

# LARGE-SCALE ENERGY STORAGE - ORIGINAL RESEARCH



## Long-duration energy storage in a decarbonized future: Policy gaps, needs, and opportunities

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### ABSTRACT

*The future U.S. electric grid is being transformed with deep decarbonization of generation (i.e., removing or reducing reliance on fossil fuels and replacing them with renewable and clean energy resources), which in practice is not achievable without a dramatic increase in the reliance on long-duration energy storage (LDES) technologies. Regulators at both the state and federal level are well advised to take steps to address current policy gaps, build frameworks that will enable a greater role for LDES to contribute to grid reliability and be fairly compensated for its grid services..*

Decarbonization by definition is dependent on an increasing reliance on variable renewable energy, primarily wind and solar resources, that needs to be stored for longer durations to maintain electric grid reliability and provide operational flexibility to grid operators. However, despite the growing realization of the need for long-duration energy storage (LDES) technologies, a persistent gap of policy levers at the federal and state level creates a vacuum in terms of defining how and where LDES technologies can be utilized to support the electric grid, along with an inadequate regulatory framework wherein these resources will need to be valued and compensated for the services they can provide. This paper—which is primarily intended for US decision makers, but should be of value for all energy professionals and the general public—addresses policy gaps, needs, and opportunities for LDES that require urgent attention from US-based policymakers at the federal and state level. This paper also provides background information on how the US E&U industry is structured and regulated, along with perspectives on LDES technologies and applications, all of which have direct relevance to the paper's primary focus on the need for LDES policymaking.

**Keywords** government policy and funding · storage · renewable · economics · energy generation · environmental impact

### Discussion

- Despite a generally accepted future need for long-duration energy storage (LDES) technologies that is directly tied to the rapid of renewable resources on the U.S. electric grid, there is a lack of policymaking, market designs, and compensation mechanisms for LDES technologies. Decarbonization (i.e., the goal of removing or reducing reliance on fossil fuels) cannot be achieved at the aggressive levels envisioned without utilizing LDES. Policymak-

ers must take steps now to build frameworks that recognize the unique ways in which LDES will increasingly contribute to grid reliability and resilience, and receive appropriate compensation for the services it provides.

## Introduction

For the deep decarbonization that is envisioned for the US electricity system, it is generally anticipated that we will need to deploy large amounts of long-duration energy storage (LDES), generally defined as technologies capable of storing power in durations measured by hours, days, weeks, and seasons. While not universally adopted across US policy frameworks as of yet, increasingly LDES is measured by durational threshold values (e.g.,  $> 4$  h,  $\geq 8$  h,  $\geq 10$  h), in what is frequently referred to as diurnal LDES and multi-day or seasonal durations, which is often referred to as “beyond-diurnal LDES.”

This unprecedented need for large amounts of LDES is intrinsically tied to national and state objectives for decarbonization, which by definition is the process by which the energy and utilities (E&U) sector transitions away from fossil fuel electricity generation and to an electricity system that is primarily supported by the large-scale integration of variable renewable energy resources (VREs). LDES collocated with generation or placed on the transmission and distribution networks that comprise the electricity system can provide a number of grid services that will become increasingly important as the level of VREs increases. Such services include the following: smoothing the intermittency of VREs; time shifting (i.e., arbitrage) of solar and wind resources and reducing curtailments when these resources cannot be immediately used; supporting the incorporation of other integrated distributed energy resources (DERs), including the electrification of vehicle fleets; deferring transmission and distribution upgrades; and other services not presently defined. Diurnal LDES, particularly from lithium-ion batteries that provide  $> 4$  h of duration, is increasingly being used to support time shifting and arbitrage in a small number of US markets, while the need for “beyond-diurnal LDES” will likely increase in direct correlation to the influx on VREs on the electric grid.

While the current and envisioned grid services that LDES can provide are becoming better understood, the policy<sup>1</sup> and regulatory frameworks that will be necessary to support the tactical rapid deployment and integration of LDES are not presently in place. These frameworks will be necessary to deploy LDES at a scale that will be needed to support both the large-scale integration of VREs and the electrification of the transportation industry—two essential components of full decarbonization. This absence of policy frameworks holds true at both the federal and state levels across the US, thereby limiting opportunities for LDES to contribute in both wholesale and retail transactions, respectively.

Moreover, at this point in time, there is no consistent pathway that has been defined for decarbonization illustrated by federal and state policies that will steer the E&U industry in the right direction. In other words, there is an emerging industry consensus that both long-duration and seasonal energy storage will be required for the envisioned decarbonization transformation. In the absence of a sound policy framework, it will remain unlikely that developers within the E&U sector will be sufficiently incentivized and otherwise enabled to make the large-scale investments associated with deploying LDES at capacities needed to support deeper decarbonization and electrification.

The result is that, at present, there are significant uncertainties that are perpetuating these problematic policy gaps, especially around the economic aspects of LDES technologies. Except for pumped hydrostorage, most other LDES technologies under consideration are either new to utility operators or have not been deployed at sufficient scales to demonstrate their full economic potential. Moreover, at this time, the cost of grid energy storage systems, including battery energy storage systems, remains more expensive and often cost-prohibitive when compared to traditional fossil fuel resources or other low-carbon solutions (e.g., energy efficiency and carbon capture technologies). In the absence of a mandate to procure, develop, or otherwise invest in LDES, most electric utilities and project developers are understandably reluctant to make the substantial financial commitments that are needed to enable the use of ES technologies in general and LDES in particular for use as a flexible grid resource. Thus, the fundamental question becomes: What is the policy and regulatory framework that is needed to support bringing new LDES into the electric utility grid and support further maturation of these emerging technologies?

As is often the case with E&U policymaking, California has advanced the most in terms of estimating the amount of LDES that will be needed in that state over the next two decades. In a report commissioned by the California Public Utilities Commission (CPUC),<sup>2</sup> it was determined that meeting California’s interim goal of 60% renewable penetration by 2030 will require capacity additions of around 2 GW of LDES with the duration of at least ten hours, for California’s investor-owned utilities, which serve roughly 75% of the load in the state. If California were to adopt a more aggressive decarbonization timeline, the report estimates that the required additions of LDES by 2030 could be as high as 11 GW. Given California’s goal of reducing GHG emissions by 90% below 1990 levels by 2045, the study estimates that between 45 and 55 GW of LDES will be needed by that time. These are steep projections, particularly when considered against California’s procurement efforts to date, which, according to the data from the CPUC, includes approved procurements of more than 1,533.52 MW of new storage capacity to be built in the state, with 506 MW of this total currently operational.<sup>3</sup> So far, all of this has been, mostly 4 h, short-duration energy storage (SDES). A request for offers published by a coalition of eight Californian community choice aggregators, led by Silicon Valley Clean Energy (SVCE), represents the only public procurement effort to solicit LDES in the state that has been made public as of this writing.<sup>4</sup> This request for offer seeks 500 MW of LDES capacity with a minimum of 8 h of discharge duration that is able to come online by 2026 and pre-dates any efforts by regulated utilities in the state to also procure specific amounts of LDES. Policymakers in California are now actively working to define policies and incentive programs that will drive the development of an LDES marketplace over the next two decades in order to achieve what the CPUC has established as a critical need.

Nevertheless, even with all the recent deployments of battery energy storage systems (BESS), the energy capacity of

such storage in California is less than 2 GWh as of the end of 2020.<sup>1</sup> This represents a tiny fraction of the average needs for a single day on a 100% renewable grid. For example, the state uses 500GWh electricity in a typical winter day.<sup>5</sup> This shortfall provides a barometer that should cause tremendous concern among policymakers in other states that will soon need to follow California's lead and take steps to determine their own LDES requirements,

where California leads other states ultimately follow, either by choice or necessity. To make the point clearly, California has been used—and provides lessons to other states—as a modeling exercise to explore how ambitious decarbonization goals will in turn drive and necessitate the need for massive amounts of energy storage generally and LDES in particular. This is especially true as we evaluate individual state decarbonization goals and the associated, by largely undefined, need for LDES. As will be further discussed in this paper, there are now 14 US states that have adopted 100% clean energy or renewable energy goals with very aggressive deadlines. However, despite having publicly adopted full decarbonization goals, none of these states has clearly outlined an LDES policy or incentive program, or taken steps to model the amount of LDES that will be needed to achieve their goal.

To be clear, California may be an obvious example for discussion purposes, but policy gaps persist in both federal and state markets across the US. These policy gaps are arguably rooted in a fundamental lack of consensus regarding the answers to several key questions about LDES that need to be answered regardless of the state or jurisdiction in question:

- What is the problem that LDES needs to solve?
- How can LDES be cost competitive and fairly compensated when compared to alternatives?
- What will remain as cost-competitive alternatives to LDES?

Without policy reform that addresses these specific questions, the challenges facing LDES that result in uncertainties about its role in supporting future grid needs can create “policy paralysis” that in turn will delay the development of the regulatory rules that are needed to enable LDES implementation in the marketplace. This paper examines the policy gaps, needs, and opportunities with a focus on issues specific to the US electric utility operations. However, as LDES is new to most grid operators, the policy issues and gaps presented are applicable to most electricity markets around the world. We hope the analysis presented in this paper will crystallize the need for, and help to shape the development of, an equitable policy and regulatory framework for the development and rapid integration of LDES in the electric grid infrastructure.

<sup>1</sup> 919.4 MWh from utility-scale batteries per 2020 release of EIA Form 860 data (<https://www.eia.gov/electricity/data/eia860/>) and 851.2 MWh behind-the-meter batteries per data from the SGIP program. (<https://www.selfgenca.com/>).

## Anatomy of the US electric grid

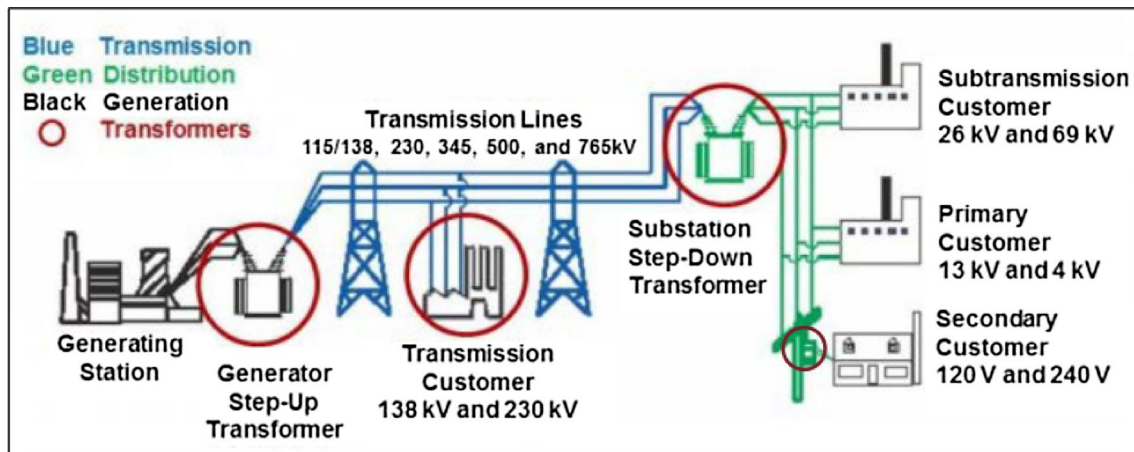
Before a deeper discussion of LDES can occur, it is important to understand how the US electric grid is built, if for no other reason than to fully appreciate<sup>6</sup> the complexities that large-scale integration of VREs and transportation electrification will face. End-use customers may be aware of how their power is delivered through distribution lines but have less understanding of the other components that comprise a distribution network, such as transformers that connect primary and secondary distribution voltages or local wiring between high-voltage electrical substations. The size of the distribution network is largely determined by the maximum power that is needed by consumers served by that network.

The distribution network is distinct from, but integrated with, a transmission network. The distribution network receives power from generating stations across transmission lines, which are necessary to move large amounts of power to distribution networks. Electric power transmission is the bulk movement of electrical energy from a generating site, such as a power plant, to an electrical substation. The interconnected lines which facilitate this movement are known as a transmission network. The combined transmission and distribution network are referred to as the electrical grid, which is locally designed to provide enough power to each consumer to meet their historical loads. Figure 1 provides a high-level perspective of the historic structure of the US electrical grid.

In the United States, the grid is comprised of inter-state transmission lines and is divided into three geographic areas: the Western Interconnect, Eastern Interconnect, and the Texas Interconnect (Fig. 2).

Transmission lines are denser near population centers. The three interconnects are weakly joined through high-voltage DC (HVDC) links that provide minimal redundancy. The longer the transmission line, the higher the cost of delivering power. Therefore, generation historically has been built near pockets of load, with the exception of nuclear and hydropower. Nuclear power plants need to be sited away from population centers and in areas that are geologically stable. Hydropower can only be sited where artificial water basins can be built, thereby considerably limiting geographical locations.

