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How much bulk energy storage is needed to decarbonize electricity?

Hossein Safaei[a]

Email: safaei@seas.harvard.edu

David W. Keith[a,b]

Email: david_keith@harvard.edu, Tel: 857-294-2050, Fax: +1-617-496-0425. To whom correspondence should be addressed.

[a] School of Engineering and Applied Sciences, Harvard University, Pierce Hall, 29 Oxford Street, Cambridge, MA 02138, USA

[b] John F. Kennedy School of Government, Harvard University, 79 JFK Street, Cambridge, MA 02138, USA

Broader Context

Cost-effective bulk storage of electricity is often assumed to be a necessity for large-scale utilization of renewables. However, bulk storage has two important rivals: dispatchable-low-carbon generators (e.g. nuclear) and gas turbines. Here we ask, how does storage compete with its rivals when deep emissions reductions are required? We explore the optimal use of storage in a simple electricity system model and find that it does little to ease the cost of cutting emissions. Gas can outcompete storage even with massive use of wind and very tight constraints on emissions. Reducing capital cost of renewables or dispatchable-low-carbon generators is far more effective in lowering the cost of electricity than is lowering the cost of bulk storage.

Abstract

High cost and technical immaturity of bulk (multi-hour) electricity storage (BES) systems are often cited as major hurdles to increasing the penetration of intermittent renewables. We use a simple model to assess the economics of BES under carbon emissions constraints. Size and dispatch of a green-field generation fleet is optimized to meet a variable load at a 15 minute time resolution. Electricity supply options are wind, gas turbine, BES, and a generic dispatchable-zero-carbon (DZC) source as a proxy for fossil fuel plants with carbon capture or nuclear plants. We review the cost of selected BES technologies and parameterize the performance of storage, focusing on the energy- and power-specific capital costs. We examine sensitivity of the electricity cost to storage performance under a range of emissions constraints. Availability of inexpensive BES systems in general and particularly electrochemical technologies has a small impact on the overall cost of decarbonization. Proportional reductions in capital costs of wind and DZC lower decarbonization costs far more. We find no economic justification for seasonal storage. Intermittent renewables can be used to decarbonize the electricity supply with a proportionally small requirement for BES because gas provides much of the intermittency management even when the carbon emissions intensity is cut to less than 30% of today's U.S. average. Substantial BES is required only when emissions are constrained to nearly zero and DZC is not allowed.

1- Introduction

Availability of low cost and scalable bulk electricity storage (BES) technologies is often considered a prerequisite for use of wind and solar energies as a means to gain deep reductions in Greenhouse Gas (GHG) emissions from the electricity grid [1-4]. Examples of such systems are pumped hydroelectric storage (PHS), compressed air energy storage (CAES), and vanadium redox flow batteries (VRB). In current electricity markets with low penetration of renewables and low natural gas prices, BES is not economical, and its technical and economic characteristics are uncertain due to its limited deployment.

Our question is: how important are the emerging BES technologies in enabling the integration of intermittent renewables? We tackle this question by analyzing the optimal deployment of electricity supply and BES technologies that meet specified GHG emissions constraints. We operationalize the *importance* of BES as the amount that it lowers the cost of electricity as the stringency of carbon constraints is increased, or almost equivalently, the amount by which it increases the penetration of renewables under the same constraints. Our analysis aims to inform policy for decarbonizing the electricity supply, and in particular for developing R&D incentives and market support for BES.

We assess the economically desired amount of BES using a simple linear-constrained optimization model that optimizes the size and dispatch of a hypothetical generation fleet under deep carbon reduction mandates (*e.g.* emissions cuts of greater than 50%). Rather than using a point estimate of future BES costs, we work parametrically, exploring how storage capital costs determine the grid-average cost and emissions intensity of electricity. Electricity storage can provide a variety of services such as frequency regulation to support integration of intermittent renewables, but here we limit our analysis to bulk (multi-hour) storage of electricity.

Our primary contribution is to assess the economics of BES as a function of its power- and energy-specific capital cost when it is used to achieve deep decarbonization of electricity supply. Applying a simple model enables us to parametrically evaluate the role of the capital cost which is the single most important determinants of the economic viability of BES. Previous work has examined the economics of specific BES technologies in comparison to gas turbines in low carbon grids [5-7]. The rationale for focusing on gas as a rival for BES is low carbon emissions compared to coal, high operational flexibility, and low capital costs. Several studies have examined the competitiveness of a wide array of storage technologies at the grid level. These systems-level assessments use complex utility-grade models (*e.g.* incorporating security-constrained unit commitment) to take into account the specifics of the modeled grid and its reliability requirements. An example is the Pacific Northwest National Laboratory's (PNNL) report on the intra-hour balancing requirements to facilitate a 20% penetration level for wind [7]. But existing literature does not cover the parametric "what if" question we address here: what are the price and performance parameters required for BES to play a significant role in enabling intermittent renewables to achieve deep emissions cuts in the electricity sector.

Our modeling approach allows us to estimate the economically optimal amount of bulk storage—both energy storage and peaking capacity. Estimating storage requirements is a complicated task.

An important factor here is the cost of storage, which the literature often underestimates. Barnhart and Benson [8] picked a storage scale equal to 4-12 hours of the average electricity demand in order to evaluate the energetic and material implications of large-scale deployment of storage systems. In a different study however, Pickard [4] used a storage size roughly 5.5 times larger than the average daily primary energy demand, while neither of these authors justified their selection from an economic point of view. Denholm and Hand [9] applied a dispatch model to the Electric Reliability Council of Texas (ERCOT) grid and concluded that wind and solar penetration levels as high as 80% while keeping the curtailment rates below 10% would require a combination of load shifting and storage of one day of demand. Similarly, Denholm and Hand's analysis is not based on any economic metrics such as cost of storage or even wind and solar plants themselves. Parametric modeling of the BES capital cost allows us to explore its impact on the overall cost of electricity supply and to assess the economically optimal deployment of BES over a wide range of estimates for the BES capital cost.

2- Data and methods

We use real world wind and load data to build our electricity system model. We optimize the size and dispatch order of the generation fleet to minimize the cost of electricity supply under a range of BES costs and GHG emissions constraints. Our analysis is based on the following key simplifying assumptions. First, since our focus is on deep emissions reductions under which essentially all coal power plants have to retire (or have carbon capture and sequestration, CCS retrofits) and because deep reductions will likely not occur until the existing fleet nears the end of its economic life, we ignore the existing capacity and perform a green-field analysis. Second, transmission costs and constraints are ignored. Third, since we are studying BES, we use a temporal resolution of 15 minutes. We do not treat reliability and security constraints of the grid. Fourth, we ignore forecast errors in the load and wind profiles. Finally, we limit our time horizon to one year, ignoring inter-annual variations in load and wind. We examine the impact of these assumptions on our policy-relevant conclusions in the Conclusion section and Table S1.

2-1- Modeling energy storage

Variations in the engineering and economic parameters of BES technologies obviously affect their cost effectiveness in supporting renewables. No BES technology, except PHS has been deployed at large scale so far (PHS accounts for 99% of the existing 141 GW global electricity storage capacity [10]. Limited experience and the emergence of new technologies make assessing the importance of BES in low emission grids difficult. As Table 1 illustrates, current literature uses widely different assumptions about the capital cost (CapEx) and efficiency of BES systems.

Hittinger et al. [11] as well as Sundararagavan and Baker [12] studied the significance of selected economic and technical parameters and concluded that CapEx was consistently the single most important parameter undermining the economic feasibility of electricity storage systems. We therefore, focus on CapEx as the main variable of BES throughout our analysis. We first draw general conclusions by treating BES as a black box with fixed technical characteristics but variable CapEx (see Table 2). This approach allows us to perform a systems level analysis to provide a first order estimate of the market share of BES in low carbon economies. We then study specific BES technologies in a wide range of CapEx estimates to assess their significance in lowering the cost of cutting carbon emissions.

We assume that the total CapEx of a BES facility is the sum of two components, one proportional to the peak power capacity and the other proportional to the stored energy capacity. We further assume that any combination of power and energy capacities is technically feasible. Power-specific capital cost (X_P) has units of $/kW, and the energy-specific capital cost (X_E) has units of $/kWh. In the case of PHS for example, X_P and X_E primarily represent the CapEx of turbomachinery and water reservoir, respectively.

We explore the balance between X_P and X_E in determining the economics of BES and as a means to guide R&D in prioritizing its cost reduction targets. This strategy also helps in assessing the economically optimal ratio of power to energy capacity over a wide range of X_P and X_E. This optimal ratio has implications for the technical feasibility of large-scale adoption of some BES technologies, such as availability of minerals and chemicals for electrodes (power capacity) and electrolytes (energy capacity) of flow batteries.

We map cost estimates for selected BES technologies on the X_E and X_P coordinate system in Figure 1. The basis of our estimates is provided in Table 1. Two distinct regions are observed. Region 1 represents mechanical systems (PHS and CAES) distinguished with low energy capital cost (X_E) but very high values for power cost (X_P). Region 2 embraces electrochemical systems with intermediate values for X_E and X_P. We refer to BES systems situated in regions 1 and 2 as mechanical and electrochemical hereafter.

