseload generators generally aim to operate at the highest capacity possible, and hence the joint owners can simply divide the available capacity and the associated costs and revenues of operation. Figure 10 presents a breakdown of the jointly owned generation assets by plant type. Like more traditional sources of generation, energy storage can be owned by a single owner/operator, jointly owned, or owned communally or by a group of investors (see Table 4).

Joint ownership of energy storage plants, however, are not likely to be this straightforward. The charge/discharge profile of the energy storage asset in question will need to be coordinated between the joint owners. The specific charge/discharge profiles desired by individual entities will depend on their operational needs, which will in turn depend on their portfolio mixes, and the regulatory and market environments they operate in. PSH in particular experiences notable economies of scale, and small-to-medium-sized utilities could potentially benefit from joint ownership. However, the complexity of asset management may present challenges to this business model. The handful of plants that are jointly owned may provide some insights into how operations of future deployments could occur.

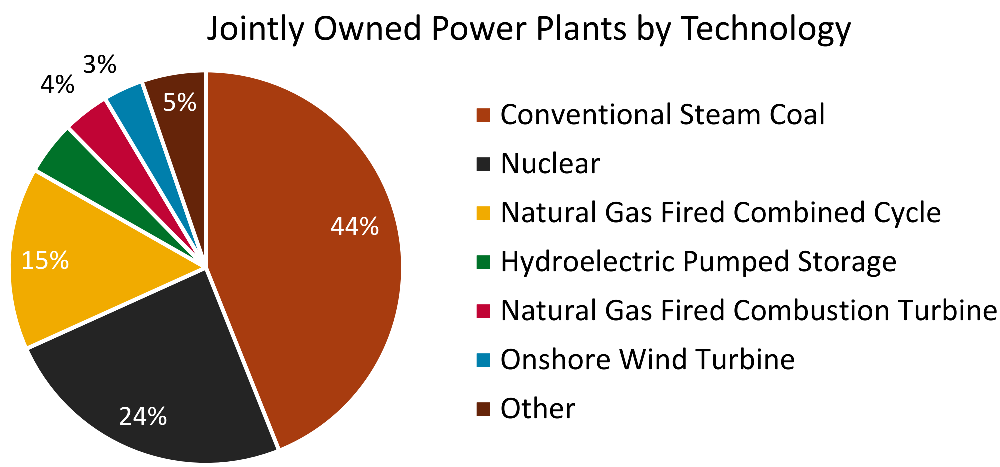

Figure 10. Proportion of jointly owned power plants by type (EIA 2020).

Table 3. Observed Ownership Arrangements for Energy Storage

Joint-Ownership Arrangement	Number of Battery Projects	Number of Pumped Storage Projects
Investor-Owned Utility (IOU)-IOU		1
IOU-Cooperative		1
IOU-Holding Company		1
IOU-Developer		1
Municipality-Developer	1	
Municipality-Government		1
Developer-Developer	1	
Developer-Finance	10	
Developer-Holding Company	1	
Finance-Finance	1	
Federal Government-State Government		1
Holding Company-Holding Company	1	

Multi-owner plants are quite diverse, operating in both regulated and deregulated markets, and located across several states. In some cases, the ownership structure has been maintained and is deeply tied to the inception of the project. These entities are tasked with managing the state/region energy and water resources and thus manage the plant in tandem. Others have been more fluid, with the owners changing somewhat frequently through sales or mergers.

The Ludington pumped storage plant and the Rocky Mountain plant, both in Georgia, present interesting case studies as the Ludington plant is owned more or less equally by two IOUs (Consumer's Energy and DTE Energy) and operates in a competitive power market (MISO), with opportunities for price discovery. While other power markets see greater wholesale competition, MISO's energy market provides the plant operators with clear price signals that a regulated market lacks. On the other hand, the Rocky Mountain plant's majority owner is an electric cooperative (Oglethorpe Power). Its minority partner is Georgia Power, and the plant operates in a fully regulated environment and must agree to operation strategies without these market signals. Together these examples provide potential strategies for energy storage operators to navigate the challenges of joint ownership.

The Ludington plant primarily aims to follow price signals from the MISO market, with most of its generation occurring at times of peak demand, and its consumption at periods of low demand. This means that the plant primarily pumps at night and releases electricity during the day. It takes 10 hours to fully fill the reservoir and the plant generally turns over two to three times per week. The operators aim to begin the week (Monday) with a full reservoir and generally generate less power during the weekends (Consumers Energy 2017). Due to the price signals provided by the MISO market, the ownership arrangement is relatively uncomplicated. Consumers Energy (the majority partner) operates the plant based on an agreed-upon strategy with its partner, DTE Energy. DTE's role is primarily financial. They are responsible for paying the operations and maintenance costs associated with the plant and receive a share of the revenues.

