The Design Space for Long-duration Energy Storage in Decarbonized Power Systems

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ABSTRACT

Long duration energy storage (LDES) is a potential solution to intermittency in renewable energy generation. Here we evaluate the role of LDES in decarbonized electricity systems and identify cost and efficiency performance necessary for LDES to substantially reduce electricity costs and displace firm low-carbon generation. We find that energy storage capacity cost and discharge efficiency are the most important performance parameters. Charge/discharge capacity cost and charge efficiency play secondary roles. Energy capacity costs must be $\leq$\$20/kWh to reduce electricity costs $\geq$10%. With current electricity demand profiles, energy capacity costs must be $\leq$\$1/kWh to fully displace all modeled firm low-carbon generation technologies. Electrification of end-uses in a northern-latitude context makes full displacement of firm generation more challenging and requires performance combinations unlikely to be feasible with known LDES technologies. Finally, LDES systems with the greatest impact on electricity cost and firm generation have storage durations exceeding 100 hours.

Introduction

To cost-effectively decarbonize the electric power sector, some combination of the following technological solutions must be employed to manage long-duration imbalances in variable renewable energy (VRE) supply and electricity demand: CO_2-emitting firm resources (coal and natural gas plants) can be replaced by firm low-carbon generation technologies (e.g. nuclear, fossil fuels with carbon capture and storage (CCS), bioenergy, geothermal, or hydrogen and other fuels produced from low-carbon processes)[1]; negative emissions technologies can be employed to offset CO_2 emissions from fossil fueled firm resources[2]; transmission network expansion can increase the balancing area to cover large geographic regions and exploit spatio-temporal variations in weather and VRE resource availability[3,4]; and/or energy storage can be employed to smooth out imbalances in VRE supply and electricity demand and substitute for firm resources[5].

Recent work has demonstrated that in scenarios that rely exclusively on VRE and storage, installed capacity increases rapidly after VRE energy shares exceeds $\sim$80% of annual energy demand[6] or when strict CO_2 emission limits (e.g., below $\sim$50 $kgCO_2/MWh$) restrict use of coal or gas-fired generation and force VRE shares above this level[1,7]. Sepulveda et al.[1] demonstrated that relying only on lithium ion (Li-ion) batteries (or other storage options with similar characteristics) to augment VRE capacity is not a cost-effective strategy for decarbonizing power systems. In contrast, including at least one firm low-carbon generation technology in the capacity mix lowered the cost of zero-emissions electricity systems by 10-62% across a range of scenarios.

Other work has suggested that energy storage technologies with longer storage durations, lower energy storage capacity costs, and the ability to decouple power and energy capacity scaling could enable cost-effective electricity system decarbonization with all energy supplied by VRE[8–10]. Although Li-ion batteries can technically sustain output for longer periods by de-rating discharge capacity and reducing discharge rates, the relatively high cost per kWh of energy storage capacity (in the 100s of $/kWh[11]) and limited ability to decouple power and energy capacity costs make Li-ion batteries uneconomic as a long duration storage option[12]. Here we use the term "long duration energy storage" (LDES) to refer to various technologies that are expected to be *both technically and economically* suitable to cycle the marginal (or least utilized increment of) energy storage capacity infrequently and store energy in sufficient amounts to sustain electricity production over periods of days or weeks[13,14].

The potential for LDES technologies to enable greater penetration of low-cost wind and solar resources and help reduce the cost of decarbonized power systems has led to a wave of new research and development efforts. For example, one ARPA-E program[13] directly supports development of LDES systems with duration (maximum constant operation at rated discharge power capacity) between 10 hours and 100 hours; power capacity cost (investment associated with charge and discharge power capacity) below $1,000/kW; and energy capacity cost (investment associated with energy storage capacity) below $100/kWh, with a focus on the $5-20/kWh range. Ziegler et al.[15] consider wind/solar and storage at the individual facility level and assess cost and duration requirements to produce a consistent "baseload" power output. They conclude that a combination of power and energy capacity costs of $1,000/kW and $20/kWh and a duration of 100 hours is sufficient to enable steady power output 100% of the time. Albertus et al.[14] argue that for high penetration of VRE generation ($\geq$ 90%), LDES systems with durations greater than 100 hours will be needed, with energy capacity cost below $40/kWh and power capacity cost in the range of $500-1000/kW. LDES encompasses a diverse range of technologies at varying technology readiness levels and include: electrochemical (e.g., low-cost flow batteries[16] or aqueous metal-air batteries[17]); chemical (e.g., production, storage, and oxidation or combustion of electrolytic hydrogen, known as "power-to-gas-to-power"[5,18]); thermal (e.g. sensible or latent heat storage[19,20]); and mechanical options (e.g., compressed air or pumped hydroelectric storage[21]).

We use an electricity system capacity expansion model (CEM) with high temporal resolution (8,760 hours) and detailed operating decisions and constraints[22] to assess the impact of different combinations of LDES design parameters on the overall economics of decarbonized power systems across 17,920 distinct cases. This work explores a number of unanswered questions: how do different combinations of LDES design parameters affect LDES deployment and the average cost of electricity in decarbonized power systems; how does LDES interact with and substitute for various firm low-carbon generation technologies and Li-ion batteries; and what are the most attractive/competitive architectures of LDES systems? We focus herein on five LDES technology parameters: charge power capacity cost ($/kW); discharge power capacity cost ($/kW); energy storage capacity cost ($/kWh); charge efficiency (%); and discharge efficiency (%). We collectively refer to the range of possible combinations of these five parameters as the LDES "technology design space" (see Methods), and we model a total of 1,280 discrete combinations of these cost and efficiency parameters encompassing performance levels that are consistent with projections for existing LDES technologies found in academic peer-reviewed studies (see Table 1 and Extended Data Figure-1) as well as domains that are currently infeasible but that could be the focus of technology development efforts in the future. Furthermore, we evaluate the technology design space for LDES in multiple power system contexts encompassing different wind, solar, and demand characteristics and different assumptions regarding the availability of firm low-carbon technologies (see Table 2). This includes both a system with weather and demand conditions typical of New England and a system with weather and demand typical of Texas, referred to herein as the Northern System and Southern System, respectively. The long-run system-level optimization methods used herein capture the declining marginal value of all resources and their resulting least-cost equilibrium penetration levels[23] and are thus suitable for evaluating the effect of LDES performance characteristics on the long-run evolution of power systems. We find that energy storage capacity cost and discharge efficiency are the most important LDES performance parameters, with charge/discharge capacity cost and charge efficiency of secondary importance. Energy capacity cost must fall below $20/kWh (with sufficient efficiency and power capacity cost performance) for LDES technologies to reduce total carbon-free electricity system costs by $\geq 10\%$. We observe a maximum of a 50% reduction in total system costs across the full technology design space considered; the maximum reduction is limited to 40% within the combination of cost and performance parameters likely to be achieved by known LDES technologies. For LDES to fully displace firm low-carbon generation, an energy storage capacity cost of $\leq$\$10/kWh is required for the least competitive firm technology considered (nuclear). Energy capacity costs $\leq$\$1/kWh as well as a combination of very low power costs and high efficiencies are required to displace firm technologies characterized by lower fixed costs and higher variable costs. e.g. natural gas w/CCS and hydrogen combustion turbines. We also find that high degrees of transportation and heating electrification in a northern-latitude power system makes displacement of firm generation more challenging, with full substitution requiring cost and efficiency performance combinations that are infeasible with known LDES technologies. Finally, in cases with the greatest displacement of firm generation and the greatest system cost declines due to LDES, optimal storage discharge durations fall between 100-650 hours ($\approx 4-27$ days).

System Value of LDES Technologies

We define the "system value" of a technology as the reduction in total electricity system cost that results from adding the new technology as an additional resource option in the capacity expansion framework (see Methods for detailed discussion of system value calculations). Figure 1 and Supplementary Figure 1 plot the system value of LDES as a function of the LDES energy storage capacity cost ($/kWh, referred to subsequently as energy capacity cost for brevity), the weighted power capacity cost ($/kW; see Eq. (3) in Methods section for derivation), and the round-trip efficiency (RTE) for the Northern and Southern Systems and for the three different cases of competing firm low-carbon technologies. These figures indicate that reductions in energy capacity cost (columns going from right to left) are the most significant driver of LDES value, followed by increases in round-trip efficiency (y-axis from bottom to top on each subplot), followed by reductions in weighted power capacity cost (x-axis going from right to left on each subplot).