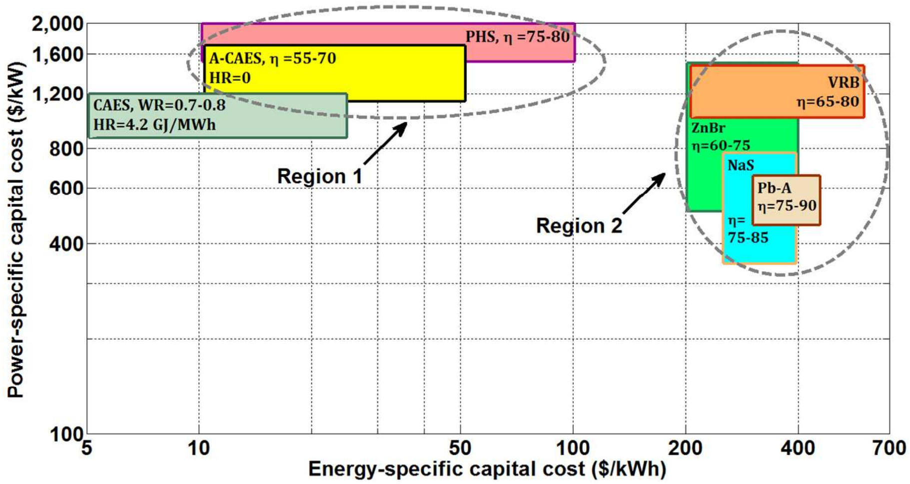


Figure 1: Mapping of selected BES technologies on the X_E and X_P plane. Each box represents a BES technology and its location corresponds to the ranges shown in bold in Table 1 for X_E and X_P. Estimates for the storage efficiency (η), heat rate (HR), and work ratio (WR) are included. WR quantifies electricity used by the CAES plant per unit of electrical energy generated. Regions 1 and 2 represent mechanical and electrochemical technologies, respectively.

Table 1: Economic and technical characteristics of selected BES technologies. Values in bold represent the authors' best estimates and are used in Figure 1.

BES technology	X_P ($/kW)	X_E ($/kWh)	Efficiency (%)
Pumped hydroelectric storage (PHS)	2300 [7], 1500-2000 [13], 1200 [14], 600-2000* [15], 1500-2300 [7], 2000 [12], **1500-2000**	10 [7], 100-200 [13], 75 [14], 0-20 [15], 12 (plus $2/kWh for BOP†) [12], **10-100**	70-85 [10, 15, 16], 80 [12], 85 [14], 50-85 [17], **75-80**
Underground diabatic compressed air energy storage (CAES)	655 [3], 850-1140 [7], 740-830 [13], 700 [14], 425-480 [15], 750-1200‡ [18], 835§ [19], 450 (plus $160/kW for BOP) [12], **850-1200**	7 [3], 3 [7], 5 [14], 3-10 (+$50/kWh for balance of plant equipment, BOP) [15], 5-25** [18], 1-2 [13], 20 [19], 10 [12], **5-25**	4.2 and 0.8 [3], 4.2 and 0.75 [18], 4.2 and 0.67 [6], **0.7-0.8 and 4.2** (Values present heat rate in GJ/ MWh and work ratio)
Aboveground diabatic CAES (AD-CAES)	800-900 [13], 517 [15], 835 [19], **850-1200**††	200-240 [13], 50 (+$40/kWh for BOP) [15], 220-260‡‡ [19], **200-250**	**0.7-0.8 and 4.2**§§ (heat rate in GJ/ MWh and work ratio)
Underground adiabatic CAES (A-CAES)	920*** [3],**1100-1700**	8 [3],**10-50**†††	77 [3], 50-75 [20], **55-70**
Lead acid battery (Pb-A)	450 (+$100/kW for BOP) [12], 420-660 [13], 400 [14], 200-580 [15], **450-650**	200-400 [12], 330-480 [13], 175-250 (+$50/kWh for BOP) [15], 330 [14], **300-450**	65-85 [10], 75 [12], 75-80 [14], 85 [15], 85-90 [19], 75-90 [21], 60-95 [22], 70-90 [23], 75-86 [15], **75-90**
Sodium sulfur battery (NaS)	3000 (+$100/kW for BOP) [12], 350 [14], 260-810 [15], **350-800**	534 [12], 350 [14], 245 (+$40/kWh for BOP) [15], **250-400**	75-85 [10, 15], 85 [12], 75 [14, 21], 75-80 [19, 24], 75-90 [23], **75-85**

* In our opinion, storage costs reported by this source are too optimistic.
† BOP: Balance of the plant equipment.
‡ We calculated this range based on the estimates for two different CAES facilities (135 MW and 405 MW with 12 hours of storage).
§ Values are based on cost estimates for two different CAES facilities (135 MW with 8 and 20 hours of storage).
** Lower and upper bounds represent depleted gas reservoirs and domal salt caverns.
†† We assume that underground and aboveground CAES have similar specific power capital costs.
‡‡ We estimated the energy-specific cost (X_E) of aboveground CAES based on the total costs cited for underground and aboveground CAES, assuming comparable values for their power-specific CapEx (X_E).
§§ We assumed underground and aboveground CAES have comparable thermodynamic performance.
*** We adjusted the limited-publically available cost estimates for A-CAES based on their and our estimates for diabatic CAES.
††† Energy density of cavern of A-CAES is roughly half of CAES. We therefore, doubled our estimates for CAES to calculate energy-specific cost (X_E) of A-CAES.

Zinc bromine battery (ZnBr)	2000 (+$100/kW for BOP) [12], 400 [14], 640-1500 [15], **500-1500**	400 [12, 14], 200-400 [15], **200-400**	75 [12, 15, 22, 23], 70 [14], 65-70 [19], 60-65 [21, 24], **60-75**
Vanadium redox battery (VRB)	3200 (+$100/kW for BOP) [12], 942-1280 [7], 400 [14], 1250-1800 [15], **1000-1500**	630 [12], 600 [14], 175-1000 [15], 173-257 [7], **200-600**	65-85 [10], 80 [12], 70-85 [15], 65-75 [19], 65 [14], 75 [7], 75-78 [24], 65-70 [21], 85 [22], **65-80**

2-2- Load and wind data

Wind and load profiles are based on historical data from ERCOT in the Unites States between May 2012 and April 2013. Load is normalized to its peak and wind is normalized to installed capacity. We choose a temporal resolution of 15 minutes. Power spectrum analysis of wind farms indicates that the majority of high amplitude variations in their output occur at low frequencies (hourly and daily timescales) [25], so a 15-minute resolution over one full year captures requirements for bulk energy storage. Performing the analysis over one full year also enables assessing the need for long duration storage of electricity. The correlations between wind availability and electric load in our model are discussed in electronic supplementary Information (ESI) section.

2-3- Electricity system model

We simultaneously optimize installed capacity and dispatch during operation of a generation fleet to meet the load at the minimum cost. We use a set of scenarios defined by a series of imposed constraints on the annual average GHG intensity of electricity ranging from 300 to 0 kgCO_2e/MWh (CO_2e equivalents are used to account for methane emissions, see ESI for details). The power- and energy-specific CapEx of BES are varied to sample the two-dimensional (X_E and X_P) space within each emissions intensity scenario. The system-average levelized cost of electricity (LCOE, $/MWh) is minimized at each emissions intensity and at the sampled values of X_E and X_P. The LCOE includes fixed and variable operating and maintenance costs (FOM and VOM), fuel costs, and amortized CapEx. This optimization problem is solved in MATLAB using linear programming with the interior-points algorithm. It takes about 500 seconds on a 2012 vintage CPU for each of 320 sample points in the X_E and X_P plane. See ESI for details of the mathematical model.

We assume that any combinations of simple and combined cycle gas turbines (SCGT and CCGT), wind farms, and BES can be utilized to meet the load. Our model also includes a generic generation source called dispatchable-zero-carbon, DZC. This category represents the (near) zero carbon but dispatchable technologies that are currently too costly but are likely to emerge as more cost effective in a carbon-constrained world. Examples can be gas turbines integrated with CCS, concentrated solar power (CSP) equipped with thermal storage, and nuclear power plants.

We vary X_E and X_P of BES in the range of 5-700 $/kWh and 100-2000 $/kW, respectively to cover 320 sample points. All BES technologies are assumed to have the same efficiency within a given scenario except for diabatic CAES which is modeled separately (because it consumes fuel during the discharging phase). Charge and discharge rates of BES are assumed to be equal.

We consider four scenarios for emissions intensity of the grid; business as usual (BAU) and caps of 300, 150, and 0 kgCO_2e/MWh. Note that these values, even BAU (this scenario leads to an emissions intensity of ~448 $kgCO_2e/MWh$) represent sharp emissions reductions compared to the existing grids, mainly because coal is not included in our model. For instance, the average carbon intensity of the entire USA grid and the global average in 2010 were 503 and 536 $kgCO_2/MWh$ [26].

Table 2 summarizes various inputs of our model. Roundtrip efficiency of storage is set at 75%, an average value based on BES technologies in Table 1. The price of gas is fixed at $5/GJ (sensitivity analysis is provided in the ESI). Operational considerations such as minimum up and down times, ramp rates, and part-load performance are not included in the model. We use a GHG intensity of 66 $kgCO_2e/GJ$ (low heating value) [6] for gas to account for upstream emissions in addition to combustion emissions, which leads to a GHG intensity of 647 and 442 $kgCO_2e$/ MWh for the modeled SCGT and CCGT plants.

Our cost estimates for gas turbines and wind farms are based on values reported by the US Department of Energy (DoE) [27], US Energy Information Administration (EIA) [28], National Renewable Energy Laboratory (NREL) [29], and Lazard Ltd [30]. We use a value of $9000/kW for DZC. Each specific DZC technology will face some geographical constraints (*e.g.* CSP requires high solar irradiance or CCS needs a suitable geologic formation). DZC, however, represents the least capital-intensive, dispatchable technology— whether CSP, nuclear, CCS, biomass or geothermal—that can be utilized in a given location. Our judgment is that 9000 $/kW is mostly likely an overestimate of this best-case DZC cost (see ESI for our rationale and the sensitivity analysis on DZC cost).