The Rocky Mountain plant on the other hand, does not operate in the same market environment. Utilities in the southeast are vertically integrated and schedule dispatch based on their own demand projections. Thus, while Rocky Mountain and Ludington have a similar ownership structure, their operations are different. The majority owner and operator of the Rocky Mountain Project is Oglethorpe Power, which holds a 75% share of the plant. Georgia Power holds a 25% share (EIA 2020). Like the Ludington plant, the partners split costs and benefits in line with their stake in the project, and the majority partner operates the plant based on an agreed-upon strategy. However, the two companies individually schedule their own blocks of capacity based on the needs of their customers ("Annual Report" 2021). Oglethorpe reserves and dispatches roughly 274 MW of power based on instructions laid out by Georgia Power in their operating plan. Further, if Georgia Power wishes to amend this plan at any time, they can require Oglethorpe to deviate, so long as they pay for any associated operating costs.

Joint ownership of large capital assets is financially more viable for individual entities but can pose potential risks for system operators. A concentration of assets among a small number of owners can lead to collusion, if they gain a sufficient degree of market power. For example, a study of Swedish power producers found that jointly owned plants had timing maintenance shutdowns to drive up power prices (Lundin, 2016). Regulators and market monitors should carefully consider whether operators can game markets through these sorts of arrangements. Despite these risks, game theory indicates that manipulation is unlikely to create an undue burden on consumers. Hartwig and Kockar (2016) find that energy storage assets can sometimes result in rent-seeking behavior and reduce consumer surplus. This process leads developers to collect a share of profits that is greater than the benefits they provide to consumers. However, even though developers are collecting an unfair share of profits, the benefits batteries can provide to ratepayers almost always outweigh the rents developers collect (Hartwig and Kockar 2016). Moreover, ownership by a system or network operator results in higher benefits than private or dual ownership.

Despite these risks from collusion, the case studies of Ludington and Rocky Mountain can show that there are benefits to joint ownership. These plants illustrate the differences between systemic and utility optimization. While, for example, Oglethorpe Power, as a small electric cooperative, may not have sufficient need for an entire PSH plant, by pairing with another utility they are able to realize all its benefits. While one offtaker alone may have chosen to meet their resource needs with other technologies, thus choosing an outcome that is more efficient for the utility; by cooperating, the two entities together are able to achieve an outcome that is more efficient for the electricity system overall. Joint-ownership arrangements could also be more likely to seek more diverse contracting arrangements, as illustrated by Ludington and Rocky Mountain. Here similar projects can pursue different revenue and operational strategies in disparate markets. Though potentially riskier, this type of ownership arrangement deserves greater attention from industry and regulators.

<u>Best Practices from Joint-Ownership of Transmission:</u>

A jointly owned transmission asset can have operational control issues similar to a jointly owned LDES. The transmission sector has a history of jointly owned assets and has developed effective strategies for governance and expansion that could be used by developers of LDES. Prior to the passage of FERC Order 1000, which laid out more concrete processes for transmission planning, many utilities would collaborate in regional transmission planning. Similar steps could be taken for LDES. The Southwest has a history of jointly owned transmission, which the energy storage industry can look to as a potential model for deployment. The American Public Power Association cites joint ownership as one of the reasons why southwestern utilities have been able to serve a rapidly growing customer base (American Public Power Association 2009). As a result, some tradeoff between providing incentives to businesses to install capacity and ensuring benefits flow entirely to consumers may be needed. The Southwest model is based on the idea that joint owners represent tenants in common, who own pro rata shares of the project. This arrangement also allows utilities to jointly plan development of the transmission project, while being responsible for separate sections.

3.3 Third-party Owned Long-Duration Storage Resources

While interest in dually owned storage assets is increasing, ownership by a single third-party market participant remains a very common arrangement for energy storage. As Figure 11 illustrates, roughly 20% of all storage systems are owned by an independent power producer operating in an electricity market, with the remainder being owned by a utility (EIA 2020). Notably, the reverse is true for batteries, where nearly 75% operate in a market environment. Given that the majority of PSH plants were developed before deregulation, this arrangement illustrates how ownership models have evolved based on underlying market characteristics. The challenge of expanding this ownership model to longer duration sources of energy storage will depend on developing stronger market values for these forms of energy. These assets are not rate based (though a utility could pass through procurement costs), and thus may be dependent on more novel compensation mechanisms like swing contracts.

