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The design space for long-duration energy storage in decarbonized power systems

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Long-duration energy storage (LDES) is a potential solution to intermittency in renewable energy generation. In this study we have evaluated the role of LDES in decarbonized electricity systems and identified the cost and efficiency performance necessary for LDES to substantially reduce electricity costs and displace firm low-carbon generation. Our findings show 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 ≤US\$20 kWh^{-1} to reduce electricity costs by ≥10%. With current electricity demand profiles, energy capacity costs must be ≤US\$1 kWh^{-1} to fully displace all modelled 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 h.

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 (for example, nuclear, fossil fuels with carbon capture and storage (w/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 fuel firm resources[2], transmission network expansion can increase the balancing area to cover large geographic regions and exploit spatiotemporal 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 shares exceed ~80% of annual energy demand[6] or when strict CO_2 emission limits (for example, below ~50 kgCO$_2$ MWh^{-1}) 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 indicated 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 derating discharge capacity and reducing discharge rates, the relatively high cost per kWh of energy storage capacity (in the hundreds of US dollars per kilowatt hour, ref. [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 used 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 the 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 programme[13] directly supports the development of LDES systems with duration (maximum constant operation at rated discharge power capacity) between 10 and 100 h, power capacity cost (investment associated with charge and discharge power capacity) below US\$1,000 kW^{-1} and energy capacity cost (investment associated with energy storage capacity) below US\$100 kWh^{-1}, with a focus on the US\$5–20 kWh^{-1} range. Ziegler et al.[15] considered wind/solar and storage at the individual facility level and assessed cost and duration requirements to produce a consistent 'baseload' power output. They concluded that a combination of power and energy capacity costs of US\$1,000 kW^{-1} and US\$20 kWh^{-1} and a duration of 100 h is sufficient to enable steady power output 100% of the time. Albertus et al.[14] argue that for high penetration of VRE generation (≥90%), LDES systems with duration greater than 100 h will be needed, with energy capacity cost below US\$40 kWh^{-1} and power capacity cost in the range of US\$500–1,000 kW^{-1}. LDES encompasses a diverse range of technologies at varying technology-readiness levels and includes electrochemical (for example, low-cost flow batteries[16] or aqueous metal–air batteries[17]), chemical (for example, production, storage and oxidation or combustion of electrolytic hydrogen, known as 'power-to-gas-to-power'[5,18]), thermal (for example, sensible or latent heat storage[19,20]) and mechanical options (for example, compressed air or pumped hydroelectric storage[21]).

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Table 1 | Future costs projections for LDES technologies

Storage method	Technology	Discharge power cost[a] (US$ kW⁻¹)	Charge power cost (US$ kW⁻¹)	Weighted power cost (US$ kW⁻¹)	Energy capacity cost[b] (US$ kWh⁻¹)	Charge efficiency (%)	Discharge efficiency (%)	Round-trip efficiency (%)
Mechanical	Pumped hydro storage[29,30]	600–2,000	–	600–2,000	20+[c]	–	–	70–85
	Compressed air energy storage[21,29,31]	600–1,150	–	600–1,150	1–30+[c]	–	–	42–67
Chemical	Power-H2-power (Brayton cycle)[11,32–34]	700–1,100	220–1,400	920–2,500	1–15+[d]	51–77	35–40	18–31
	Power-H2-power (combined cycle)[11,32–34]	900–1,100	220–1,400	1,120–2,500	1–15+[d]	51–77	50–55	26–42
	Power-H2-power (fuel cell)[11,21,32–34]	220–2,000	220–1,400	440–3,400	1–15+[d]	51–77	40–60	20–46
	Power-syngas-power (Brayton cycle)[11,32–34]	700–1,100	600–1,700	1,300–2,800	1–5+[d]	49–65	35–40	17–26
	Power-syngas-power (combined cycle)[11,32–34]	900–1,100	600–1,700	1,500–2,800	1–5+[d]	49–65	50–55	25–36
	Power-syngas-power (fuel cell)[11,21,32–34]	220–2,000	600–1,700	820–3,700	1–5+[d]	49–65	40–60	20–39
Electrochemical	Aqueous sulfur flow batteries[16]	500–2,000	–	500–2,000	10–20	–	–	60–75
	Vanadium redox flow batteries[16]	270–600	–	270–600	40–200	–	–	65–80
Thermal	Multijunction photovoltaic thermal storage[19]	250–350	–	250–350	8–36	–	–	40–55
	Reciprocating heat pump energy storage[35]	400–900	–	400–900	15–25	–	–	52–72
	Firebrick resistance-heated (Brayton cycle)[11,20,34]	700–1,100	30–50	730–1,150	5–10	98	35–40	34–39
	Firebrick resistance-heated (combined cycle)[11,20,34]	900–1,100	30–50	930–1,150	5–10	98	50–55	49–54

[a]The values quoted for some technologies include the cost of the charging component as well (for example, pumped hydro storage). [b]The energy capacity capital cost is denoted in units of storage medium and not kWh of electricity. [c]The full energy capacity cost range is subject to geological and geographic constraints. [d]The lower end of the energy capacity cost range is subject to geological and geographic constraints.

In the study reported here we used an electricity system capacity expansion model (CEM) with high temporal resolution (8,760 h) 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. We explored 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 focused on five LDES technology parameters: charge power capacity cost (US$ kW^{-1}), discharge power capacity cost (US$ kW^{-1}), energy storage capacity cost (US$ kWh^{-1}), 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). We modelled 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 (Table 1 and Extended Data Fig. 1) as well as domains that are currently infeasible but that could be the focus of technology development efforts in the future. Furthermore, we evaluated 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 (Table 2). This included 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 the Southern System, respectively. The long-run system-level optimization methods used in this study captured the declining marginal value of all resources and their resulting least-cost equilibrium penetration levels[23], and were thus suitable for evaluating the effect of LDES performance characteristics on the long-run evolution of power systems. We found 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 US$20 kWh^{-1} (with sufficient efficiency and power capacity cost performance) for LDES technologies to reduce total carbon-free electricity system costs by ≥10%. We observed a maximum of 50% reduction in total system costs across the full technology design space considered; the maximum reduction is limited to 40% for the combination of cost and performance parameters likely to be achieved by known LDES technologies. For LDES to fully displace firm low-carbon generation,

Table 2 | Scenario definitions for LDES technology design space exploration in multiple power system contexts

Scenario	System[a]	Load[b]/Weather conditions[c]	Firm resource[d]	VRE and Li-ion cost[e]	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

[a]Systems: Southern (Electric Reliability Council of Texas (ERCOT)-like system), Northern (ISO New England (ISONE)-like system). [b]Load profiles: base (linear growth), electrified (see Methods under explored scenarios). [c]Weather conditions: base, higher VRE CF, lower VRE CF (see Methods under explored scenarios). [d]Firm resources: nuclear, natural gas w/CCS, blue H_2. [e]VRE and Li-ion storage cost: low NREL ATB, mid NREL ATB. NREL ATB, National Renewable Energy Laboratory Annual Technology Baseline.

an energy storage capacity cost of ≤US\$10 kWh^{-1} is required for the least competitive firm technology considered (nuclear). Energy capacity costs of ≤US\$1 kWh^{-1} 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, for example, natural gas w/CCS and hydrogen combustion turbines. We also found that high degrees of transportation and heating electrification in a northern latitude power system make 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 and 650 h (~4–27 d).

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 to the capacity expansion framework (see Methods for a detailed discussion of system value calculations). Figure 1 and Supplementary Fig. 1 show the system value of LDES as a function of the LDES energy storage capacity cost (US\$ kWh^{-1}, referred to subsequently as the energy capacity cost for brevity), the weighted power capacity cost (US\$ kW^{-1}; see equation (3) in Methods 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 crucial driver of LDES value, followed by increases in RTE (y axis from bottom to top in each subplot), followed by reductions in weighted power capacity cost (x axis going from right to left in each subplot).