Table 2: Technical and economic inputs of the model in the base case

Parameter	Value	Notes
CapEx of Wind, SCGT, CCGT, DZC	2000, 800, 1100, and 9000 $/kW	Wind and gas turbine data are based on references [27-30]. FOM and VOM of DZC are based on nuclear and CSP [28, 30]
FOM of Wind, SCGT, CCGT, DZC	35, 10, 12, and 100 $/kW/yr	
VOM of Wind, SCGT, CCGT, DZC	0, 10, 3, and 0 $/MWh	
Heat rate of SCGT, CCGT, and CAES	9.8, 6.7, and 4.2 GJ/MWh	
Work ratio of CAES	0.75	CAES data are based on Table 1
Storage efficiency	75%	An average based on Table 1
Price of gas	5 $/GJ	Based on lower heating value
Blended cost of capital	10%	Equivalent to a discount rate of ~8% for 20 years
X_P and X_E of BES	100-2000 $/kW and 5-700 $/kWh	Range used in simulation that cover 320 points in X_P, X_E space

Finally, our analysis treats the electricity grid in isolation from the other parts of the economy, most importantly transportation sector. It is reasonable to envision both a low-carbon power and transportation sector under economy-wide GHG emissions constraints in future. Storage of electricity in the form of low-carbon fuels to power the transportation and electricity generation fleet is a scenario that our analysis does not cover. Storage of electricity as a fuel (*i.e.* electrofuels and hydrogen) is more technically and economically likely than storage of electricity itself over long time scales (*e.g.* seasonal battery storage). Other low-carbon fuels (*e.g.* biofuels) can also fuel the power sector, which is not considered in our model.

3- Results and Discussions

3-1- Cost of electricity

In our BAU scenario, wind and DZC are not economically viable and gas turbines and storage supply the electric load. CCGT dominates the electricity supply because of the high operating and fuel costs of SCGT compared to CCGT (see Table 2). Even without an emissions constraint, cheap BES reduces the need for peaking plants (SCGT) by increasing utilization of CCGT and thus lowering the cost of electricity. Emissions intensity, however, is insensitive to the storage cost because BES supplies at most 3% of the annual load. CCGT supplies almost all (>97%) of total electricity. Note that the 15-minute resolution may slightly overestimate the share of CCGT as it understates the advantage SCGT should get from its faster ramp rate.

Our central research question is how the capital cost of storage impacts the overall cost of electricity supply under tight carbon constrains. Figure 2 illustrates LCOE at various emission caps over a wide range of X_E and X_P. The most general result is that energy capital cost (X_E) has a stronger influence on LCOE than does power cost (X_P) under all emission scenarios. Comparing Figure 1 and Figure 2, we can see that the existing mechanical BES systems are more likely to cost effectively curb emissions due to their significantly lower X_E compared to electrochemical technologies, despite higher X_P of the mechanical systems.

A second result is that inexpensive BES has a small impact on the LCOE in all scenarios except for the carbon free grid. LCOE differs only 6% (56.6 and 60.3 $/MWh) between the cheapest and most expensive BES system that we model in BAU. As expected, the impact of BES on LCOE rises when a tight cap of 150 kgCO_2e/MWh is imposed. But even then, BES cuts the costs by only 17% (81.2 versus 97.8 $/MWh) even though emissions are cut by 67% compared to BAU, an even deeper cut when compared with current emissions which include coal.

LCOE is more sensitive to storage cost when emissions are constrained to zero at which point there is a 27% difference between LCOE of the carbon free grid utilizing the cheapest BES system (X_E=5 and X_P=100, LCOE=$143.9/MWh) and the most expensive BES system (X_E=700 and X_P=2000, LCOE=$195.9/MWh).

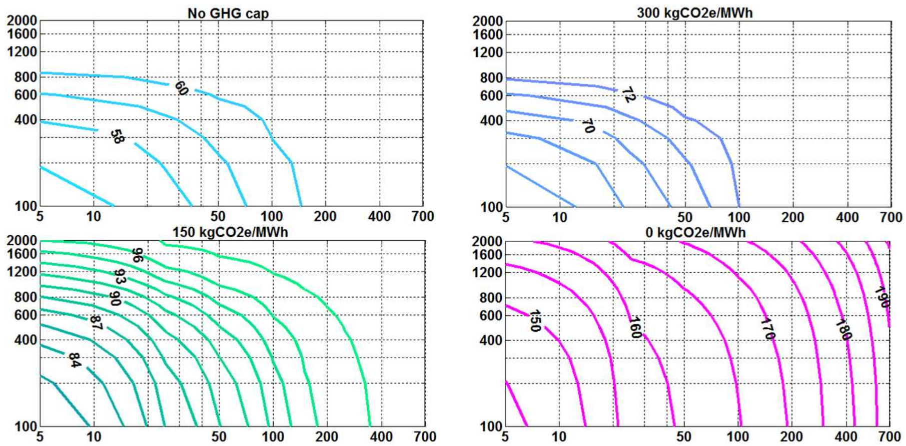


Figure 2: Impact of X_E and X_P and emissions constraints on LCOE. Horizontal and vertical axes show X_E ($/kWh) and X_P ($/kW), respectively. Values on the graphs present LCOE ($/MWh). Subfigures from top left in counter clockwise order correspond to BAU (no emissions constraint), and caps of 300, 150, and 0 $kgCO_2e$/MWh. In all the contour plots, 320 discrete sample points are simulated to cover the range of 5-700 and 100-2000 for X_E and X_P. Contour spacing is constant in each plot; therefore, absence of contour lines in an area indicates no changes larger than the contour spacing. Also note that sharp changes are an artifact of the contouring algorithm.

The strong impact of storage cost on the LCOE in the completely decarbonized system is driven by the absence of gas turbines. Even under the low 150 $kgCO_2e$/MWh scenario, gas turbines (particularly CCGT) can cost-effectively manage the variability of wind, as explored in section 3-2. Despite their higher fuel and operational cost, the relatively low CapEx of gas turbines allows them to out-compete BES in managing the variability of wind.

3-2- Storage cost and wind penetration

Since emission constraints and availability of affordable BES are often considered as requirements for large-scale adoption of intermittent renewables, we explore effect of these parameters on the economically optimum level of wind penetration in our model. Because our focus is on deep decarbonization targets, we discuss the results for the 150 $kgCO_2e$/MWh scenario (~33% of BAU emissions).

The distinct impact of mechanical and electrochemical BES technologies is evident in Figure 3. While electricity cost is almost the same (<5% difference), optimal size of the wind fleet using electrochemical BES is only 60% of the wind fleet using mechanical systems. This indicates that BES systems with low energy capital cost (X_E) facilitate higher penetration of wind energy. If electrochemical rather than mechanical BES systems are utilized, the optimal sizes of the SCGT and DZC fleet get larger to compensate for the smaller wind fleet. The optimal size of CCGT is almost insensitive to the storage cost (approximately 53% for both BES categories).

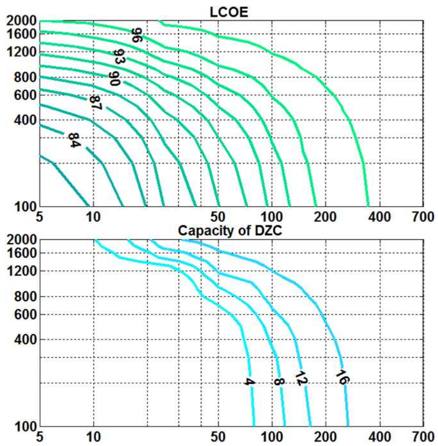


Figure 3: Electricity system characteristics at an emissions cap of 150 kgCO$_2$e/MWh. Subfigures from top left illustrate LCOE, normalized wind capacity, DZC, and SCGT. All size values are percentage of peak electric load. Horizontal and vertical axes show X_E ($/kWh) and X_P ($/kW).

These results lead to the conclusion that the optimal wind capacity is very sensitive to the CapEx of BES, especially to its energy capacity cost (X_E). Therefore, mechanical BES systems (region 1 in Figure 1) are better suited for large-scale integration of intermittent renewables, at their current costs.

While lower-cost storage increases wind's share of annual generation, it does little to change the overall electricity cost because it just shifts the balance between wind and DZC. This does not answer a related energy policy question: how important is bulk storage to manage high penetration of intermittent renewables? We explore this by removing DZC from the generation fleet—so intermittent renewables (wind in this case) are the only way to decarbonize—and then enforce a 150 kgCO$_2$e/MWh emissions cap. We then operationalize the "how important" question by comparing the optimal wind capacity to the capacities of BES and gas when we assume a generic mechanical BES system (energy and power costs of X_E=$30/kWh and X_P=$1500/kW). We find that the optimal capacities BES and gas are ~20 and 60% (respectively) of the capacity of wind. So one could say that BES is three times less important than gas in providing peaking power, under this tight emissions constraint and with current capital cost estimates. Under these conditions, about a third of annual load comes from gas, 6% from BES and the rest from wind. See Table S3 in ESI for the extended results.

This result changes only as emissions are pushed towards zero. Then with zero or near-zero emissions and no use of DZC, larger storage capacities will be needed to manage wind's intermittency as GT gets too polluting for such extremely low-carbon grids.

3-3- Economically optimal deployment of storage

The amount of BES that is technically required for decarbonization with intermittent renewables is (somewhat) independent of the impact of storage on electricity costs. Based on the 150 kgCO$_2$e/MWh scenario, we can make the following comments on the economically efficient penetration level of BES. Refer to Figure S4 in ESI for graphical results.

The power capacity of BES remains below 30% and 10% of the peak load for the mechanical and electrochemical BES systems, respectively. Although mechanical technologies have higher X_P, their optimal power capacity is noticeably higher compared to electrochemical systems. This observation again highlights the significance of the energy-specific cost (X_E) in the overall economic viability of BES systems —a major disadvantage of the existing battery systems.

The optimal energy capacity of BES turns out to be small in general, even when we impose ~70% emission reductions compared to BAU. The mechanical storage fleet was sized to supply the average electric load for one full day on its own. This value sharply drops as the energy cost (X_E) increases while the power cost (X_P) simultaneously drops; *i.e.* moving to electrochemical systems. These relatively low energy capacities signal the unimportance of large-scale storage of electricity over long time horizons (*e.g.* seasonal storage) from an economic point of view. This is driven by the lower competitiveness of BES systems coupled with wind in comparison to low carbon and dispatchable generation facilities, like CCGT and DZC modeled here. Even when we consider the cheapest BES system simulated (X_E=5 and X_P=100, the lower left corner of Figure 1), the BES fleet would be sized to store enough energy to meet the average load for ~40 hours. In other words, intermittent renewables (wind, as modeled here) can be used to decarbonize the electricity supply with a proportionally small requirement for BES since gas can provide much of the intermittency management, even when the emissions intensity is cut to less than 30% of today's U.S. average. Substantial BES is required only when emissions are constrained to nearly zero and DZC is not allowed.