Comparing Figure 1 and Supplementary Figure 1 reveals that the two geographic regions exhibit very similar behaviors

Table 1. Future Costs Projections for Long Duration Energy Storage Technologies

Storage Method	Technology	Discharge Power Cost [c] ($/kW)	Charge Power Cost ($/kW)	Weighted Power Cost ($/kW)	Energy Capacity Cost [d] ($/kWh)	Charge Efficiency (%)	Discharge Efficiency (%)	Round-trip Efficiency (%)
Mechanical	Pumped Hydro Storage (PHS)[24,25]	600-2000	-	600-2000	20+ [b]	-	-	70-85%
	Compressed Air Energy Storage (CAES)[21,24,26]	600-1150	-	600-1150	1-30+ [b]	-	-	42-67%
Chemical	Power-H2-Power (Brayton Cycle)[11,27–29]	700-1100	220-1400	920-2500	1-15+[a]	51-77%	35-40%	18-31%
	Power-H2-Power (Combined Cycle)[11,27–29]	900-1100	220-1400	1120-2500	1-15+[a]	51-77%	50-55%	26-42%
	Power-H2-Power (Fuel Cell)[11,21,27–29]	220-2000	220-1400	440-3400	1-15+[a]	51-77%	40-60%	20-46%
	Power-SynGas-Power (Brayton Cycle)[11,27–29]	700-1100	600-1700	1300-2800	1-5+[a]	49-65%	35-40%	17-26%
	Power-SynGas-Power (Combined Cycle)[11,27–29]	900-1100	600-1700	1500-2800	1-5+[a]	49-65%	50-55%	25-36%
	Power-SynGas-Power (Fuel Cell)[11,21,27–29]	220-2000	600-1700	820-3700	1-5+[a]	49-65%	40-60%	20-39%
Electro-chemical	Aqueous Sulfur Flow Batteries[16]	500-2000	-	500-2000	10-20	-	-	60-75%
	Vanadium Redox Flow Batteries[16]	270-600	-	270-600	40-200	-	-	65-80%
Thermal	Multi-Junction PV Thermal Storage[19]	250-350	-	250-350	8-36	-	-	40-55%
	Reciprocating Heat Pump Energy Storage[30]	400-900	-	400-900	15-25	-	-	52-72%
	Firebrick Resistance-Heated (Brayton Cycle)[11,20,29]	700-1100	30-50	730-1150	5-10	98%	35-40%	34-39%
	Firebrick Resistance-Heated (Combined Cycle)[11,20,29]	900-1100	30-50	930-1150	5-10	98%	50-55%	49-54%

[a] Lower end of the cost range subject to geological and geographic constraints
[b] Full cost range subject to geological and geographic constraints
[c] The quoted value for some technologies include the cost of the charging component as well (e.g. PHS)
[d] Energy capital cost is denoted in units of storage medium and not kWh of electricity.

Table 2. Scenario Definitions

Scenario #	System	Load/ Weather Condition	Firm Resource	VRE & Li-ion Cost	Total Demand [MWh]	Peak Demand [MW]
1	Southern	Base/ Base	Blue H_2	Low	441,166,204	90,735
2	Southern	Base/ Base	Gas w/CCS	Low	441,166,204	90,735
3	Southern	Base/ Base	Nuclear	Low	441,166,204	90,735
4	Northern	Base/ Base	Blue H_2	Low	181,472,557	35,912
5	Northern	Base/ Base	Gas w/CCS	Low	181,472,557	35,912
6	Northern	Base/ Base	Nuclear	Low	181,472,557	35,912
7	Northern	Electrification/ Base	Blue H_2	Low	299,950,796	76,619
8	Northern	Electrification/ Base	Gas w/CCS	Low	299,950,796	76,619
9	Northern	Electrification/ Base	Nuclear	Low	299,950,796	76,619
10	Northern	Base/ Higher VRE	Gas w/CCS	Low	181,472,557	35,912
11	Northern	Base/ Lower VRE	Gas w/CCS	Low	181,472,557	35,912
12	Northern	Electrification/ Base	Blue H_2	Medium	299,950,796	76,619
13	Northern	Electrification/ Base	Gas w/CCS	Medium	299,950,796	76,619
14	Northern	Electrification/ Base	Nuclear	Medium	299,950,796	76,619

[1] Systems: Southern(ERCOT), Northern (ISONE)
[2] Load Profiles: Base (linear growth), Electrified
[3] Firm Resources: Nuclear, Natural Gas with CCS, Blue H_2
[4] Weather Years: Base, Higher VRE CF, Lower VRE CF
[5] Variable Renewable (VRE) and Li-ion Storage Cost: Low NREL ATB, Mid NREL ATB

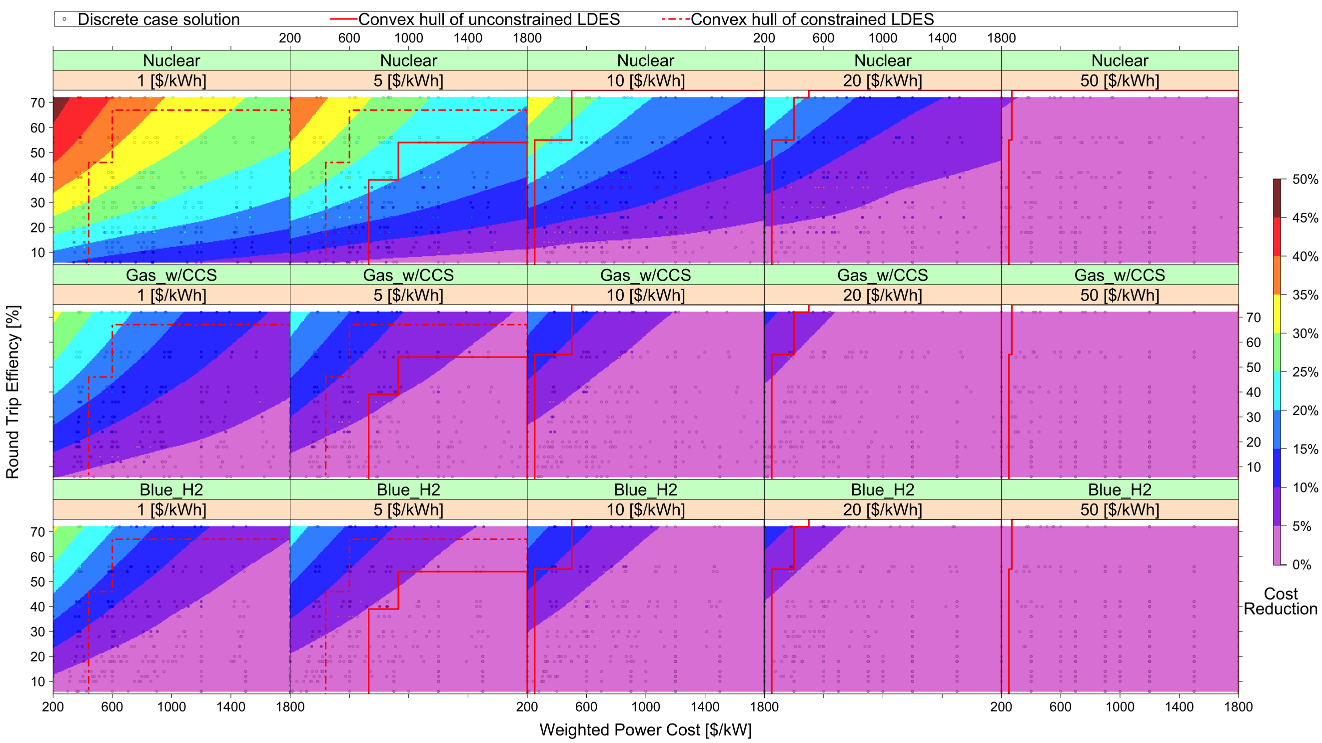

Figure 1. System cost percentage reduction in the Northern System for LDES parameter combination. Percentage reduction calculated compared to Reference Cases (Scenarios 4-6 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system costs. "Future feasible regions" for known LDES technologies from Extended Data Figure-1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) for each row (see Methods "LDES Future Feasible Regions" for details). Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total annualized system costs for the reference cases (in USD per MWh) are as follows: nuclear - $74.01; gas w/CCS - $57.20; Blue H_2 - $56.02.

for the value of LDES as a function of the technology design space parameters. At the same time, the figures show that the ability of LDES to deliver value to the system depends significantly on which firm low-carbon technology is available (also confirmed by Table 3). For the same combination of LDES design space parameters, LDES delivers greater system value for cases with nuclear power as the only available firm low-carbon resource than for cases with gas w/CCS or hydrogen combustion ("Blue H_2"). Nuclear power has relatively higher capital cost, lower variable cost, and lower flexibility (ramping capability, minimum stable output, and cycling parameters) than the other firm low-carbon resources modeled. These techno-economic characteristics appear to make nuclear less well suited to pair with low-cost wind and solar, at least for the specific generation cost and performance assumptions herein (see Supplementary Table 2 & Supplementary Table 4). Across the full range of modeled technology design space parameters, the largest power system cost reduction due to LDES deployment is in the 45-50% range. When the parameter range is limited to the "future feasible regions" for known LDES technologies (red lines marked in Figure 1; see Extended Data Figure-1 and Methods section for details), the maximum cost reduction is in the 35-40% range. For the gas w/CCS and Blue H_2 cases, the maximum observed cost reduction declines to 30-35% across the whole modeled design space, to 20-25% within the future feasible regions for geographically-constrained LDES technologies, and 10-15% for geographically unconstrained technologies.

In order to better understand the drivers of LDES value creation, we perform a regression analysis on the 7,680 data points included in Figure 1 and Supplementary Figure 1 . For the regression analysis we preserve the original dimensionality of the LDES design space (5 dimensions, versus the 3 dimensions plotted in the figures) and include categorical variables for the system context and available firm low-carbon technology (Table 2). Table 3 shows a summary of the regression analysis on the data after a Min-Max Normalization of the non-categorical regressors (β_1 - β_5).

The results demonstrate the rather modest impact of regional geography (β_6) on the LDES system value. Keeping everything else constant, the cost reduction would be only 0.3% greater in the Northern System than the Southern System. The impact of varying the available firm low-carbon resource is larger (β_7 and β_8). With blue H_2 as reference, and keeping everything else constant, the average cost reduction (i.e., the increase in LDES system value) would be 1% greater if gas with CCS is the available firm resource and 9% greater if nuclear is available.

The regression also confirms that energy capacity cost (β_1) is the largest coefficient predicting system value of LDES. Supplementary Figure 3 shows the yearly cycling of the least-utilized 1% of installed LDES energy storage capacity, which we refer to as the "marginal increment of capacity," versus the LDES system value and demonstrates that in cases with the greatest LDES system value, the marginal increment of energy storage capacity is cycled (charged/discharged) less than 10 times per year. Such infrequent utilization requires very low energy capacity costs to be economic.