Comparing Fig. 1 and Supplementary Fig. 1 reveals that the two geographic regions exhibit very similar behaviours 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 importantly on which firm low-carbon technology is available (also confirmed by the data presented in 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 a higher capital cost, lower variable cost and lower flexibility (ramping capability, minimum stable output and cycling parameters) than the other firm low-carbon resources modelled. 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 (Supplementary Tables 2 and 4). Across the full range of modelled 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 Fig. 1; see Extended Data Fig. 1 and Methods 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 modelled design space, to 20–25% within the 'future feasible regions' for geographically constrained LDES technologies and to 10–15% for geographically unconstrained technologies.

To better understand the drivers of LDES value creation, we performed a regression analysis on the 7,680 data points included in Fig. 1 and Supplementary Fig. 1. For the regression analysis we preserved the original dimensionality of the LDES design space (five dimensions, compared with the three dimensions plotted in the figures) and included categorical variables for the system context and available firm low-carbon technology (Table 2). A summary of the regression analysis on the data after a min–max normalization of the non-categorical regressors (β_1–β_5) is presented in Table 3.

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 in 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 (that is, the increase in LDES system value) would be 1% greater if gas w/CCS is the available firm resource and 9% greater if nuclear is available.

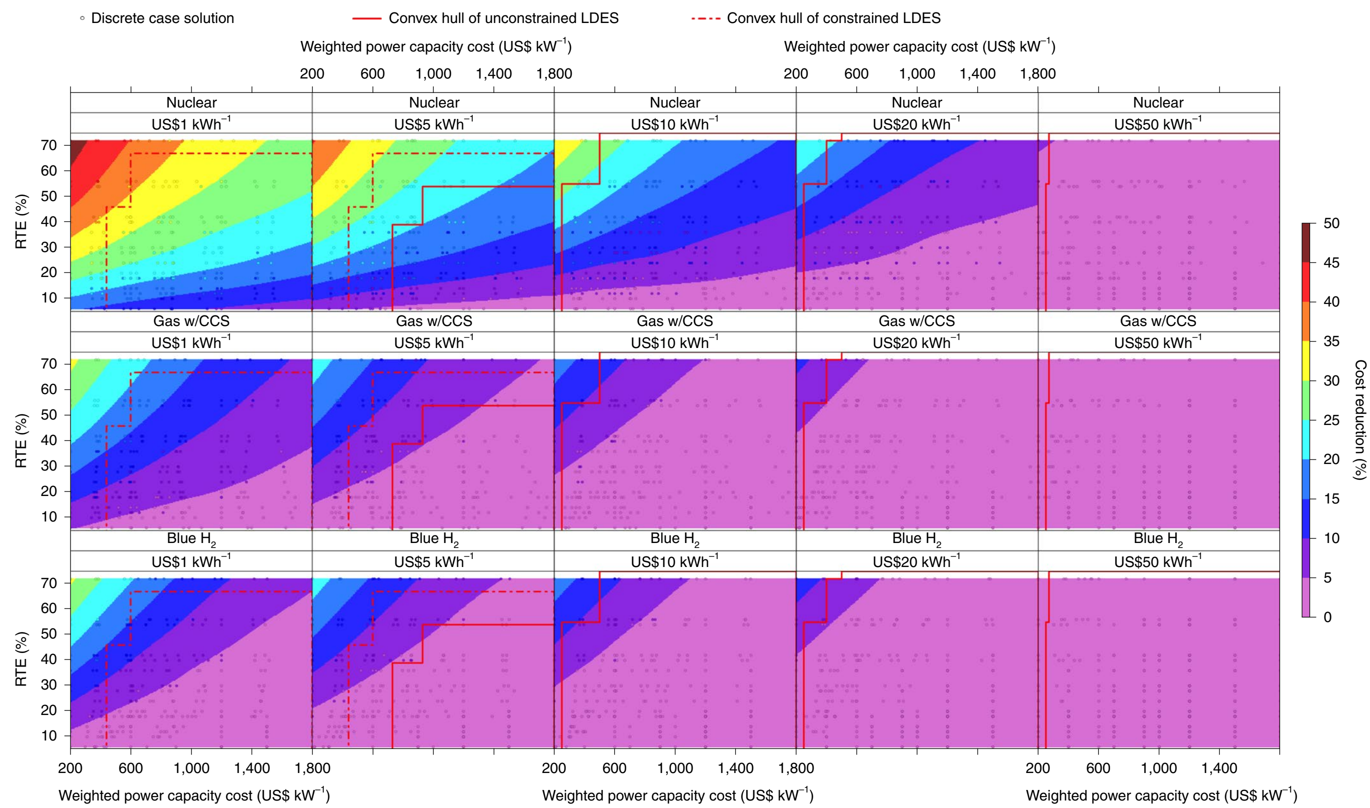

Fig. 1 | System cost percentage reduction in the Northern System for LDES parameter combination. Percentage reduction calculated compared with reference cases (Scenarios 4–6 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system cost. 'Future feasible regions' for known LDES technologies from Extended Data Fig. 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) in each row (see 'LDES future feasible regions' in Methods for details). Each column represents a specific LDES energy capacity cost (US$ kWh^{-1}) assumption in the LDES parameter combination. Within each subplot the *x* axis represents the weighted power capacity cost and the *y* axis the RTE. The total annualized system costs for the reference cases are as follows: nuclear, US$74.01 MWh^{-1}; gas w/CCS, US$57.20 MWh^{-1}; blue H_2, US$56.02 MWh^{-1}.

The regression also confirms that energy capacity cost (β_1) is the largest coefficient predicting system value of LDES. Supplementary Fig. 3 shows the yearly cycling of the least-used 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 in energy storage capacity is cycled (charged/discharged) less than ten times a year. Such infrequent use requires very low energy capacity costs to be economic.

Additionally, this regression analysis decomposes charge and discharge power costs and efficiencies, and the results indicate that discharge efficiency (β_5) is the second most important factor in determining LDES system value after energy capacity cost, whereas charge efficiency (β_4) and discharge and charge power capacity cost (β_2 and β_3) are of secondary importance. The regression coefficients indicate that a given improvement in discharge efficiency has roughly twice the impact of 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 (β_2) have slightly greater impact than equivalent improvements in charge power capacity cost (β_3). Comparing the percentage of hours that are spent in charging and discharging (Supplementary Fig. 4) 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.

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 (ref. [24]). 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. The LDES

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	$<2\times10^{-16}$***
Energy capacity cost (US$ kWh^{-1})	β_1	−9.94	0.15	−68.27	$<2\times10^{-16}$***
Discharge power capacity cost (US$ kW^{-1})	β_2	−3.26	0.14	−23.63	$<2\times10^{-16}$***
Charge power capacity cost (US$ kW^{-1})	β_3	−2.89	0.14	−20.95	$<2\times10^{-16}$***
Charge efficiency (%)	β_4	3.21	0.14	22.90	$<2\times10^{-16}$***
Discharge efficiency (%)	β_5	7.30	0.14	52.07	$<2\times10^{-16}$***
System: Northern[a]	β_6	0.31	0.11	2.97	0.00299**
Firm technol.: gas w/CCS[b]	β_7	1.14	0.13	8.90	$<2\times10^{-16}$***
Firm technol.: nuclear[b]	β_8	9.00	0.13	70.26	$<2\times10^{-16}$***

Model: cost reduction (%) $=\alpha+\beta_1+\beta_2+\beta_3+\beta_4+\beta_5+\beta_6+\beta_7+\beta_8$. Observations: 7,680. Residual standard error: 4.581 on 7,671 degrees of freedom. Multiple $R^2=0.6579$, adjusted $R^2=0.6576$. *F* statistic = 1,844 on 8 and 7,671 degrees of freedom, $P<2.2\times10^{-16}$. [a]Binary for categorical variable ‘System’ (Northern, Southern) uses Southern as reference. [b]Binaries for categorical variable ‘Firm technol.’ (gas w/CCS, nuclear, blue H_2) uses blue H_2 as reference. Pr, probability. ***$P<0.001$, **$P<0.01$.