The BES share of the total supply of electricity is also small compared to of the rest of the generation fleet. Approximately 6% of the demand is met by the electricity stored in mechanical BES systems (very sensitive to X_E) while this figure becomes marginal for battery technologies with their current capital costs. Even using the cheapest storage assumptions given above, the contribution of BES remains about 10%. The drop in the share of storage (and consequently the wind fleet) of the electricity supply at elevated storage costs is compensated by DZC.

3-4- Implications for specific BES technologies

Which BES technologies are closer to having an impact under carbon constraints and thus would merit a higher priority in R&D efforts directed at decarbonizing the electricity supply? We explore this question through a scenario in which energy- and power-specific costs of each BES technology are cut in half. As a measure of impact, we use share of the annual load supplied by BES (market share). Figure 4 shows results for an emissions cap of 150 kgCO_2e/MWh while Figure S5 shows a similar graph but for LCOE instead of market share.

None of the existing technologies gain noticeable market share, but when costs are halved PHS and A-CAES make larger gains in market share (7% and 9%, respectively) and make a corresponding impact in reducing the electricity cost (Figure S5). The simulated battery technologies remain prohibitively expensive even when their costs are halved compared to the current estimates.

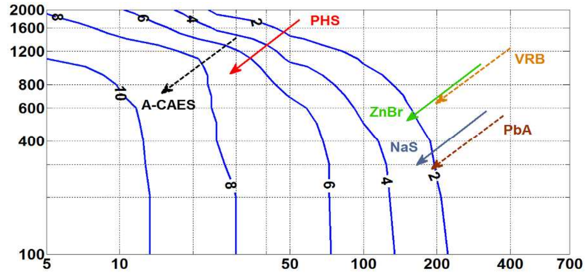


Figure 4: Market share of BES (% of load supply) with a carbon cap of 150 kgCO2e/MWh. Horizontal and vertical axes indicate X_E ($/kWh) and X_P ($/kW). Arrows start from the current cost estimates (average of the range shown for each technology in Figure 1) and end at points with 50% reduction in both X_E and X_P.

We analyzed diabatic CAES separately since unlike all other BES technologies it has non-negligible emissions. The CAES plant modeled here emits 277 $kgCO_2$/MWh. We varied X_E and X_P of diabatic underground CAES in the range of 5-25 $/kWh and 850-1200 $/kW. Heat rate and work ratio of CAES are set at 4.2 GJ/MWh and 0.75. Aboveground CAES was not modeled due to its obvious weaker performance (caused by much higher energy-specific capital cost of >200 $/kWh). Availability of diabatic CAES made negligible differences in LCOE. The cheapest CAES system modeled (X_E=5 $/kWh and X_P=850 $/kW) could only store enough electricity to meet the average load for ~1 hour and its power capacity is 7% of the peak load. Despite having the lowest energy-specific cost (X_E) among all other BES systems, underground diabatic CAES is not a cost effective decarbonization tool. See ESI for details on the CAES modeling.

4- Conclusions

We draw two policy-relevant conclusions from this work. First, large-scale adoption of bulk electricity storage compared to variable renewables and gas turbines is neither technically required nor cost effective as a means to reduce carbon emissions even when variable renewables play a large role. In other words, intermittent renewables need not to wait for the availability of cheap bulk storage to become an effective tool for decarbonization. This conclusion breaks down only when emissions must be reduced by more than about 70% *or* when the cost of dispatchable-low-carbon power sources is very high (above $9000/kW with an emissions cap of 150 $kgCO_2e$/MWh at current BES cost estimates, see Figure S2 and Figure S3). Second, at their current costs, adiabatic CAES and PHS show the most appealing prospects in lowering the decarbonization cost among other BES technologies due to their low energy-specific capital costs and despite their much higher power-specific capital costs

The strength of our analysis, like any other, turns on its assumptions. Our most important simplifications include ignoring transmission, ignoring forecast errors of wind and load, and using a green-field model rather than one that allows dynamic adjustment of capacity over time. We have limited the simulation to 15-minute time intervals and have not modeled any reliability requirements (*e.g.* reserve margin). We have also used a fixed gas price of $5/GJ and a constant storage efficiency of 75%.

The following paragraphs tease out the quantitative conclusions that underpin each of the high-level claims, and explain why we think the policy-relevant conclusions are robust to our simplifying assumptions. Table S1 in ESI provides a systematic overview of all significant assumptions and their likely impact on the conclusions.

Our first conclusion is that availability of inexpensive BES has relatively small effects on the overall cost of electricity generation, unless extremely tight emission mandates are in place *or* dispatchable-low-carbon technologies are very expensive. Under an emissions cap of 150 $kgCO_2e/MWh$ – a ~70% cut in emissions intensity compared to the current USA or world average – a reduction in storage costs by more than an order of magnitude (to X_E=5 $/kWh and X_P=100 $/kW from already optimistic values of X_E=25 and X_P=1500 from the mechanical BES category) cuts the cost of electricity generation by 16%. This is not a significant reduction when compared to the impact of cutting the capital cost of wind or DZC by 50%, which lowers electricity cost by 26% and 29%, respectively (see Table S6 for a complete list of cases and comparative costs and emissions). One should note that assessing the likelihood and the associated costs of cutting the capital cost of different technologies were not in the scope of our analysis. We analyzed only the effects of reducing the capital cost of BES, wind, and DZC on the cost of electricity supply.

The economically optimal deployment of bulk storage was a relatively small fraction of peak capacity, even when we imposed a tight emissions allowance of 150 $kgCO_2e/MWh$ (see Figure S4). It is crucial to note that despite its smaller capacity compared to the wind and gas fleet in our model, the optimal capacity of BES turned out to be substantially large compared to its current deployment level. As a case in point, the ratio of the existing BES power capacity to the peak load in the United States is below 3% (below 0.1% if PHS is excluded) [31]. Therefore, our simulation calls for massive increase in capacity of BES, from the current value of 3% of the peak load to ~10% (for mechanical systems with their current costs, as shown in Figure 3). Our model also shows the need for larger buildup of wind compared to BES capacity. The ratio of the existing wind fleet to peak load is ~8% in the United States while the optimal value for the wind capacity using mechanical BES systems in Figure 3 is ~70%. Therefore, one can argue that the capacity of wind should increase three times more compared to of BES (with current cost estimates for mechanical systems and with an emissions cap of 150 $kgCO2_e/MWh$).

The energy capacity of our optimally sized storage fleet sufficed to supply the average electric demand continuously for only 2 days with an emissions cap of 150 $kgCO_2e/MWh$, even with the cheapest storage cost system that we simulated (X_E=5 $/kWh and X_P=100 $/kW). Other than niche applications that are not captured in this analysis, it is therefore hard to justify the development of storage for significantly longer than a day. The optimal energy capacity of BES in the carbon-free grid also remained small (below one day of average load) when $X_E \geq$ $25/kWh and $X_P \geq$ $100/kW. Obviously if the cost of storage is significantly reduced compared to other decarbonization pathways and compared to its current values, BES would capture a larger market share.

In many respects, we use assumptions that are optimistic for BES and therefore we give an upper bound for its cost effectiveness. The economically optimal size of the wind fleet would be lower in the real world once transmission requirements are taken into account (*i.e.* more capital-intensive wind farms). A smaller wind fleet would likely translate to a larger DZC fleet and hence, less variability in electricity supply. Therefore, the need for bulk storage and its impact on the overall cost of electricity would likely be lower than what we have presented here (see Table S1). Imperfect forecasts of wind availability and electric load would also hurt the economics of wind and storage compared to dispatchable generators. Finally, increased geographical dispersion of wind farms in future low carbon grids can lower the variability in the aggregate wind generation and reduce the need for BES.

The price of natural gas in the future is obviously uncertain. Due to the strong performance of gas turbines in our results, especially CCGT, we assessed the effects of higher gas prices on the impacts that availability of cheap BES will have on the cost of electricity generation. Using higher gas prices mildly changes the aforementioned 16% drop in the cost of electricity with $5/GJ gas when the storage cost is reduced by more than an order of magnitude to X_E=5 $/kWh and X_P=100 $/kW (see Table S6). The same order-of-magnitude drop in storage costs but now with 10 $/GJ gas, reduces the electricity cost by only 14%. This saving is again not significant when we compare it with the benefits of lowering the capital cost of wind itself or DZC. Halving the cost of wind and DZC at $10/GJ gas lowers the cost of electricity by 23% and 28%, respectively.

While electrochemical batteries are currently very far from being cost effective for bulk storage of electricity, they are or may be technically important and cost competitive in two other important applications in a low-carbon economy. First, they can be attractive tools for managing mismatch between supply and demand of electricity at finer temporal resolutions, which are not included in our study or ensuring reliability of the grid. These technologies have an economic advantage over other BES systems (*e.g.* PHS) and low carbon generators (*e.g.* DZC): they can be deployed in smaller scales and have higher operational flexibilities (*e.g.* higher ramp rates). Second, the electrochemical battery (and also hydrogen-based) technologies may play a central role in decarbonizing the transportation sector. Finally, note that each BES technology may well find a market niche (*e.g.* small islands with wind and diesel generation); here we examined only the large-scale electricity systems.

Our second high-level conclusion is that the economics of BES are primarily driven by its energy-specific capital cost. Therefore, mechanical storage technologies (characterized with low energy-specific X_E, but high power-specific X_P, capital costs) are currently more competitive compared to electrochemical systems (intermediate X_E and X_P). Even halving the capital costs of batteries makes marginal changes in the overall cost of electricity generation (see Figure 4). Nevertheless, lowering the capital cost of mechanical systems, especially power-specific cost, drives a much steeper drop in decarbonization costs and it also boosts integration of wind and market share of storage. (Note that we have assessed the relative impacts of cutting the cost of various technologies on the cost of supplying low-carbon electricity. We have not, however, studied the relative effects of R&D investment in reducing the capital cost of various technologies.) Therefore, developing BES technologies with low energy-specific capital costs (*e.g.* A-CAES) deserves a higher priority for bulk storage applications, unless the capital cost of systems with high power-specific costs (*e.g.* flow batteries) can be reduced much faster and cheaper.

