Context and economics for long-duration electrical energy storage systems

Joe Manser, Rusty Heffner, and Paul Albertus

Five years ago, the majority of newly-installed grid storage systems offered durations of 30-minutes or less, sufficient to provide frequency regulation services. Utility-scale systems now typically include two to four hours of storage that can serve numerous functions, including providing capacity, participating in wholesale energy markets, firming output from variable renewables, and providing backup power during outages. As the role of energy storage on the electricity grid expands, durations are likely to continue increasing; one recent U.S. installation required eight hours of storage duration to defer expansion of transmission infrastructure.

Electrical energy storage (EES) system specifications such as cost, power:energy ratio, cycle life, round trip efficiency, and energy density are dictated by the type of grid service or services the system is to provide. The time scales associated with various grid applications range from sub-second frequency regulation to multi-day bulk energy time shift. Figure 1 presents hypothetical operation of EES systems in three applications: diurnal energy time shift (Figure 1A), frequency regulation (Figure 1B), and firming of variable energy resources (VERs) (Figure 1C). It is immediately evident that characteristic duty cycles vary widely between the different applications. Diurnal time shift may frequently utilize the full energy capacity of the storage system, whereas a system providing frequency regulation may be held within a narrow state of charge (SOC) window when operated in an energy neutral fashion. A long-duration storage (LDS) system designed to provide quasi-baseload output when coupled to a VER generator has its own a distinct duty cycle. The normalized energy throughput (Figure 1C, bottom panel), defined here as $E_i / \sum_{i=1}^{10} E_i$, where E_i is the amount of energy transacted through a given decile of the SOC range, i, demonstrates the large discrepancy in the amount of energy that passes through the high-, mid-, and low-SOC ranges of this illustrative LDS system. Power is primarily delivered at high SOC, while deep discharge events are infrequent in this coupled VER/LDS example. As discussed below, this operational profile places unique constraints on capital costs necessary to realize economically-viable LDS systems.

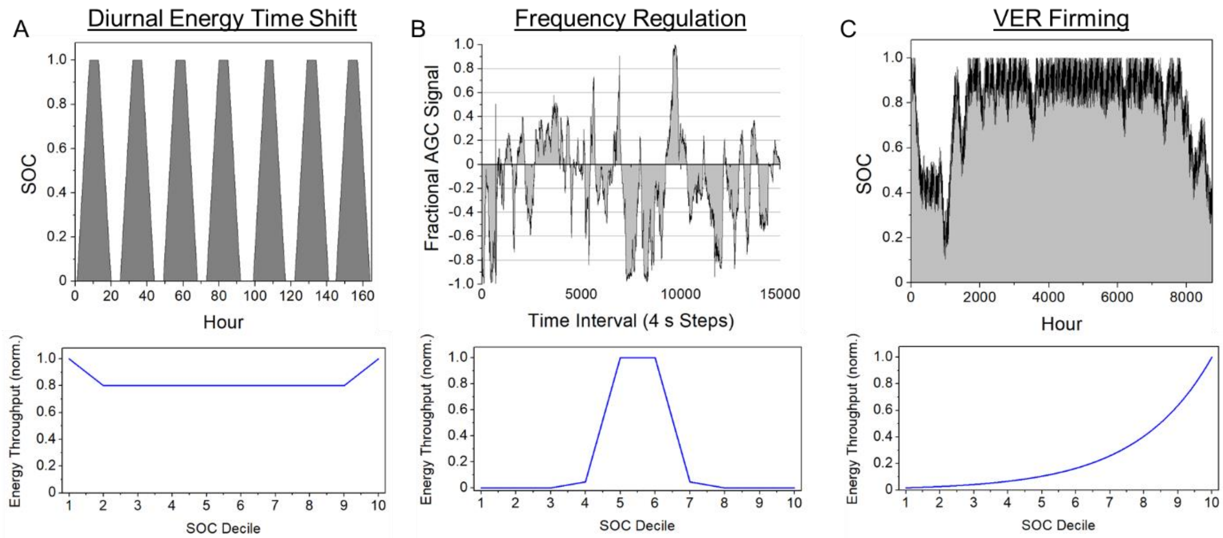

Figure 1. EES system duty cycles for various prototypical grid applications: (A) diurnal energy time shift of a single solar generator, (B) frequency regulation, and (C) VER firming at the regional grid scale. Top panels display state of charge (SOC) of the storage system in (A) and (C), and a typical automatic generation control (AGC) signal in (B). Data is shown across different time scales for each application: one week in (A), 16 h in (B), and one year in (C). Bottom panels show normalized energy throughput across the full SOC range of the storage system divided into deciles, where 1 = 0-10% and 10 = 90-100% SOC. Creating ultra-firm VERs requires storage systems to be sized such that deep discharge events, which are much less frequent than in typical diurnal applications, can be handled.