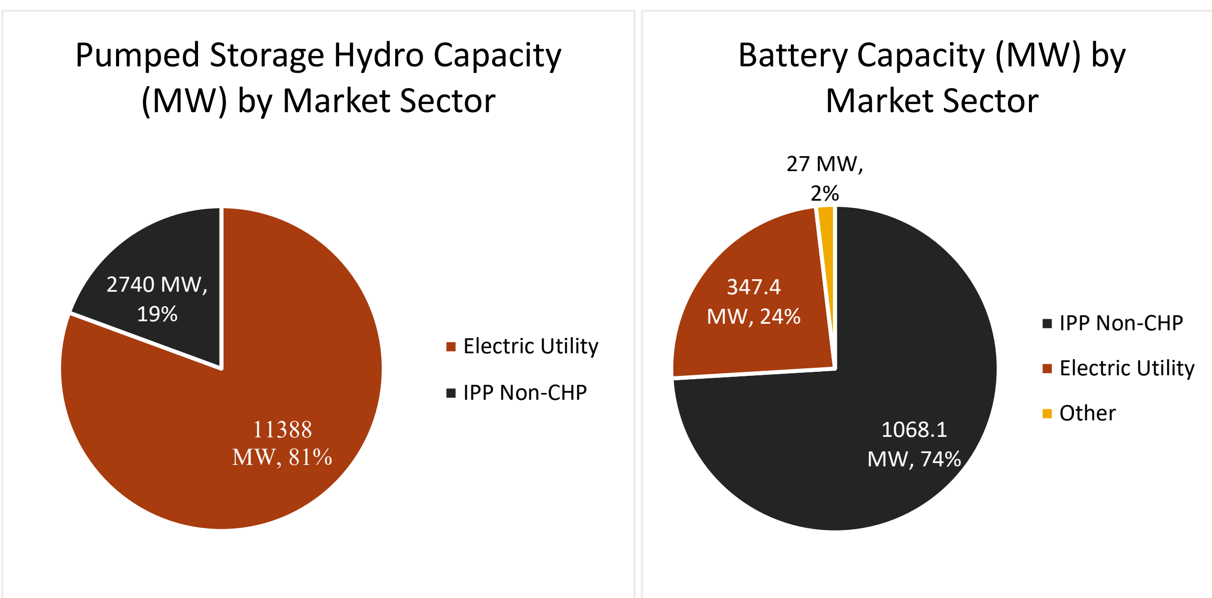

Figure 11. Energy storage ownership by market participant.

Section 4 provides more information on what these compensation mechanisms could look like. CAISO (which has an energy storage mandate) is the largest market for batteries followed by PJM (which sees high levels of battery deployment due to the ancillary services market) and the Electric Reliability

Council of Texas (ERCOT), which has lucrative arbitrage opportunities.[15] Developing clear market signals will be necessary for long-duration storage assets to gain traction with this business model.

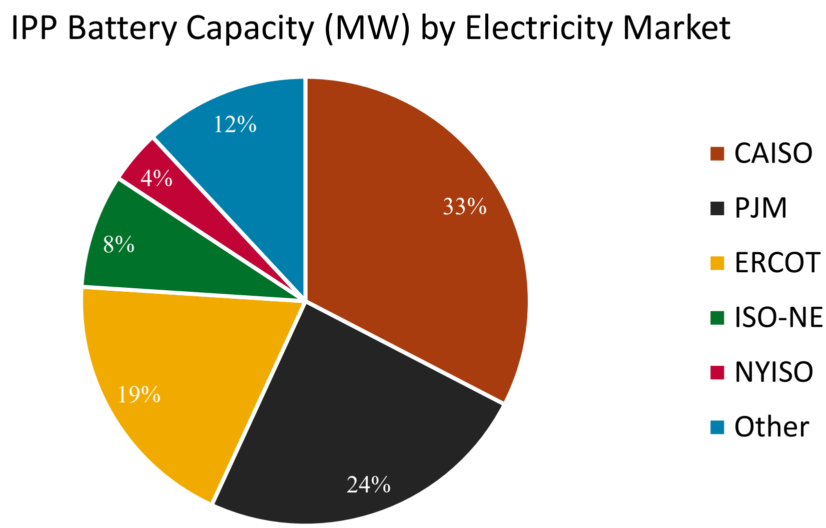

Figure 12. Installed energy storage battery systems by market.