We acknowledge that siting of pumped-hydro and underground compressed air energy storage projects is geographically constrained in contrast to electrochemical systems. PHS requires two large water reservoirs with sufficient elevation difference and has a large land footprint.

Underground storage of air needs a suitable geologic formation such as a salt dome. Our study did not include such restrictions.

We were surprised by the promise of underground adiabatic CAES in contrast to very poor performance of diabatic CAES. Despite having the lowest energy-specific capital cost (X_E) among all BES technologies we studied, gas combustion of diabatic CAES hurts its competitiveness under emissions constraints. The results points to the importance of developing storage technologies with low cost of energy capacity and low emissions and the more limited importance of roundtrip efficiency and power-specific cost of BES systems in lowering decarbonization costs.

Efficiency of electricity storage obviously varies with the type and design of the BES technology. We focused on the capital cost of storage systems as the dominant parameter impacting the economics of BES. Nevertheless, A-CAES has one of the lowest efficiencies among BES technologies; an average value of 63% compared to 75% for the generic BES system that we modeled (Table 1). In order to assess robustness of the results, we adjusted storage efficiency of the specific BES technologies in three scenarios: 75%, current estimates, and 10% improvement compared to the current values (see Table S8). Even accounting for its low storage efficiency, A-CAES remains the most cost-effective technology.

Finally, note that that we simulated the generation fleet under an optimal GHG constraint. Non-economic choices may produce very different outcomes. A region that forgoes nuclear power or other large-scale DZC or restricts gas turbines beyond the carbon constraints simulated here will use more bulk storage.

List of Abbreviations

A-CAES	Underground adiabatic compressed air energy storage
AD-CAES	Aboveground diabatic compressed air energy storage
BAU	Business as usual scenario
BES	Bulk electricity storage
CAES	Compressed air energy storage (underground and diabatic)
CapEx	Capital cost
CCGT	Combined cycle gas turbine
CCS	Carbon capture and sequestration
CSP	Concentrated solar power
DZC	Dispatchable-zero-carbon generator
FOM	Fixed operating and maintenance cost
GHG	Greenhouse gas
GT	Gas turbine
LCOE	Levelized cost of electricity
NaS	Sodium sulfur battery
Pb-A	Lead-acid battery
PHS	Pumped hydroelectricity storage
SCGT	Simple cycle gas turbine
VOM	Variable operating and maintenance cost
VRB	Vanadium redox battery
X_E	Energy specific capital cost of BES
X_P	Power specific capital cost of BES
ZnBr	Zinc bromine battery

Electronic Supplementary Information

S-1- Sensitivity to model structural assumptions

Here, we expand the discussion provided in the Conclusion section on the impact of the major assumptions and simplifications on our key results. Table S1 lists the key assumptions and our judgment on whether they favor or disfavor BES.

Table S1: Qualitative comparison of the major assumptions and simplifications of the model to the real world and their likely impact on the key results. A plus sign indicates the corresponding assumption/ simplification favors BES in our model compared to a given counterfactual. A negative sign shows the assumption disfavors BES.

Assumption	**Counterfactual**	**Implications**	**Impact on BES**
Green-field analysis	A model with temporal evolution and vintaging of generation capacity in which factors costs and emissions constraints gradually approached the values used in our model (*i.e.* brown-field analysis).	The brown-field model would keep much of the existing gas assets, making BES less competitive as the capital cost of gas turbines would be 'free'.	+
Transmission costs and constraints are ignored	A model with transmission constraints which also considers costs of adding new transmission	Transmission costs driven by resource remoteness would increase the net cost of wind. This would make wind a bit less competitive with DZC and gas, slightly decreasing the need for BES. Moreover, siting of some BES systems (*e.g.* PHS) is geographically constrained. Therefore, considering transmission would hurt economics of some BES.	+
		Transmission costs can incent siting BES near generation (especially wind and solar) to allow economic optimization of the transmission capacity. Moreover, strategically siting of BES across the grid can relieve constraints and defer transmission upgrades.	-
Wind data are from ERCOT with a capacity factor of 35%	A model considering a wide range of geographical areas with different wind and load profiles	ERCOT is endowed with relatively strong wind resources. Lower capacity factors would make wind more capital-intensive and give gas and DZC an advantage over wind and BES. System-wide capacity factors significantly beyond 35% seem	+ (for capacity factors below 35%)

		unlikely to us.	
		Correlation between wind and load may vary in different geographical regions. Repeating the simulation for other systems can enhance robustness of results.	-
Solar energy is not modeled	A model allowing both wind and solar capacity	Solar farms have lower capacity factors and are currently more expensive (~>1.5 times) compared to wind farms. Therefore, we do not expect considering solar will alter our conclusions about the need for BES, unless cost of solar steeply drops below of wind in future.	nil
		Wind availability is sometimes higher overnight and in winter, in contrast to load. Changes in solar irradiance may follow changes in load better. This may improve economics of solar-based electricity, which could move the need for storage in both directions. Modeling a broader set of generation portfolio, including solar will strengthen the analysis.	-
15-minute time resolution	A model considering finer resolutions and reliability/ security requirements of the grid (*e.g.* black start)	A high-temporal resolution model would build storage for the short duration load balancing, but this is independent from bulk storage of electricity, the focus of this paper.	nil
1-year simulation period	Taking into account inter-annual variations in wind	Renewable energies, especially wind, can experience large inter-annual variations, which increase their effective cost and reduce their optimal capacity.	+
Static modeling	A model considering future reductions in cost of all technologies (gas, wind, and DZC), not just BES	Using current cost estimates for gas turbine, DZC, and wind can favor BES providing their costs can be reduced faster than BES and vice versa.	nil
Gas price of \$5/GJ	A model considering future gas prices across various region and electricity markets	According to section S-6, we do not expect major impacts on the key conclusions unless gas prices are above \$20/GJ.	- (if price is beyond ~\$20/GJ)
Forecast errors in load	A model considering forecast errors (ax-ante rather than	Utilization factor of wind and BES would be lower in the real world. Our	+

and wind are ignored	ex-post) and their improvement over time	model can build the smallest amount of wind and BES to economically meet the electric load. Therefore, considering forecast errors would make wind and BES more capital intensive and less economical.	

S-2- Correlation between wind and load profiles

Correlations between wind availability and electric load obviously impact storage requirements. ERCOT is a large electricity grid (peak load of 66.5 GW and wind capacity of 10.0 GW in 2012), so the chosen profiles represent an important real world case. The load factor defined as ratio of the average to peak load is 56% for our load profile. There is a slight anti-correlation (coefficient of -0.15) between our load and wind profiles. Cumulative duration curves for load and wind are shown in Figure S1. Note that there are periods with insignificant wind availability while the load does not ever fall below 34% of its peak. Even if wind capacity is 1.6 times of the peak load– the point at which annual average wind production matches the annual average load– wind will still be incapable of supplying all of the load 53% of the time (marked by point "B" on the graph). This value is still non-negligible (17%) even when wind capacity is 5 times larger than peak load (point "C" on "n=5" line).

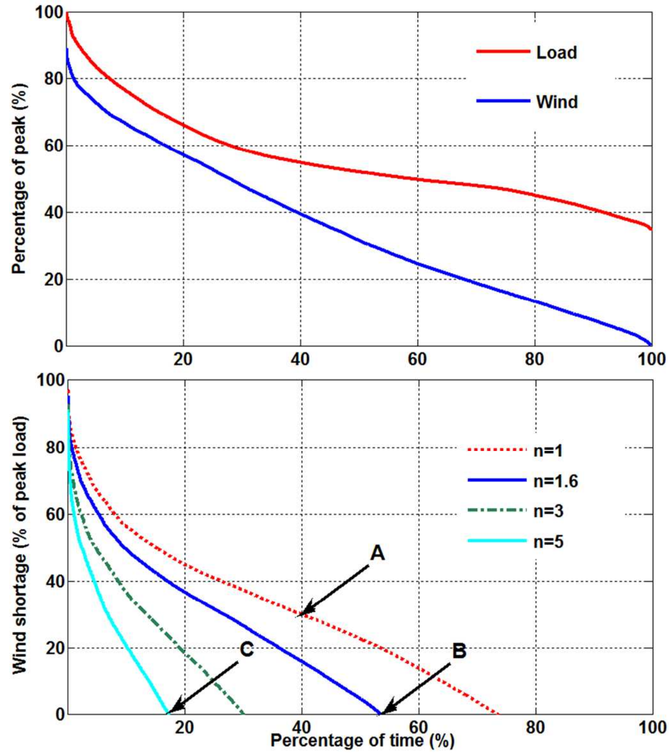


Figure S1: Temporal distribution of wind and load profiles used for the simulation. The top figure illustrates percentage of time (on horizontal axis) during which wind availability or electric load is higher than a certain value shown on the vertical axis (*a.k.a.* duration curve). Wind and load profiles are normalized to peak load and installed wind capacity, respectively. The lower plot shows percentage of time during which wind shortfall in supplying the load is higher than a certain value shown on the vertical axis. Parameter "n" is the ratio of wind capacity to peak load. Point "A" for example, shows that in 40% of the year shortage in wind supply is at least 30% of the annual peak load, when the installed wind capacity is equal to the annual peak load (n=1).

S-3- Mathematical formulation of optimization

We simultaneously optimize installed capacity and dispatch during operation of a generation fleet to meet the load at the minimum cost. We use a set of scenarios defined by a series of imposed constraints on the annual average GHG intensity of electricity ranging from 300 to 0 $kgCO_2e$/MWh. The power- and energy-specific CapEx of BES are varied to sample the two-dimensional (X_E and X_P) space within each emissions intensity scenario. The system-average levelized cost of electricity (LCOE, $/MWh) is minimized at each emissions intensity and at the sampled values of X_E and X_P. The LCOE includes fixed and variable operating and maintenance costs (FOM and VOM), fuel costs, and amortized CapEx. The objective function is given below, given the definitions in Table S2.

$$\sum_{y}\left[\left\{Capt_y \times \left(BC \times CapEx_y + FOM_y\right)\right\} + \left\{\sum_{z}\left(EL_{y,z} + ST_{y,z}\right) \times \left(HR_y \times \pi_{NG} + VOM_y\right)\right\}\right]$$

Where $y \in Y = \{SCGT, CCGT, Wind, BES, DZC\}$ and $z \in Z = \{1,2,3, \dots, 365 \times 24 \times 4\}$

Table S2: List of parameters and variables of the objective function.