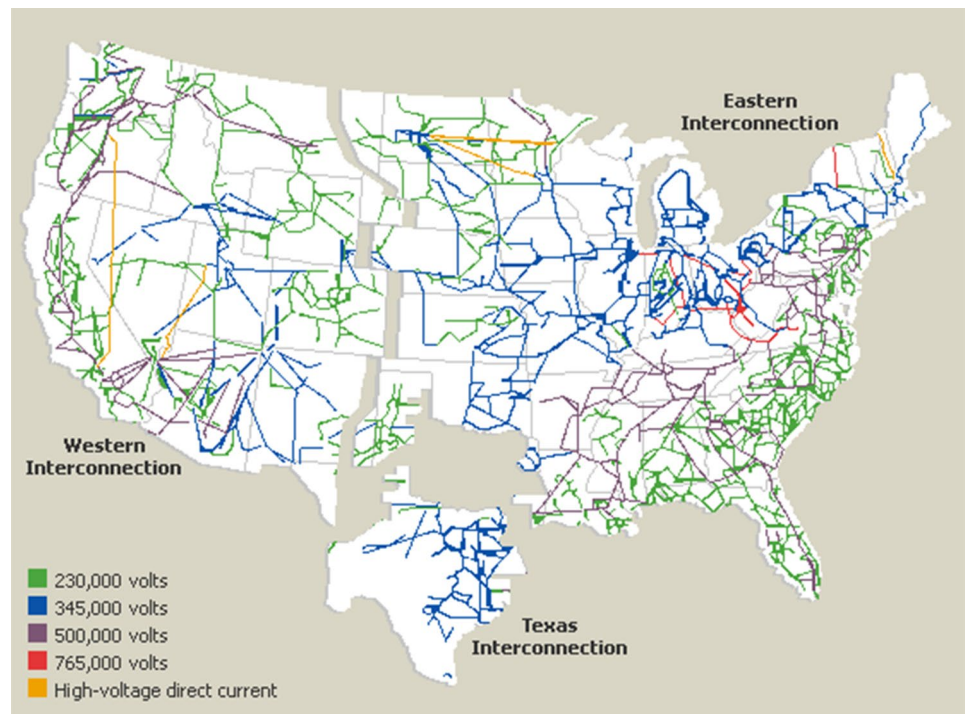
In the late 1990s, a large percentage of the US electricity market embarked on a process known as restructuring, which was intended to dismantle the long-standing monopoly structure of the E&U sector and create competition in generation sales in both retail and wholesale markets. Under federal regulations issued by the Federal Energy Regulatory Commission (FERC) (Orders 888 and 889), the concept of an Independent System Operator was formulated as one way for then-existing power pools to satisfy the requirement of providing non-discriminatory access to transmission transactions. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations (RTOs) to administer the transmission grid on a regional basis throughout North America.<sup>7</sup> Some regions of the US have not been restructured, such as Texas in which transmission lines do not cross into



Source: U.S. Federal Energy Regulatory Commission and U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

Figure 1. Structure of the electric grid.

**Figure 2.** Major US transmission lines in the continental US. (Source: North American Electric Reliability Council, Atlanta, GA, 2020).



another state and therefore do not trigger federal oversight by FERC. Other areas such as the Southeast US have opted out of restructuring and chosen to remain in a vertically integrated market structure. Figure 3 illustrates how ISOs and RTOs have been created across the US.

Distinctions between federal and state regulatory jurisdiction are germane to the discussion of both VREs and LDES. Generally speaking, the federal government, primarily FERC, has jurisdiction over the rules governing wholesale markets and transmission lines, while state utility commissions have jurisdiction over the operations of distribution networks, retail market transactions, and utility rates.

As this paper delves further into the need for a policy and regulatory framework specific to LDES, the roles of federal and state policymakers will be further discussed. However, at this point, it is important to simply establish the fact that the E&U sector within the US is far from homogenous. In fact, it is comprised of regions with very different regulatory approaches and needs and distinctions are made between “vertically integrated” markets (also known as regulated markets) and restructured markets. This will also become quite relevant as policy needs for LDES are further examined. Figure 4 illustrates how restructuring efforts across the US create a patchwork of dissimilar marketplaces.



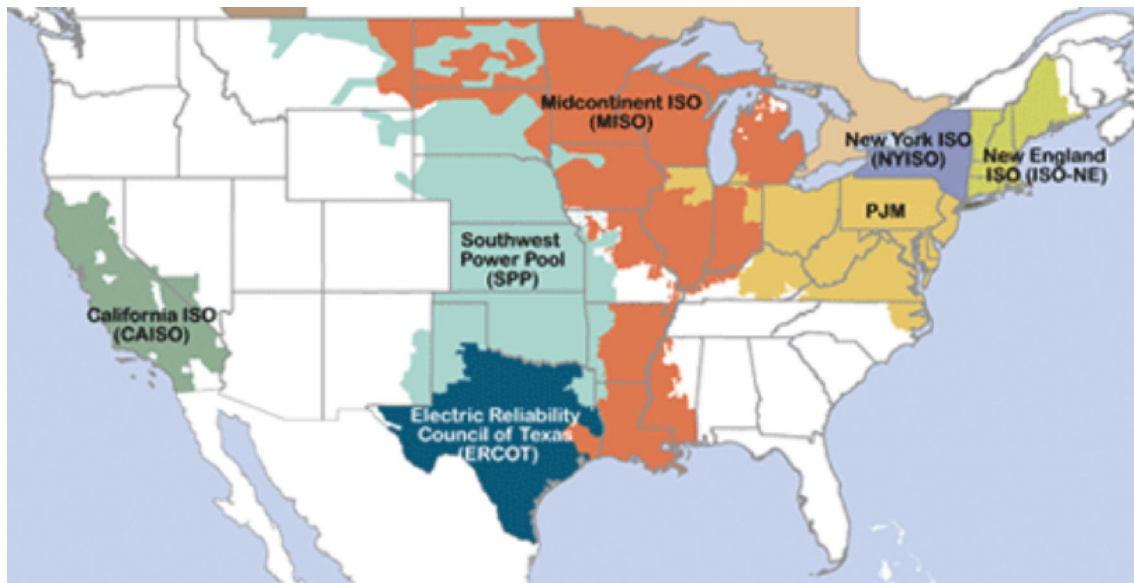


Figure 3. ISOs/RTOs in the US (Source: Federal Energy Regulatory Commission).

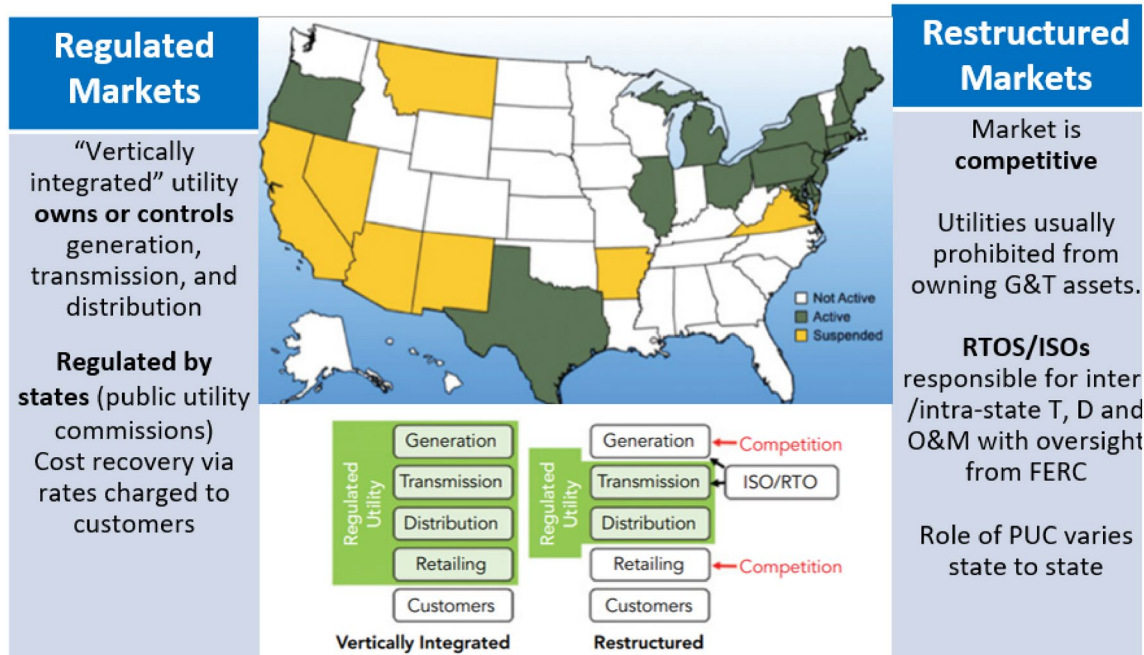




Figure 4. Status of US electric restructuring by state.

Figure 4 provides a high-level and rather simplistic view of how US electric markets are organized. The regulatory oversight roles and responsibilities of the federal and state governments have continued to evolve as a result of electric restructuring, and distinctions between the jurisdictional role of federal and state regulators are not always clear. For instance, vertically integrated utilities are predominant in the RTO markets of MISO and SPP, and thus state regulators play a primary role in those regions. In

addition, even in regions where there is not an established RTO or ISO, FERC still has domain over transactions such as setting transmission rates. And of course, there are exceptions regarding FERC’s involvement in regulating RTOs/ISOs—for example, Texas is not subject to FERC regulation since its transmission lines do not extend beyond state boundaries. These exceptions notwithstanding, there are defined roles for policy makers that can potentially impact LDES as shown in Table 1.

**Table 1.** The roles of US Federal and State Governments in regulating the E&U sector.

 <b>U.S. Federal Government</b> <i>FERC, Congress, and presidential orders</i>	 <b>State Governments</b> <i>Public utility commissions (PUCs), state legislatures, and executive directives from governors</i>
Rules governing wholesale markets/RTOs (FERC) <hr/> Rules governing transmission lines (FERC) <hr/> Tariff design for wholesale transactions (proposed by RTOs/ISOs and approved by FERC) <hr/> Goals for decarbonization and/or renewables development can be set by either by Congress or through a presidential order	Retail markets (regulated by PUCs) <hr/> Operations of distribution networks (Utilities with oversight from PUCs) <hr/> Utility rates (proposed by utilities; approved by PUCs) <hr/> Integrated resource plans (proposed by utilities; approved by PUCs) <hr/> Other enabling policies and/or mandates for renewables and decarbonization can be set by state legislatures or executive directives from governors

## The evolution of US fuel sources

Throughout the twentieth century and into the early years of the twenty-first century, most of the energy used in the US has come from coal, oil, and natural gas. In 2018, those “fossil fuels” fed about 80% of the nation’s energy demand, down slightly from 84% a decade earlier.<sup>8</sup> Over the last 50 years, the configuration of the electric grid in this country has standardized around established technologies and practices. In the US, in 2020, electricity generation has depended primarily on carbon-emitting sources like coal (~ 20%), and natural gas (~ 40%).<sup>9</sup> Low-carbon sources, like nuclear (20%), and hydropower (7%) historically have accounted for <30% of the total generation mix transmitted across the electric grid. In 2020, Wind and solar generation sources accounted for about 10% of all the energy used in the US.<sup>10</sup>

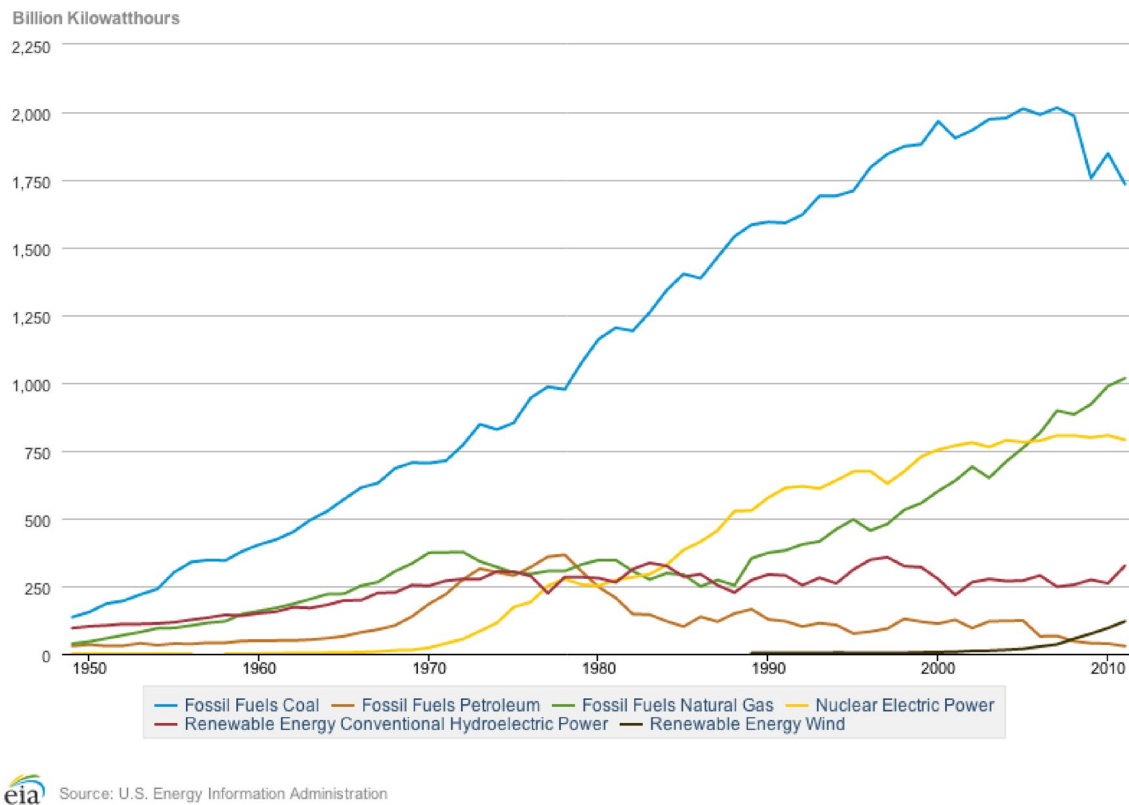
As shown in Fig. 5, coal has primarily supported the growth of the electric generation in the United States since the 1950s. Nuclear and natural gas have followed coal in supporting US electric operations and, in fact, generation sourced from natural gas has increased steadily since the late 1980s and has emerged as the only other generation resource that has rivaled coal in terms of prominence for electricity generation. Nuclear power generation has remained fairly constant since the 1990s, but has reached a plateau.

The fuel for carbon-emitting generation sources is easy to transport, use, and store. The electric grid relies on these attributes, and therefore has relied on fossil fuel resources, to provide reliable and inexpensive electricity. As of December 31, 2020, there were 22,731 electric generators at about 10,346 utility-scale electric power plants in the United States.<sup>11</sup> Utility-scale

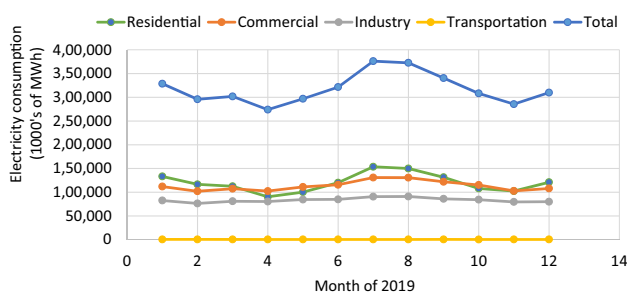
power plants have a total nameplate electricity generation capacity of at least 1 megawatt (MW). In addition, there are more than 1,000 fossil fuel peaker plants operating across the US today, and the vast majority of those existing peaker plants have relied on fossil fuel resources.<sup>7</sup> Also directly relevant to this discussion of LDES is the fact that power consumption in the US is not uniform throughout the year. Power consumption increases, not surprisingly, in the summer and winter months with the increased use of cooling and heating systems. Figure 6 shows the electricity consumption as a function of the month of the year for the year 2019 in various sectors.