Capital costs for EES systems can generally be separated into those associated with energy capacity (C_E in \$/kWh) and those that scale with rated power (C_P in \$/kW), as indicated by Equation 1

$$C_T = C_E + \frac{C_P}{t_d} \qquad (1)$$

where C_T is total installed capital cost per unit energy and t_d is the charge or discharge duration at rated power (equivalent for symmetric charging and discharging). Allocating costs in this way is most appropriate for EES systems in which power and energy can be scaled independently. Equation 1 is a simplified handling of capital costs that does not explicitly account for important factors such as engineering, procurement, and construction (EPC) and portions of the balance of plant (BOP). Nonetheless, this relation provides a convenient framework to study the scaling of system costs as a function of duration or power capacity.

Using Equation 1 and assigning power and energy costs for a hypothetical EES system yields the dashed gray cost-duration curve shown in Figure 2A. This assumes aggressive capital costs (C_E = 50 \$/kWh and C_P = 500 \$/kW) representing a low-cost future technology that exhibits energy scaling comparable to today's systems (i.e. additional energy capacity is achieved through addition of identical tanks of energy storage media). In the limit of large t_d, system capital costs approach the energy costs (including associated energy-specific installed BOP such as containers, pumps, heat exchangers, pipes, concrete pads, site preparation, etc.). This highlights the importance of selecting low-cost energy storage media with sufficient energy density to limit BOP costs in the design of LDS systems.