Additionally, this regression analysis decomposes charge and discharge power costs and efficiencies and indicates that discharge efficiency (β_4) is the second most important factor in determining LDES system value after energy capacity cost, while charge efficiency (β_5) and charge and discharge power capacity cost (β_2 and β_3) are of secondary importance. Regression coefficients indicate that a given improvement in discharge efficiency has roughly twice the impact as an equivalent improvement in charge efficiency. This makes intuitive sense in that an improvement in discharge efficiency reduces both the energy storage capacity and the charge power capacity required to deliver a given amount of electricity output upon discharge. In other words, higher (lower) discharge efficiency requires lower (higher) charge power and energy storage capacity cost, all else equal.

Finally, improvements to discharge power capacity cost have slightly greater impact than equivalent improvements in charge power capacity cost (β_2 and β_3). Supplementary Figure 4 compares the percentage of hours that are spent in charging versus discharging and shows that LDES systems generally spend a greater fraction of the year charging than discharging. This indicates that LDES technologies in decarbonized power systems are able to charge over longer periods of time when excess VRE is available and electricity prices are zero or near-zero, whereas these assets will be required to discharge energy during shorter periods of time due to VRE shortages, making improvements in discharge power capacity cost more valuable to the system than improvements in charging power capacity cost.

Table 3. Reduced Cost Multivariate Regression On Min-Max Normalized Descriptors

Coefficients	Factor	Estimate	Std. Error	t value	Pr(>|t|)[2]
(Intercept)	α	2.96	0.18	16.71	<2e-16 ***
USD kWh	β_1	-9.94	0.15	-68.27	<2e-16 ***
USD kW Discharge	β_2	-3.26	0.14	-23.63	<2e-16 ***
USD kW Charge	β_3	-2.89	0.14	-20.95	<2e-16 ***
Charge Eff.	β_4	3.21	0.14	22.90	<2e-16 ***
Discharge Eff.	β_5	7.30	0.14	52.07	<2e-16 ***
System: Northern[a]	β_6	0.31	0.11	2.97	0.00299 **
Firm Tech: Gas w/CCS[b]	β_7	1.14	0.13	8.90	<2e-16 ***
Firm Tech: Nuclear[b]	β_8	9.00	0.13	70.26	<2e-16 ***

Model: $Cost\ Reduction[\%] = \alpha + \beta_1 + \beta_2 + \beta_3 + \beta_4 + \beta_5 + \beta_6 + \beta_7 + \beta_8$
[1] observations: 7680
[2] Significance codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
[3] Residual standard error: 4.581 on 7671 degrees of freedom
[4] Multiple R-squared: 0.6579, Adjusted R-squared: 0.6576
[5] F-statistic: 1844 on 8 and 7671 DF, p-value: < 2.2e-16
[a] Binary for categorical variable "System" {Northern,Southern}
[b] Binaries for categorical variable "Firm Tech" {Gas w/CCS,Nuclear,Blue H_2}

Figure 2 presents the system value of LDES in the Northern System under a scenario with high electrification of transportation, heating, and industrial energy supply, consistent with the goal of reducing economy-wide greenhouse gas emissions by 80% below 1990 levels by 2050[31]. The results indicate that further electrification of energy supply in Northern latitudes reduces the system value of LDES. The maximum system value in the future feasible regions for known LDES technologies remains at 35-40% under the high electrification scenario, but only in the most extreme upper-left corner of the feasible region for geographically-constrained resources and only when nuclear is the firm resource. For LDES resources without geographic constraints the maximum system value falls from 25-35% with current electricity demand profiles to a maximum of 15-20% with high demand electrification. Similarly, when gas w/CCS and H_2 are available, the maximum system value of LDES in the feasible region for geographically-constrained LDES technologies falls from 25-30% to 15-20% under high electrification. LDES system value is limited to 10% in the feasible region for technologies without geographical constraints. Under high electrification, the peak demand in the Northern System increases from 36 GW to 77 GW, the median demand increases from 21 GW to 33 GW, the maximum hourly change in demand (ramp) increases from 3.4 GW to 17.4 GW, and the median ramp increases from 0.5 GW to 1.7 GW. As shown in Supplementary Figure 26, electrification also adds a strong seasonal component to load variation due to electrification of heating. These demand profile changes increase the value of power capacity in the system relative to the value of energy shifting capacity, thereby increasing the competitiveness of firm low-carbon resources while reducing (but not eliminating) the relative system value of LDES.

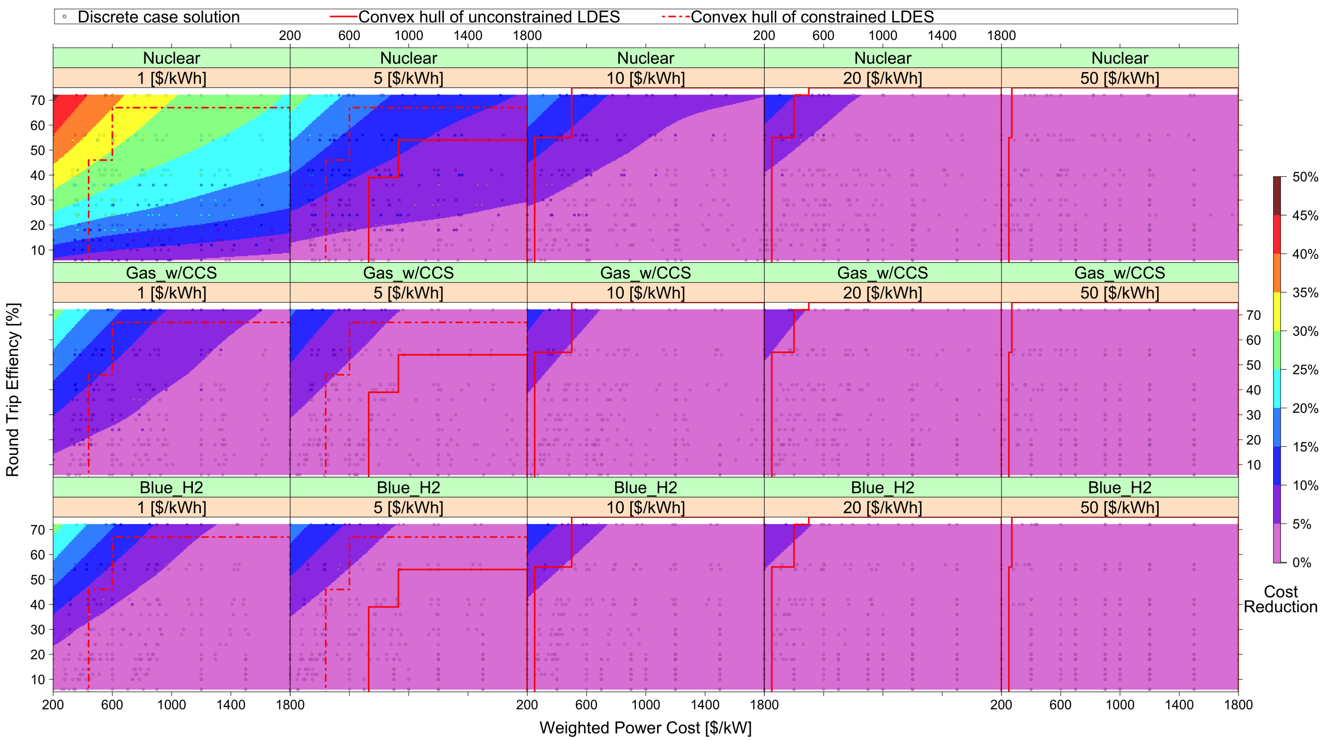

Figure 2. System cost percentage reduction in Northern System with Electrified Load for LDES Parameter Combination. Percentage reduction calculated compared to Reference Cases (Scenarios 7-9 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system costs. "Future feasible regions" for known LDES technologies from Extended Data Figure-1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) for each row (see Methods "LDES Future Feasible Regions" for details). Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total annualized system costs for the reference cases (in USD per MWh) are as follows: nuclear - $90.33; gas w/CCS - $66.93; blue H_2 - $66.78.

Future costs of wind, solar, and Li-ion batteries are predicted to continue declining, yet the exact pace remains uncertain. On the one hand, lower cost wind and solar favor increasing VRE penetrations and the accompanying volatility in net load, thereby increasing the market opportunity for storage technologies. On the other hand, lower cost wind, solar, or batteries reduce the relative capacity substitution value of LDES, which is shown to be central to the system value of storage technologies[32]. Which effect dominates outcomes is unclear *a priori*. Scenarios 12-14 investigate the impact of higher VRE and battery costs for the Northern system under high electrification scenarios (see Supplementary Table 4). As compared to Scenarios 7-9 outcomes, we find that the maximum system cost reduction from LDES declines from 50% (Figure 2) to 37% (Supplementary Figure 2) with higher battery and VRE costs. That said, higher VRE and Li-ion cost also lead to greater LDES system value in other regions of the LDES design space investigated here. For example, when LDES cost and performance is similar or superior to Li-ion storage assumptions in Scenarios 7-9 (e.g. \$50/kWh,<\$1000/kW) , we see greater value of LDES in Scenario 12-14 (Supplementary Figure 2) vs. Scenario 7-9 (Figure 2). This trend is most evident in the case of nuclear as the firm resource, since storage's ability to improve firm capacity utilization is most valuable for high capital cost and less flexible resources like nuclear (discussed in more detail later).

Extended Data Figure-2 depicts the sensitivity of the average cost of delivered electricity due to changes in the weather data under more extreme weather years (see Methods) with availability of wind and solar resources (higher or lower VRE capacity factor) across the full range of LDES technology design space cases. Note that capacity results are re-optimized in each case pointing to the effect that weather uncertainty would have on the spread of the distribution of results if capacity were optimized in a stochastic environment. The results show that in general, for the same combination of LDES parameters, the average cost of electricity is lower for the Higher VRE CF (Capacity Factor) Scenario and higher for the Lower VRE CF Scenario. This is expected, as higher/lower VRE availability should decrease/increase the levelized cost of electricity from wind and solar resources and have a corresponding effect on total electricity system cost. However, the figure demonstrates that for very low energy capacity cost LDES cases (i.e., \$1/kWh), weighted power cost below \$1000/kW, and RTE greater than 50% the average cost of electricity with lower VRE availability approaches the solid line (i.e., the result is the same as in the case using base weather assumptions), whereas the cost savings for the higher VRE availability case are greater. This suggests that LDES technologies with very low energy capacity costs can provide a hedge against the adverse impacts of years with unfavorable wind and solar conditions.