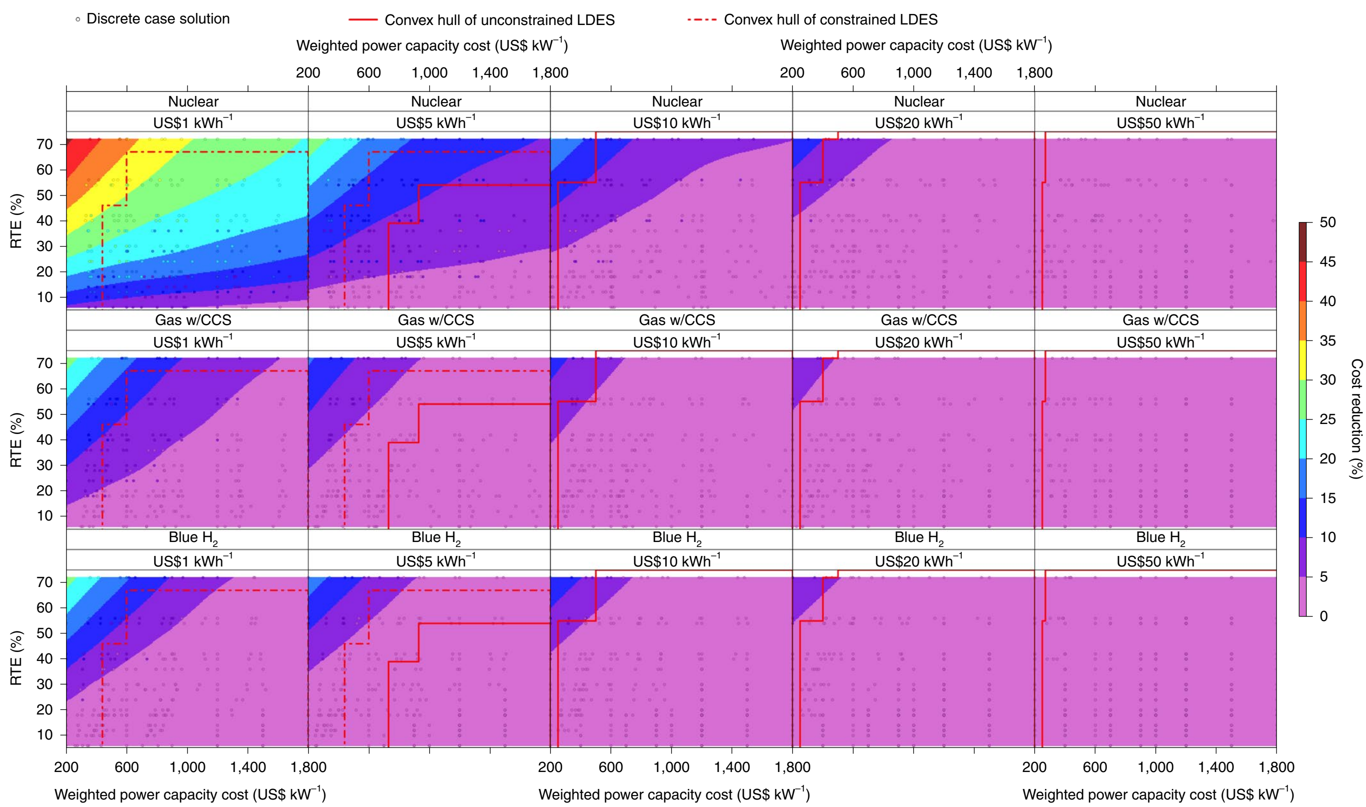

Fig. 2 | System cost percentage reduction in the Northern System with electrified load for LDES parameter combination. Percentage reduction calculated compared with reference cases (Scenarios 7–9 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in system cost. ‘Future feasible regions’ for known LDES technologies from Extended Data Fig. 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) in each row (see ‘LDES future feasible regions’ in Methods for details). Each column represents a specific LDES energy capacity cost (US$ kWh^{-1}) assumption in the LDES parameter combination. Within each subplot the *x* axis represents the weighted power capacity cost and the *y* axis the RTE. The total annualized system costs for the reference cases are as follows: nuclear, US$90.33 MWh^{-1}; gas w/CCS, US$66.93 MWh^{-1}; blue H_2, US$66.78 MWh^{-1}.

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 to 77 GW, the median demand increases from 21 to 33 GW, the maximum hourly change in demand (ramp) increases from 3.4 to 17.4 GW and the median ramp increases from 0.5 to 1.7 GW. As shown in Supplementary Fig. 26, electrification also adds a strong seasonal component to load variation due to the 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.