$CapEx$	Specific capital cost (\$/MW or MWh)	$Capt$	Installed capacity (MW or MWh)
BC	Blended cost of capital (%)	EL	Electricity delivered to load (MWh)
FOM	Fixed operation and maintenance cost (\$/MW or MWh/year)	VOM	Variable operation and maintenance cost (\$/MWh)
Y, y	Set Y includes the electricity supply technologies, *i.e.* gas turbines, wind, BES, and DZC (index y)	Z, z	Set J includes the planning periods over the entire year at a 15-minute resolution (index j)
π_{NG}	Price of gas (\$/GJ)	ST	Electricity stored in BES (MWh)
HR	Heat rate (GJ/MWh)		

This objective function calculates the total annual cost of electricity supply and has two parts (shown in curly brackets). The first section takes into account the amortized capital cost and the fixed operations and maintenance cost of the generation and storage fleet. The second part of the objective function considers the fuel cost and the variable operation and maintenance cost associated with electricity generation (both directly provided to the load and stored in BES) and by the generation fleet. Note that we simultaneously optimize the capacity and dispatch of the generation fleet. We develop a simplified utility planning model, which minimizes the system-wide cost of electricity supply in a green-field setup.

The decision variables include installed capacity (size) of the generation fleet and their dispatch in each 15-minute period over the simulation period (one year). The key constraints include:

- The electricity load must be satisfied in each 15-minute time interval.
- The annual average GHG emissions (kgCO2e/MWh) should be less than a preset value (*e.g.* 0 in the carbon free scenario), except in the BAU scenario.
- Output of each system component cannot exceed its capacity.
- Conservation of energy must hold for BES; the change in the stock of energy in each 15-minute period should be equal to the difference between energy injected and withdrawn, after taking into account the storage efficiency.

S-4- GHG emissions intensity of gas-based electricity

We use a GHG intensity of 66 kgCO_2e/GJ (low heating value, LHV) [6] for natural gas to account for upstream emissions in addition to combustion emissions, which leads to a GHG intensity of 647 and 442 kgCO_2e/ MWh for the SCGT and CCGT plants modeled. Although estimating life-cycle GHG emissions of natural gas-based electricity is uncertain (partly due to fugitive methane emissions), our values fit well within the current estimates. For instance, in a 2014 study, O'Donoughue et al. [32] applied a meta-analytical process on 250 published references to harmonize estimates of the life-cycle GHG emissions of electricity fueled by conventionally produced gas. They reported an interquartile range (IQR) of 570-750 with a median of 670 kgCO_2e/MWh for SCGT. The IQR and median values reported for CCGT are 420-480 and 450 kgCO_2e/MWh, respectively.

S-5- Sensitivity to capital cost of DZC

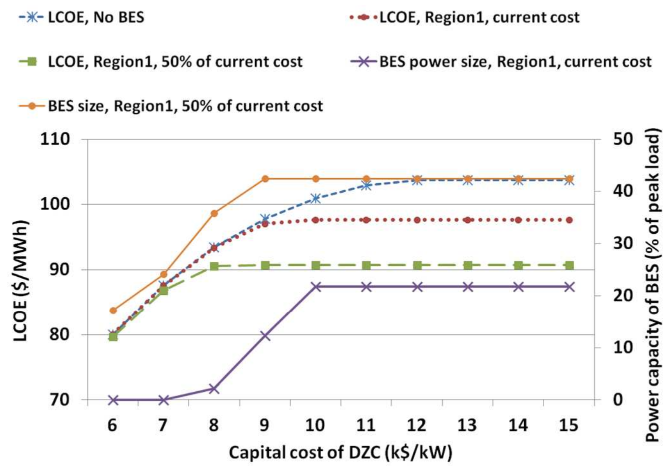
Cost figures for DZC are extremely uncertain due to their limited recent deployment. As a case in point, estimates for the Vogtle AP1000 nuclear plant currently under construction in GA, USA is around 6400 $/kW [33]. The figures for the Korea-UAE nuclear contracts announced in 2009 ($3700/kW [34]) is however, almost half of for the Vogtle project. In a recent study, Abdulla et al. [35] used expert elicitations to estimate capital cost of light water reactors, both based on current technology and small modular reactors (SMR). The median of the estimates for a 1 GW reactor ranged from $2600 to $6600/kW while it varied between $4000 and $16300/kW for a 45 MW light water SMR. Cost figures for CSP also lay in a wide range. Estimates for the Crescent concentrated solar power plant (110 MW, 10 hours of thermal storage, under construction in NV, USA) are about $9000/kW [36, 37] . The price tag of the Solana plant (250 MW, 6 hours of thermal storage, commissioned in 2013 in AZ, USA) is roughly $8000/kW [37]. We use a value of $9000/kW for capital cost of DZC in the base case model.

Figure S2 explores the robustness of our key results and conclusions to the capital cost of DZC. Three scenarios are illustrated in this figure:

a) no BES is allowed (to quantify the economic value of BES at current capital costs in decarbonizing the electricity supply),
b) BES is available at the current costs, and
c) a scenario with 50% reduction in both the energy-specific capital cost (X_E) and power-specific capital cost (X_P) of BES compared to the current levels considered in case b.

We chose one generic BES system from the mechanical (with current costs of X_E=30 $/kWh and X_P=1500 $/kW) and electrochemical (X_E=375 $/kWh and X_P=550 $/kW) BES category to perform this sensitivity analysis. All other simulation inputs have the same values as the base case simulation (listed in Table 2).

The simulated mechanical BES system is much more successful in reducing the LCOE and its power capacity is consistently and considerably (~2-3 times) higher than of the electrochemical system. The optimal BES capacity is almost zero when the cost of DZC is ≤$6000/kW (for the mechanical category) and $9000/kW (for the electrochemical system) with current cost estimates for BES. This is because wind and BES lose their economic competitiveness as DZC gets less capital intensive. Even cutting both power and energy capital costs of the battery makes marginal changes in the LCOE (≤ $1/MWh) unless capital cost of DZC remains above $9000/kW. As we discussed in section 2-3, DZC represents the least capital intensive, dispatchable technology—CSP, nuclear, CCS, biomass or geothermal (possibly even with high voltage direct current, HVDC, transmission lines)—that can be utilized in a given location. We believe that the value of 9000 $/kW used in this paper is mostly likely an overestimate of this best-case DZC cost.



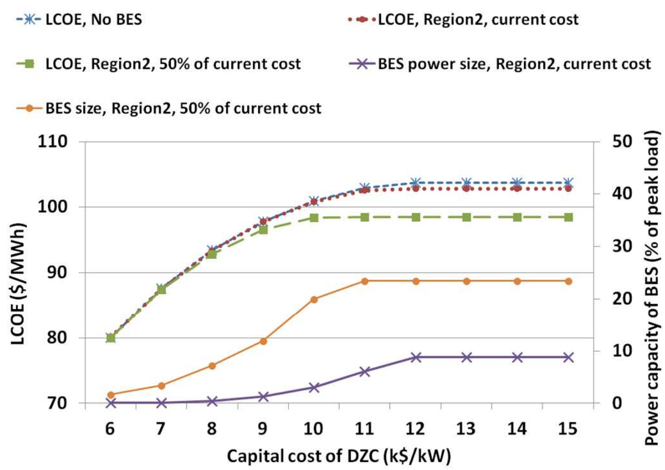


Figure S2: Sensitivity of LCOE and power capacity of BES to capital cost of DZC. Each sub-plot presents three cases: a) no BES is allowed, b) BES at the current capital costs and, c) BES with 50% reduction in both X_E and X_P values considered in case b. The sub-figure on top shows the results for a generic BES system in region 1 with X_E=30 $/kWh and X_P=1500 $/kW as its current costs. The sub-figure at the bottom represents region 2 with X_E=375 $/kWh and X_P=550 $/kW as the current costs. Region 1 and 2 represent mechanical and electrochemical bulk storage systems (see Figure 1). Price of gas is $5/GJ.

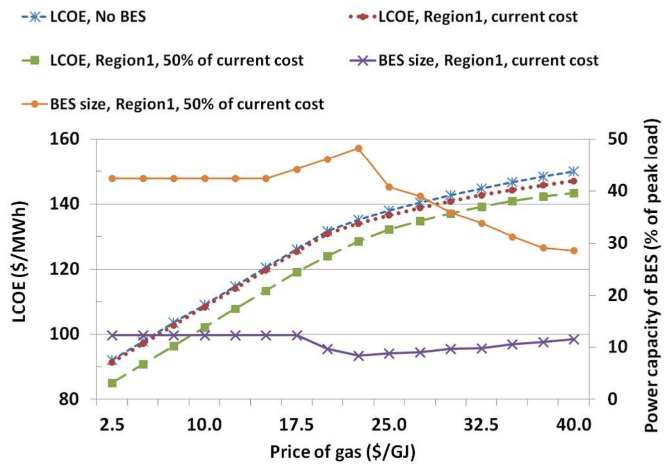
S-6- Sensitivity to price of gas

We used $5/GJ as the price of natural gas in the base case results presented. This value is comparable to the average price of $4.8/GJ paid by power plants across the United States between 2009 and 2013 [38]. Due to uncertainties in future gas prices especially under emissions restrictions and in the wake of the unconventional gas revolution, here we evaluate robustness of our key conclusions to this parameter. Similar to Figure S2, Figure S3 illustrates the LCOE and power capacity of a generic mechanical and a battery BES system, but with respect to price of gas instead of DZC CapEx. The GHG emissions intensity is capped at 150 kgCO_2e/MWh and all parameters except price of gas are the same as Table 2.