Displacing Firm Generation and Lithium Ion Storage Capacity

Figure 3 and Supplementary Figure 5 show the reductions in firm low-carbon capacity enabled by LDES for the Northern and Southern systems under current demand profiles relative to the corresponding cases without LDES (Scenarios 1-6). In contrast to the previous results for the system value of LDES, there are significant differences between the Northern and Southern systems in this outcome metric. In general, the impact on firm capacity displacement is greater in the Southern system. As with system value, the results are sensitive to which firm low-carbon technology is assumed to be available. When nuclear is the firm resource, the extent of substitution by LDES is generally greater than for gas w/CCS and blue H_2. In both regions, complete displacement of gas w/CCS and H_2 would require LDES technologies with energy capacity cost $\leq$\$1/kWh, power cost $\leq$\$400/kW, and round-trip efficiency $\geq$50%, a combination that appears to fall outside the feasible performance region for projected technologies.

Under high electrification (Scenarios 7-9), the percentage reduction in firm low-carbon capacity with LDES adoption is drastically reduced in the case of the Northern system as shown in Figure 4, with most of the 100% displacement regions seen in Figure 3 eliminated. Together with cost results shown in Figure 2, these results indicate that electrification of energy supply in northern latitudes increases the value of firm capacity due to increased short-term variability and more pronounced seasonal

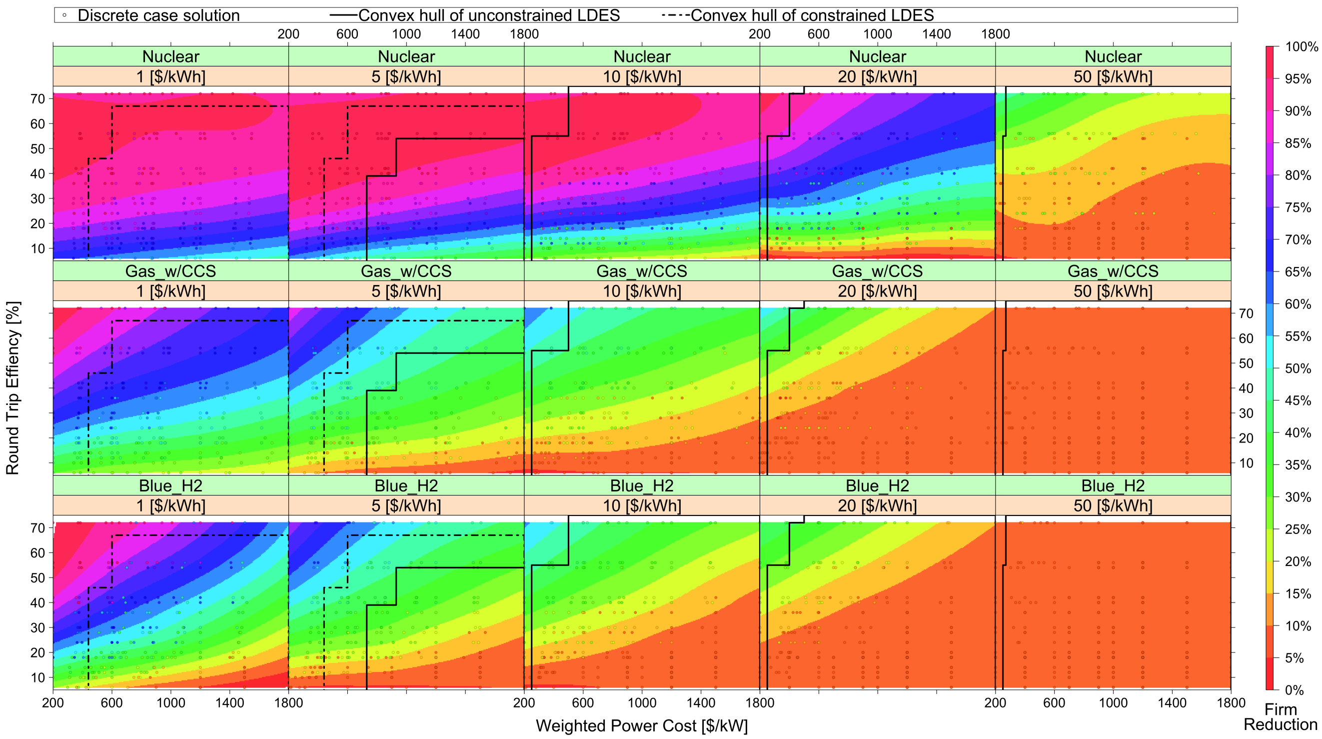

Figure 3. Firm capacity percentage reduction in Northern System for LDES Parameter Combination. Percentage reduction calculated compared to Reference Cases (Scenarios 4-6 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in firm capacity. "Future feasible regions" for known LDES technologies from Extended Data Figure-1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) for each row (see Methods "LDES Future Feasible Regions" for details). Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total firm capacity for the reference cases normalized by peak demand (in %) are as follows: nuclear - 48.6%; gas w/CCS - 48.5%; blue H_2 - 44.3%.

variations in demand. While the displacement of firm low-carbon generation is diminished in high-electrification scenarios, LDES still retains the potential to reduce electricity cost in such scenarios, as Figure 2 shows.

With higher VRE and Li-ion capital costs (Scenarios 12-14, Supplementary Figure 6), firm substitution further declines (relative to Scenarios 7-9) across all firm technologies and areas of low energy capacity cost (e.g. <5$/kWh) and higher RTE (>50%). This confirms the relatively lower system value of LDES if wind, solar, and storage costs decline at a more moderate rate in future years. However, across areas with higher energy storage capacity costs (10-50$/kWh), changes in firm substitution are more complex: areas of 10-50% firm substitution expand for gas w/CCS and H_2, but shrink for nuclear. Indeed, with nuclear, there are now areas of the design space where LDES increases nuclear capacity by up to 10%. The likely cause of these seemingly contradictory effects is actually the same: in this region of the design space, LDES is deployed with shorter duration (<50 hours, Supplementary Figure 21) and competes primarily with Li-ion batteries. As Li-ion is more costly in Scenarios 12-14 relative to Scenarios 7-9, LDES achieves greater substitution of Li-ion (Supplementary Figure 13 and Supplementary Figure 14). With LDES now relatively cheaper than Li-ion in this shorter-duration role, the greater deployment of LDES reduces both peaks and valleys in the net load that must be served by firm resources. Gas w/CCS or H_2 capacity that is used to meet infrequent peaks in net load can thus be avoided, while valleys in net load are also reduced, increasing the capacity factor and relative value of nuclear. These differing substitution effects for nuclear vs. gas w/CCS and H_2 stem from the ratio of fixed to variable costs (higher for nuclear, lower for the two fuel combustion technologies). This example of possible complex system interactions reinforces the importance of systems-level modeling rather than isolated assessment (e.g.[15]) of LDES technology competitiveness.

Supplementary Figure 7 through Supplementary Figure 14 show the impact on Li-ion power and energy capacity of introducing LDES to the capacity expansion framework. These results demonstrate that LDES does not significantly displace Li-ion capacity until LDES weighted power cost falls ≤$800/kW at ≥70% RTE. There are also areas of the LDES design space where Li-ion power and energy capacity are higher than the case with no LDES. These findings indicate that unless LDES technologies exhibit a sufficient combination of low power costs and relatively high efficiency, they are weak substitutes or even complements for Li-ion batteries. This confirms the finding in Sepulveda et al.[1] that Li-ion batteries play a very different role in low-carbon power systems as "fast burst balancing resources" that primarily provide power and flexibility services over shorter durations (typically a few hours). By contrast, LDES technologies, which provide sustained energy supply over long periods, have the potential to substitute directly for firm generation, particularly if low energy capacity costs are achieved. Supplementary Figure 22 reinforces this finding by highlighting the different operating patterns of LDES and Li-ion across a range of LDES power capacity and energy capacity costs for the Northern system with gas w/CCS (Scenario 5). As LDES energy capacity cost is reduced from $10 to $1/kWh, firm displacement increases and is accompanied by a shift in LDES operations from multiple near-complete charge-discharge cycles to a single such cycle spanning seasons. If LDES simultaneously achieves both low energy capacity cost and low power cost/high RTE, then LDES could substitute for both firm generation and Li-ion or other short-duration "fast burst" storage technologies. In such a case, Supplementary Figure 22