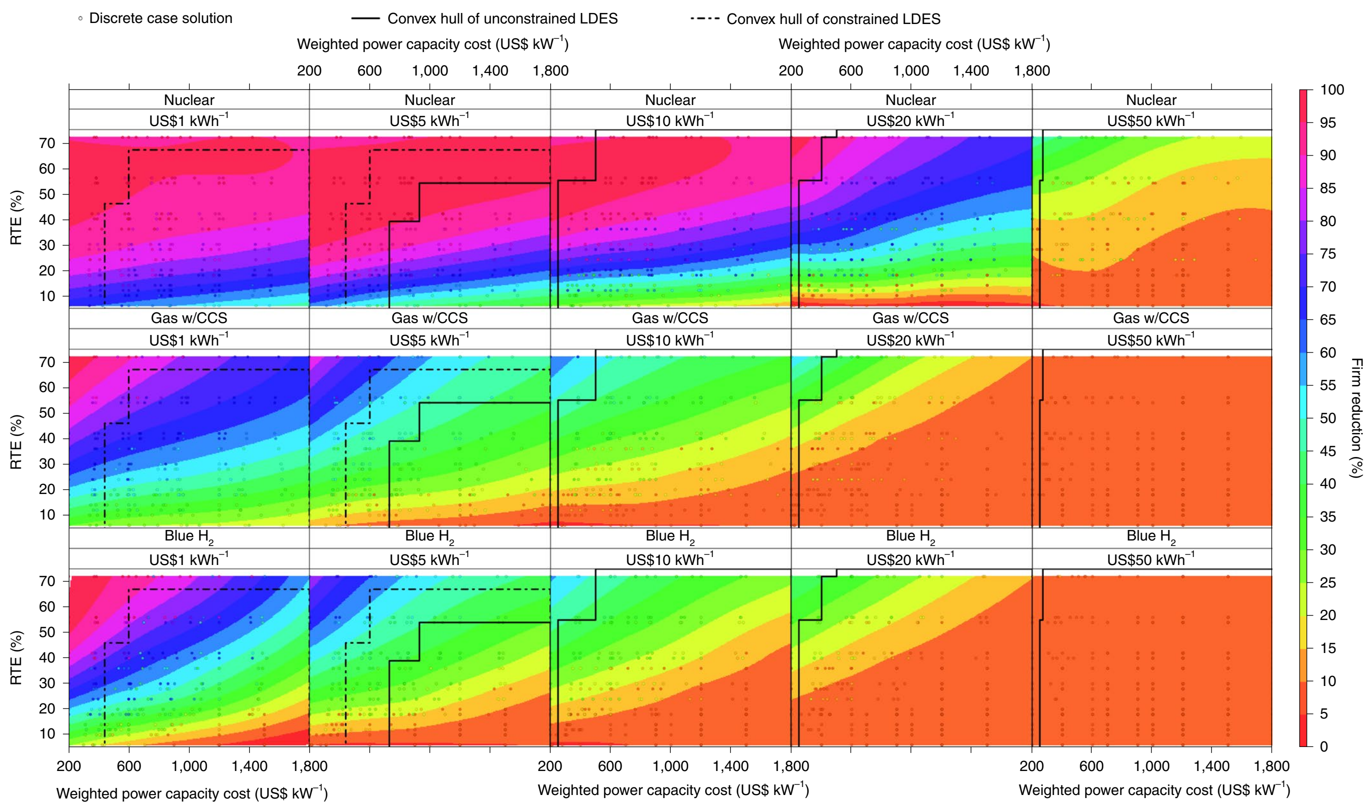

Fig. 3 | Firm capacity percentage reduction in the Northern System for LDES parameter combination. Percentage reduction calculated compared with reference cases (Scenarios 4–6 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, and consequently a different reference case was used to calculate the percentage change in firm capacity. 'Future feasible regions' for known LDES technologies from Extended Data Fig. 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) in each row (see 'LDES future feasible regions' in Methods for details). Each column represents a specific LDES energy capacity cost (US$ kWh^{-1}) assumption in the LDES parameter combination. Within each subplot the *x* axis represents the weighted power capacity cost and the *y* axis the RTE. The total firm capacities for the reference cases normalized by peak demand are as follows: nuclear, 48.6%; gas w/CCS, 48.5%; blue H_2, 44.3%.

The 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 favour 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 and batteries reduce the relative capacity substitution value of LDES, which is shown to be central to the system value of storage technologies[25]. 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 (Supplementary Table 4). As compared with the outcomes of Scenarios 7–9, the maximum system cost reduction from LDES declines from 50% (Fig. 2) to 37% (Supplementary Fig. 2) with higher battery and VRE costs. That said, higher VRE and Li-ion costs also lead to greater LDES system value in other regions of the LDES design space investigated here. For example, when LDES cost and performance are similar or superior to the Li-ion storage assumptions in Scenarios 7–9 (for example, US$50 kWh^{-1} and <US$1,000 kW^{-1}), we see a greater value of LDES in Scenarios 12–14 (Supplementary Fig. 2) compared with in Scenarios 7–9 (Fig. 2). This trend is most evident in the case of nuclear as the firm resource, because the ability of storage to improve firm capacity use is most valuable for high capital cost and less flexible resources such as nuclear (discussed in more detail later).

Extended Data Fig. 2 depicts the sensitivity of the average cost of delivered electricity to changes in the weather data under more extreme weather years (see Methods) with the availability of wind and solar resources (higher or lower VRE capacity factor) across the full range of LDES technology design space cases. Note that the capacity results were reoptimized in each case to illustrate 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 capacity factor (CF) 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, Extended Data Fig. 2 demonstrates that for very low energy capacity cost LDES cases (that is, US$1 kWh^{-1}), weighted power cost below US$1,000 kW^{-1} and RTE greater than 50%, the average cost of electricity with lower VRE availability approaches the solid line (that is, 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 of unfavourable wind and solar conditions.

Displacing firm generation and Li-ion storage capacity

Figure 3 and Supplementary Fig. 5 show the reductions in firm low-carbon capacity enabled by LDES for the Northern and

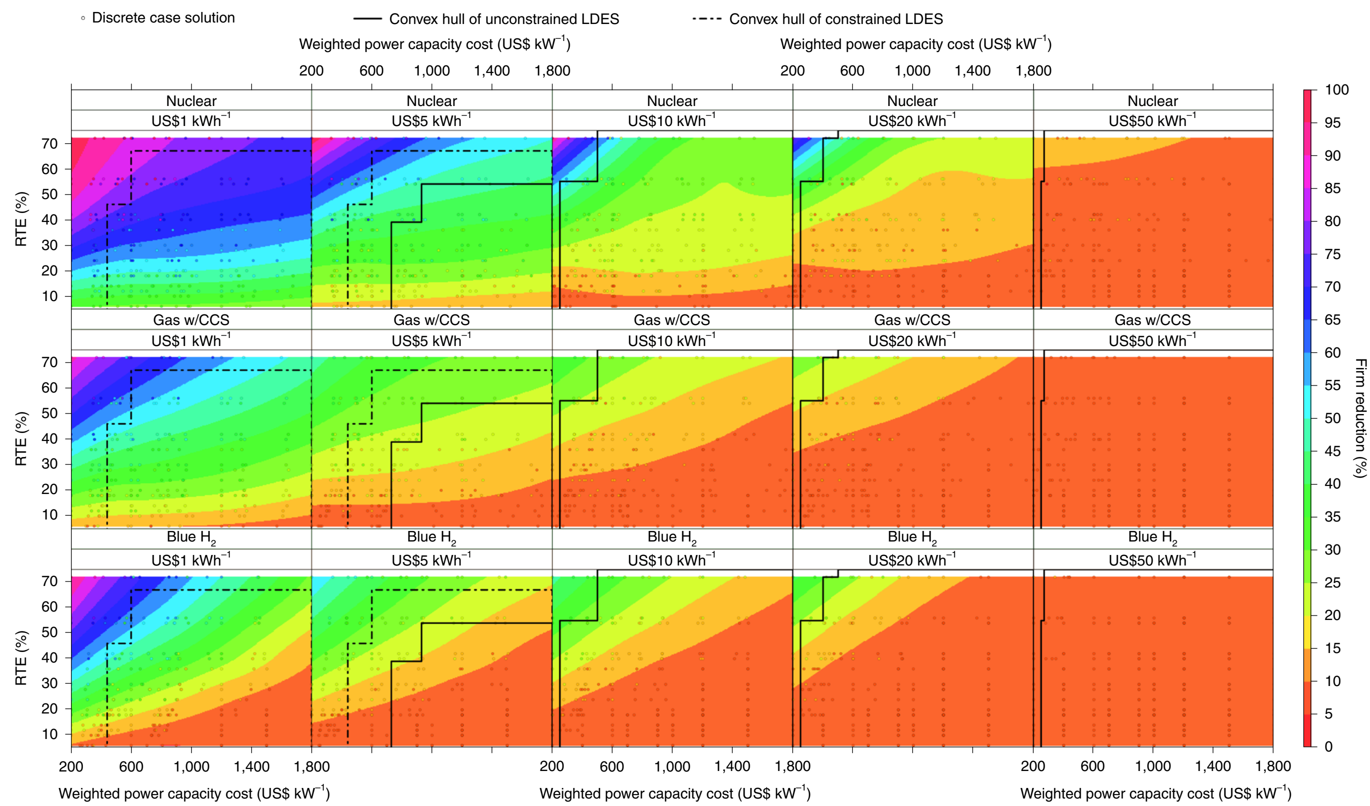

Fig. 4 | Firm capacity percentage reduction in the Northern System with electrified load for LDES parameter combination. Percentage reduction calculated compared with reference cases (Scenarios 7–9 in Table 2). Each row of plots represents a different scenario using a different firm low-carbon technology, 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 Fig. 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) in each row (see 'LDES future feasible regions' in Methods for details). Each column represents a specific LDES energy capacity cost (US$ kWh^{-1}) assumption in the LDES parameter combination. Within each subplot the *x* axis represents the weighted power capacity cost and the *y* axis the RTE. The total firm capacities for the reference cases normalized by peak demand are as follows: nuclear, 48.6%; gas w/CCS, 51.3%; blue H_2, 47.5%.