The US electric system peaks in the summer months due to air-conditioning loads and in the winter months, due to heating loads. Therefore, the national generation fleet that is required to maintain reliability across the US electric grid includes a certain amount of additional capacity (known as peaker plants) that is used for a limited number of hours each year. Peaker plants historically have been operated by fossil fuel resources such as coal or natural gas, and the replacement of these units will become a critical step in the pathway toward decarbonization across the country. The correlation between the challenge of replacing existing peaker plants and achieving established decarbonization goals is discussed in greater detail later in this paper.

Of the anticipated increase in electricity demand that is projected (38,700 terawatt-hours by 2050 on a global scale),<sup>12</sup> renewables are expected to provide 50% of that energy.<sup>13</sup> Thus, the historic and current data regarding the nation’s energy resource mix do not reflect what the grid of the future will entail. This is due to several factors that are simultaneously developing in real time. First, solar and wind farms have dominated new power plant builds in the US in recent years. In 2019, wind (9.1



**Figure 5.** Generation resources of US electricity generation (Source: US Energy Information Administration, 2021).



**Figure 6.** Consumption of electricity by various sectors in 2019 (Source: US Energy Information Administration 2021 Annual Energy Outlook).<sup>7</sup>

GW) and solar (5.3 GW) represented 62% of all new generating capacity, according to the EIA, which also projected that most new electric generated post-2020 would come from wind and solar.<sup>14</sup>

This increase of VREs is also occurring in parallel with a dramatic reduction in traditional fossil fuel resources, which is a second barometer of factors shaping the grid of the future. Of the new electric generation added in 2020, EIA data indicate that new natural gas plants represented less than a quarter of new generating capacity, while 14 GW of coal-fired capacity was retired.<sup>15</sup> A June 2021 report focused on coal-fired power plant retirements in the US estimated that three-quarters of existing coal-fired electricity generators in the US will be retired in the

next 20 years, most of them in the next five years, with little opportunity for policy action to alter this course and outcome.

The third indicator of how different the electric grid of the future will operate can be found in the aforementioned 100% clean energy or renewable goals that have been established. In April 2021, President Biden announced a new target for the US to achieve a 50–52% reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030, along with a pledge of powering the country with 100% clean electricity by 2035.<sup>16</sup> This builds upon the momentum that has commenced at the individual state level, wherein 15 states have established either 100% clean energy or 100% renewables goals. As previously mentioned, the distinction between these two is that “clean energy” includes non-renewable fuels such as nuclear power, whereas the term “renewables” is more restrictive and primarily consists of solar, wind, geothermal, biomass, and hydropower.

At a high level, some of the apparent challenges that these states face become self-evident. New Jersey and New York, for example, have set ambitious renewable energy production and storage targets for the coming decade, yet two-thirds of peaker plants in New Jersey and one-third in New York continue to operate,<sup>17</sup> which produces high rates of pollution per unit of electricity generated. By comparison, the Southwestern states that have adopted clean energy goals (Arizona and New Mexico) are home to peaker units (some still quite young, as is the case in New Mexico) that are often operated as baseload resources, and

yet both states have little to no existing policy support for energy storage development and deployment that could ultimately be used to replace these units.

## Decarbonization, the future electric grid, and VREs

Between 1990 and 2009, energy-related emissions of carbon dioxide (CO<sub>2</sub>), the primary greenhouse gas emitted through human activity, grew in the US by an average 1.0% per year.<sup>18</sup> Between 2007 and 2020, energy-related CO<sub>2</sub> emissions have declined by an average of 2.1% per year.<sup>19</sup> The magnitude of this trend is largely driven by precipitous drops in emissions in 2009 and 2020 result from economic recessions; during the years 2009 to 2019, the pace of decline was on the order of 0.5% per year. That said, the emission reduction in 2009 was ultimately sustained over the course of the economic recovery from the Great Financial Crisis.

The recent pace of emissions reduction is too slow for the United States to meet the interim emissions reduction target of 45% relative to 2010 levels by 2030, as recommended by the Intergovernmental Panel on Climate Change (IPCC) to limit global temperature rise to 1.5 °C.<sup>20</sup> Even if emissions continued to decline at a rate of 2.1% for the entirety of the 2020s (unlikely given the strong economic recovery in 2021), annual US energy-related CO<sub>2</sub> emissions would only fall by 36% relative to their 2010 levels. Furthermore, the IPCC's recommendation of net-zero emissions by 2050 is far out of reach for the US electricity sector. The US Energy Information Administration's (EIA) 2021 Annual Energy Outlook projects that zero-emission sources of electricity will only constitute 53% of US electricity generation in 2050, based on currently enacted policies, trends in technology costs, and forecasted fuel prices.<sup>21</sup>

Thus, policy measures to address climate change in the US are built upon a presumption that sustained reductions in CO<sub>2</sub> emissions and other greenhouse gases would limit climate change, if immediate action is taken by policymakers that regulate the E&U industry. Accordingly, an objective to decarbonize the US economy and eliminate the emission of conventional pollutants, both by transitioning power generation to low- or zero-emission sources and by making much greater use of decarbonized electricity as a substitute for fossil fuels in transportation, buildings, and industry, now permeates and features prominently in energy policy discussions at both the federal and individual state levels.

The conundrum is that, more often than not, the objective of decarbonization that is publicly adopted remains frustratingly broad and theoretical and lacking in specifics on the tactical steps that will be taken to ensure that the objective will be achieved. The lack of specificity in climate commitments may in fact be a symptom of a deeper problem: political differences that perpetuate barriers to the enactment of binding climate policies that would result in aggressive emission reductions. Decarbonization will require transformational change that is demonstrated by using a wide range of innovative solutions supporting a dramatic increase in the use of VRE resources.

Generally speaking, VREs—also known as intermittent renewable energy sources—are renewable energy sources that are not dispatchable due to their fluctuating nature, such as wind and solar power. VREs that are highlighted in decarbonization objectives often receive the most attention as they sound promising in a bold-type headline—for example, the Biden administration's goal of powering the country with 100% clean electricity by 2035, and the 14 states that have set targets for similar goals of 100-percent clean energy or 100-percent renewables. (The distinction between clean energy and renewable energy, which is not always clear to the general public, is that the former is more encompassing and allows the inclusion of nuclear power, whereas the latter primarily consists of wind and solar.) Table 2 summarizes the actions that, as of this writing, have been taken by the 14 states that have adopted decarbonization goals with their associated deadlines.

The announcements of these state targets have made for good public relations. However, upon deeper examination, it becomes less clear exactly how these states will actually reach these goals, or the role that LDES will need to play, when the existing mix of resources currently in existence and the aggressive transformation timelines that have been established are evaluated. The challenge of achieving a state's decarbonization goal will often-times fall upon regulated utilities that have the regulatory obligation to procure resources, and while a state may have adopted an aggressive decarbonization goal, it may not be correlated with utility procurement plans. Thus, without references to specific modeling exercises that have been conducted, typically within utility integrated resource plans (IRPs) that identify needed resources 20 to 30 years in future, or any requirement to confirm within those plans the projected amount of LDES that will be needed it is arguable that these goals are more speculative (i.e., theoretical) than actionable or achievable. California is an exception to this, and as of this writing, it remains the only state that conducted extensive modeling to determine the specific amount of LDES that will be needed for the state to achieve its target of eliminating greenhouse gas emissions from its electricity sector by 2045.















For other states, in the absence of sanctioned modeling available for public review, there are several prisms through which we can analyze the practicalities of reaching these decarbonization goals:

- (1) The state's current percentage of non-renewable resources in its total resource mix (2020);
- (2) Current number of peaker units in operation;
- (3) Current percentage of solar, wind and hydro in its total resource mix (2020);
- (4) Established renewables goals; and
- (5) Whether or not the state has a procurement mandate for energy storage in place.

Table 3 illustrates the challenges facing those 14 states that have adopted decarbonization due to the respective issues



**Table 2.** US decarbonization goals at the state level.

Decarbonization Goals at the State Level			
	RENEWABLE ENERGY	CLEAN ENERGY	
			R REGULATORY ORDER L LEGISLATION
	TYPE OF 100-PERCENT TARGET	YEAR	ORIGIN
ARIZONA		2070	R
CALIFORNIA		2045	L
COLORADO		2050	L
CONNECTICUT		2040	R
HAWAII		2045	L
MAINE		2050	L
NEVADA		2050	L
NEW JERSEY		2050	R
NEW MEXICO		2045	L
NEW YORK		2040	L
RHODE ISLAND		2030	R
VIRGINIA		2045	L
WASHINGTON		2045	L
WISCONSIN		2050	R

related to transitioning from a fossil fuel dominant to a renewables-dominant energy mix; replacing a large existing number of peaker plants fueled by fossil resources; and the extent to which ES technologies have been mandated in the state.

Analyzing these 14 states against the five criteria listed in Table 2 suggests a herculean effort facing those states that have publicly committed to decarbonization when compared to a baseline of current dynamics. The amount of fossil fuel based generation, either in existing baseline or peaker units, that will need to be replaced plus the associated replacement of these resources with VREs to ensure grid stability simply will not occur without policymaking that includes a suite of mandate, incentives and other means of financial support.

The inclusion of peaker plants among these prisms is critical because peaker plants, which historically have been fueled with natural gas and oil resources, are typically used in conjunction with baseload plants and are dispatched infrequently during periods when energy demand runs unusually high, or “peaks.” Peak demand profiles and peaker plant characteristics can vary from state-to-state based on electric loads, geographical locations, community needs, and differing state regulations for air quality and plant emissions.

However, because peaker plants supply energy only occasionally, they are less efficient and typically release greater amounts

of emissions per kWh of energy generated when compared to their baseload counterparts. Moreover, peaker units often have been located in disadvantaged or low-income communities, which has raised many concerns about environmental justice and energy equity with calls to retire these units and replace them with VRE alternatives. From a national perspective, as of 2021 more than 1,000 fossil fuel peaker plants remain in operation across the US.<sup>23</sup>

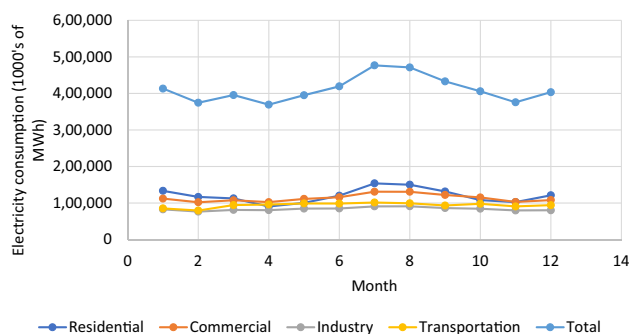
The decarbonization of the vehicle fleet will also put additional loads on the electric grid – again causing the need for generation to increase. Assuming an average value of \$0.35 kWh/miles, and a monthly average of 290,000 million miles driven, a complete electrification of the transportation fleet will significantly increase electricity consumption, as show in Fig. 7.<sup>24</sup>

As of this writing, the current levels of VRE penetration across the US electrical grid have not posed significant operational concerns, primarily because they continue to play a comparatively small role in the nation’s overall resource mix by supplementing, rather than replacing, traditional fossil fuel resources. However, the situation will change as the percentage of VREs will increase.

It is true that other strategies in addition to VREs will also need to be considered to achieve full decarbonization, namely load shifting, conventional generating capacity with carbon capture, energy efficiency measures, and new transmission line

**Table 3.** Comparative data for states with 100% clean energy or 100% renewables goals.<sup>22</sup>

State and Target	Current Percentage of Non-Renewables in Energy Mix	Current Number of Peaker Units in Operation	Current Percentage of Solar, Wind & Hydro	Renewables Goal	Procurement Mandate for Energy Storage
<b>ARIZONA</b> Target: 100% clean energy by 2070	Coal, 12.5% Natural gas, 46.4% Nuclear, 28.3%	17	Solar, 5.5% Wind, 0.6% Hydro, 5.9%	No	No
<b>CALIFORNIA</b> Target: 100% clean energy by 2045	Coal, 0.1% Natural gas, 48.1% Nuclear, 8.4%	80	Solar, 15.7% Wind, 7% Hydro, 11%	<b>100%</b> by 2045	Yes; 1,825 MW by 2020
<b>COLORADO</b> Target: 100% clean energy by 2050	Coal, 35.9% Natural gas, 34% Nuclear, 0%	N/A	Solar, 2.8% Wind, 23.5% Hydro, 3.3%	<b>100%</b> by 2050	No
<b>CONNECTICUT</b> Target: 100% clean energy by 2040	Coal, 0% Natural gas, 57% Nuclear, 38.2%	N/A	Solar, 2.8% Wind, 23.5% Hydro, 3.3%	<b>44%</b> by 2030	A target, but not a mandate, for on 300MW by year's end 2024, 1 GW by 2030
<b>HAWAII</b> Target: 100% renewable energy by 2045	Coal, 12.5% Natural gas, 0% Nuclear, 0%	N/A	Solar, 5.7% Wind, 6.2% Hydro, 1.0%	No	No
<b>MAINE</b> Target: 100% renewable energy by 2050	Coal, 0.5% Natural gas, 16.9% Nuclear, 0%	4	Solar, 0.3% Wind, 24% Hydro, 34.4%	<b>100%</b> by 2050	A target, not a mandate, for 300 MW of storage capacity by the end of 2025, 400 MW through 2030, after which new goals will be re-evaluated every two years
<b>NEVADA</b> Target: 100% clean energy by 2050	Coal, 4.3% Natural gas, 66.1% Nuclear, 0%	5	Solar, 13.0% Wind, 0.8% Hydro, 4.8%	<b>100%</b> by 2050	A goal, not a mandate 1 GW by 2030
<b>NEW JERSEY</b> Target: 100% clean energy by 2050	Coal, 4.3% Natural gas, 50.3% Nuclear, 43.5%	15	Solar, 2.6% Wind, 0% Hydro, (0.2)%	<b>50%</b> by 2030	Yes; 2,000 MW by 2030
<b>NEW MEXICO</b> Target: 100% clean energy by 2045	Coal, 37.2% Natural gas, 35.7% Nuclear, 43.5%	11	Solar, 4.9% Wind, 20.9% Hydro, 0.5%	<b>100%</b> by 2045	No
<b>NEW YORK</b> Target: 100% clean energy by 2040	Coal, 0.1% Natural gas, 40.1% Nuclear, 29.1%	49	Solar, 0.8% Wind, 3.8% Hydro, 0%	<b>70%</b> by 2030	Yes; 3,000 MW by 2030; interim goal of 1,500 MW by 2025
<b>RHODE ISLAND</b> Target: 100% renewable energy by 2030	Coal, 0% Natural gas, 91.8% Nuclear, 0%	N/A	Solar, 2.6% Wind, 2.9% Hydro, 0%	No	No
<b>VIRGINIA</b> Target: 100% clean energy by 2045	Coal, 3.7% Natural gas, 60.7% Nuclear, 29.5%	N/A	Solar, 1.4% Wind, 0% Hydro, 0.5%	<b>100%</b> by 2050	Yes
<b>WASHINGTON</b> Target: 100% clean energy by 2045	Coal, 4.5% Natural gas, 12.4% Nuclear, 8.3%	N/A	Solar, 0% Wind, 7.3% Hydro, 66.1%	<b>10%</b> by 2045	No
<b>WISCONSIN</b> Target: 100% clean energy by 2050	Coal, 39.0% Natural gas, 34.3% Nuclear, 16%	4	Solar, 0.2% Wind, 2.9% Hydro, 4.7%	No	No



**Figure 7.** Electricity consumption by sectors assuming that 100% of the transportation fleet in 2019 was electrified (Source: US Energy Information Administration, 2021).

construction. However, the pursuit of these alternative solutions does not remove the anticipated challenges that large-scale integration of VREs will create, for which LDES is uniquely qualified to address.