Storage-as-Service: Subscription-Lease Model:

Third-party owned resources are another promising deployment mechanism for energy storage. If multiple utilities are required to take full advantage of an LDES system, and management and operation issues make a joint-ownership strategy unwieldy, then a single entity operating an asset that serves multiple offtakers may be the best option. Many battery developers have begun to market ESaaS, where a single owner/operator builds a storage project and sells potential value streams to a single or group of offtakers. When capacity or generation from batteries is uncontracted, the developer can bid directly into the market. For example, a utility may contract with a developer to purchase firm capacity during periods of peak demand. Outside of these times, the developer may choose to enter into arbitrage arrangements or sell output into the ancillary services market. Operators could also enter into contracts with multiple utilities for complementary services. Of the models listed in this section, this remains the most flexible, but also the model with the most potential financial risk. Financers generally prefer to have long-term contracts in place before underwriting construction. Low costs may be necessary for storage operators with significant exposure to the market to be deemed credit worthy. However, developers who offer disparate services with long-term contracting mechanism could be more successful.

Though still a nascent business model, many battery companies have begun to outline ESaaS strategies. Fluence, for example, deployed one of its first ESaaS plants in Finland, offering power quality enhancements and energy efficiency services to a commercial offtaker and frequency regulation to the local utility (Kistner 2021). Battery providers like Stem and Alturus have focused on the commercial and industrial segment as the most likely adopters of ESaaS in the near term. Others have promoted portable, containerized batteries that can be rapidly deployed to meet demand as a potential product (Schönfeldt 2018). This sort of arrangement could be rapidly deployed to help utilities address temporary power gaps or meet seasonal needs for peaking power ("Energy Storage as a Service: Why Renting Can Be Better Than Buying" 2019). These arrangements also limit the subscriber's downside risk.

[15] A more comprehensive look at how these batteries are dispatched is available in EIA's Battery Storage in the United States (July 2020).

While ESaaS business models have been primarily applied to lithium batteries that are under 4 hours in duration, there is no reason why similar business models could not be applied to other energy storage technologies, including those with longer duration. Projects that have higher capacities could market to utilities that have different peak demands or resource curves. However, financing these projects without fixed contracts may prove difficult.

3.4 Private Commercial and Industrial Customers

To date, there are no PSH systems listed by EIA, or otherwise identified, as being owned by a commercial or industrial customer. However, this arrangement could change in the future as commercial and industrial (C&I) customers take an increasing control over their energy usage, particularly for LDES resources that easier to own and operate (than PSH). Though most procurement from large C&I customers has been for renewable power ("CEBA Deal Tracker" 2021), there has been a growing interest in adding energy storage to these procurement processes. In 2020, interest was announced in procuring battery storage for the first time (Bebon 2021).

Much of this interest has been driven by an evolution in how C&I customers are treating their renewable energy goals. Many early commitments from large commercial customers were focused on meeting annual demand with renewable purchases. That is, they would simply add up their total consumption for a year, and sign contracts to purchase a set number of MWh, regardless of location or the time in which it was generated. More recently, many C&I purchasers have begun to adopt more sophisticated procurement strategies based on the concept of "additionality." Google, one of the first C&I customers to use the additionality framework, describes this concept as embracing projects that spur the development of new renewable energy that would otherwise not have been added to the grid (Google 2016). In recent years, Google has expanded this metric to embrace "technologies or services that enable 24-7 clean energy" (Google 2019). Meeting these commitments—that is meeting all energy requirements with clean energy—will almost certainly require scalable options for LDES.

Data centers may be a key application for LDES technologies. Aside from their environmental commitments, companies view their data centers as critical infrastructure that must be resilient to power loss. While many data centers have some form of backup generation, and in fact some have installed natural gas fuel cells to mitigate unreliable grid energy delivery, these entities are also beginning to embrace more novel forms of energy storage to enable resiliency. However, most data center operators do not anticipate installing these technologies before 2025 for resiliency purposes (Ascierto and Johnson 2021). It is when these environmental and resiliency goals are combined, the options for large-scale and eventually LDES technologies are most relevant. As an example, Google is working to deploy a 350 MW solar project combined with 280 MW of batteries at a Las Vegas data center in pursuit of these dual goals (Mytton 2021). Similarly, Microsoft has expressed a desire for clean technologies that can support renewable generation to provide the high reliability and resiliency needs of their data centers, explicitly identifying hydrogen as an LDES technology to enable this.[16]