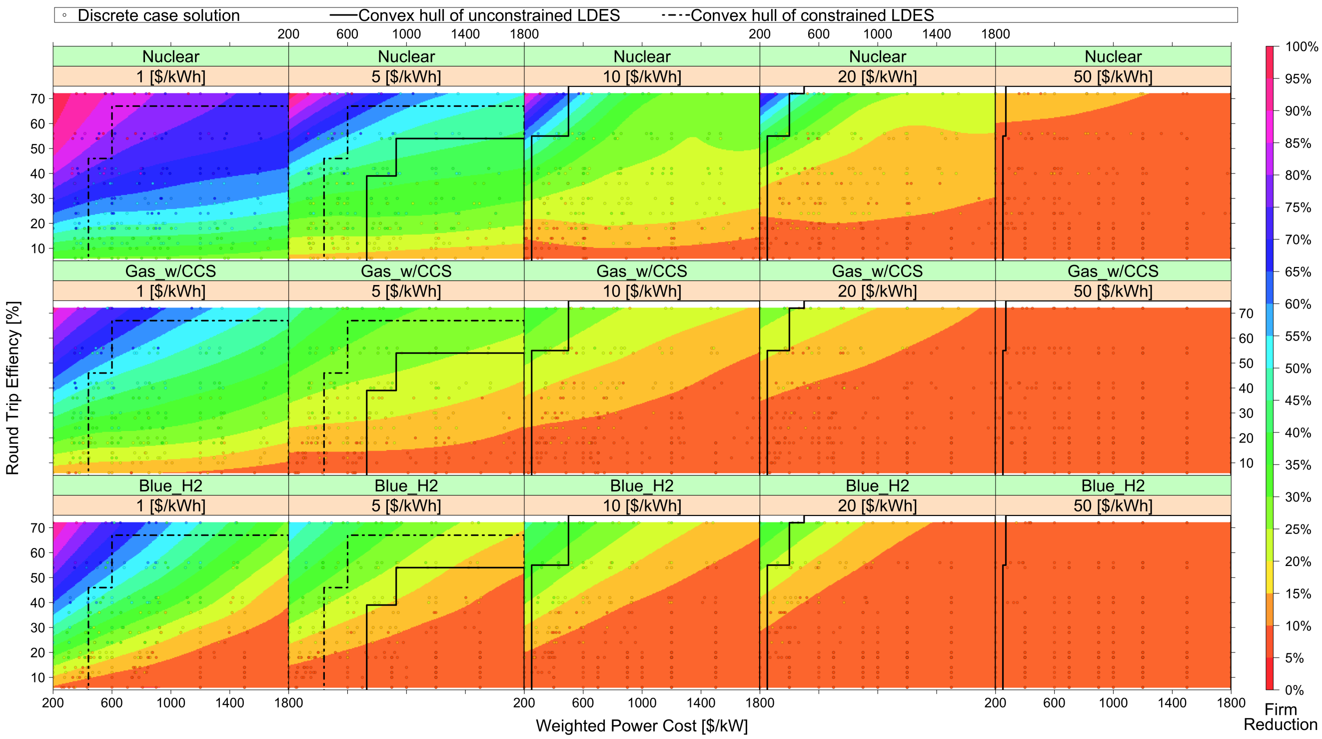

Figure 4. Firm capacity percentage reduction in Northern System with electrified load for LDES Parameter Combination. Percentage reduction calculated compared to Reference Cases (Scenarios 7-9 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in firm capacity. "Future feasible regions" for known LDES technologies from Extended Data Figure-1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) for each row (see Methods "LDES Future Feasible Regions" for details). Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency. Total firm capacity for the reference cases normalized by peak demand (in %) are as follows: nuclear - 48.6%; gas w/CCS - 51.3%; blue H_2 - 47.5%.

indicates that LDES operations will exhibit increased high power, low energy (e.g. intra-day) cycling to compensate for the role played by Li-ion without impacting high energy cycles occurring over longer periods. However, the LDES performance requirements to fully displace Li-ion and also displace a large amount of firm resources mostly lie beyond the future feasible regions for known LDES technologies.

Design of LDES Technologies

In this study, we set the minimum energy capacity to discharge power ratio for LDES systems at 10:1 and the maximum at 1000:1 (Li-ion storage is modeled as $\leq$10:1 energy to power ratio). The CEM then optimizes energy capacity and discharge capacity independently within this range. Note that energy to power ratio is often described as the storage duration. However, the maximum duration of sustained discharge that any storage technology can achieve is also affected by the discharge efficiency, which is important given that some LDES technologies have relatively low discharge efficiencies. We therefore define LDES 'duration' (in hours) as $(E \cdot \eta^{-})/P_d$, and refer to the ratio of E/P_d as the LDES 'energy to power ratio,' where E, P_d, and η^{-} are the energy capacity, discharge power capacity, and discharge efficiency, respectively.

Supplementary Figure 15 and Supplementary Figure 16 plot LDES energy to power ratio for the Northern and Southern systems respectively, and Figure 5 and Supplementary Figure 19 present the LDES duration. These figures show that for energy capacity costs of $\geq$\$10/kWh, LDES duration is generally in the 100 hour range (with energy-to-power ratios reaching as high as 300:1 when efficiency is low). This also holds for energy capacity costs of \$5/kWh if gas w/CCS or blue H_2 are the available firm generation options. Additionally, duration is largely unaffected by weighted power capacity cost at these levels but somewhat more affected by round-trip efficiency. In general, higher energy-to-power ratio and discharge durations occur in both the Northern and Southern systems when nuclear is the available firm low-carbon technology. With very low energy capacity costs of \$1/kWh, duration approach 400 hours, with energy-to-power ratios as high as 900:1. These findings suggest that the maximum sustained discharge period required for LDES capacity generally ranges from several days to a few weeks, rather than months or seasonally. However, LDES may charge over longer time periods (Supplementary Figure 4), and the utilization of energy capacity may exhibit seasonal patterns (Supplementary Figure 22).

Supplementary Figure 17 and Supplementary Figure 20 show LDES energy-to-power ratio and discharge duration results for the Northern System under high electrification assumptions. Duration increases with electrification, especially for cases when nuclear power is the firm resource, reaching values in the 650 hour range for an energy capacity cost of \$1/kWh. Note that the imposed maximum energy-to-power ratio of 1000:1 is binding in 60 cases with high electrification in the Northern System and with very low discharge efficiencies ($\leq$ 36% RTE) and an energy capacity cost of \$1/kWh (Supplementary Figure 17).

While most electrochemical storage technologies use the same cathode/anode system for charging and discharging and thus have symmetric power capacity and efficiency parameters, most chemical and thermal storage technologies and some mechanical storage technologies use distinct mechanisms or devices for charging and discharging. Extended Data Figure-3 and Supplementary Figure 23 explore the relationship between the discharge power capacity and the charge power capacity

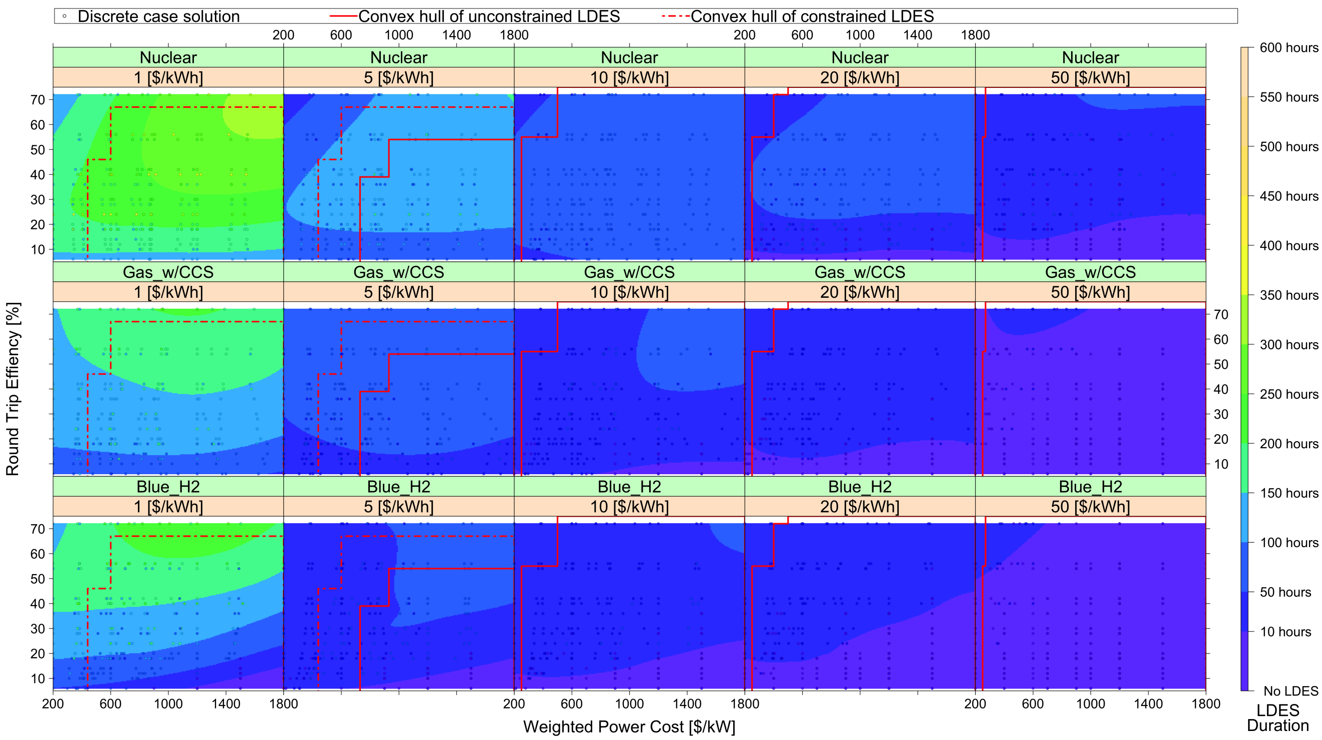

Figure 5. LDES duration (Energy Capacity x Discharge Efficiency)/(Discharge Capacity) in hours in Northern System for optimal deployment of LDES. Each row of plots represents a different scenario using a different firm low-carbon technology. “Future feasible regions” for known LDES technologies from Extended Data Figure-1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) for each row (see Methods "LDES Future Feasible Regions” for details). Each column represents a specific LDES energy capacity cost ($/kWh) assumption in the LDES parameter combination. Within each subplot the x-axis represents the weighted power capacity cost and the y-axis the round-trip efficiency.

relative to peak demand in the Southern and Northern systems respectively. The figures show that optimized LDES power capacities are frequently unbalanced, with a generally greater need for discharge capacity. This is attributable to the fact that LDES systems are able to charge over longer periods of time, but must inject energy back into the system more rapidly when VRE resources are unavailable (Supplementary Figure 4). Nevertheless, a small number of cases exhibit unbalanced systems in the other direction, with a preference for greater charge capacity. Specifically, these occur for combinations of very low energy capacity cost and very low charge power capacity cost. The optimal configuration of LDES power capacities thus depends on where a technology ultimately falls within the LDES design space.