### Increased VREs will create new grid challenges

In an E&U industry in which VREs play a minor role, as is the case today, LDES is not a primary concern of grid operators and planners. However, as the penetration of VREs increases incrementally and ultimately exceeds levels of greater than 50%, this will dramatically change grid operations and require significantly different profiles for demand and supply.

At its most basic level, variations in the weather and consumption that will underline an increased penetration of VREs will necessitate the need for ever-greater durations to store energy several days, weeks, months, etc. This in essence is the core role that LDES will play in the grid of the future, because LDES resources by definition will be capable of storing large quantities of electricity generated when supply exceeds demand, and deliver it later, over the course of longer timelines. LDES will enable managing the grid on par with how it functions today (matching demand with supply in real time) even when VRE systems run below their normal output for extended periods. The utilization of LDES technologies that can be called upon to store energy for multiple days, weeks, and seasons will be a critical need to maintain grid stability.

In addition, decarbonization requirements will very likely lead to over-capacity scenarios. In other words, it is likely that, in order to be able to meet average demand with VREs, more renewable capacity will be installed than is needed when demand is lower. This will lead to curtailment situations enforced by grid operators, often on an involuntary basis. Further, concerns about inflexibility capacity—instances where there may be a may be large inflexible plants on the grid, e.g., nuclear plants, that cannot be turned down to allow use of power from VREs when it's available—can also result in unanticipated curtailments.

All of these factors, when taken together, will create a myriad of new challenges not previously encountered by the E&U industry. In fact, the ambitious decarbonization goals discussed

throughout this paper represent a major overhaul from how VREs factor into the E&U industry stands today. As of year-end 2020, VREs accounted for about 12% of total US energy consumption and about 20% of electricity generation, according to the EIA.<sup>25</sup> As of this writing, the current levels of VRE penetration across the US electrical grid have not posed significant operational concerns, primarily because they continue to play a comparatively small role in the nation's overall resource mix by supplementing, rather than replacing, traditional fossil fuel resources. However, a commitment to decarbonization is obviously a game changer; as electric grids incrementally add large amounts of VREs and reach levels of 50-, 80-, or 100-percent penetration levels, the variability on the grids from those resources from the point of the supply as well as from demand induces creates a myriad of operational concerns.

According to a new report released in November 2021 by the LDES Council and McKinsey & Company, shifting to a power system that predominantly relies on VREs presents three key challenges,<sup>26</sup> as summarized in Table 4.

Valid concerns about the grid's ability to accept an unprecedented amount of VREs are top of mind for grid planners and operators who are simultaneously charged with maintaining grid stability and resiliency. The challenge of such a dramatic influx of VREs, particularly wind and solar, is rooted in the inherent intermittency of these resources, which in general has historically classified them as “non-dispatchable resources,” defined as a power sources that cannot be controlled by operators. In addition to daily and weekly fluctuations in solar and wind, there can be yearly or even multi-year fluctuations that result from the increased penetration of VREs. Along with other technological strategies, such as optimized solar configurations comprising advanced tracking systems and smart inverters, energy storage is generally seen as the solution to the non-dispatchability of VREs.

Some states (e.g., New Mexico<sup>28</sup>) are now requiring that regulated utilities consider energy storage in their integrated resource plans, and there are other examples of utilities that have voluntarily opted to take this step.<sup>29</sup> Planning for and implementing appropriate levels of long and very long-duration storage will require data resources, tools, and paradigms beyond today's state of the art. Better understanding of what load profiles will be under climate change and electrification, better knowledge of what the weather impacts of climate change will be and their impacts in turn on renewable energy production will be needed. Probabilistic approaches to long-term IRP that include co-optimization of long-term storage levels will be needed. And most importantly, policy makers will need to understand the cost-risk tradeoffs and how to obtain public buy-in for the measures needed to achieve energy security long term. Nevertheless, with the cost of VREs such as solar and wind resources going down rapidly, the role of distributed generation has become significantly more important in resource planning. And this is beginning to show in the long range planning forecasts for new generation capacity.

The US Department of Energy, Energy Information Administration 2021 Annual Energy Outlook indicates that forecasted capacity additions through 2050 are dominated by addition of

**Table 4.** System challenge created by a VRE-centric grid.<sup>27</sup>

System challenge	Explanation
Power supply and demand imbalances	By definition, the addition of renewables to the electricity mix creates imbalances in supply and demand, since the natural fluctuations in wind and solar do not match with fluctuations in power demand. Increased shares of geographically concentrated wind and solar in the generation mix will thus lead to more frequent periods of power surplus and shortage. As VREs become more common, the grid will need to become more flexible to develop the capacity to maintain the supply and demand balance. Compounding this challenge, the higher frequency of extreme weather events caused by climate change will also create more strain on a grid dominated by VREs
Changes in transmission flow patterns	An electric grid that is predominantly VRE concentrated will see a shift in geographical supply patterns and an alternation of transmission line power flows. These changes result from the increased deployment of decentralized VREs
Decrease in system inertia	Conventional generators (fossil fuels and nuclear) have played a crucial role in safeguarding the stability of the electricity system through their provision of inertia. In a system disturbance, the rotating machines connected to the grid help all generators remain synchronized by resisting a change in the frequency of the grid. If unrectified, stability faults can result in blackouts with high economic and societal costs. New technologies like solar and wind lack rotating masses directly connected to the grid and therefore cannot provide inherent system inertia. As a result, generation disturbances, frequency, and voltage deviations necessitate the installation of new stability resources

solar and wind resources, and the rapid retirement of generation fleets using coal.<sup>30</sup> Further, the retirement of the coal fleet is happening faster than anticipated. This is driven by the lower cost of bringing renewable generation capacity and also by policy changes intended to reduce reliance on fossil fuels. In fact, the percentage of coal dropped from 50% in 2007 to about 20% in 2020.<sup>31</sup>

From a macro level, the roll-out of VREs across the US electric grid has been uneven. Even in those electricity markets with significant VRE deployment, fossil fuels continue to provide most of the baseload and peaking capacity for those markets. Even as states have ambitious plans to move toward fossil-free electricity generation, the transition is likely to be slow and will require large new investments in generation capacity and infrastructure upgrades. For example, the transition to a decarbonized grid will require significant energy storage investments. These investments decisions are complicated as the previously made investments in an existing asset base (i.e., “the sunk cost”) is usually significant, and any early retirements have to be economically justified, especially in deregulated models.<sup>32</sup> Thus, major investment decisions for moving the resource mix to clean energy technologies including long-duration energy storage significant

policy support to make large project investments economically attractive.

Along with the significant integration of VREs that is the cornerstone of decarbonization, the electrification of the transportation sector, new distribution system upgrades, the increased integration of transmission and distribution planning, and the anticipated need for significant amounts of short-durations ES technologies altogether create an industry need for massive amounts of LDES that is unprecedented and will be operationally challenging.

## What problems can LDES address?

In order to fully appreciate the specific problems that LDES can address, it is first important to understand where other short-duration energy storage technologies have participated to date, and whereby they may become increasingly inadequate going forward.

The vast majority of this current new deployment has been comprised of short-duration lithium-ion batteries, typically



4 h or less in duration. In fact, in the last two decades, batteries have generally accounted for about 51.6% of new ES capacity added since 2000, and 41.4% of new capacity additions since 2010 were lithium-ion batteries, which had an average duration of four hours or less.<sup>33</sup> There are several reasons for this: the “grid-readiness” of lithium-ion batteries, the fact that lithium-ion batteries are available to meet short-term needs such as forecasted power outages, and the continuing price and performance improvements with Li-ion battery technologies. These factors have driven what is now a consensus within the E&U sector that short-duration storage (< 4 h duration) is now economically able to provide almost all market and utility services and, more specifically, short-duration ES technologies have been mostly adequate to accommodate current penetrations of VREs.

As a result of the proliferation of lithium-ion BESS, there has been a lot of progress in terms of developing the market uses for (short-duration) ES technologies within the E&U sector. As the increase of VREs has occurred slowly and not resulted in more than a minimal contribution to grid operations, the deployment of hundreds of megawatts of Li-ion BESS have been successfully used to time shift and firm the comparatively small amount of VREs on the grid. However, due to the inherent duration limitations that have been associated with lithium-ion batteries, they will likely be insufficient to support the envisioned, VRE-centric grid of the future.

There is also an established effort within federal policy discussions at the RTO/ISO level and within individual states to define what can be considered as the “multiple use applications, for energy storage, which speaks to the various, simultaneous uses for both short-duration ES technologies and, increasingly, LDES applications. Within this context, “market uses” are often referred to interchangeably as “applications.” There is now an abundance of policy within the E&U sector that defines the services that (short-duration) ES technologies can offer to both wholesale and retail markets, and these services have been organized into categories as follows:

- Bulk energy services (e.g., arbitrage, renewable energy smoothing, peak shaving)
- Ancillary services (e.g., frequency regulation, spinning/non-spinning reserves, voltage support, black start)
- Transmission infrastructure services (e.g., upgrade deferral, congestion relief)
- Distribution infrastructure services (e.g., upgrade deferral, voltage support)
- Customer energy management services (e.g., power quality, power reliability, retail electric energy time shift, demand charge management)

By comparison, up to this point developers have had difficulty locating a marketplace in which LDES can earn money. Until recently there was not a lot of focus on LDES because there has not been universal consensus within the E&U sector about the fundamental needs that LDES might serve and the requirements for defining its usage (i.e., essentially the “where, how, and why

questions”). The lack of consensus on an LDES definition results from a lack of agreement on what LDES technologies would, could, or should be required to do, which in turn perpetuates the absence of a well-established marketplace in which LDES can actively participate.

Unlike commodity markets for coal or natural gas, there is presently no comparable market that compensates LDES simply for existing, and the services that LDES can, should, and will provide remain largely undefined. In many ways, LDES has been restricted as a solution looking for a problem to solve, with anticipation that the problem will most definitely permeate the grid of the future. As a result, technologies have struggled to find a more prominent and defined role in initiatives focused on climate change mitigation, decarbonization, electrification, and the continued integration of VREs. This is a conundrum for the industry, because, in fact, perhaps the greatest challenge facing the anticipated increase of VREs on electric grids is the lack of availability of LDES technology solutions.

The previous sections of this paper have established what will be an undeniable future need for LDES that is directly correlated to the inevitable increase of VREs on the US electrical grid. Deep decarbonization of electricity production is a societal challenge that likely can only be achieved with sustained high penetrations of VREs (i.e., penetrations that of VREs that increase beyond 50-percent levels on any grid location). The challenges associated with VREs, primarily their inherent intermittency and resulting unreliability, are well documented.

Nevertheless, even while there may be great hope and numerous projections for future usage of LDES, a marketplace that correlates specific use-case applications and opportunities for LDES still needs to be developed in both retail and wholesale markets. At a high level, the role of LDES will likely continue on a growth trajectory that runs in parallel to the increasing percentage of electricity production that comes from VREs. For instance, the erratic fluctuations in power generated by an increase in variable renewable resources can be detrimental to maintaining transient and dynamic stability on a grid system. Power quality concerns generally associated with renewable energy sources include voltage transients, frequency deviation, and harmonics. If loads cannot be regulated, an LDES resource can be used to shift the load profile through “peak shaving” or “peak smoothing.” The LDES resource is charged while the electrical supply system is powering minimal load and the cost of electric usage is reduced, such as at night. It is then discharged to provide additional power during periods of increased loading, while costs for using electricity are increased.

Long-duration storage can help utilities smoothly integrate increasing amounts of renewables as they make progress toward decarbonizing the power grid. Some of the strongest utility use cases for LDES are:

- Time shifting solar and wind power: LDES can store excess renewables production and shift energy to when it has greater economic and resilience value. Storage also helps avoid curtailments to maximize the benefits of clean energy assets.

- **Smoothing renewable intermittency:** The fast-response capability of LDES enables it to instantly react to changes in renewable generation output with fast, unlimited charge-discharge capacity.
- **Augmenting or replacing high-emission peaker plants:** Fossil-powered peaker plants are the last-resort generators that utilities activate when grid energy demand is at its highest. LDES can enable a firm power source from intermittent renewables with the duration, capacity and cyclic flexibility to help utilities avoid (or at least mitigate) use of polluting peaker plants.
- **Supporting market participation:** LDES is also a multi-purpose asset that can provide frequency regulation and other ancillary services. As markets evolve, LDES can offer spinning reserve and even energy capacity.
- **Deferring transmission and distribution system upgrades:** LDES alleviates congestion on T&D routes by storing power when lines are at capacity and delivering it later. This service can defer or entirely avoid costly, long-term asset upgrades.
- **Stabilizing microgrids and supporting virtual power plants:** LDES boosts the reliability and flexibility of distributed energy resources, greatly reducing or eliminating reliance on diesel-powered generators for backup.