Military bases could also be an application where resiliency and environmental goals converge to create favorable opportunities for long-duration storage. Executive Order 14057 sets carbon-neutral goals for government agencies, including the military. Featured among these goals is a requirement to procure 100% carbon-pollution-free electricity by 2030, including 50% on a 24-hours-a-day, 7-days-a-week basis (The White House, n.d.). Likewise, the Department of Defense also has stringent resilience standards for military bases and operations, with a current 14-day continuous delivery of energy in contingency situations as their resiliency standard. Meeting this standard while avoiding on-site storage of fossil fuels

[16] Private direct communication.

will necessitate the use of LDES technology. Fort Hood in Texas installed a solar-wind battery microgrid, which could enable it to be islanded from external power sources for 14 days with sufficient battery storage installed. Though military bases more broadly have not yet looked to LDES technologies, these systems could provide bases with even greater islanding capabilities to enhance resiliency and reduce systemic risks.

4.0 Compensation Options and Mechanisms

The ultimate structure of ownership these projects take will depend on the mechanisms that regulators choose to develop for compensation of long-duration storage. As discussed above, many industry observers believe that current compensation mechanisms are not adequate to promote sufficient deployment of LDES. While value streams within electricity markets have expanded, energy remains the largest market for most generators. Paying a per-MWh basis is complicated by the growth in renewable energy, which has low operating costs and will typically generate even if market prices are low. In places with large amounts of solar and wind, negative prices are common during periods of peak generation. While in the near term this creates opportunities for energy storage through arbitrage, in a future with very high renewable penetration, the market may not be equipped to send adequate price signals to generations. Therefore, reforms and innovations are needed in market designs and contracting structures to create appropriate investment signals for LDES. Additionally, the opportunities to compensate projects using regulated rates should also be considered, where applicable. This section outlines these changes and examines their applicability in various regions.

4.1 Multipart Payment Contracts

Most electricity markets have some form of a capacity market, where generators are paid for their *ability* to generate during peak demand, rather than the generation itself. Capacity markets are often used as a strategy to meet resource adequacy requirements in a market environment. Payments are typically made in $/MW-year format. While properly designed battery systems can qualify for capacity payments in some markets, there is considerable debate as to whether these payments accurately value the services provided by energy storage. Further, capacity credits generally do not vary over a given year, and generators face steep penalties if they are unable to dispatch when instructed. One potential solution to this problem is the introduction of swing contracts, which provide additional sources of revenue to developers and greater flexibility to system and plant operations.

In developing a swing contract, a plant operator will first develop an offer price (a price the system operator will pay for availability). This functions similarly to a capacity payment and is designed to allow the generator to recover upfront costs. Alongside this offer price, the developer will outline a series of power paths, different generation or charge/discharge patterns that the generator could offer to the grid. If the swing contract is triggered, the system operator may request the generator to execute these power paths at any agreed-upon time. The contract will also include performance payments, which allow the power producer to recover operating costs after the fact (Tesfatsion 2020). Market operators could subscribe to a variety of generators with different power paths, building a portfolio of potential operating strategies. While no major power market in the United States has begun offering swing contracts, Hawaii and Israel have begun experimenting with the mechanism (see discussion in Section 2.3).

Though these multipart contracts have seen limited adoption, their clear strength is providing payment for availability and resource adequacy. These contracts could be accepted in any market that accepts PPAs. Furthermore, wholesale electricity markets could be adapted to provide some of these features. Swing contracts are a more flexible option for solving the “missing money problem” that capacity markets were intended to solve (Hogan 2017). As payment is only provided if the offer price is accepted, it can also protect utilities and ratepayers from “gold plating” and overinvestment in capacity resources. However, this arrangement places more risk on the developer and project owner. Renewable project developers may have difficulty adapting from standard PPA contracts (which often feature a buy-all, sell-all clause) to less-stable forms of revenue. Investors may also demand a risk premium when considering these projects.

4.2 Regulated Rate of Return

Traditionally, long-duration storage has been built through the rate base of a monopoly utility. Most PSH plants before the widescale adoption of electricity markets in the 1990s have been operated continuously since. Of the plants entering operations after 1990, all but one (Lake Hodges) were built in vertically integrated territories (EIA 2020). This trend holds true in other countries. In the UK, virtually all pumped hydro plants were built before the introduction of energy markets (Stoker 2021). Clearly, the existing structure of the electricity sector has not been conducive to creation of new long-duration storage projects. While some of the changes previously outlined in this paper would help create more opportunities, deploying LDES through a regulated rate of return remains an option.