Discussion

A variety of potential LDES technologies exist that offer different combinations of potential cost and performance parameters which is captured within the wide design space assessed in this paper. This work thus offers a thorough evaluation of a diverse range of potential LDES technologies and provides insight into their potential value in decarbonized electricity systems. Supplementary Discussion 1 presents an extended summary of findings. Supplementary Discussion 2 presents a more detailed discussion of the implications for LDES technology selection and design including technologies in Table 1.

Methods

LDES Technology Design Space

Given uncertainty in future technology development, we evaluate a LDES "technology design space" that both encompasses performance levels that are consistent with projections of "future feasible regions" identified in the literature for existing or emerging LDES technologies (Table 1 and Extended Data Figure-1) and also includes domains of performance lying outside these regions as a basis for exploring potential targets for future development efforts. These include: i) charge and discharge power capacity cost of 100, 300, 600, and 900 \$/kW, ii) energy capacity cost of 1,5, 10, 20, 50 \$/kWh, iii) charge efficiency of 30, 50, 70, 90 %, and iv) discharge efficiency of 20, 40, 60, 80 %. The full combination of the above values defines the LDES technology design space explored in this research. A total of **1,280** combinations of these parameters were tested under different power system scenario configurations (Table 2). Note that while we present the projected performance regions for existing LDES technologies as simple boxes for plotting in Extended Data Figure-1, not all points within the plotted areas may be simultaneously achievable due in particular to trade-offs between power capital costs and efficiency (e.g., the regions of lowest projected power cost and highest projected round-trip efficiency may not be practically achievable for all technologies)

All capacity costs are modeled on a fully installed basis. Charge and discharge efficiencies are assumed to be invariant with discharge or charge rate or state of charge. Charge and discharge power capacity costs are based on AC power injected or withdrawn from the grid and assumes inclusion of grid interconnection costs. Because energy capacity and power capacities are independently sized based on the above defined cost parameters, storage "duration", representing the numbers of hours operation at peak discharge, is a dependent parameter that is a model output rather than an input (see Eq. (1)). .

LDES power and energy capital costs are transformed into annuitized investment cost using a 30-year capital recovery period and a weighted average cost of capital of 7.1% (nominal). We provide a conversion table (Supplementary Table 5), which can be used to compare a resource with a different asset life or a different cost of capital assumption to the findings in this paper. The charge power capacity and energy storage capacity investments are assumed to have no O&M costs associated with them. A comparable fixed O&M cost from Li-ion batteries is assumed to be associated with the discharge power capacity investments of LDES. Self-discharge losses and system degradation for LDES systems and Li-ion batteries were not modeled in this work.

Additionally, we set the minimum ratio of rated energy capacity to rated discharge power capacity for the LDES technologies to be at least 10:1[13]. We model a maximum LDES energy-to-power ratio of 1,000:1. This constraint ends up non-binding in all but 60 cases modeled herein, all of which have RTE of 36% or lower and energy capacity cost of $1/kWh. The LDES design space includes a variety of technologies, with some technologies allowing energy and power capacity to be scaled independently and some also allowing charge and discharge power capacity to be scaled independently. Our exploration of the LDES design space assumes that the three scaling dimensions – energy capacity, discharge power capacity, and charge power capacity – can be varied independently, even though all three degrees of freedom are not possible for certain technologies.

Li-ion batteries are deployable with energy to power ratios between 0.5:1 and 10:1 and with energy and power capacity sized independently – i.e., we assume a constant energy capacity scaling cost for Li-ion batteries with duration between ∼30 minutes and ∼10 hours.

Explored Scenarios

Table 2 shows the attributes of the different scenarios explored, i.e., alternative power systems (Northern vs Southern), load profiles (Base vs Electrified), available firm low-carbon resources (Nuclear, Gas w/CCS, and Blue H_2), and weather years (Base, Higher VRE availability and Lower VRE availability). The Supplementary Information presents detailed procedures used to develop the electricity demand and wind/solar inputs for each of these scenarios, including using a cluster-based approach to characterize spatial variability in wind resources (see section on "Variable Renewable and Demand Assumptions"). These profiles are typical of New England (for the Northern system) and Texas (for the Southern system) and are selected in order to explore the impact of variation in latitude, air conditioning and heating demand, and other weather and climate-related conditions on LDES system value and capacity deployment. Note that we are not modeling with realism the New England or Texas power systems in this study, and findings should not be interpreted as indicative for planning in these regions. Supplementary Note 3: Variable Renewable and Demand Assumptions presents details regarding Variable Renewable and Demand Assumptions. Supplementary Figure 24 shows the different duration curves for the solar and wind profiles used for the base weather year for each system. Supplementary Figure 25 shows the different duration curves for the solar and wind profiles used for the higher and lower VRE availability years for the Northern system. Supplementary Figure 26 shows a comparison of the base and higher electrification profiles for the Northern system. Additionally, we test sensitives to differences in wind, solar, and battery costs. As we use the low-range cost trajectory for these technologies from the National Renewable Energy

Laboratory Annual Technology Baseline 2018 (NREL ATB 2018) for Scenarios 1-11, we also run Scenarios 12-14, which replicate Scenarios 7-9 (Northern System, High Electrification) with the ATB 2018 mid-range cost trajectory for wind, solar and batteries (see Supplementary Table 4).

We investigate the value of LDES in conjunction with three different firm low-carbon generation technologies – nuclear power, natural gas plants with CCS, and hydrogen combustion power plants – selected to span the range from high fixed/low variable costs to low fixed/high variable costs. We parameterize the hydrogen combustion plants using assumptions for the cost of hydrogen derived from natural gas reforming with CCS (referred to as "blue H_2"), although this resource could represent any power plant burning a zero or near-zero carbon fuel with similar costs ($\sim$\$15 per million BTU). In order to isolate the effect that different firm low-carbon resources can have on LDES deployment and system value, each scenario only includes a single type of firm low-carbon resource. This experimental approach creates a more favorable (less realistic) setting for LDES, but also allows for better understanding of the impact of a specific competing firm low-carbon generation source on the system value of LDES. All cases correspond to decarbonized power systems in which only firm low-carbon resources, wind, and solar PV are eligible to contribute to electricity supplies. In total, **14** different scenarios were constructed as shown in Table 2 and **17,920 distinct cases**, each consisting of a particular combination of LDES parameters and a scenario, were simulated in the CEM framework.

Model and Parameters

This research uses the GenX model, an electric power system CEM described in detail elsewhere[22]. In its application in this paper, the model considers detailed operating characteristics such as thermal power plant cycling costs and constraints (unit commitment), limits on hourly changes in power output (ramp limits), and minimum stable output levels, as well as inter-temporal constraints on energy storage. The model also captures a full year of hourly chronological variability of electricity demand and renewable resource availability. The linear programming model selects the cost-minimizing set of electricity generation and storage investments and operating decisions to meet forecasted electricity demand reliably over the course of a future year, subject to specified policy constraints. Supplementary Note 1: Model Configuration provides details regarding model configuration for this study. A full mathematical formulation of the model as used for this study is provided in the Supplementary Note 4: GenX Overview. This section also includes details regarding time wrapping and coupling. Specific modifications needed to model LDES technologies are detailed in Supplementary Note 5: Long-duration Energy Storage Implementation. As we are modeling hypothetical systems, not specific regional power systems, no explicit transmission constraints are modeled within each region. Each region includes several clusters of candidate wind and solar sites, each with different profiles and a maximum capacity limit. Each region also includes one additional wind cluster with a high capacity factor and no maximum capacity but with implicit transmission connection costs added to the capital cost to represent a distant but productive wind resource area.

Supplementary Note 2: Economic and Operational Parameters provides details regarding technical and economical parameters. Supplementary Table 2 through Supplementary Table 6 show the economic and technical assumptions used in this research, which are sourced from a variety of literature sources. Where possible, input parameter values were extracted from the NREL ATB 2018[33]. Capital cost assumptions for solar and wind generators and Li-ion battery storage used in this research correspond to the 2045 low cost projection of ATB 2018 in Scenarios 1-11 and mid cost projection for Scenarios 12-14.

LDES Impact Measurement

In order to understand the dynamics of LDES deployment and its system effects, for each of the 14 scenarios a reference LDES "Base Case" was specified which does not include any LDES capacity deployment. Supplementary Table 1 presents a summary of the main results of the 14 Base Cases including the total system cost (bn$), the average cost of electricity ($/MWh), the total firm capacity deployed in the system (MW), the total wind and solar capacities deployed in the system (MW), and the energy (MWh) and power (MW) capacities of Li-ion batteries.

The bulk of the analyses presented here calculate the changes relative to the 14 Base Case results when LDES is added to the capacity expansion framework as an eligible resource, with different combinations of LDES cost and efficiency parameters selected from across the design space. We define the system value of LDES by calculating the percentage reduction in annualized electricity system cost for a given case with LDES relative to the corresponding Base Case without LDES but with all other model parameters identical. We likewise calculate the percentage reduction in firm low-carbon generation capacity and Li-ion battery capacity relative to the corresponding Base Case when LDES is made available to the CEM.