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 notable 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 ≤US$1 kWh^{-1}, power cost ≤US$400 kW^{-1} and RTE ≥50%, a combination that appears to fall outside the feasible performance range 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 (Fig. 4), with most of the 100% displacement regions seen in Fig. 3 eliminated. Together with the cost results shown in Fig. 2, these results indicate that the electrification of energy supply in northern latitudes increases the value of firm capacity due to increased short-term variability and more pronounced seasonal variations in demand. Although 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 Fig. 2 shows.

With higher VRE and Li-ion capital costs (Scenarios 12–14; Supplementary Fig. 6), firm substitution further declines (compared with Scenarios 7–9) across all firm technologies and areas of low energy capacity cost (for example, <US$5 kWh^{-1}) and higher RTE (>50%). This confirms the 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 (US$10–50 kWh^{-1}), changes in firm substitution are more complex: the 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 h; Supplementary Fig. 21) and competes primarily with Li-ion batteries. As Li-ion batteries are more costly in Scenarios 12–14 compared with in Scenarios 7–9, LDES achieves greater substitution of Li-ion batteries (Supplementary Figs. 13 and 14). With LDES now cheaper than Li-ion batteries 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, and valleys in net load are also reduced, increasing the capacity factor and relative value of nuclear. These differing substitution effects for nuclear compared with 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 modelling rather than the isolated assessment (for example, see ref. [15]) of LDES technology competitiveness.

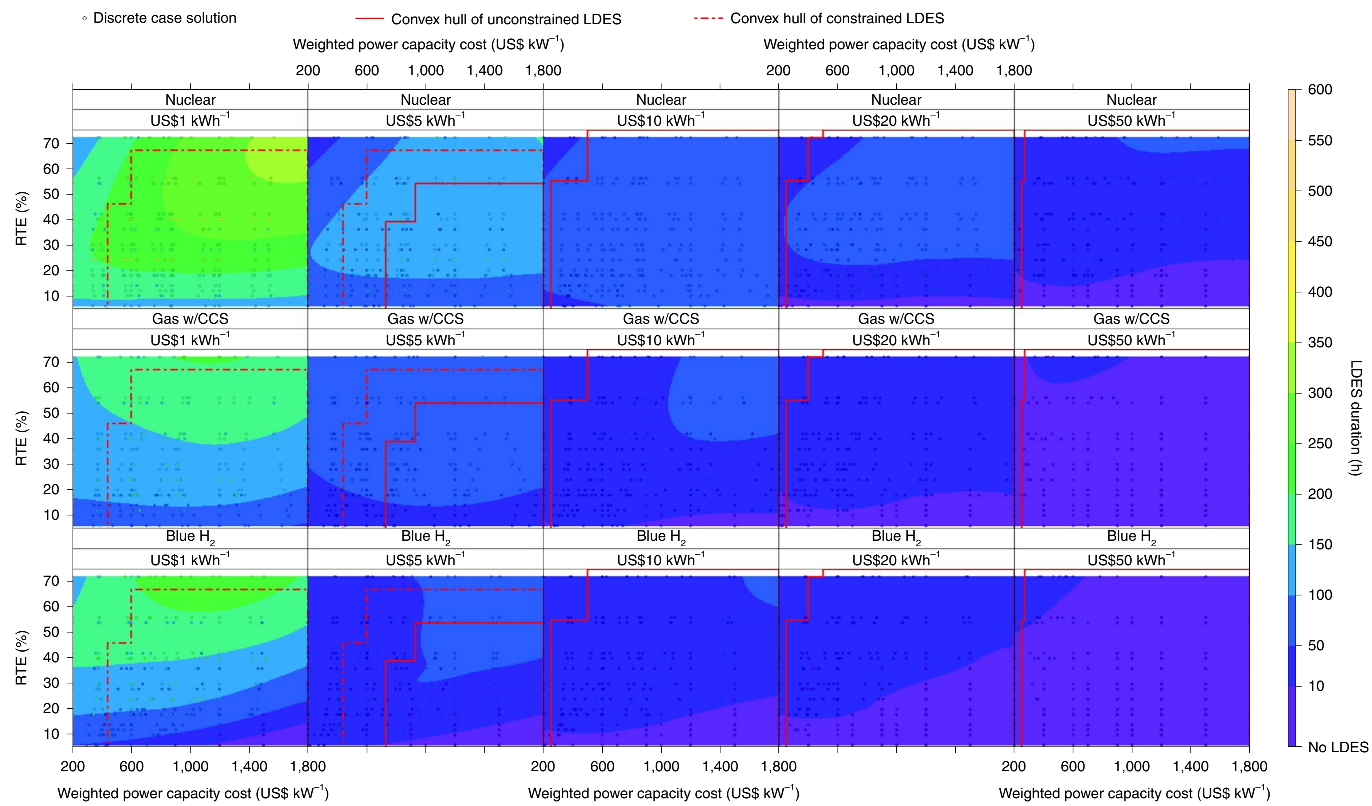

Fig. 5 | LDES duration in hours in the Northern System for the optimal deployment of LDES. Each row of plots represents a different scenario using a different firm low-carbon technology. 'Future feasible regions' for known LDES technologies from Extended Data Fig. 1 are plotted to the right of the dash-dotted lines (convex hull of geographically constrained LDES) and solid lines (convex hull of geographically unconstrained LDES) in each row (see 'LDES future feasible regions' in Methods for details). Each column represents a specific LDES energy capacity cost (US$ kWh^{-1}) assumption in the LDES parameter combination. Within each subplot the *x* axis represents the weighted power capacity cost and the *y* axis the RTE.

Supplementary Figs. 7–14 show the impact on Li-ion power and energy capacity of introducing LDES into the capacity expansion framework. These results demonstrate that LDES does not meaningfully displace Li-ion capacity until LDES weighted power cost falls to ≤US$800 kW^{-1} 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 by 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 Fig. 22 reinforces this finding by highlighting the different operating patterns of LDES and Li-ion batteries across a range of LDES power capacity and energy capacity costs for the Northern System with gas w/CCS (Scenario 5). As the LDES energy capacity cost is reduced from US$10 kWh^{-1} to US$1 kWh^{-1}, 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 Fig. 22 indicates that LDES operations will exhibit increased high-power, low-energy cycling (for example, intra-day) to compensate for the role played by Li-ion batteries without impacting high-energy cycles occurring over longer periods. However, the LDES performance requirements to fully displace Li-ion batteries 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 ratio of energy capacity to discharge power for LDES systems at 10:1 and the maximum at 1,000:1 (Li-ion storage is modelled with an energy-to-power ratio of ≤10:1). The CEM then optimizes energy capacity and discharge capacity independently within this range. Note that the 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 $(E\times\eta^{-})/P_{\mathrm{d}}$, where E, P_{d} and η^{-} are the energy capacity, discharge power capacity and discharge efficiency, respectively, and refer to the E/P_{d} ratio as the LDES 'energy-to-power ratio'.

Supplementary Figs. 15 and 16 show the LDES energy-to-power ratio for the Northern and Southern Systems, respectively, and Fig. 5 and Supplementary Fig. 19 present the LDES duration. These figures show that for energy capacity costs of ≥US$10 kWh^{-1}, LDES duration is generally in the 100-h range (with energy-to-power ratios reaching as high as 300:1 when the efficiency is low). This also holds for energy capacity costs of US$5 kWh^{-1} if gas w/CCS or blue H_2 is the available firm generation option. Additionally, the duration is largely unaffected by weighted power capacity cost at these levels, but somewhat more affected by RTE. In general, higher energy-to-power ratios 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 US$1 kWh^{-1}, the duration approaches 400 h, with energy-to-power ratios as high as 900:1. These findings indicate 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 Fig. 4) and the use of energy capacity may exhibit seasonal patterns (Supplementary Fig. 22).