In many ways, regulators are already using this mechanism to deploy more energy storage. Eight states mandate the procurement of energy storage for integration and reliability purposes (Burwin 2020). Though this is slightly different than the utility building and operating the asset (utilities are typically asked to contract with third parties through a competitive auction or proposals) the cost of the battery can be recovered through the rate base. In some ways this strategy seeks to embrace the benefits of markets, alongside the reliability of a regulated return. States could theoretically expand this model by determining the volume of storage needed to ensure resource adequacy, and direct utilities to build out the capacity, either through proposals or direct ownership.

Other jurisdictions have attempted to seek a balance between fully regulated assets and an overreliance on energy market. One proposed solution is incorporating price caps and floors in market design, which is discussed more broadly in Section 2.3. In this scenario, project owners receive payments analogous to a guaranteed rate of return, but the generators operate in a standard market environment. The price floor prevents plants from becoming unprofitable, and the cap prevents windfalls from flowing to developers. These arrangements can be particularly useful when financers require revenue guarantees to underwrite a project.

> There are two examples of current LDES development, specifically PSH, under rate base. One is in Virginia. Dominion Energy partially justified its proposal and received regulatory approval for its 300 MW Tazewell PHS plant, which would employ former coal miners in an economically depressed region where coal mining employment has declining significantly as the demand for coal has dropped. This followed supportive legislation in Virginia that sets a target for development of energy storage with a cutout for PSH (Dominion Energy 2019).
>
> Another example is the West Kauai Energy Project, being built under contract for the Kaua'I Island Utility Cooperative. The cooperative has signed an agreement to develop a PSH, solar, and battery storage project to support renewable integration on the island and take advantage of existing water infrastructure (Yunker 2021). The utility is reliant on oil-fired units for balancing, and this plant will add a significant LDES resource to reduce that reliance, providing a clean source of balancing to manage solar fluctuations from cloud coverage and delivering a firm capacity resource to meet state adequacy requirements. Further, the utility and project identify the use of PSH synchronous spinning machinery as a significant benefit over inverter-based systems to deliver inertia, voltage support, and fault-current support, supporting grid stability and reliability (WKEP 2021).

Regulated rates of return offer guarantees for utilities and developers. A utility can be sure that a project has the features it requires to maintain system reliability, and a developer (if third-party owned) sees dedicated payments from the purchaser. This traditional arrangement was preferred by the utility industry for decades due to its simplicity and operational flexibility. However, like all vertically integrated options, it shifts risk from industry to the ratepayer. Utilities may attempt to overinvest to receive a return on equity, and consumers are reliant on policymakers to contain costs. Due to these risks, many jurisdictions have eliminated these options and bar utilities from owning their own assets. For fully deregulated states, regulators would have to conduct significant market reforms to allow these options.

4.3 Tax Credits for Long-Duration Energy Storage

Tax credits for energy storage technologies in the United States are only available at present through the Solar Investment Tax Credit (ITC), which offers a federal income tax credit of 26% of the system cost for solar energy systems installed in 2022. The tax credit is scheduled to decrease to 22% in 2023, then to 10% for commercial and utility-scale systems and 0% for residential systems in 2024 and thereafter. While the ITC does not explicitly contemplate energy storage technologies, the Internal Revenue Service has interpreted the credit to apply to technologies that are used to further enhance the value of solar generation and allows energy storage devices that are directly connected to an ITC-eligible solar system, and charged by that system at least 75% of the time, to also receive the ITC.

Securing an ITC for standalone storage systems has been a priority of the energy storage industry for years (Wood Mackenzie and Energy Storage Association 2021). In the current session of Congress, there are three proposals to create an energy storage ITC. The proposals vary in five key areas, as identified in Table 5.

Table 4. Energy Storage ITC Proposals

	Clean Energy for America Act	**Energy Sector Innovation Credit Act**	**Energy Storage Tax Incentive and Deployment Act**
Initial ITC rate	30% (40% for projects in disadvantaged communities)	40%	26%
Phase-out	Emissions Based Begins when U.S. electric sector emissions decrease to 25% of 2021 level; credit decreases by 25% per year thereafter	Deployment Based Credit decreases as deployments increase: ▪ 30% (0.5% of installed U.S. generation) ▪ 20% (1% of generation) ▪ 10% (1.5% of generation ▪ 0% (2% of generation)	Date Based Follows existing ITC phase-out (22% in 2023, permanent 10% in 2024 and after)
Technology eligibility	Applies equally to all energy storage technologies	Applies to all technologies, but creates four phase-out tracks: (1) lithium-ion, (2) pumped storage, (3) all other short-duration systems, (4) all other long-duration systems	Applies equally to all energy storage technologies
System size eligibility threshold	5 kWh	1 MW	5 kWh (3 kWh for residential)
Residential systems eligible?	Yes	No	Yes