LDES Impact Visualization

In order to present the results of our analysis within the limitations of two-dimensional visualizations, we introduce the following additional metrics using LDES's energy capacity, E (MWh), discharge power capacity, P_d (MW), and charge power capacity, P_c (MW): i) *duration*, d (hours) – maximum continuous discharge at rated capacity – is calculated as the ratio of energy capacity and discharge power capacity multiplied by the discharge efficiency (η^-) (Eq. (1)); (ii) *round-trip efficiency*, η^2 (%) is calculated as the product of charge efficiency, η^+ (%) and discharge efficiency, η^- (%) (Eq. (2)); and (iii) *weighted power capacity cost*, C_{WP} ($/kW) is introduced to express the charge power cost, c_{CP} ($/kW) and discharge power cost, c_{DP} ($/kW) in one combined metric. As shown in Eq. (3), the weighted power capacity cost is calculated as the capacity-weighted sum of the discharge power capacity cost and the charge power capacity cost divided by the average power capacity of the LDES system. Weighted average power cost thus corresponds to the equivalent power capacity cost per kW for a technology that uses the same component for charging and discharging (such as an electrochemical battery). The Maximum functions in Eq. (3) are needed to calculate the weighted power capacity cost in cases with no deployment of LDES capacity. Using the metrics shown in (2) and (3) it possible to explore our results in an LDES design space that has lower dimensionality and thus allows us to better visualize results.

$$d = \frac{E \times \eta^-}{P_d} \tag{1}$$

$$\eta^2 = \eta^+ \cdot \eta^- \tag{2}$$

$$C_{WP} = \frac{c_{DP} \cdot \max(1, P_d) + c_{CP} \cdot \max(1, P_c)}{(\max(1, P_d) + \max(1, P_c))/2} \tag{3}$$

In various figures herein representing system value or firm and Li-ion capacity substitution of LDES, the shaded regions are colored differently for each 5% increment in electricity system cost/capacity reduction. The colored dots in these figures correspond to discrete cases and their color shading also indicates percent cost reduction/firm capacity reduction on the same color scale. The shaded regions correspond to a smooth surface calculated using the LOESS method with a functional form $z \sim x * y$ where z corresponds to the system value of LDES, x corresponds to the LDES weighted power capacity cost, and y corresponds to the LDES round-trip efficiency. When the LDES technology design space parameters are projected from the original 5-dimensional space (energy capacity cost, charge power capacity cost, discharge power capacity cost, charge efficiency, and discharge efficiency) to a lower 3-dimensional LDES technology space (energy capacity cost, weighted power capacity cost, and round-trip efficiency), some features of the results cannot be observed directly. For this reason we apply a Locally Weighted Polynomial Regression (LOESS)[34] to the data to calculate smooth surfaces that can better represent trends and dynamics in our results. Supplementary Figure 27 through Supplementary Figure 35 present results for system cost reduction in the original 5-dimensional space for energy capacity costs of \$1-10/kWh. Supplementary Figure 36 through Supplementary Figure 44 present results for firm capacity reduction in the original 5-dimensional space for energy capacity costs of \$1-10/kWh.

LDES Future Feasible Regions

We map the future LDES technology projections or "future feasible regions" in Table 1 into our lower-dimensional LDES design space as shown in Extended Data Figure-1, differentiating between geographically constrained and unconstrained resources. For each category we construct a convex hull or feasibility line by joining the points with highest RTE and lowest weighted power cost for each resource of each category (geographically constrained and unconstrained) at each energy capacity cost level as shown in Extended Data Figure-1. These feasibility lines are then projected on all figures mapping the LDES design space. The resulting feasibility lines divide the LDES design space into (i) infeasible future region (the region to the left of the left-most feasibility line), (ii) geographically constrained future feasible region (region to the right of the constrained feasibility line and to the left of the unconstrained feasibility line), and (iii) unconstrained future feasible region (region to the right of the unconstrained feasible line). For energy levels where the unconstrained feasibility line reaches lower weighted power cost and higher RTE levels than the constrained feasibility line, only the former is plotted. Extended Data Figure-1 makes clear that our LDES design space includes parameter combinations that are not identified in any of the projected "future feasible regions." However, given the inherent uncertainty in those projections it is useful to include these larger spaces of potential future performance, in part because of the opportunity to generate useful information to inform future LDES research and innovation targets.

Limitations

Finally, we note several limitations of this work. First, several LDES storage technologies with different combinations of cost and performance parameters may co-exist in future power systems. Having identified the subset of the broad LDES design space that is likely to produce economically attractive LDES technologies, this paper paves the way for future work that could include a discrete subset of these technologies with differing parameters and evaluate how multiple LDES technologies might compete with or complement one another. Second, we do not consider the impact of transmission constraints on the value and market adoption of LDES. By storing energy during periods of network congestion and delivering it when networks are unconstrained, LDES may act as a (partial) substitute for transmission network upgrades, which may present a niche or early market opportunity for these technologies. Additionally, where transmission network expansion is significantly constrained by siting, permitting, and cost-allocation challenges, LDES may be a long-term and important alternative to integrate larger amounts of renewable energy[35]. A thorough evaluation of the specific technical and economic characteristics necessary for LDES to act as an effective substitute to transmission (or distribution) network upgrades remains a topic for future research. Third, we evaluate only techno-economic related considerations in this optimization framework. All resources considered herein, including the wide range of LDES technologies, have environmental and societal impacts or entail risks or hazards that may constrain their development, differentiate them on non-cost related dimensions, and ultimately impact their deployment. Promising LDES technologies should be further evaluated along a variety of non-cost related dimensions, including their own relative risks or impacts as well as their potential to change the aggregate portfolio of electricity resources and mitigate or exacerbate associated non-cost related impacts.

Data availability

The data that support the figures and other findings of the study are available from the corresponding author upon reasonable request given the size of the data sets generated for this research. Input data and sources can be found in the Supplemental Information

Code availability

The code used to generate and analyze the data that support the findings of this study are available from the corresponding author upon reasonable request. The CEM model "GenX" used in this research is being prepared for open-source release

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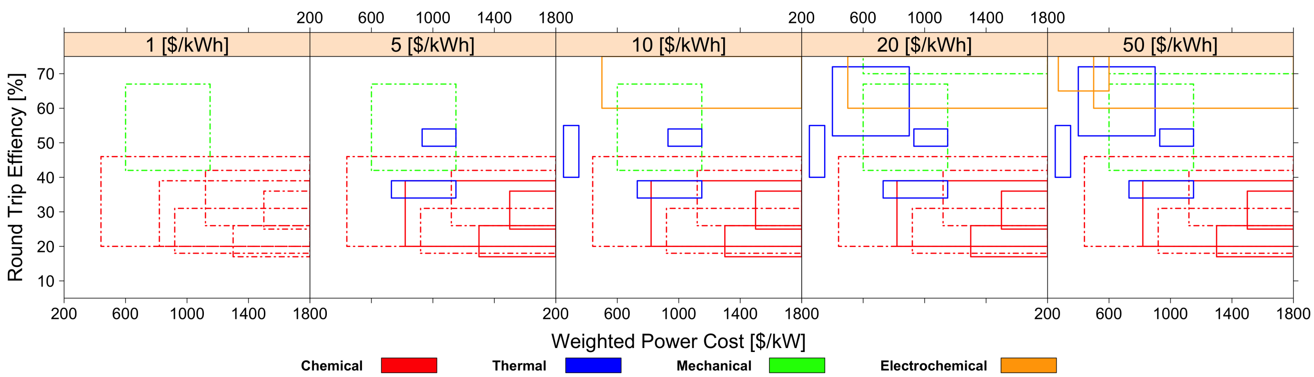
Author contributions statement

N.A.S. and J.D.J conceptualized the study. N.A.S, J.D.J and A.E. implemented the required model modifications. N.A.S., J.D.J., A.E. and D.S.M developed the experimental design. N.A.S and A.E. performed the model evaluations. N.A.S developed formal analysis, visualization, investigation, and produced figures. N.A.S and J.D.J drafted and finalized the manuscript. D.S.M. and R.K.L. advised on analysis and reviewed and revised the manuscript. N.A.S, J.D.J. and D.S.M responded to reviewer comments and revised the manuscript for re-submission.

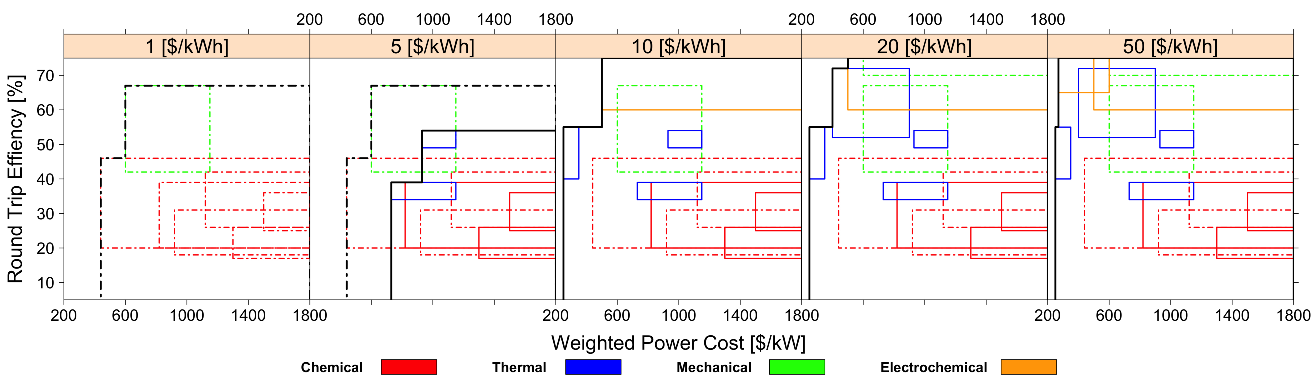
Financial and non-financial competing interest

N.A.S and J.D.J. are partners in DeSolve LLC which provides consulting and analytical services for for-profit and nonprofit clients including (within the last 12 months): CorPower Ocean, Westinghouse Electric Corporation, Qvist Consulting Limited, Environmental Defense Fund, and Clean Air Task Force. R.K.L. serves on the Scientific Advisory Council of Engie. A.E works at the Cadmus Group, a strategic and technical consulting firm where she works on clean and renewable energy planning projects for public, nonprofit, and private sector clients