The availability of BES marginally impacts the overall cost of electricity with the current BES capital costs figures, although the mechanical BES system starts to matter at high gas prices ($20/GJ). Reducing the energy-specific and power-specific capital costs (X_E and X_P) of the mechanical BES by

50% lowers the LCOE much more (3.5-7.0 \$/MWh compared to LCOE at current X_E and X_P cost figures), particularly with gas prices below \$20/GJ, compared to the generic electrochemical system. There is a maximum of \$2.5/MWh difference between the electricity supply cost of the generation fleet utilizing the electrochemical system with the current capital costs and with 50% cost reduction (occurring at an unrealistically high gas price of \$40/GJ).

The optimal power capacity of BES is far more sensitive because of the reduced optimal capacity of gas turbines at high gas prices and the competition between wind, BES, and DZC to compensate for that. Our conclusion that the optimal capacity of the mechanical BES systems is higher (~2-3 times) compared to of the battery systems, especially with 50% cost reductions, is also robust to changes in gas prices.



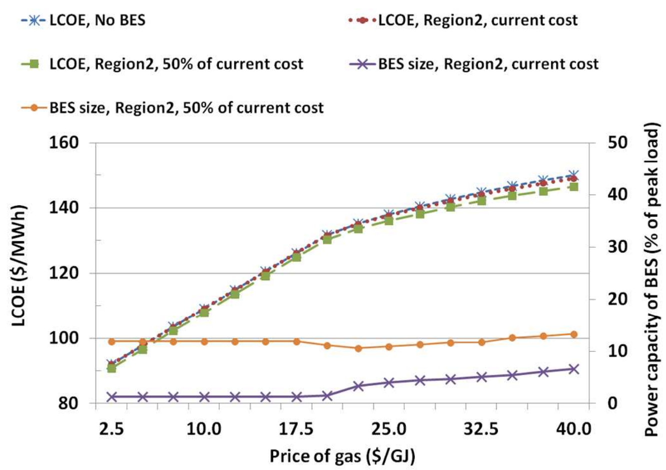


Figure S3: Sensitivity of the LCOE and optimal power size of BES to the price of gas. Each sub-plot presets three cases: a) no BES is allowed b) BES at the current costs, and c) 50% reduction in both X_E and X_P compared to case b. The top sub-figure presents a generic mechanical BES system (from region 1 in Figure 1) with X_E=30 $/kWh and X_P=1500 $/kW as its current costs. The sub-figure at the bottom represents a generic electrochemical technology (from region 2 of Figure 1) with X_E=350 $/kWh and X_P=550 $/kW as the current costs.

S-7- Optimal size and market share of storage

Figure S4 illustrates the power and energy size of BES, percentage of annual load supplied by the energy stored in BES (i.e. market share of BES), and share of DZC of the total electricity production, as discussed in section 3-3.

The power capacity of BES remains below 30% and 10% of the peak load for the mechanical and electrochemical battery BES systems, respectively. The optimal energy capacity of BES is also small; the cheapest storage system modeled (X_E=5 $/kWh and X_P=100 $/kW) barely has enough capacity to meet the average load for 40 hours. Note that the small BES share of annual electricity supply in comparison to its relatively larger capacity size (especially the power size for mechanical systems) indicates that BES is dispatched infrequently and mainly in the periods of high load (*i.e.* peak shaving application).

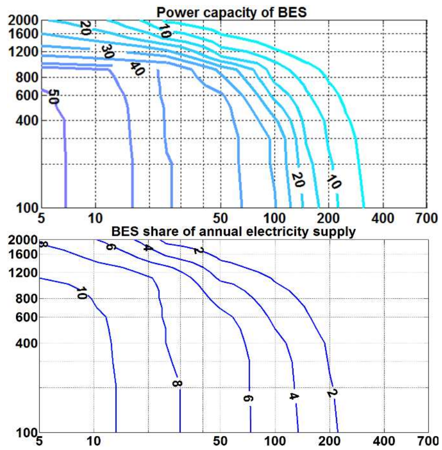


Figure S4: Market share of storage at an emissions cap of 150 kgCO2e/MWh. Subfigures from top left illustrate normalized power size and energy size of BES, percentage of annual load supplied by the energy stored in BES, and DZC share of the total annual electricity production. Horizontal and vertical axes show X_E ($/kWh) and X_P ($/kW).

As discussed in section 3-2, we quantify the importance of BES versus gas turbine for wind integration by comparing their optimal capacity when DZC is kept out of the generation fleet. Table S3 presents the key system parameters when DZC is eliminated from the generation fleet and the same emissions constraint of 150 $kgCO_2e/MWh$ is enforced. A sample BES system from each category (*i.e.* mechanical and electrochemical) was modeled. The energy- and power-specific costs of the mechanical BES system were X_E=30 $/kWh and X_P=1500 $/kW while these values were X_E=375 $/kWh and X_P=550 $/kW for the sample electrochemical BES system. We also evaluated the sensitivity of the results to a drastic 50% reduction in both X_E and X_P of these two BES systems.

The required amount of storage remained relatively small (≤22% of peak load, except when the energy and power costs of the mechanical BES system were halved). In contrast, capacity of the gas turbine fleet (aggregate of SCGT and CCGT) remained above 75% of the peak load with the current storage costs of both BES systems and still above ~50% when the costs of the mechanical BES were halved. Moreover, less than 10% of the annual electricity load was supplied by BES in the best case (50% reduced energy and power costs of the mechanical system). Also note the low sensitivity of the overall cost of electricity (LOCE) to reductions in the capital cost of BES. Halving both the power and energy cost of the mechanical and electrochemical systems reduced LOCE by 7% and 4%, respectively.

Using the example of the mechanical BES system shown in Table S3 (with energy and power costs of X_E=$30/kWh and X_P=$1500/kW), we see that capacity of BES and gas are ~20% and 60% (respectively) of the capacity of wind. So one could say that BES is three times less important than gas in providing peaking power under this tight emissions constraint and with current capital cost estimates. Under these conditions, about a third of annual load comes from gas, 6% from BES and the rest from wind.

Table S3: Key characteristics of the generation fleet when DZC is eliminated from the model at an emissions cap of 150 $kgCO_2e/MWh$ and gas price of $5/GJ. The "Reduced CapEx" columns refer to 50% reduction in both the energy (X_E) and power (X_P) capital cost of storage, compared to the current cost estimates. Region 1 and 2 represent a generic mechanical and electrochemical BES system (see Figure 1). GT refers to simple (SCGT) and combined (CCGT) cycle gas turbines. All other input parameters are the same as Table 2.

	Current CapEx		**Reduced CapEx**	
Storage system	**Region 1**	**Region 2**	**Region 1**	**Region 2**
Energy-specific CapEx ($/kWh)	$30	$375	$15	$188
Power-specific CapEx ($/kW)	$1500	$550	$750	$275
LCOE ($/MWh)	$97.6	$103.0	$90.7	$98.9
BES power capacity (% of peak load)	22	8	42	22
BES energy capacity (hrs of average load)	9	1	18	3
BES market share (% of annual load)	6	1	9	4
GT capacity (% of peak load)	75	88	54	74
GT generation share (% of annual electricity generation)	34	34	34	34
Wind capacity (% of peak load)	120	138	115	127
Ratio of BES power to wind capacity	0.18	0.06	0.37	0.18
Ratio of GT to wind capacity	0.62	0.64	0.47	0.58
Ratio of GT to BES capacity	3.4	10.7	1.3	3.2

The relative importance of BES and GT depends on stringency of the emissions cap too. Here we presented the results at an emissions cap of 150 $kgCO_2e/MWh$ – ~70% reduction compared to the current emissions levels in the United States. With zero or near-zero emissions and no use of DZC, larger storage capacities will be needed to manage wind's intermittency as GT gets too polluting for such extremely low-carbon grids.

Price of gas is another important factor in determining the relative importance of bulk storage. To explore its effect, we repeat the simulation with a much higher gas price of $20/GJ (Table S4) instead of $5/GJ (Table S3). The optimal ratios of BES and GT to wind capacity do not vary in a substantial manner with $20/GJ gas, except when the cost of the mechanical system is cut by 50%. This indicates that the low capital cost of the gas turbine fleet (Table 2) out-competes its higher operation and fuel costs, hence the GT still supplies one third of the load with $20/GJ gas.

Table S4: Key characteristics of the generation fleet when DZC is eliminated and at an emissions cap of 150 $kgCO_2e/MWh$ and gas price of $20/GJ. The "Reduced CapEx" columns refer to 50% reduction in both the energy (X_E) and power (X_P) capital cost of storage. Region 1 and 2 represent a generic mechanical and electrochemical BES system (see Figure 1). All other parameters are the same as of Table 2.

	Current CapEx		Reduced CapEx	
Storage system	**Region 1**	**Region 2**	**Region 1**	**Region 2**
Energy-specific CapEx ($/kWh)	$30	$375	$15	$188
Power-specific CapEx ($/kW)	$1500	$550	$750	$275
LCOE ($/MWh)	$131.7	137.1	124.1	133.0
BES power capacity (% of peak load)	22	8	46	22
BES energy capacity (hrs of average load)	9	1	23	3
BES market share (% of annual load)	6	1	11	4
GT capacity (% of peak load)	75	88	50	74
GT generation share (% of annual electricity generation)	34	34	27	34
Wind capacity (% of peak load)	120	138	130	127
Ratio of BES power to wind capacity	0.18	0.06	0.36	0.18
Ratio of GT to wind capacity	0.62	0.64	0.39	0.58
Ratio of GT to BES capacity	3.4	10.7	1.1	3.2

S-8- Effect of reducing energy and power capital costs on LCOE

Figure S5 illustrates the impact of a 50% reduction in both energy- and power-specific costs of BES at an emissions cap of 150 $kgCO_2e/MWh$, similar to Figure 4 but for LCOE instead of market share of storage. As shown, none of the existing technologies alter LCOE in a major way. Consistent with Figure 4, mechanical BES systems (A-CAES and PHS) are more beneficial in lowering LCOE, although their impact is small.