Supplementary Figs. 17 and 20 show the LDES energy-to-power ratio and discharge duration results for the Northern System under high electrification assumptions. The duration increases with electrification, especially for cases when nuclear power is the firm resource, reaching values in the 650-h range for an energy capacity cost of US$1 kWh^{-1}. Note that the imposed maximum energy-to-power ratio of 1,000:1 is binding in 60 cases with high electrification in the Northern System and with very low discharge efficiencies (≤36% RTE) and an energy capacity cost of US$1 kWh^{-1} (Supplementary Fig. 17).

Although 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 Fig. 3 and Supplementary Fig. 23 show the relationship between the discharge power capacity and the charge power capacity relative to peak demand in the Southern and Northern Systems, respectively. The figures show that the 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 Fig. 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, and these have been captured within the wide design space assessed in this study. We have reported herein a thorough evaluation of a diverse range of potential LDES technologies and provided insight into their potential value in decarbonized electricity systems. Supplementary Discussion 1 presents an extended summary of our findings, and Supplementary Discussion 2 presents a more detailed discussion of the implications for LDES technology selection and design including the technologies in Table 1.

Methods

LDES technology design space. Given the uncertainty in future technology development, we evaluated a LDES 'technology design space' that encompasses performance levels that are consistent with the projections of 'future feasible regions' identified in the literature for existing or emerging LDES technologies (Table 1 and Extended Data Fig. 1) and also includes domains of performance lying outside these regions as a basis for exploring potential targets for future development efforts. These included (1) charge and discharge power capacity costs of 100, 300, 600 and 900 US$ kW^{-1}, (2) energy capacity costs of 1, 5, 10, 20 and 50 US$ kWh^{-1}, (3) charge efficiencies of 30, 50, 70 and 90%, and (4) discharge efficiencies of 20, 40, 60 and 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 although we have presented here the projected performance regions for existing LDES technologies as simple boxes for plotting in Extended Data Fig. 1, not all points within the plotted areas may be simultaneously achievable due in particular to trade-offs between power capacity capital costs and efficiency (for example, the regions of lowest projected power cost and highest projected RTE may not be practically achievable for all technologies).

All capacity costs were modelled on a fully installed basis. Charge and discharge efficiencies were assumed to be invariant with discharge or charge rate or state of charge. Charge and discharge power capacity costs were based on a.c. power injected or withdrawn from the grid and assumed inclusion of grid interconnection costs. Because energy and power capacities are independently sized on the basis of 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 equation (1)).

LDES power and energy capital costs were 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 in Supplementary Table 5, which can be used to compare a resource with a different asset life or a different cost of capital assumption with the findings reported in this paper. The charge power capacity and energy storage capacity investments were assumed to have no O&M costs associated with them. A comparable, fixed operations and maintenance (O&M) cost from Li-ion batteries was 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 modelled 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 (ref. [13]). We modelled a maximum LDES energy-to-power ratio of 1,000:1. This constraint ends up non-binding in all but 60 of the cases modelled herein, all of which have an RTE of 36% or lower and an energy capacity cost of US$1 kWh^{-1}. The LDES design space included 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. In our exploration of the LDES design space it was assumed that the three scaling dimensions, that is, 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, that is, we assumed a constant energy capacity scaling cost for Li-ion batteries with duration between ~30 min and ~10 h.

Explored scenarios. The attributes of the different scenarios explored, that is, 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), are displayed in Table 2. The procedures used to develop the electricity demand and wind/solar inputs for each of these scenarios, including a cluster-based approach to characterize spatial variability in wind resources, are described in detail in Supplementary Note 3. These profiles are typical of New England (for the Northern System) and Texas (for the Southern System), and were selected 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 did not model 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. Also included in Supplementary Note 3 are details on variable renewable and demand assumptions. Supplementary Fig. 24 shows the different duration curves for the solar and wind profiles used for the base weather year for each system, Supplementary Fig. 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, and Supplementary Fig. 26 shows the base and higher electrification profiles for the Northern System. Additionally, we tested the sensitivity to differences in wind, solar and battery costs. We used 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, and for Scenarios 12–14, which replicate Scenarios 7–9 (Northern System, high electrification) we used the ATB 2018 mid-range cost trajectory for wind, solar and batteries (Supplementary Table 4).

We investigated the value of LDES in conjunction with three different firm low-carbon generation technologies, namely nuclear power, natural gas plants w/CCS and hydrogen combustion power plants, selected to span the range from high fixed/low variable costs to low fixed/high variable costs. We parameterized the hydrogen combustion plants using assumptions for the cost of hydrogen derived from natural gas reforming w/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 (~US$14 per gigajoule). 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 favourable (less realistic) setting for LDES, but also allows for a 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 photovoltaic 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 scenario, were simulated in the CEM framework.

Model and parameters. For this research we used the GenX model, an electric power system CEM described in detail elsewhere[22]. In its application in this study, the model considered 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 intertemporal constraints on energy storage. The model also captured a full year of hourly chronological variability of electricity demand and renewable resource availability. The linear programming model selected the cost-minimizing set of electricity generation and storage investments and operating decisions to meet forecast electricity demand reliably over the course of a future year, subject to specified policy constraints. Supplementary Note 1 provides details regarding the model configuration for this study. A full mathematical formulation of the model as used for this study is provided in Supplementary Note 4, including details regarding time wrapping and coupling. The specific modifications needed to model LDES technologies are detailed in Supplementary Note 5. As we were modelling hypothetical systems, not specific regional power systems, no explicit transmission constraints were modelled within each region. Each region included several clusters of candidate wind and solar sites, each with different profiles and a maximum capacity limit. Each region also included 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 provides details regarding technical and economical parameters. Supplementary Tables 2–6 show the economic and technical assumptions used in this research, which were sourced from a variety of literature sources. Where possible, input parameter values were extracted from the NREL ATB 2018 (ref. [26]). The 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 for Scenarios 1–11 and the mid-cost projection for Scenarios 12–14.

LDES impact measurement. To understand the dynamics of LDES deployment and its system effects, for each of the 14 scenarios a reference LDES 'base case' was specified that did not include any LDES capacity deployment. A summary of the main results of the 14 base cases is presented in Supplementary Table 1, including the total system cost (US\$ billions), the average cost of electricity (US\$ MWh^{-1}), 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 involved calculating 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 calculated the system value of LDES as 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 calculated 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. To present the results of our analysis within the limitations of two-dimensional visualizations, we introduced the following additional metrics using the LDES energy capacity, E (MWh), discharge power capacity, P_d (MW), and charge power capacity, P_c (MW): (1) the duration, d (h), that is, maximum continuous discharge at rated capacity, calculated as the ratio of energy capacity and discharge power capacity multiplied by the discharge efficiency (η^-) (equation (1)), (2) the RTE, η^2 (%), calculated as the product of charge efficiency, η^+ (%) and discharge efficiency, η^- (%) (equation (2)), and (3) the weighted power capacity cost, C_{WP} (US\$ kW^{-1}), introduced to express the charge power cost, c_{CP} (US\$ kW^{-1}), and discharge power cost, c_{DP} (US\$ kW^{-1}), in one combined metric. As shown in equation (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. The 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 equation (3) are needed to calculate the weighted power capacity cost in cases with no deployment of LDES capacity. Using the metrics shown in equations (2) and (3), it is possible to explore our results in an LDES design space that has lower dimensionality and thus allows us to better visualize the results.