Only one of the bills, the Energy Sector Innovation Credit Act, differentiates between short- and long-duration technologies, but it only creates different buckets of the ITC for different technologies. All technologies would receive the same rate and the same phase-out schedule within those buckets. This would not initially create a specific signal for investment in long-duration vis-à-vis short-duration technologies, and because it uses the same sized bucket for each technology, it would place PSH at a relative disadvantage to other technologies. Because PSH already accounts for about 1.8% of installed capacity in the United States, it would only receive a 10% credit, and would likely only accommodate two or three more projects before reaching the 2% cap. Lithium-ion batteries, meanwhile, only account for about 0.2% of U.S. capacity, giving them significant room to compete with the short- and long-duration technologies in the final two buckets at the same 30% ITC, despite lithium-ion's significant head start on cost and supply chain.

4.4 Storage-as-a-Service Model: Miniature Market Hub

In a regional market setting like Ludington's, the asset could be co-owned by multiple parties and operated by market signal, with the resulting revenue flowing to the co-owners. The primary challenge under this model would be creating market products that compensate long-duration storage for the value it provides to the grid, though the emerging approaches to valuing capacity in Section 2.2 may resolve that issue.

Co-ownership of PSH in a vertically integrated region presents a much greater operational challenge. Absent market signals to operate the asset based on regional needs, each utility would seek to operate the device according to its own needs, which may conflict with those of the other co-owners. In this setting, there would likely need to be a third party to exercise operational control over the asset and "net out" the signals sent by co-owning utilities. In this way, the PSH facility could be thought of as a miniature market hub. Figure 14 illustrates this concept.

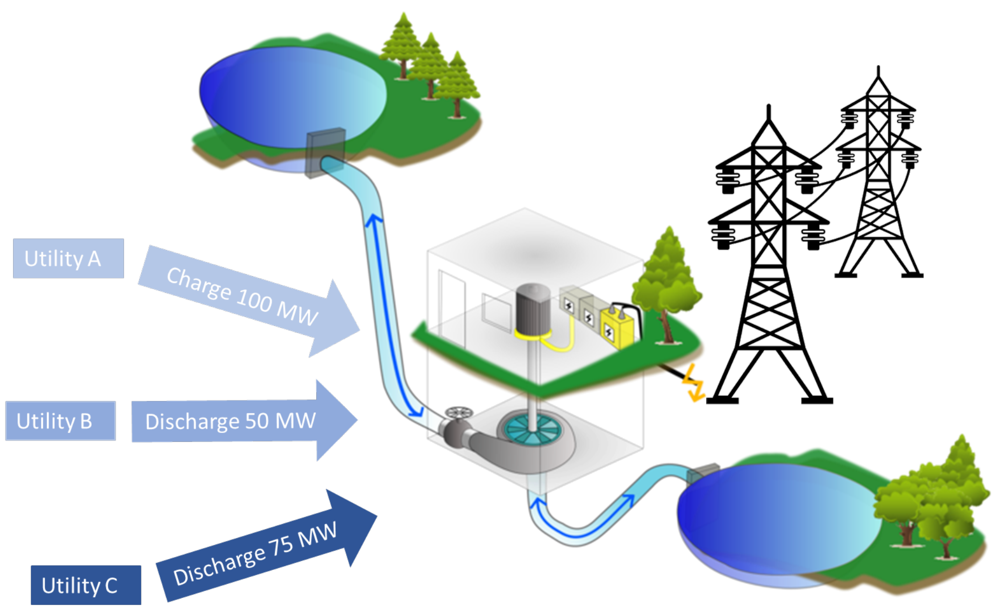

Figure 13. Miniature market hub.

Each co-owner sends independent dispatch signals to the PSH facility based on its system needs. The PSH operator nets out the different dispatch signals, resulting in Utility A's excess 100 MW flowing to Utilities B and C, and the PSH discharging 25 MW to satisfy Utility C's signal.