Despite these anticipated use cases that will likely gain momentum in the coming decade, LDES is still in the early stage of the product maturity curve and there are many economic and operational challenges that must be addressed if it is to play a key role in supporting the grid. The need and the role that LDES can play are mammoth; achieving deep decarbonization in the US alone will require days, and potentially weeks, of energy storage to be available. While LDES is commonly used as a catch-all label for energy storage solutions that offer a duration of greater than about 4 h, identifying key operational and application roles for LDES is frequently confounded by fundamental differences in the technology sets, the potential applications, and the value streams associated with technologies that could be classified as offering an LDES solution.

Moreover, it is not difficult to see that there will be a tremendous future need for LDES across the E&U industry, but how that need translates into specific applications in specific markets remains more difficult to ascertain. While there is a consensus within the E&U industry that a pervasive deployment of LDES technologies would support a low-cost, reliable, carbon-free electric grid, the reality is that these technologies have not been widely utilized or valued in any major market in the US (or globally) today. According to the EIA, US energy system with net-zero greenhouse gas emissions could require as much as 180 GW of new storage capacity, and the majority of that capacity may need to be capable of providing LDES services.<sup>30</sup>

As a result, the expansion of ES technologies—and the thinking around how these technologies can be used—has continued on a growth trajectory throughout 2021, adding momentum to an expansion that started to take hold only several years ago.

Deployments are expected to accelerate dramatically in 2021 with between 3.7 GW and 12 GW of new storage<sup>34</sup>—three times the amount added in 2020. Such progress will continue to enable renewables to be more stable resources, leading the way into a clean energy future.

The solution to this challenge very likely will be found in a widescale and pervasive development and utilization of LDES technologies that can firm energy produced by VREs for ever-long durations so that these resources can be stored and then called upon when needed, and not be forfeited through curtailment. As tomorrow's grid will have a much higher penetration VREs, longer duration storage will be needed in order to avoid disastrous imbalances that could lead to blackouts. LDES technologies are generally defined as having a capability to store energy for a minimum of four hours but increasingly are being called to provide increased durations above 10 h, and possibly multiple days or weeks.

## LDES categories and technologies





Among the challenges facing policymakers tasked with creating market-enabling policies for LDES is the broad scope of technologies that fall into this category. In other words, LDES technologies do not comprise one uniform set of solutions but rather a number of different technologies with different physical principles, performance characteristics, application potentials, and market maturity. This makes policymaking for LDES even complicated as a uniformed approach toward LDES is not likely to be practical or feasible. As a result, it is challenging to provide a unified perspective of LDES performance characteristics.

In general, LDES can be organized into categories with their associated technologies as follows as illustrated in Table 5:

Historically, mechanical forms of ES technologies have always been capable of providing long-duration needs. These technologies include pumped hydrostorage, gravity-based, and compressed air. In fact, most of the presently installed LDES is in the form of pumped hydrostorage, which accounts for 95% of the total energy storage capacity worldwide. Pumped hydro remains the least expensive energy storage technology in the world in terms of capital costs per installed kilowatt-hour of capacity. Capital costs include equipment, facilities, structures, land, and roads. While costs projections are very contingent on-site location, public data available suggest that project costs range between \$106 and \$200 per kilowatt-hour, compared to between \$393 and \$581 for lithium-ion batteries.<sup>35,36</sup> Due to the fact that hydropower technologies are mature, cost reduction potentials are therefore small and generally limited to improvements in civil engineering techniques and processes. Longevity has also been a key attribute as well, as pumped hydrostorage plants have a lifetime of more than 40 years for the electromechanical equipment and 100 years for the dam.

However, the challenge for these mechanical forms of ES technologies and pumped hydrostorage in particular is that traditionally mechanical systems have relied on special geographies and large upfront capital costs. For example, pumped hydrostorage

**Table 5.** LDES categories and associated technologies.

LDES category	Associated technologies (market readiness; duration potential)
	Pumped hydro (commercial; 0–15 h) Compressed air energy storage (commercial; 6–24 h) Gravity-based (pilot phase; 0–15 h) Liquefied air (pilot, with some commercial activity announced; 10–25 h) Liquid CO <sub>2</sub> (pilot phase; 4–24 h)
<b>CHEMICAL</b> 	Hydrogen (pilot phase; 500–1,000 h) Synthetic gas (pilot phase; 500–1,000 h)
<b>THERMAL/ THERMOCHEMICAL</b> 	Sensible heat (e.g., molten salts, rock material, concrete) (R&D/pilot phase; ~ 200 h) Latent heat (e.g., aluminum alloy) (commercial; 25–100 h) Thermochemical heat (e.g., zeolites, silica gel) (R&D; unknown) Thermochemical heat (e.g., zeolites, silica gel)
<b>ELECTROCHEMICAL</b> 	Lead-acid batteries (commercial; < 8 h) Lithium-ion batteries (commercial; < 8 h) Zinc alkaline batteries (commercial < 8 h) Flow batteries (commercial; < 8 h)

plants require two flat reservoirs with at the least 300 m of elevation difference. Thus, these solutions are quite dependent on the morphology of the territory, which for some developers restricts their viability. Some groups are proposing to pump water underground in wells. New versions of this established technology are emerging to reduce its dependence on geographical conditions. Another well-known drawback of pumped hydrostorage facilities is the potential for leakage. Water leakage causing cracks can develop in aging pumped storage stations for various reasons ranging from earth movement to daily or seasonal temperature changes that cause expansion and contraction, often referred to as freeze-thaw. It is not uncommon to find pumped hydrostorage facilities that have been operating for decades and, as a result of age, require maintenance to resolve groundwater leaking in (infiltration) or out (exfiltration) due to leaks and cracks, along with other efficiency concerns. Other emerging forms of mechanical energy storage solutions include compressed air energy storage and gravity-based energy storage.

There also appears to be renewed interest in chemical, hydrogen-based systems throughout the E&U sector. Chemical energy storage systems store electricity through the creation of chemical bonds. The two most popular emerging technologies are

based on power-to-gas concepts: power-to-hydrogen-to-power, and power-to-syngas (synthetic gas)-to-power. Electricity is used to power electrolyzers, which produce hydrogen molecules that can be stored in tanks, caverns, or pipelines. The energy is discharged when the hydrogen is supplied to a hydrogen turbine or fuel cell. If the hydrogen is combined with CO<sub>2</sub> in a second step to make methane, the resulting gas—known as syngas—has similar properties to natural gas and can be stored and later burned in conventional power plants. Similarly, hydrogen can be converted to ammonia for direct combustion. Thermal storage presents several advantages. It can be used to store electricity from solar (through, for example, Concentrated Power Solar) and used to run steam turbines. These systems, however, are large, and similar to mechanical forms of LDES require a large geographic footprint that may limit development opportunities.

The capital costs for hydrogen systems, along with engineering, procurement, and construction and O&M costs, are project- and location-specific and can vary substantially. Cost estimates for a 100 MW, 10-h hydrogen energy storage system, at 2030 values, range from \$1,440/kW (low) to \$1,824 (high).<sup>37</sup> The expected lifespan of commercial hydrogen tanks is assumed to be 10 years,<sup>38</sup> and leakage must be closely monitored as compressed

hydrogen fuel tanks can be subject to potential failures associated with pressure vessels. In the event of a failure, hydrogen can leak through the cracks developed in these vessels, creating a hazardous situation for both property and human health.<sup>39</sup>

Thermal energy storage technologies store electricity or heat in the form of thermal energy. In the discharge cycle the heat is transferred to a fluid, which is then used to power a heat engine and discharge the electricity back to the system. The most widespread thermal LDES technology is molten salts coupled with concentrated solar power plants; however, this technology is different from other novel LDES as it presents different characteristics (e.g., it cannot be widely deployed as it is not modular, the CSP plant has a large footprint and is only effective in regions with high solar radiation).

Table 6 provides a summary of the traditional, non-electrochemical forms of ES technologies that offer a potential for use in LDES scenarios, with their associated advantages and challenges.

Table 6 illustrates the fundamental challenge of non-electrochemical systems, which is that while they may be capable of providing day-long storage but do not easily scale down and typically require a very specific setting with a large geographic footprint. Thus, perhaps in response to the challenges of these mechanical, chemical, and thermal forms of LDES, future prospects for market development of LDES solutions appear to be focused on electrochemical and battery-based alternatives. The Lithium-ion battery industry has grown, driven by the growth of consumer electronics and electric vehicles. The industry will continue to incrementally improve performance and decrease cost to respond to market forces. Other technologies, like alkaline batteries, flow batteries, and hydrogen-based storage technologies, will have to balance the need to scale with the uncertainty of the markets for LDES while proving and refining their products.

This high-level review of potential LDES technologies is by no means exhaustive, and trends continue to emerge. As the grid evolves, LDES technologies are expected to emerge anywhere on the electric grid, behind the meter, and on the distribution and transmission services. The closer these energy storage assets are located to the customer, the higher their value will be. Figure 8 illustrates the current thinking within the E&U sector of the role of both electrochemical and non-electrochemical LDES technologies and the services they can provide.

In Fig. 8, “System Power Ratings” for energy storage systems are supplied by the system manufacturer and represent how much real power the device can supply at a time under ideal conditions. Given that future electrochemical LDES solutions will increasingly become a focus among developers at both the retail and wholesale level, interest in the potential applications for utility-scale battery deployment is gaining momentum. The applications illustrated in Fig. 9 are also relevant to behind-the-meter battery LDES solutions due to FERC’s Order 2222, released in September 2020, which directed RTOs/ISOs under federal regulation to allow for aggregated forms of energy storage to participate in wholesale transactions and prepare associated market rules and tariffs to allow these transactions. As of this writing, RTO/ISO filings outlining their compliance with

Order 2222 are still being prepared with submission deadlines occurring in mid-2022.

## LDES and nuclear power






The 2021 Annual Energy Outlook<sup>10</sup> projects a gradual decline in the share of American electricity generated by nuclear power over the next three decades, from 19% in 2020 to 11% in 2050. This projection reflects anticipated retirements of old plants, the economic uncompetitiveness of new nuclear construction in the United States, low prices of natural gas, and the prevalence of state policies that mandate deployment of renewables (to the exclusion of nuclear) in order to decarbonize the electricity sector. As noted above, some states have broadened their definition of eligible zero-carbon generation sources, which removes one barrier to new nuclear deployment. In any case, market appetite for new nuclear in the United States is unlikely to materialize without drastic reductions in overnight capital cost and construction lead time. Such breakthroughs—if they are to happen at all—will come from either small modular reactors (SMRs),<sup>41</sup> the importation of best practices for construction management from abroad,<sup>42</sup> or both.

Whether nuclear power will or should play an expanded or diminished role in a future energy system is beyond the scope of this article. When considering the interactions of LDES and nuclear power, we observe that LDES could complement nuclear power in several ways:

- *Maximize Capacity Factor* While nuclear reactors have operated in load-following mode in a few countries<sup>43,44</sup> and advanced reactors are being designed with even greater capability for flexible operation,<sup>45</sup> the economics of nuclear power—low marginal generating costs and high capital costs—is best suited to baseload operation. Whereas short-duration storage is appropriate to address diurnal patterns of excess VRE plus nuclear generation, LDES would be needed to avoid curtailment of nuclear generation during weeks or seasons of high VRE generation.
- *Provide replacement power during plant outages* Forced outages at large nuclear reactors are commonly the single largest contingency that must be planned for to ensure grid reliability.<sup>46</sup> The most prevalent causes of forced outages at nuclear plants entail a mean time to repair on the order of hundreds of hours.<sup>47</sup> In the absence of other sources of on-demand supply (historically, fossil generation), LDES would be vital to assure security of supply. Planned outages, primarily for refueling, are typically scheduled during months of low demand and therefore pose less risk. Hypothetically, refueling outages could be rescheduled to seasons of VRE output in excess of demand, somewhat lessening the need for seasonal LDES.
- *Provide on-site backup power to meet critical loads in the event of an emergency* Currently, this role is served by a combination of diesel generators and lead acid batteries. The lead acid batteries are typically sized to supply instrumentation,



**Table 6.** Non-battery ES technologies providing LDES applications.

ES technology	Advantages	Challenges
<b>PUMPED HYDRO</b> 	Mature technology Demonstrated large capacity (~GWh) > 90% of US grid energy storage Improved turbines and electrical systems Small modular pumped hydrosystems Good reliability	Unique geologic resources and water availability Existing pumped hydrofacilities can require costly retrofits of turbines in order to provide more flexible operation Small modular pumped hydrosystems are not cost competitive (yet)
<b>COMPRESSED AIR</b> 	Demonstrated capability at large scales Moderate round-trip efficiency Good potential for long-duration storage	Unique geologic resources Well integrity Repository integrity
<b>HYDROGEN</b> 	Can be stored in large capacities for long periods of time and be used for both grid and transportation Environmentally friendly	Low round-trip efficiency of hydrogen production and storage High cost Leakage and safety of hydrogen gas
<b>THERMAL (SENSIBLE)</b> Thermal (sensible) 	Mature technology Demonstrated large capacity with concentrating solar power (~GWh) Low cost	Heat loss Large volumes required Heat exchanger performance and cost
<b>THERMOCHEMICAL</b> 	Large energy density Potential for long-duration storage	Low maturity High cost Material durability and kinetics