$$d = \frac{E \times \eta^-}{P_d} \quad (1)$$

$$\eta^2 = \eta^+ \times \eta^- \quad (2)$$

$$C_{WP} = \frac{c_{DP} \times \max(1, P_d) + c_{CP} \times \max(1, P_c)}{[\max(1, P_d) + \max(1, P_c)]/2} \quad (3)$$

In the various heatmap figures representing system value, firm and Li-ion capacity substitution, and duration of LDES, the shaded regions are coloured differently for each 5% increment in electricity system cost/capacity reduction or 50 h duration increments. The coloured dots in these figures correspond to discrete cases and their colour also indicates percentage cost reduction/firm capacity reduction or duration on the same colour scale as the coloured regions. The shaded regions correspond to a smooth surface calculated using the locally weighted polynomial regression (LOESS) method with functional form $z \sim x \times y$ (z as function of x and y interactions), where z corresponds to the system value of LDES, x corresponds to the LDES weighted power capacity cost and y corresponds to the LDES RTE. When the LDES technology design space parameters were projected from the original five-dimensional space (energy capacity cost, charge power capacity cost, discharge power capacity cost, charge efficiency and discharge efficiency) to a lower three-dimensional LDES technology space (energy capacity cost, weighted power capacity cost and RTE), some features of the results could not be observed directly. For this reason we applied LOESS[27] to the data to calculate smooth surfaces that can better represent the trends and dynamics in our results. Supplementary Figs. 27–35 show the results for the system cost reduction in the original five-dimensional space for energy capacity costs of US\$1–10 kWh^{-1}, and Supplementary Figs. 36–44 present the results for the firm capacity reduction in the original five-dimensional space for energy capacity costs of US\$1–10 kWh^{-1}.

LDES future feasible regions. We mapped the future LDES technology projections or 'future feasible regions' in Table 1 into our lower-dimensional LDES design space, as shown in Extended Data Fig. 1, differentiating between geographically constrained and unconstrained resources. For each category we constructed 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 Fig. 1. These feasibility lines were then projected onto all figures mapping the LDES design space. The resulting feasibility lines divide the LDES design space into (1) an infeasible future region (the region to the left of the left-most feasibility line), (2) a geographically constrained future feasible region (the region to the right of the constrained feasibility line and to the left of the unconstrained feasibility line) and (3) an unconstrained future feasible region (the region to the right of the unconstrained feasible line). For energy capacity cost levels for which the unconstrained feasibility line reaches lower weighted power cost and higher RTE levels than the constrained feasibility line, only the former has been plotted. The data in Extended Data Fig. 1 make 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 coexist 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 did 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 importantly constrained by siting, permitting and cost-allocation challenges, LDES may be a long-term and important alternative to integrate larger amounts of renewable energy[28]. A thorough evaluation of the specific technical and economic characteristics necessary for LDES to act as an effective substitute for transmission (or distribution) network upgrades remains a topic for future research. Third, we evaluated 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 with 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 Supplementary Information.

Code availability
The code used to generate and analyse 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
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 the formal analysis, visualization and investigation, and produced the figures. N.A.S. and J.D.J. drafted and finalized the manuscript. D.S.M. and R.K.L. advised on the 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.

Competing interests
N.A.S. and J.D.J. are partners in DeSolve LLC which provides consulting and analytical services for for-profit and non-profit 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, non-profit and private sector clients.