Extended data figures and tables

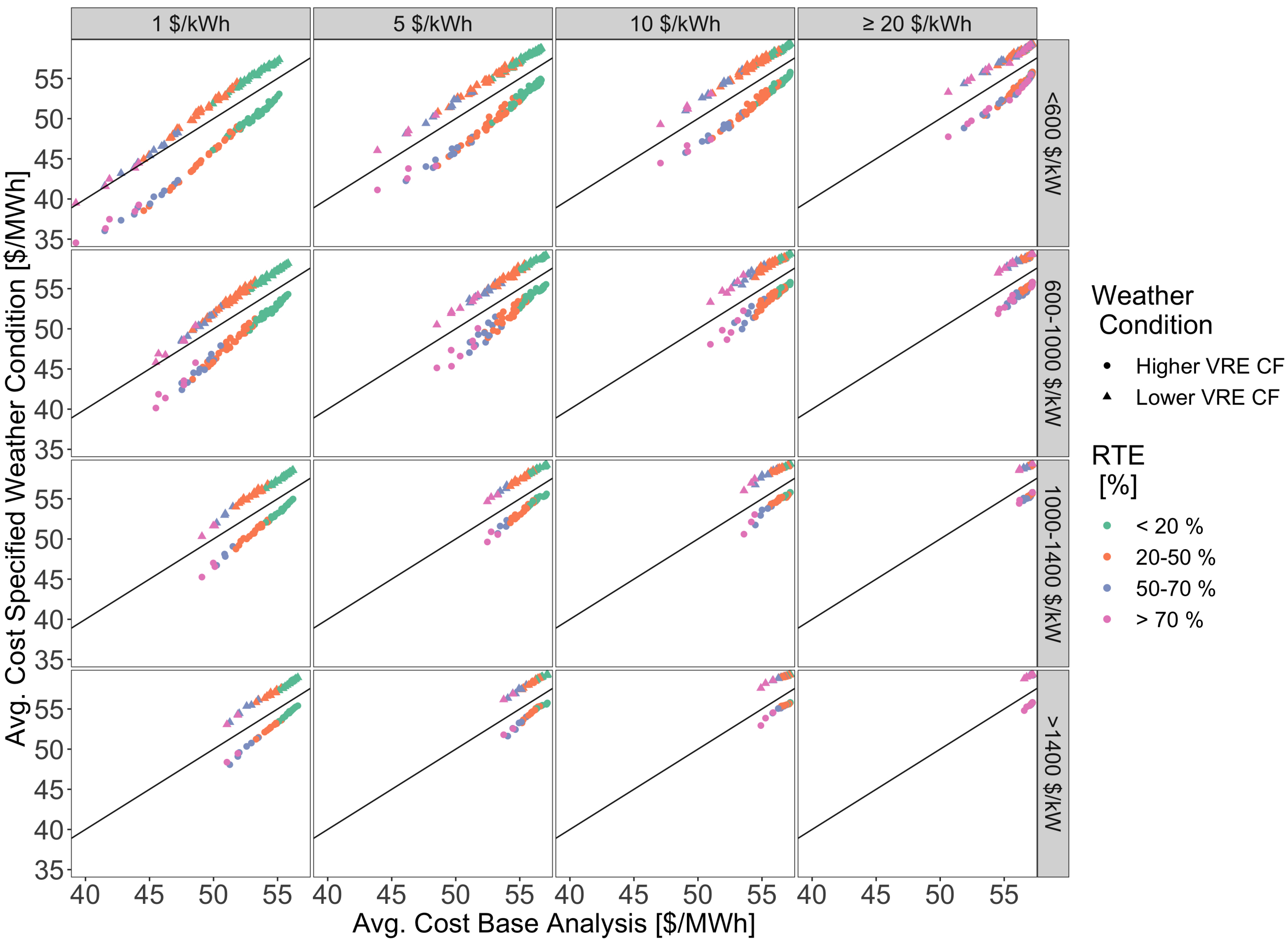


(a)

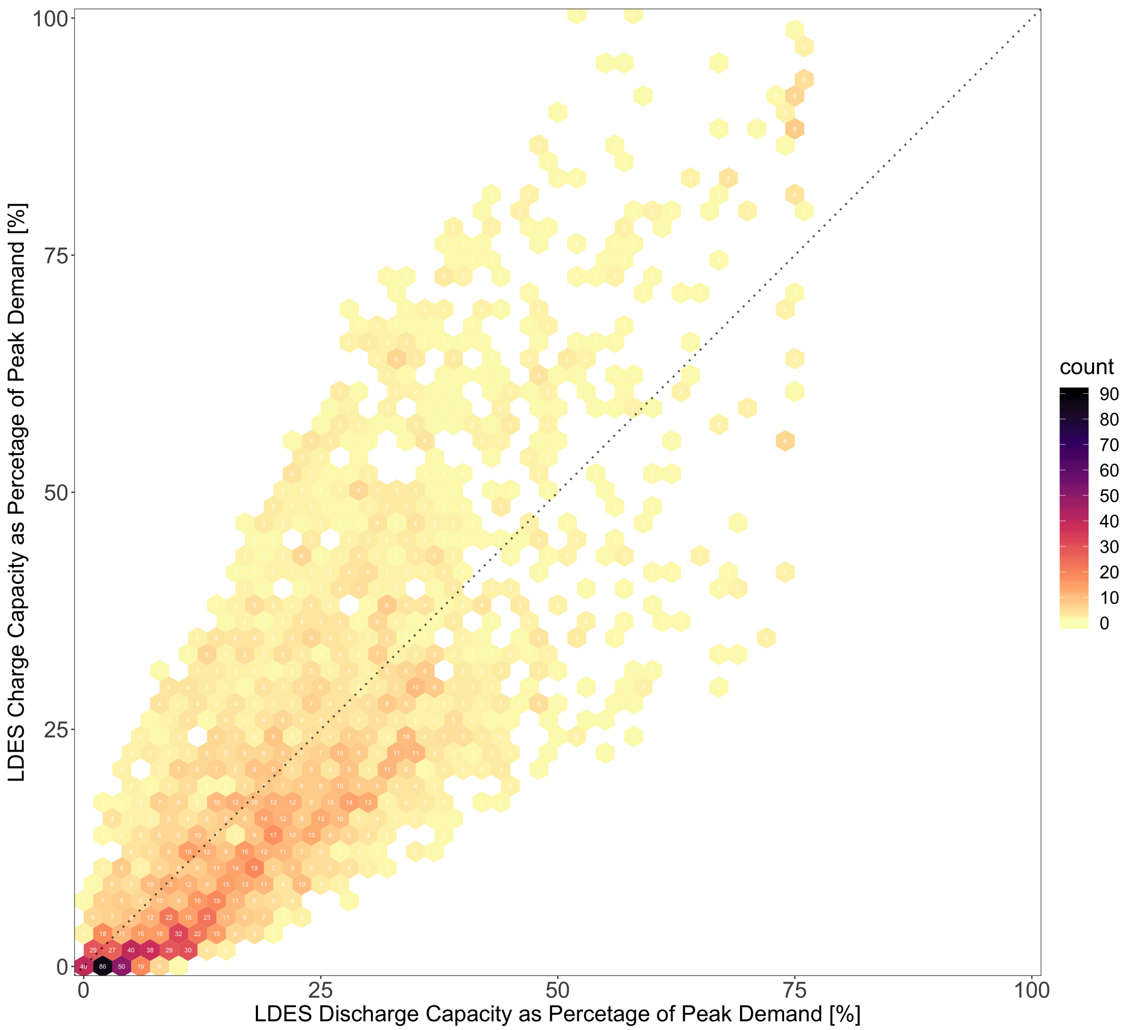


(b)

Extended Data Figure-1. Intersection between LDES Technology Space and Future Technology Projections. Data from Table 1. Each column represents a specific Energy Capacity Cost [$/kWh] assumption in the "LDES Technology Space". Within each subplot the x-axis represents the Weighted Power Capacity Cost and the y-axis the Round-Trip Efficiency. In (a) Dash-dotted lines depict technologies subject to geological and geographic constraints. in (b) feasibility lines in black correspond to the convex-hull of the lowest weighted power cost and highest round-trip efficiency regions of different geological and geographic constrained and unconstrained LDES projected technologies. For cases with the unconstrained feasibility line reaching higher efficiency and lower power cost levels than the constrained one, only the unconstrained line is shown.



Extended Data Figure-2. Effect on Average Cost of Electricity due to Changes in Weather (VRE Availability) Conditions in Northern System The figure shows the perturbation effect of VRE profile changes on average cost of electricity, the solid line marks the region of no perturbation (points in the line) in average cost of electricity cost as VRE availability changes. Each data point on the plot corresponds to a specific set of LDES design space parameters, the x-axis value is the result obtained under base weather assumptions (Scenario 5 in Table 2), while the the y-axis value is the result obtained when changing the weather conditions (Scenarios 10 and 11 in Table 2). The space above the line corresponds to the region of increased average cost of electricity and the space below the line corresponds to the region of reduced average cost of electricity. Panels going left-right indicate different energy capacity cost levels and panels going bottom-up indicate different weighted power cost levels.



Extended Data Figure-3. Distribution of Discharge and Charge Power Capacities Normalized as Percent of Peak Demand in Northern system. Discharge power capacity and charge power capacity are both normalized by the peak demand. The resulting values range between 0% and 100% of peak demand and the hexbins (2D bins) have a width of 2%. The dotted line indicates balanced or symmetrical charge and discharge power capacities and separates the space into two diagonal sub-spaces: the upper diagonal sub-space contains systems with more charge power capacity than discharge power capacity, and the lower diagonal space contains systems with more discharge power capacity than charge power capacity.