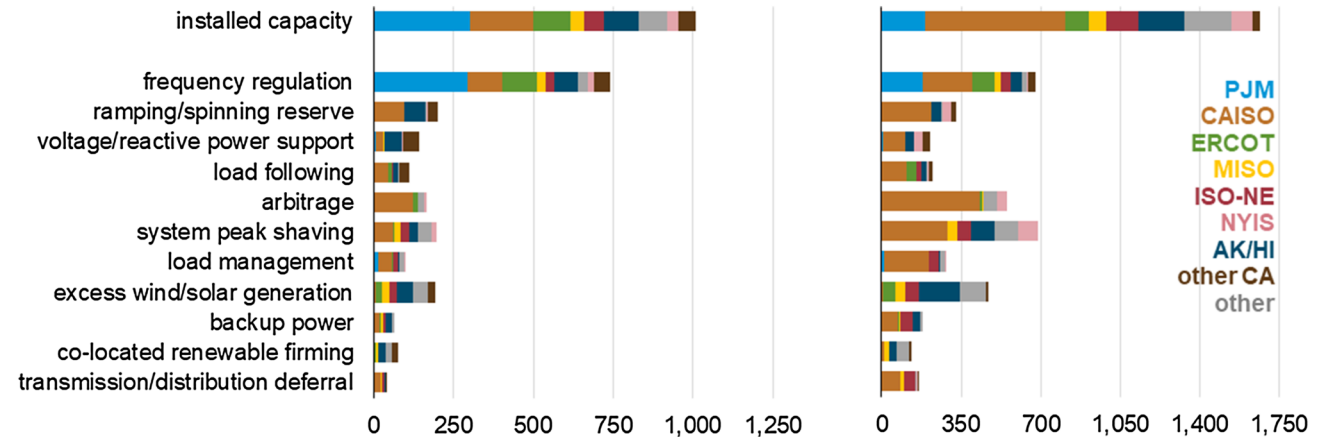
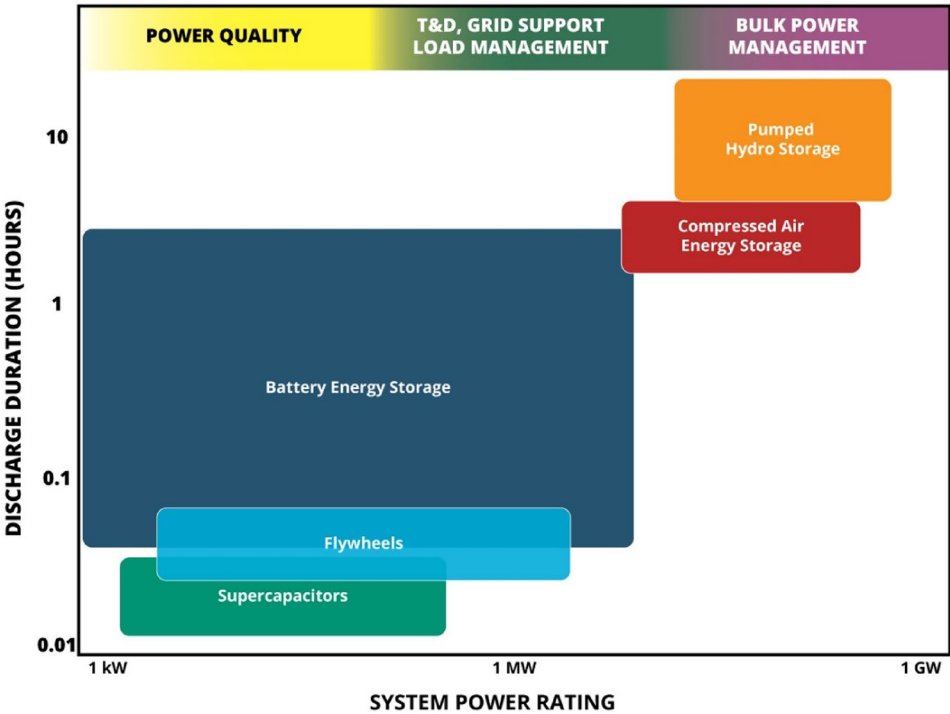
communication, and lighting loads for a few hours. The diesel generators are responsible for much larger plant loads—especially those associated with reactor safety systems. Current NRC requirements call for a minimum of 7 days’ supply of fuel.<sup>48</sup> A total commitment to decarbonization would preclude the continued use of diesel generators for this purpose; LDES technologies could potentially fill this role.

- *Couple nuclear reactors with thermal LDES* Piping heat from a nuclear reactor into thermal storage would give nuclear power a considerable economic advantage relative to grid-supplied electricity. Roughly one third of nuclear heat is

ultimately delivered to the grid as electricity; hence, nuclear heat is (to a first approximation) three times as cheap per unit energy as nuclear electricity. Such systems are speculative but theoretically promising.<sup>49, 50</sup>

On the other hand, there is some evidence that LDES and nuclear power substitutes. Research modeling future electricity grids widely find that the cost of an electricity grid which relies solely on VRE and short-duration energy storage rapidly escalates as VRE shares approach 100%.<sup>51, 52</sup> The inclusion of firm, low-carbon generation (nuclear, hydro, biomass, geothermal,

**Figure 8.** Comparison of existing and emerging energy storage technologies. Source: 2020 Grid Energy Storage Technology Cost and Performance Assessment, Department of Energy .<sup>37</sup>



**Figure 9.** Potential applications envisioned for electromechanical battery-based battery LDES deployment<sup>40</sup>.

CCS) in generating mixes greatly reduces the costs of decarbonization by reducing the magnitude and timescale of imbalances between supply and demand.<sup>53</sup> However, the availability of cost-effective LDES substantially alters this calculus. It has been estimated<sup>54</sup> that, if there existed a storage technology with duration greater than 100 hours and whose energy subsystem cost no more than \$10 per kWh, such LDES would “fully displace” any economic need for nuclear power in a net-zero electricity grid. In short, provided sufficiently cheap LDES, the always-available nature of nuclear power becomes less valuable and hence 100-percent carbon-free grids can rely on higher shares of VRE cost-effectively.

### Cost components of LDES

Even under conditions of aggressive climate policy encouraging massive deployment of renewable energy, LDES will face stiff competition from fossil fuels in the management of imbalances in energy supply and demand on monthly, seasonal, and inter-annual timescales. If LDES technologies are not cost competitive in solving the challenges of very high penetrations of VRE, they will not be deployed. Without deployment, they will not have the opportunity to experience cost reductions and performance improvements that result from learning-by-doing.

Several studies have examined the role of LDES in future decarbonized electricity grids<sup>55-59</sup> All of them concur that the single most important component of the cost of LDES is the

cost of energy capacity. Energy capacity refers to the quantity of energy an LDES facility can store when fully charged; the cost of energy capacity is most commonly expressed in terms of \$/kWh.

The importance of cheap energy capacity arises from the exceptionally low rate of utilization of LDES in its envisioned future applications. LDES facilities may perform as few as one duty cycle per year, charging up during months when surplus energy is available and discharging during months when VRE generation is not sufficient to meet demand. This can be contrasted with short-duration energy storage, which may perform anywhere from one to dozens to hundreds of duty cycles over the course of a day, depending on the application. Each duty cycle is an opportunity to earn the revenue necessary to cover operational costs and earn a return on investment from the upfront expense of building the facility.

Certain applications may be more financially remunerative per duty cycle, which can compensate for lower utilization. For example, LDES deployed to avoid the need to expand transmission and distribution networks can charge at exceptionally low cost during hours of network congestion (when generation would otherwise have to be curtailed) and earn additional revenue reflecting the avoided cost of grid expansion.<sup>2</sup> As noted in Fig. 10, transmission and distribution account for a substantial share of the total cost of the retail price of electricity, so LDES applications that avoid T&D costs have a greater opportunity to generate revenue than those other applications that solely provide value in the generation subsector.

However, to fully decarbonize the electricity grid, LDES will need to be competitive against conventional generation in the provision of bulk energy services. While energy prices vary across geographies and time, the average cost of generation presented in Table 7 conveys the order of magnitude of revenue available to LDES per kWh sold in wholesale energy markets.

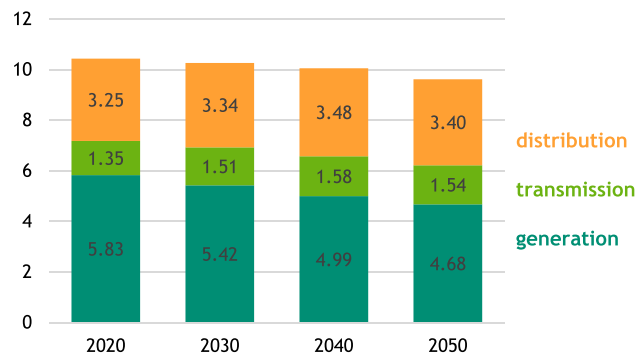
Consider a hypothetical storage technology with an energy capacity of cost of \$100/kWh, 100% round-trip efficiency,<sup>3</sup> an economic lifespan of twenty years, and an investor willing to accept a modest 5% rate of return. It will need to earn an annual operating profit of \$8/kWh to recover its energy capacity cost.<sup>4</sup> If the duty cycle consists of a daily charge and discharge, then its energy capacity cost can be recovered with operational profits as low as 2.3¢/kWh of delivered energy.<sup>5</sup> Considering of average wholesale generation costs on the order of 5¢/kWh and typical intraday variation in wholesale energy prices, a daily duty cycle

<sup>2</sup> Provided appropriate policies or market mechanisms are in place to identify, measure, and remunerate the contribution of LDES for avoided costs.

<sup>3</sup> The effect of realistic efficiencies on LDES economics will be considered below. The unrealistic assumption is made for ease of exposition.

<sup>4</sup>  $\$100 \times \frac{0.05(1+0.05)^{20}}{(1+0.05)^{20}-1} = \$8.02$ . The second term in this equation is the capital recovery factor, which annualizes the upfront expense over the economic life of an asset while accounting for the time value of money.

<sup>5</sup>  $\frac{\$8.02}{350} = 2.3 \text{ ¢}$ . To account for maintenance outages, it is assumed that the facility operates 350 days per year.



**Figure 10.** Predicted cost of electricity over the next 30 years, disaggregated by subsector Source: Energy Information Administration. Annual Energy Outlook 2021.

of energy arbitrage for this hypothetical technology could be economically viable.

However, if the duty cycle were to consist of a single charge and discharge over the course of the year to provide seasonal balancing, there is no conceivable set of market conditions such that it would earn sufficient revenues to cover the upfront costs of its energy capacity. Scarcity prices like those observed in Texas in February of 2021—when prices reached the regulated cap of \$9/kWh—are exceptionally rare and not a sound basis for an investment in LDES. This back-of-the-envelope exercise illustrates the relationship between energy capacity cost and utilization: at lower rates of utilization, an energy storage technology requires lower energy capacity costs to be economically viable.

We will now consider this insight in relation to the costs of the technology currently dominating the market for new energy storage deployment, lithium-ion batteries.

The average cost of utility-scale battery storage in the United States has rapidly decreased from \$2,102/kWh in 2015 to \$589/kWh in 2019; these figures are broadly representative of lithium-ion batteries which accounts for more than 90% of the battery capacity (both in terms of energy and power) installed during these years.<sup>60</sup> As a result of these rapidly declining costs, the economic viability of using lithium-ion batteries in applications with longer duty cycles and lower utilization has expanded, from frequency response (timescale of seconds) to spinning reserves (timescale of minutes) to providing an alternative to peaking generation (timescale of a few hours). Data from US EIA show that the average discharge duration steadily increased from 30 min for utility-scale batteries installed in 2015 to 3.2 h in 2019.

The latest estimates of the total system cost of utility-scale Li-ion battery energy storage systems (BESS) with four hours of duration are presented in Table 7. Most estimates are on the order of \$380 per kWh, although the exact dollar figure differs with assumptions such as chemistry or whether the system shares infrastructure with a renewable generation facility. Total system costs are inclusive of power capacity costs, i.e., the costs that scale with the power rating of the facility. Per Mongird et al. (2019), power capacity costs account for approximately

**Table 7.** Recent estimates of the total system cost of utility-scale, 4-h lithium-ion battery energy storage systems.

Citation	Date of installation	Scale		Notes	\$/kWh
		MW	MWh		
Augustine & Blair (2020)	2019	60	240	Standalone BESS	\$ 382
Ramasamy et al. (2021)	2021 Q1	60	240	Standalone BESS	\$ 375
Ramasamy et al. (2021)	2021 Q1	60	240	DC coupled with 100 MW PV system	\$ 329
Mongird et al. (2020)	2020	100	400	Standalone BESS, LFP Chemistry	\$ 385
Mongird et al. (2020)	2020	100	400	Standalone BESS, NMC Chemistry	\$ 395
Minear et al. (2020)	2021	100	400	Standalone BESS	\$ 292

20percent of total system costs of a utility-scale lithium-ion BESS with four hours of discharge duration. Therefore, we can infer current energy capacity costs—including not only the cost of battery modules but their installation—are on the order of \$300 per kWh. This number is indicative of the marginal cost of expanding energy capacity while holding power capacity constant, such as if one wished to size a Li-ion BESS for LDES applications requiring 100 or more hours of storage.

With anticipated further price reduction of Li-ion batteries, installed costs could conceivably decrease to \$200/kWh by the year 2030 and \$150/kWh by the year 2050 (total system cost, inflation-adjusted 2020 dollars).<sup>61</sup> Such cost reductions could enable the viability of marginally longer discharge durations but are far from adequate for Li-ion batteries to make financial senses for LDES applications discharges durations of 100 h or more. A major constraint on long-term price declines for lithium-ion batteries is the commodity price for raw lithium, which has seen explosive price growth due to surging demand for Li-ion batteries.<sup>62</sup> Unless new sources of supply and efficiencies in use can grow faster than the demand, the use of lithium-ion batteries will necessarily be economically limited to its highest value applications, namely electric vehicles, consumer electronics, and short-duration energy storage. As argued above, an energy capacity cost of \$100/kWh far exceeds the economic requirements for LDES, so technologies which are not expected to reduce costs substantially below this level should not be considered for LDES.

A handful of recent studies have modeled the role of LDES in future decarbonized electricity grids and evaluated the sensitivity of results to the cost and performance of LDES technologies. Two studies<sup>63</sup> recommend an energy capacity cost target of \$20/kWh (2020 dollars) while a third (see Footnote 1) lays out different targets contingent on the discharge duration of the desired application: \$40/kWh for 10 h storage, \$7/kWh for 50 h storage, and \$3/kWh for 100 h storage. Each study takes a different

approach, so the results are not fully comparable, but they are illustrative of the order of magnitude of energy capacity cost that is necessary to enable LDES to compete economically with firm generation under policy conditions that favor the decarbonization of the electricity sector.