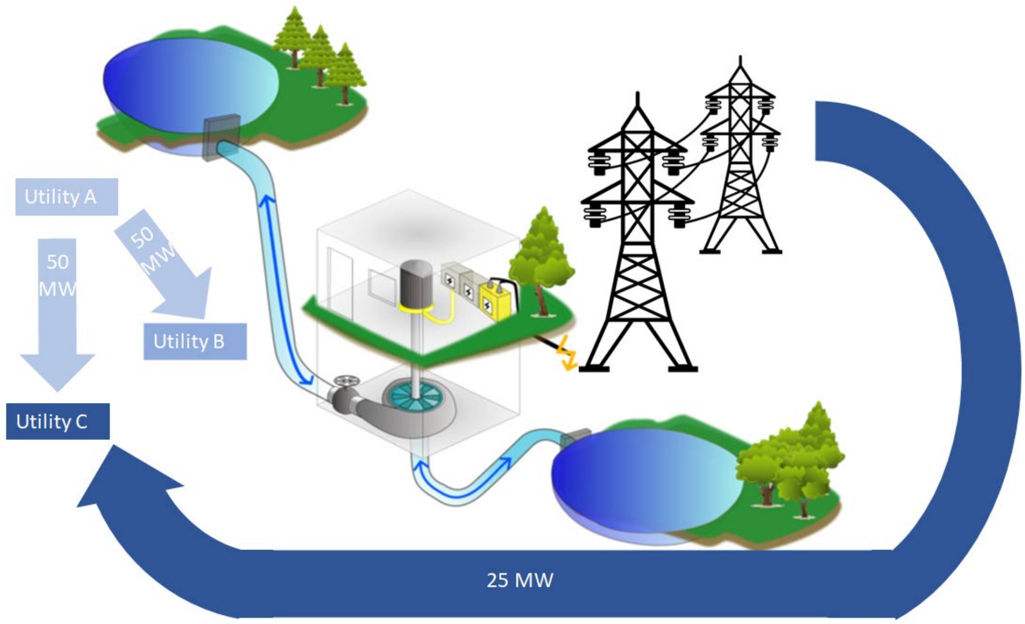

Figure 14. Example operational scheme for a PSH facility with multiple owners.

In practice, the miniature market hub model would require contractual arrangements to prevent free ridership and ensure equitable usage of the facility. Given that reliability would be the primary value to participating utilities, they would need assurance that stored energy would be available when needed. Whether contractual arrangements allow for trades between participating utilities or establish an operational schedule for charging and discharging the asset, and the duties of the participating utilities to provide or take the energy pursuant that cycle, those arrangements would be crucial to the successful operation of a jointly owned PSH facility in vertically integrated territory (Figure 14).

5.0 Conclusions

This paper investigates (1) the need for LDES, (2) recent trends in the market for energy storage deployments, contracts, policies, and regulations, (3) ownership structures that may emerge for long-duration storage assets, and (4) compensation mechanisms that may be needed to enable its deployment.

Although there is wider and wider agreement across the electric industry that long-duration storage resources will be a critical component of a future clean power system, there has been little to no change in the electric market or regulatory structures that might incentivize their deployment. Energy arbitrage has been the primary value stream for energy storage resources, but those opportunities are likely to shrink in the future because of increasing penetration of renewables. The arbitrage opportunities, even if they persist, do not present the right incentives for LDES because they are typically limited to differences in diurnal energy prices. Storing energy for longer durations will require creation of new incentive mechanisms, both market-based and regulated. CAISO, for instance, is in the process of refining resource adequacy requirements to account for long-duration stored energy. There are emerging examples from countries, such as Israel, of guaranteed payment for a certain amount of available (stored) energy. Such mechanisms also ensure that the developers have an assured long-term revenue stream, which is not dependent on energy generation but instead on stored energy. Plagued by chronic volatility in energy supply, the Colombian power system now operates a capacity market that compensates resources based on long-term availability. This ensures that sufficient capacity is installed as opposed to just meeting peak load.

Although related to compensation structures, the high capital costs of LDES assets may warrant alternative ownership and management structures than those for conventional generation assets. Unlike conventional assets, management of a jointly owned energy storage asset will be a more complex undertaking because the state of charge (charge/discharge cycles) will need to be managed to meet the requirements of multiple owners. Management of such an asset may not be too unlike the transmission system, and hence may give rise to a new entity class of storage owners. A third-party ownership model of energy storage could lead to alternative business and revenue models, such as subscription/lease options for various durations of energy storage. These options will give utilities flexibility to customize energy storage portfolios to best match their needs. Future work in this area will entail an in-depth analysis of best practices from other industries, such as warehousing and the storage of goods, and their application to the power sector.

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