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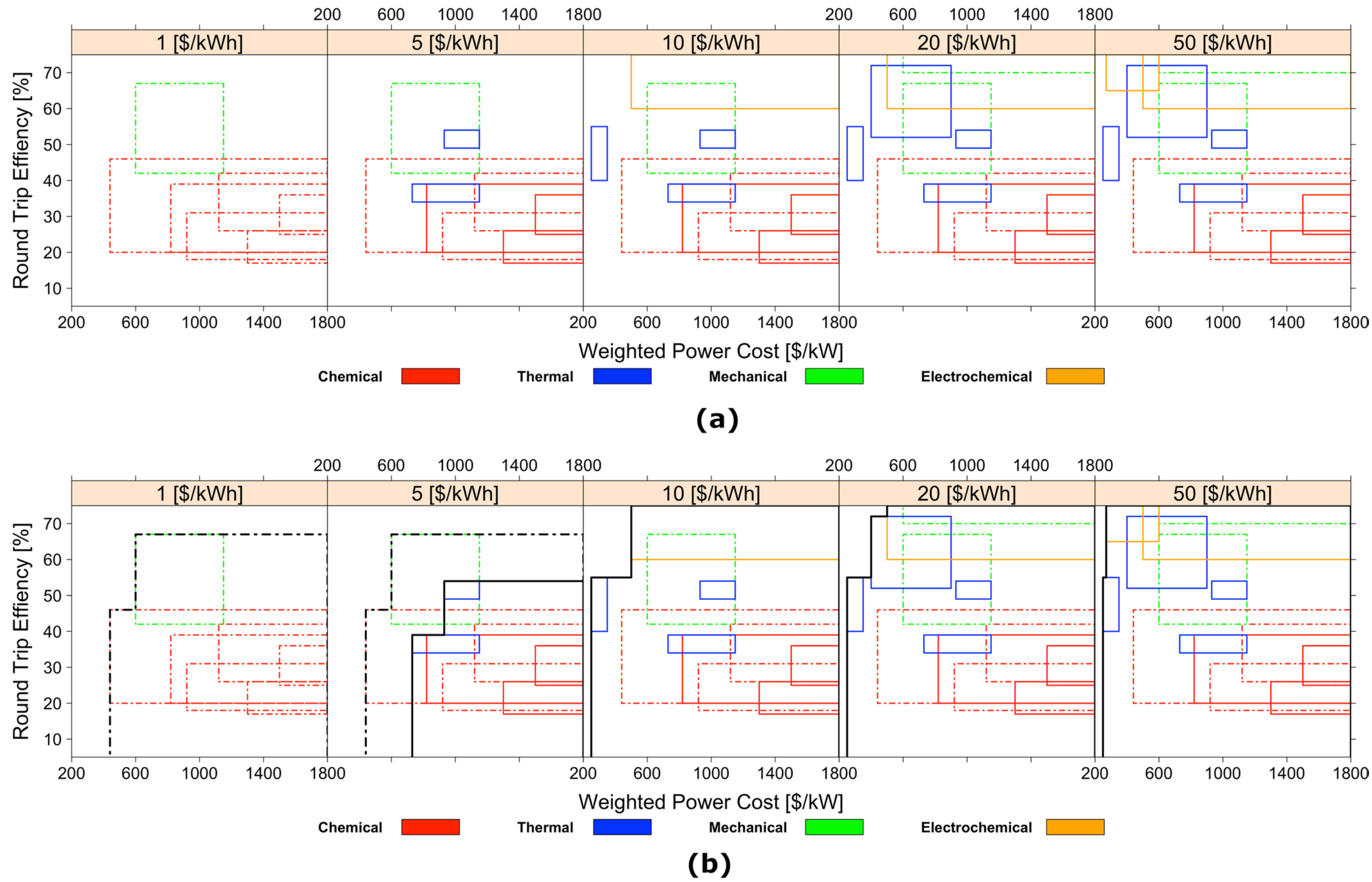
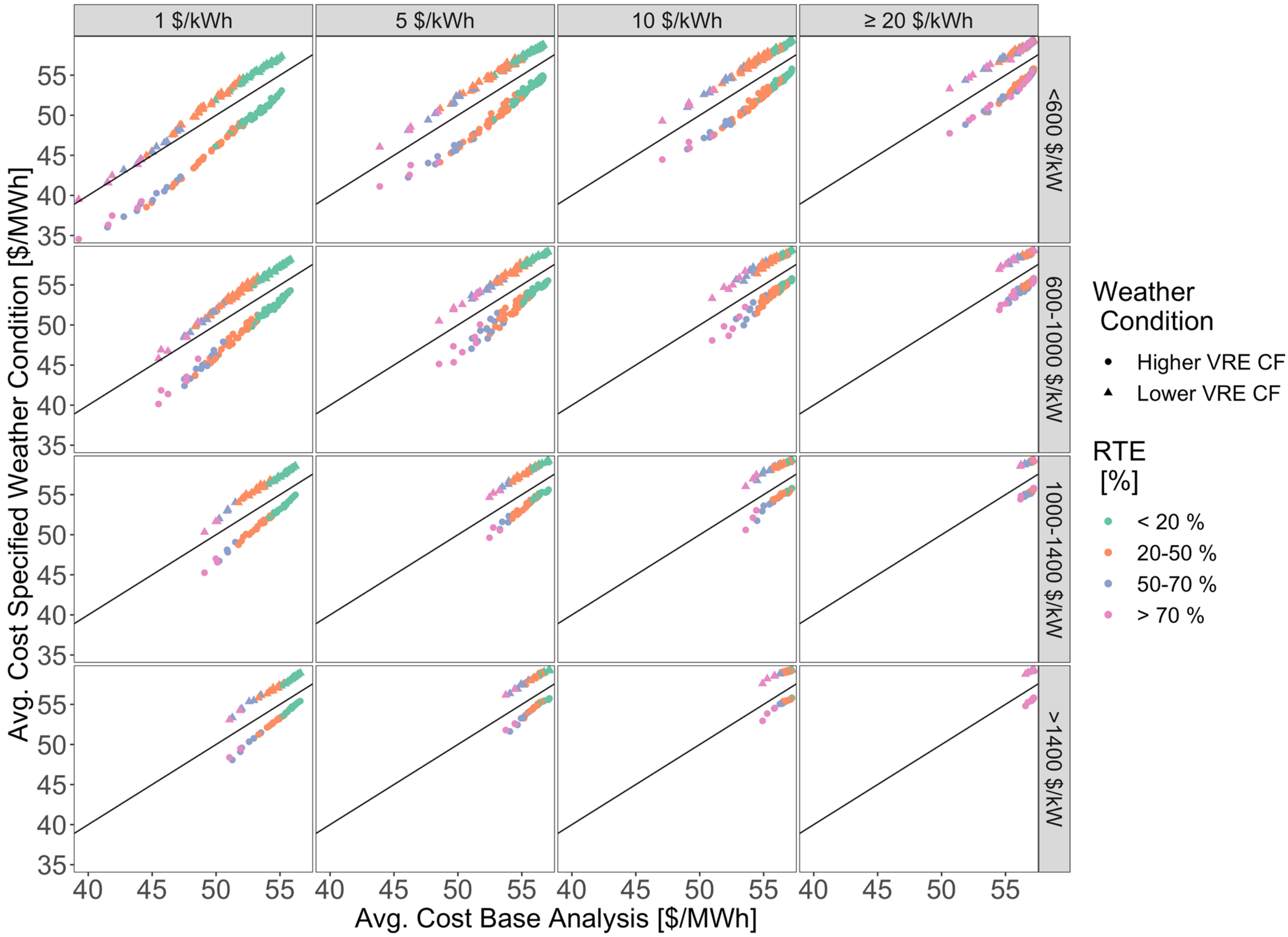
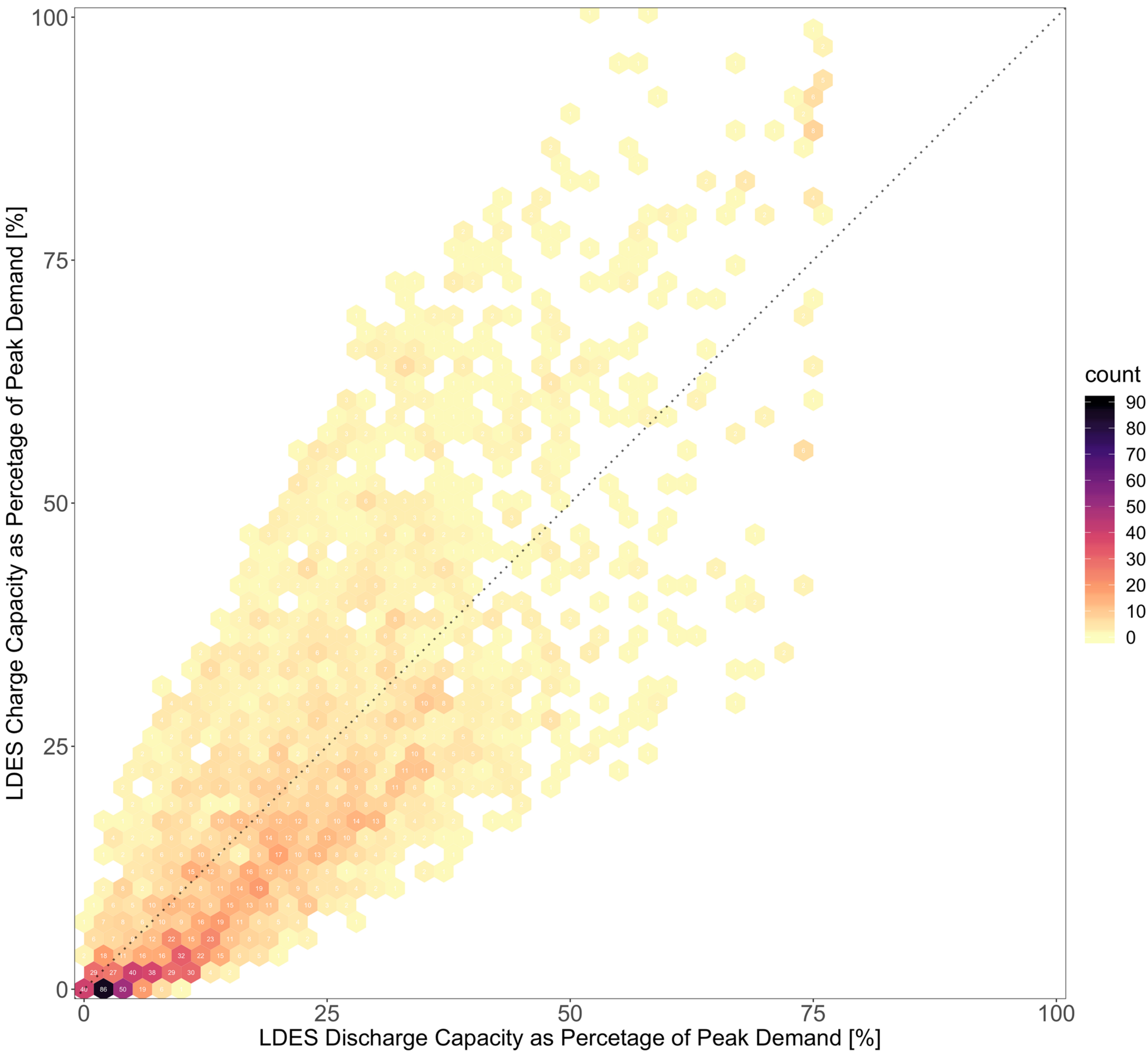


Extended Data Fig. 1 | Intersection between LDES Technology Space and Future Technology Projections. Data from Table 1. Each column represents a specific Energy Capacity Cost [$/kWh] assumption in the 'LDES Technology Space'. Within each subplot the x-axis represents the Weighted Power Capacity Cost 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 Fig. 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 Fig. 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.