Another cost component of high importance for the economic viability of LDES is the discharge efficiency. While most studies only consider round-trip efficiency, Sepulveda et al. evaluated charge efficiency separately from discharge efficiency.<sup>64</sup> Discharge efficiency is the rate at which stored energy is converted into delivered energy, while charge efficiency is the rate at which purchased energy is converted into stored energy. They find that the discharge efficiency is roughly twice as important as the charge efficiency when compared on the basis of how improvements in each efficiency reduce the total cost of the electricity system. While all efficiencies (charge, discharge, and parasitic loads) are important determinants of operating costs, discharge efficiency plays a role in capital costs. This intuition—although not laid out explicitly by the authors—can also be gleaned from ARPA-e analysis, (see Footnote 1) wherein the energy capacity cost is divided by the discharge efficiency in the computation of the total cost of ownership of an LDES system.

To illustrate this intuition with a simple example, consider two technologies that are otherwise identical in all respects (including energy capacity cost) except that the first has a discharge efficiency of 40% and the second has a discharge efficiency of 80%. To supply 100 MWh of energy over the course of a duty cycle, the first technology must install an energy capacity of 250 MWh while the second technology must install an energy capacity of 125 MWh. Thus, even though they are identical in all other respects, the second technology has an *effective* energy capacity cost 50% cheaper than the first technology due to the fact that it must install twice as much energy capacity to offer identical performance.



A cost factor that will influence the economic viability of LDES is the cost of renewable energy. The low and still falling costs of wind and solar PV are a major factor in all forecasts of the future electric generation mix. Additionally, renewables portfolio standards and federal tax credits (if renewed) will contribute to the massive deployment of wind and solar PV. Massive deployment will bring about many hours of the year during which VRE generation (A) drives down electricity prices to very low levels or (B) even exceeds demand, causing negative prices. Such hours are the most economical time for LDES systems to charge in order to minimize operating costs, so the future trajectory of VRE cost and the scale of deployment are another crucial factor for the economic viability of LDES.

Pumped hydro, which remains by far the most dominant energy storage source in terms of installed capacity, has a projected cost estimate of \$262/kWh for a 100 MW, 10-h duration installed system.<sup>37</sup> When considering only the costs of pumped hydro that scale with energy capacity, the marginal energy capacity cost can be as low as \$20/kWh, but this requires favorable geography.<sup>53</sup> At such costs, pumped hydro will be limited to diurnal (or slightly longer) duty cycles. Furthermore, the geographic siting restrictions of pumped hydro may create difficulties in reaching scale to the level that will be needed to accommodate future energy storage requirements.

The installation costs for CAES, which are very site specific and dependent on available reserves that are needed to pump the air, are typically associated with costs in the range of \$119/kWh, but may even reach \$50/kWh in some US markets, again based on the ability to site near suitable geologic formations.<sup>37</sup> While installation costs could conceivably reach the \$40/kWh level with favorable reservoir conditions, this is still double the \$20/kWh target. The installation costs for thermal storage options are averaging as low as \$50/kWh in some US markets, but still come up short when evaluated against the \$20/kWh target for commercial viability (Ibid).

Research into new, lower-cost materials for flow batteries represents one opportunity for innovation and cost reduction in LDES. Similar opportunities exist across many LDES alternatives, including mechanical, thermal, and innovative technologies associated with CAES. For the very longest duration storage (100 or more hours), innovation in electrolysis and hydrogen fuel cells represents one of the most promising pathways to balance seasonal variations in supplies of renewables due to the exceptionally low energy capacity cost of geologic storage of gaseous fuels. One analysis<sup>27</sup> finds that, if the DOE's "Hydrogen Shot" cost target of \$1/kg is achieved, hydrogen will be the LDES *par excellence*, edging out all other potential competitors for applications with discharge durations exceeding somewhere between 50 and 150 h.

All that said, as this paper has addressed, it will be extremely difficult for emerging LDES technologies to mature and scale in the next decade if the current gap of federal and state policy structures continue. Policy structures that support viable LDES prototypes, which in turn provide markets for LDES services, can become the catalyst for LDES technologies to reach

maturing in the next decade. The next section summarizes the policy gaps that continue to create uncertainties around LDES' ability to contribute to future needs across the grid, and emerging efforts taking place to bring LDES technologies to market.

## The need for LDES policy

Forecasting, planning, and building a national grid system that will be able to meet clean energy goals and safely operate decades into the future poses an extreme challenge for policy-makers (along with grid planners, utilities and other industry stakeholders). This extreme challenge is exacerbated by the fact that technologies enabling the use of renewable energy and energy storage technologies are rapidly evolving in real time. Moreover, no single entity has total responsibility for planning, managing and executing this enormous challenge; rather, the process relies on a multitude of disparate market participants that may hold different visions for how LDES should be defined, utilized, managed, and priced.

Barriers that may exist primarily within state policies include the following: non-existing policies for energy storage in general or LDES specifically (only about 15 US states have substantive energy storage policies, and only a few have addressed LDES specifically); inconsistencies regarding ownership for energy storage assets, which determines how the assets are used; and in vertically integrated markets, concerns about cost recovery through ratebase have created a bias toward lower-cost, short-term duration storage options, thereby limiting opportunities for LDES to participate.

Barriers that may exist primarily within federal or regional policies include the following: wholesale structures and incentives that do not provide a favorable environment for investment in existing or new LDES technologies; revenue opportunities for LDES at the wholesale that presently derive primarily from arbitrage services, which typically are insufficient to cover the high capital costs associated with LDES technologies; and capacity markets (where they exist) that aim to ensure resource adequacy at the lowest possible cost, and typically do not acknowledge the key benefits that LDES technologies can deliver to the system. Organized markets under ISOs/RTOs may or may not have annual resource capacity markets and otherwise have only intraday spot markets. Longer-term markets are left to exchanges where futures contracts are traded. These markets do not provide incentives for LDES development or mechanisms to monetize benefits, and such markets will not develop absent resources able to participate – a chicken-and-egg problem.

The greatest obstacle LDES faces in terms of defining its role in future grid is economics. It is difficult for developers to find a marketplace in which LDES can generate revenue today. The industry consensus in the US is that a robust market for LDES may not develop in earnest for another ~ 5-10 years as policy frameworks in individual states increasingly require larger amounts of intermittent renewables. In addition, there is little consensus regarding how envisioned (and critical) services such as time shifting, resource adequacy contributions, ancillary

services, and resiliency should be priced. Policies that enable value stacking or dual-use would certainly benefit LDES, particularly in the energy market (time shifting of MWh), capacity market (resource adequacy in terms of MW), and as a transmission asset (mitigating thermal overload and deferring upgrades). In addition, policies that value long-term resiliency following natural disasters and other threats to the grid can also benefit LDES.

Another challenge for quantifying the amount of LDES required to meet decarbonization goals is the tradeoff between renewable curtailment, transmission expansion, and storage deployment. Increasing renewable generation and curtailment can reduce the requirements for energy storage. Similarly, transmission expansion can reduce renewable variability by expanding the connections to other regions, thus reducing storage requirements. The electric power grid is a system, and the lowest cost highest reliability system requires consideration of the overall design and operation. Because different entities often own and regulate generation, transmission, and LDES, it is very difficult to arrive at the optimal system design. In addition, policies and regulations that restrict or limit renewable curtailment will impact the storage requirements. While most curtailment in the United States is based on market incentives, rooftop solar in most cases cannot be curtailed. Therefore, policies or incentives for additional rooftop solar will increase LDES requirements.<sup>65</sup>

Energy equity is a critical component in resilient, secure, and stable social, economic, and political systems. Energy equity refers to the condition in which energy is provided to all in a consistent and systematically fair, just, and impartial manner regardless of race, geography, social standing, or economic position. Long ignored, energy equity, and justice measures are being adopted by US federal government and many states through legislation and policy measures. The Justice40 Initiative is part of a US presidential executive order with a goal of delivering 40% of the overall benefits of federal investments to disadvantaged communities, which includes energy investments. Disadvantaged and underserved populations generally suffer disproportionately from power outages, high energy prices, and polluting energy generation facilities. Policy measures that include energy storage and LDES technologies can help provide energy equity to all populations.

If a market for LDES is to be created both for wholesale and retail markets across the US, it will only occur as a result of the development of sound policies at the federal and individual state levels. At present, no such policy framework for LDES exists in any market in the US, although progress is being made incrementally in some jurisdictions. The creation of a sound policy framework is essential to achieve two foundational goals:

- Define the ways in which LDES can contribute to grid functions (i.e., removing barriers that prevent LDES' participation, and developing enabling policies to encourage its usage); and

- Create a marketplace in which LDES can be properly valued and compensated for the services it brings to the grid.

These goals will likely be approached in ways, depending on the regulatory construct that is present in any specific marketplace. The extent to which a market has been restructured will be relevant for determining how LDES will find an entrée into specific markets, as there are disparate regulatory frameworks that sometimes overlap across the US. As a result of restructuring of the electric industry in the US that began in earnest in the late 1990s, states are now characterized as either being regulated/vertically integrated markets, or restructured markets.

At the state level, existing and new policies can create, fortify, or break-down barriers for the development of ES technologies, including LDES. For example, state governments can help developers absorb the cost burden of LDES/SES technologies through offering subsidies, tax incentives, or utility programs for which the costs can be recovered in ratebase. Policymaking regarding ES is gaining momentum; examples of relevant state policies include ES procurement mandates, resource adequacy requirements that include ES, integrated resource planning (IRP) and other long-term resource planning that may include ES requirements, and incentive programs made available to ES technologies. However, it is still quite rare for LDES to be distinctly addressed in policy that addresses energy storage, with the exception of California. While California did not originally carve out a requirement for LDES in its ES procurement mandate, the state subsequently conducted extensive modeling to determine the amount of LDES that would be necessary to meet its decarbonization goals (as previously noted, California's interim goal of 60% renewable penetration by 2030 will itself spur a requirement of between 2 GW and 10-h + of LDES).<sup>2</sup>

Efforts to help developers absorb the cost challenge that continues to undermine ES and LDES development are taking place at both the federal and individual state level. For example:

- At the US federal level:
  - o 2020 BEST Act: Requires the DOE to establish cross-cutting energy storage R&D to reduce cost and extend duration of energy storage systems (federal legislation)
  - o DOE Long-duration Storage Energy Earthshot: Intended to reduce cost of grid-scale energy storage by 90% for systems that deliver 10 + hours of duration within a decade
  - o DOE Hydrogen Energy Earthshot: Intended to reduce the cost of hydrogen to \$1 per kg in a decade
  - o The DOE ARPA-E DAYS and SETO CSP programs provide funding for LDES projects
- At the US state level:
  - o Arizona: Offers a battery incentive program structured to encourage LDES, offering the full incentive only for

storage technologies that offer discharge durations longer than five hours.<sup>66</sup>

- o New York: \$12.5 million is being made available through the New York State Energy Research & Development Authority's Renewable Optimization and Energy Storage Innovation Program, which seeks pre-commercial stage LDES technologies including hydrogen, electrical, chemical, mechanical or thermal storage technologies that are six hours or more in duration.<sup>67</sup>
- o California: The state recently proposed US\$350 million of support for pre-commercial long-duration storage projects. California Energy Commission (2020 GFO-19-308) – Issued funding for “Assessing Long-duration Energy Storage Deployment Scenarios to Meet California’s Energy Goals.” Eight community choice aggregators (CCAs) launched a joint request for offers to procure up to 500 MW of long-duration storage in October 2020.<sup>68</sup>

Once policy determines where (and how) ES technologies—including LDES—may be used, the applications of specific technologies become much easier to determine. Nevertheless, the inherent technological capabilities of specific LDES technologies may also play an important role in determining where specific technologies can be used. In addition, the extent to which renewable resources are being added to local distribution systems will also determine the potential need (and thus applications) for LDES technologies.

## Policy options for LDES

As discussed above, the technical & business case for LDES rests upon an especially high share (80% or more). Under the currently enacted policies, technology costs, and market conditions, such shares of VRE are not anticipated to arise in the United States except in a handful of states that have already enacted deep decarbonization policies into law or regulation. Policies that drive deep and rapid decarbonization will give rise to the conditions favorable for LDES—large imbalances between supply and demand on multi-day and even season timescales resulting from high shares of VRE create arbitrage opportunities for LDES.

In the absence of aggressive climate policy or market conditions that aggressively reduce the market share of fossil fuels, LDES is certain to need specific incentives to promote it. Otherwise, the policy gap that we have Duration-agnostic incentives for energy storage are certain to be taken up by short-duration energy storage, as its economically viability is much stronger given its costs and current market conditions. In principle, technology-neutral climate policy and technology-specific policies to promote LDES can work side-by-side.

Moreover, policymakers in the E&U sector would be well advised to take action now to develop a policy framework that will enable the unique aspects of LDES technologies to increasingly participate in the electric grid infrastructure to support

the anticipated influx of massive amounts of VREs policymaking over the coming decades. Without question, government action at the federal and individual state levels will be required with a focus on clearly identifying pathways for LDES use cases, lowering technology costs, incentivizing the necessary investment capital, and creating mechanisms for both wholesale and retail transactions that will provide an appropriate rate of return on LDES.

At a high level, policymakers can address the existing policy gaps in four primary ways: (1) considering the development of policies that are built to enable what is already known about the best use-case scenarios for LDES; (2) requiring the inclusion of LDES in long-term system planning, particularly within the framework of established decarbonization goals; (3) supporting the early deployment of LDES through incentives to market developers and/or ensuring cost recovery for utility pilot programs; and (4) developing supportive market designs that begin to capture the full value of LDES, allowing it to play a greater role in resource adequacy requirements, capacity markets, and providing other ancillary services.

Below, we discuss more granular approaches to LDES policymaking, and how they would enable LDES deployment.

**Enabling Policies:** There are a number of potential policy levers that could ultimately fall under a broad designation of enabling policies for LDES:

- Procurement Mandates:
- Integrated Resource Planning Requirements:
- Deployment Projects:
- Compensation Mechanisms

As previously discussed, policymaking that is specific to LDES remains very limited at either the federal or individual state level. Even policymaking that has been developed for short-duration energy storage remains in patchwork fashion when evaluating the US as a whole; some states have no energy storage to speak of while others have very well-developed policies. It is likely fair to assume that policy built around either short-duration or generic energy storage would need to precede policy that is specific to LDES. Thus, the policy levers discussed below may ultimately be approached as LDES-specific carve-outs to existing energy storage policies.