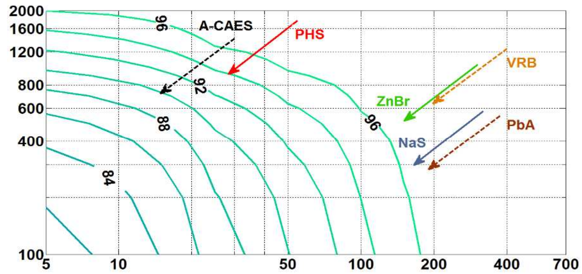


Figure S5: Overall cost of electricity ($/MWh) at an emissions cap of 150 kgCO2e/MWh when different BES technologies are deployed. Horizontal and vertical axes indicate X_E ($/kWh) and X_P ($/kW). Arrows start from the current cost estimates (average of the range shown for each technology in Figure 1) and end at points with 50% reduction in both X_E and X_P.

S-9- Performance of diabatic CAES

We analyzed diabatic CAES separately since unlike all other BES technologies it has non-negligible emissions. The heat rate and work ratio of CAES were set at 4.2 GJ/MWh and 0.75 in our model, respectively. Therefore, the simulated CAES facility emitted 277 kgCO_2 per MWh of electricity generated (inside-the-fence lines emissions). We varied X_E and X_P of diabatic underground CAES in the range of 5-25 $/kWh and 850-1200 $/kW, based on the estimates from Table 1. Aboveground CAES was not modeled due to its obvious weaker performance (caused by much higher energy-specific capital cost of >200 $/kWh, refer to Table 1 for details).

We present results from the 150 kgCO_2e/MWh cap scenario in Table S5. Availability of diabatic CAES made negligible differences in LCOE. The cheapest CAES system modeled (X_E=5 $/kWh and X_P=850 $/kW) could only store enough electricity to meet the average load for ~1 hour and its power capacity is 7% of the peak load. A higher gas price of $10/GJ instead of $5/GJ did not improve the competitiveness of CAES.

For the sake of comparison, we also modeled A-CAES system (heat rate of zero and efficiency of 63%) with the same emissions cap and gas prices. We used the range of 1100-1700 $/kW and 10-50 $/kWh for the power and energy capital cost of A-CAES (refer to Table 1). As seen in Table S5, the role of A-CAES turned out more significant compared to diabatic CAES despite its much higher capital cost. LCOE of the system equipped with A-CAES instead of diabatic CAES was lower (~4% in the base case). Moreover, both the power and energy capacity of A-CAES were much higher compared to of diabatic CAES. The GHG emissions of diabatic CAES severely limit its competitiveness as a BES system under emissions constraints. Note that the significance of diabatic CAES (measured by its impact on LCOE and by its optimal installed capacity) turned out to be even smaller under no emissions constraints (BAU scenario). These results lead to the conclusion that diabatic CAES is too capital intensive for today's grids (no major GHG emissions restrictions) and too polluting for the future low-carbon grids.

Table S5: Key characteristics of underground diabatic CAES and A-CAES at a grid emissions cap of 150 kgCO_2e/MWh. All other inputs are the same as Table 2.

Parameter	**Diabatic CAES**		**A-CAES**	
Power CapEx ($/kW)	850-1200		1100-1700	
Energy CapEx ($/kWh)	5-25		10-50	
Efficiency (%)	NA		63	
Work ratio (MWh in/ MWh out)	0.75		1.60	
Heat rate (GJ/MWh)	4.2		0	
Price of gas ($/GJ)	5	10	5	10
LCOE ($/MWh)	97.7-97.8	109.1	93.8-97.8	105.2-109.1
Power capacity (% of peak load)	6-0	6-0	33-1	33-1
Energy capacity (hours of average load)	1-0	1-0	19-0.2	19-0.2

S-10- LCOE of scenarios discussed in the Conclusion section

Table S6 provides the LCOE of various scenarios discussed in the Conclusion section for the sensitivity of the key conclusions to price of gas, capital cost of wind, DZC, and BES, and storage efficiency of A-CAES.

Table S6: LCOE corresponding to sensitivity analysis discussed in the Conclusion section. All cases assume an emissions cap of 150 $kgCO_2e/MWh$.

Scenario	LCOE ($/MWh)	% change W.R.T base case
Base case (Table 2 with X_E=25 $/kWh, X_P=1500 $/kW, and GHG cap= 150 $kgCO_2e/MWh$)	96.8	0%
Base case with X_E=5 $/kWh and X_P=100 $/kW	81.2	-16%
Base case with $1000/kW wind	72.0	-26%
Base case with $4500/kW DZC	68.6	-29%
Base case with $10/GJ gas	108.1	+12%
Base case with X_E=5 $/kWh, X_P=100 $/kW, and $10/GJ gas	92.6	-4%
Base case with $4500/kW DZC and $10/GJ gas	83.4	-14%
Base case with $1000/kW wind and $10/GJ gas	77.7	-20%
Base case with X_E=30 $/kWh and X_P=1400 $/kW (A-CAES cost values)	96.7	~0%
Base case with X_E=30 $/kWh, X_P=1400 $/kW, and efficiency of 63% (A-CAES cost and efficiency values)	97.3	1%
Base case with X_E=30 $/kWh, X_P=1400 $/kW, and efficiency of 70% (A-CAES cost values and 10% improvement in efficiency)	97.0	0%

S-11- Comment on California's energy storage policy

Cost-reduction efforts of various BES technologies should be prioritized, among other goals, according to their economic potential. As a case in point, the California Public Utilities Commission's 2013 decision to exclude PHS plants larger than 50 MW from the California's 1.3 GW (by 2020) electricity storage mandate seems hard to defend on the basis of cost effectiveness or technical potential. The Commission argues that "the sheer size of PHS projects would dwarf other smaller, emerging technologies; and as such, would inhibit the fulfillment of market transformation goals" [39]. We strongly support the deployment storage technologies to enable learning-induced cost reductions. However, we caution that such technology-favoring policies can delay development of more cost-effective storage technologies such as PHS that seem to play a more significant role in decarbonizing electricity.

S-12- Upper bound for penetration of storage

What would be the economically optimal deployment of bulk storage provided that storage is free and ideal (*i.e.* without energy losses)? This question gives the upper bound for the market share that the BES industry could gain. According to Table S7, the ultimate market share of BES would be 31% in the best case (gas price of $10/GJ or higher and with an emissions cap of 150 $kgCO_2e/MWh$). The rest (69%) of the load is directly supplied by wind in this scenario and the contributions of GT and DZC are zero. The optimal power capacity of BES is 96% of the peak load and its energy capacity is large enough to meet the average electric load for 52 days. In the carbon-free scenario, the optimal capacity of GT and DZC turn out to be zero too, regardless of the gas price.

Table S7: Optimal characteristics of the storage and wind fleet assuming almost free (X_E=X_P=0.001) and almost ideal (efficiency=99.99%) bulk storage with a GHG emissions cap of 150 kgCO_2e/MWh. All other input parameters are similar to Table 2.

Gas price	**LCOE**	**BES power capacity**	**BES energy capacity**	**BES market share**	**Wind capacity**	**Wind gen. share**
$/GJ	$/MWh	% of peak load	Hours of avg. load	% of annual load supply	% of peak load	% of annual generation
5	67.9	78	1027	22	105	66
7.5	73.6	78	1027	22	105	66
≥10	76.9	96	1248	31	159	100

S-13- Sensitivity to storage efficiency

The roundtrip efficiency of electricity storage obviously varies among different BES technologies. We focused on the capital cost of storage systems as the dominant parameter impacting the economics of BES throughout the analysis. Nevertheless, A-CAES is among the least efficient BES systems; an average value of 63% compared to 75% for the generic BES system that we modeled (Table 1). In order to assess robustness of the results, we adjusted storage efficiency of the specific BES technologies in two scenarios: 75% (independent of the BES type, similar to Table 2) and the current estimates (according to values listed in Table 1). As shown in Table S8, the storage efficiency has insignificant impact on our key results. Even accounting for its low efficiency, A-CAES remains the most cost-effective technology followed by PHS.

Table S8: Sensitivity of the key results to the storage efficiency of specific BES technologies at an emissions cap of 150 $kgCO_2e/MWh$. Average of the values shown in bold in Table 1 are used as the energy- and power-specific capital cost of each storage technology (similar to Figure 4). Two values for storage efficiency are considered: 75% (independent of BES technology) and technology-specific values (see Table 1). All other parameters are similar to Table 2.

Parameter	**PHS**		**A-CAES**		**Pb-A**		**NaS**		**ZnBr**		**VRB**	
Efficiency (%)	75	78	75	63	75	83	75	80	75	68	75	73
X_E ($/kWh)	55		30		375		325		300		400	
X_P ($/kW)	1750		1400		550		575		1000		1250	
LCOE ($/MWh)	97.7	97.7	96.7	97.3	97.7	97.7	97.7	97.7	97.8	97.8	97.8	97.8
BES power (% of peak)	2.6	3.2	14.5	10.0	1.3	1.3	1.6	1.6	0.0	0.0	0.0	0.0
BES energy (hrs of average load)	0.4	0.5	4.6	2.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
BES market share (%)	0.8	1.0	4.3	1.9	0.1	0.1	0.2	0.2	0.0	0.0	0.0	0.0

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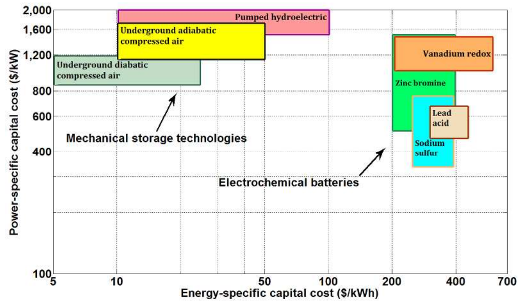

One sentence highlighting the novelty of the work (20 words):

Impacts of capital cost of bulk energy storage on cost of electricity supply is parametrically studied under various emissions constraints.