**Procurement Mandates** Procurement mandates are policies that require regulated entities to procure specified quantities of a certain technology, energy sources, or class of technologies or energy sources. Examples include Renewables Portfolio Standards (RPS) and Clean Energy Standards (CES) for electric utilities, California’s Low Carbon Fuel Standard (LCFS), the federal Renewable Fuel Standard (RFS), and similar policies are a procurement mandate for bioenergy alternatives to combustion fuels in the transportation sector. Pursuant to state legislation, the CPUC issued a decision in 2013 that mandated procurement of 1,325 MW of energy storage among regulated utilities by 2020. This decision was focused on short-duration storage; policymakers could easily tailor a future policy to require

procurement of long-duration by placing requirements on the ratio of energy-to-power.

The central argument in favor of procurement mandates is that they accelerate deployment-led innovation by promising investors certainty that there will be a sufficient demand to justify the upfront cost of investments in supply chains, manufacturing capacity, and installation workforce. The primary critique of procurement mandates is that—relative to carbon pricing—they necessarily offer less flexibility as to how to reduce emissions. For example, an RPS requires deployment of non-hydro renewables; fuel switching from coal to natural gas receives no compliance credit under an RPS even though this action by utilities can significantly reduce emissions. The counterargument to is that many procurement mandates require that effect entities take actions that must occur anyways, regardless of policy mechanism, if deep decarbonization is to be achieved. This view in favor of procurement mandates shifts responsibility for determining the optimal pathway toward and final configuration of a deeply decarbonized economy from the market (as under carbon pricing) to policymakers.

If policymakers pursue procurement mandates for LDES as part of deep decarbonization policy, they must be careful to get the details right. For example, a hypothetical procurement mandate for LDES would require policymakers to define a minimum ratio of energy-to-power they consider “long duration” and specify how much LDES is appropriate for their jurisdiction. This runs the risk of choosing a duration and/or quantity of LDES that does not align with the technical needs of the grid or pass a cost-benefit analysis. For example, some degree of overbuild and curtailment of VRE is likely to be more cost-effective than mandating procurement of sufficient LDES to store all VRE generation. A procurement mandate for 100% clean energy or a sufficiently large carbon tax would result in conditions where LDES would be economically viable, leaving to the market to decide on the details of how many megawatts and megawatt-hours to deploy.

Alternately, if policymakers pursue more limited, temporary procurement mandates for LDES to jumpstart deployment-led innovation, the risk of “overshooting” the optimal amount of LDES is avoided. Such an approach would set a near-term target for LDES deployment well below the level plausibly required to decarbonize the economy in the long run. The resulting near-term deployment of LDES would provide real-world information to policymakers, researchers, and market participants about which LDES technologies are most promising. Such a policy could be complementary with technology-agnostic climate policy for deep decarbonization by ensuring that the best set of LDES technologies has favorable utility-scale commercial experience before embarking on a campaign of widespread deployment.

**Subsidies** Tax credits, tax exclusions, below-market prices offered by state-owned enterprises, and other implicit or explicit transfers of government fiscal resources for energy production, consumption, and infrastructure are widespread globally.<sup>69</sup> According to estimates by US EIA, federal financial interventions

and subsidies in the United States amounted to nearly \$15 billion in fiscal year 2016.<sup>70</sup> These policies influence consumption, production, and investment choices by altering the prices that otherwise would have been paid and received.

The historically most common forms of subsidy for clean energy in the United States are tax credits. For wind, geothermal, and biomass, that is the production tax credit (PTC), which entitles the owner to a reduction in tax liability per MWh generated. By contrast, an investment tax credit (ITC) applies to solar, which reduces tax liability by a percentage of the upfront capital cost of the system. The IRS has ruled that storage paired with solar qualifies for the ITC; however, standalone storage is not eligible for any tax credits. LDES deployment would obviously benefit from the introduction of an ITC for standalone energy storage, especially those LDES technologies that do not lend themselves to co-siting with solar farms.

The primary arguments in favor of and against tax credits are similar to that for procurement mandates: they promote deployment-led innovation, but they entail policymakers “picking winners and losers.” Where the two policies differ is in how they accomplish their goals: whereas procurement mandates choose quantities, tax credits influence prices. At first glance, the practical effect tax credits (or other subsidies) for clean energy may seem practically equivalent to carbon pricing of fossil fuels and thus more market-oriented. However, an important difference is that carbon pricing raises the price of energy to reflect its social costs, thereby transmitting to consumers a stronger incentive to conserve or invest in energy efficiency. Subsidies for clean energy lower prices paid by consumers and therefore do not adequately reward reductions in demand. The price paid by consumers for energy is highly salient to voters and has received considerable attention among scholars of climate politics.<sup>71</sup> Voters strongly prefer lower rather than higher energy prices, which explains the global prevalence of energy subsidies.

It is also important to note that production tax credits have led to unintended consequences – negative pricing as wind farms seek to preserve the PTC as much as possible. Investment tax credits drive the capacity investment but have no impact on operational characteristics.

**Carbon Pricing** Carbon pricing policies are those which cause consumers and business to face costs in proportion to the quantity of their greenhouse gas emissions.<sup>6</sup> The two possible implementations of carbon pricing consist of: (1) a carbon tax, whereby emitters pay a tax per metric ton of CO<sub>2</sub> or the equivalent thereof for other GHGs; and (2) cap & trade,<sup>7</sup> whereby the policymaker auctions off a fixed number of permits (the “cap” on emissions) for the right to emit GHGs to private entities, who may “trade” their permits at a later date. Carbon pricing policies compel consumers and businesses to “internalize” the global, social costs of GHG emissions to their own private decision making. Placing a price on GHG emissions incents emissions

<sup>6</sup> “Carbon pricing” policies generally also apply to non-carbon greenhouse gases.

<sup>7</sup> also known as an emission trading scheme (ETS).



reductions through a broad range of channels, including conservation, efficiency improvements, and switching to lower or zero-carbon energy sources.

Carbon taxes and cap & trade are theoretically equivalent; they can be calibrated to have identical effects, provided the policymaker has perfect information about the costs and benefits of emissions abatement.<sup>72</sup> This is, of course, a strong assumption and hence opinions differ over which policy to prefer. Carbon taxes provide certainty to consumers and businesses regarding the price they must pay to emit. Cap & trade offers policymakers flexibility in how to allocate the effective “tax burden” of buying permits by allocating initial ownership of permits to entities other than the government, such as utilities (who may then be instructed to pass on cost savings to ratepayers), trade-exposed industries (to protect them from competition located in jurisdictions without carbon pricing), or local governments of disadvantaged communities. Such free allocations preserve the beneficiaries’ incentive to reduce emissions—as they can profit by reducing emissions and trading away permits they no longer need—while advancing policymakers’ goals regarding equity.

Carbon pricing (if sufficiently stringent) would tend to promote deployment of LDES for the simple reason that LDES would become relatively more economically attractive than fossil fuels in the performance of the supply-demand balancing currently served by the storage of fossil fuels.

As of 2021, there were 64 carbon pricing policies in effect,<sup>73</sup> covering a range of jurisdictions from international (e.g., the European Union), national (e.g., Japan), and subnational jurisdictions (e.g., California). Collectively, carbon pricing policies apply to roughly 22% of the world’s annual GHG emissions (Ibid). However, the magnitude of carbon prices (the level of the tax or the price of emissions permits) tends to be fairly low, commonly ranging from single digit dollars per metric ton to \$40 per metric ton.<sup>72</sup> Where they are implemented, current carbon prices are generally lower than the range of estimates for the carbon prices needed limit global warming to 2 °C, and far off from those consistent with limiting global warming to 1.5 °C.<sup>74</sup> For context, a carbon tax of \$10 per metric ton would add about \$4.50 / MWh to the levelized cost of electricity generated from a combined-cycle natural gas power plant.<sup>8</sup>

Carbon pricing policies have long been championed by economists<sup>75</sup>; surveys of economists routinely return a near-unanimous consensus in favor of carbon pricing,<sup>76–78</sup> with a preference for carbon taxes over cap and trade.<sup>79</sup> The theoretical basis for carbon pricing dates to the work of Pigou (1920). As for the empirical evidence, the efficacy of carbon pricing is contested.<sup>80</sup> The primary difficulty in evaluating the efficacy of carbon pricing lies in the relatively low carbon prices that prevail in those jurisdictions with carbon pricing policies. Research has estimated that in Sweden that the introduction of a moderate

carbon tax on transportation fuel in 1991—plus an end to the exemption of transportation fuels from value-added tax—was responsible for a 12.5-% reduction in annual, per-capita CO<sub>2</sub> emissions from the transportation sector by of 2005.<sup>81</sup>

Beyond matters of political acceptability, carbon pricing faces criticism on the merits of the policy compared to alternative policies. We do not address all of them here but present two criticisms that are relevant to LDES. Carbon pricing is argued to be inferior to industrial policies (i.e., sector-specific regulations or technology-specific subsidies) that stimulate deployment-led innovation. “Deployment-led innovation” refers to reductions in cost and improvements in performance of a technology that arises from “learning-by-doing,” such as reductions in the cost of lithium-ion batteries that have occurred through the decades of experience of with and scaling up for their manufacture. Because carbon pricing is technology-agnostic and seeks to minimize the net present value of costs of emissions abatement, critics argue that it does not advance the techno-economic readiness of technologies (such as LDES) for which the market demand is not currently pressing. In other words, carbon pricing will initially prioritize low-cost, intermediate steps (e.g., fuel switching from coal to natural gas, extending the lives of existing nuclear power plants, improved fuel economy of internal combustion engines), rather than innovating toward a deeply decarbonized future.

A second criticism of carbon pricing is that it cannot address market, behavioral, or policy failures that lie outside the framework of negative externalities. An example market failure not addressed by carbon pricing is the public goods nature of R&D. Knowledge is a public good whose utility for one party is not diminished by its use by another party; unlike apples, steel, or natural gas, knowledge cannot be “used up.” Even if emissions are appropriately priced, thereby increasing the economic competitiveness of LDES, the market may under invest in LDES R&D because the costs are borne by those who finance the research while some of the benefits accrue to other firms as “knowledge spillovers.” While intellectual property regimes are intended to enable innovators to capture revenues commensurate with the social benefits of their innovation, the scholarly literature on innovation finds that this approach is imperfect, and spillover is a widespread phenomenon.<sup>82</sup> Subsidies for private R&D or direct public financing of R&D are two options to counteract this market failure and could be considered among a package of policies to advance LDES.

## Conclusions

As this paper has substantiated, it is a generally accepted position within the E&U sector that LDES can play a prominent role in serving needs across the US electrical grid, particularly in initiatives that are focused on: (1) climate change mitigation through decarbonization; (2) electrification, and (3) grid modernization. A caveat to the great optimism about the future prospects for LDES is that future use of these technologies is contingent upon steps being taken to address and remove existing policy barriers that prevent a

<sup>8</sup>  $\frac{\$10}{tCO_2} \times \frac{1t}{10^6g} \times \frac{450gCO_2}{kWh} \times \frac{10^3kWh}{MWh} = \frac{\$4.50}{MWh}$  The estimate of lifecycle emissions is sourced from (O’donoghue, Heath, Dolan, & Vorum, 2014).

robust marketplace for LDES technologies from developing. In other words, while there is great optimism about the future prospects for LDES, there is no unanimous agreement about where, how, and why LDES will be deployed, which continues to render the consideration of LDES more theoretical than practical as this time. The market transformation that must exist to support full decarbonization and enable widescale deployment of LDES technologies will require a coalition of efforts across policymakers, including utilities; legislators and regulators; grid operators; and energy storage technology developers and buyers. In other words, LDES technologies, particularly battery-based technologies, are still immature and determinations of how they can be used are still evolving. These uncertainties can create “policy paralysis” that can create delays the development of the regulatory rules that are needed to enable LDES implementation in the marketplace. Moreover, regulators are seeking to define the potential role of energy storage solutions in general, and specifically LDES as well, within a broader context of grid decarbonization, 100-percent renewables, and other clean energy goals.

Market certainty regarding the economic viability of LDES specifically and its ability to accelerate solar and wind penetration, grid resiliency, and serve to stabilize volatile energy prices, is still evolving. However, LDES will likely not become pervasive until the technology itself matures, regulators adapt to the capabilities of the technology, define the ways in which LDES applications can be used, and establish clear market rules for both the federal and individual compensation mechanisms that are lucrative for developers.

On the positive side, realizations about the operational opportunities for LDES continue to crystallize. Existing policies are being reconsidered and new policies are being formulated to address barriers and create opportunities for LDES to be utilized. These considerations continue to add to the momentum and enthusiasm that is currently associated with LDES, and efforts to define the future role of LDES as a technological capability within the E&U sector are bearing fruit. Regulators are tasked with seeking to define the potential role of ES in general, and specifically LDES as well, within a broader context of grid decarbonization, 100-percent renewables, and other clean energy goals.

Policymakers can play an important role in driving innovation, encouraging cost reductions, and assessing the benefits of storage to provide greater options for maintaining reliability in future decarbonized grids through research and development, demonstration projects, and regional studies. New approaches to financing, planning, and procurement could reduce barriers to the adoption of LDES technologies. Policies developed at both the federal level and within individual states have the potential to directly impact the market opportunities for LDES. Policymakers would be wise to build a policy framework for LDES today that will support the anticipated need for a proliferation of LDES technologies over the coming decades. A prudent pathway toward LDES policymaking would focus on (1) enabling the envisioned use cases for LDES; (2) establishing new

requirements to include LDES in long-term resource planning; (3) providing financial incentives to reduce risk of investment; and (4) developing new market designs that will fairly compensate LDES for the value it brings to the grid.

## Author contributions

All authors contributed equally to the manuscript.

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## Data Availability

Not Applicable.

## Code availability

Not Applicable.

## Declarations

### Conflict of interest

There is no conflict of interest/competing interests to report.

## Ethical approval

Not Applicable.

## Consent to participate

Not Applicable.

## Consent for publication

All authors have consent for publication.

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