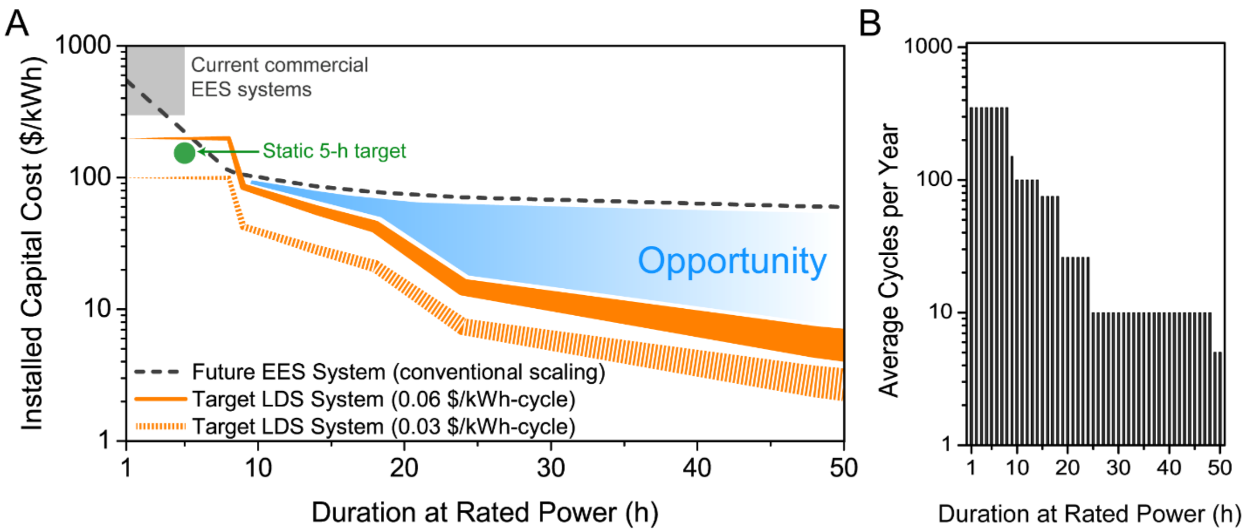

Figure 2. (A) Capital cost-duration curves for a hypothetical, future low-cost EES technology (500 $/kW, 50 $/kWh) with conventional energy scaling (dashed gray) and an LDS system that operates at a fixed 0.03 $/kWh-cycle (dashed orange) and 0.06 $/kWh-cycle (solid orange) across all hours of storage. The identified technical development opportunity is indicated, as are the current costs of siteable commercial EES systems and current static cost targets (~150 $/kWh for a 5 h system). (B) Cycle-duration curve used to calculate the present value of net revenue for the target LDS system in (A). The duty cycle was derived by assuming daily operation for the first 8 hours of storage, weekly cycling from hours 9-14, and subsequently lower annual cycle counts for longer durations. Such a cycling profile could potentially be relevant for VER firming applications at the individual plant level, or for a transmission-connected asset in a network with a high penetration of VERs.

In the interest of pushing beyond the scaling capabilities of current EES systems without siting constraints, it is instructive to consider storage economics using a top-down, revenue-based approach. In other words, rather than specifying the cost per unit energy and unit power from the bottom up using material, component, manufacturing, and other costs, capital cost targets can instead be determined top-down by calculating the present value of expected revenue over the lifetime of the EES system. For energy arbitrage (buy low, sell high) or VER firming applications, fixing the cost *per cycle* ($/kWh-cycle) sets a limit on the premium the system owner must place on the price of storage to recover the margin, capital and operating costs, overhead, and all other expenses, while also accounting for round-trip efficiency losses. The net present value (NPV) of future revenues is given by Equation (2)

$$NPV = \sum_{t=1}^{T} \frac{N_t}{(1+r)^t} - C_T \quad (2)$$

where N_t is the net revenue per unit energy for time interval t, r is the discount rate, and C_T is the total installed capital cost per unit energy as defined above. Setting NPV equal to zero yields the maximum present capital cost allowance for an EES system given the anticipated lifetime net revenue (Equation (3)).

$$C_T = \sum_{t=1}^{T} \frac{N_t}{(1+r)^t} \quad (3)$$

Note that in this formulation, r represents the internal rate of return (IRR) for the project.

To determine N_t, and subsequently capital cost targets, it is necessary to define both the cost per cycle and number of cycles per unit time for each unit of storage capacity. For the former, we have set 0.03 $/kWh-cycle as a fixed target across all hours of storage. If achieved, this would represent a transformational advancement that would enable EES systems to readily serve a variety of services in the future power grid that are not accessible with today's storage technology. Possible business models include dispatchable wind and solar power that is cost competitive with conventional fossil generation, as well as extended backup power for critical infrastructure that can greatly improve grid resiliency. For wind and solar installations in favorable locations, levelized cost of energy (LCOE) values of 0.03 $/kWh are already realized today. With storage adding $0.03 for each kWh passed, that would result in a total cost for that kWh of $0.06, comparable to new natural gas combined cycle capacity today. Of course, only a fraction of the total energy produced by a wind or solar installation would need to pass through the storage system. To determine cycling frequency and establish an energy throughput distribution across each hour of storage duration requires explicit knowledge of the application-specific duty cycle (as discussed in Figure 1). Because there is substantial uncertainty in the operation of future LDS systems, assumptions here regarding cycle counts should be considered primarily illustrative.

The orange regions in Figure 2A show the present value of storage revenue for a hypothetical system that operates at a fixed 0.03 $/kWh-cycle (dashed) and 0.06 $/kWh-cycle (solid) with a 10% IRR and the operational profile provided in Figure 2B. Because we are assuming a single source of energy-based remuneration for the storage asset, the higher per-cycle target reflects either additional sources of energy-based revenue for the system (i.e. revenue stacking), or a scenario where higher energy prices may be warranted. For example, in the limit of ideal diurnal solar energy shifting with 50% of daily solar generation stored and 50% provided directly to the grid, a solar LCOE of 0.03 $/kWh and storage premium of 0.06 $/kWh-cycle (0.09 $/kWh for the 50% of the plant output that passes through the storage system) would yield a net

LCOE of 0.06 \$/kWh for the combined system. The increased capital cost distribution at longer durations shown in Figure 2 represents additional uncertainty in the frequency of deep discharge events relative to daily cycling (approximately ≤ 8 h at rated power).

The discrepancy between capital costs of a future EES system with conventional energy scaling and the target LDS system (blue shaded region) highlights the need to fundamentally shift the scaling economics of storage systems out to durations beyond daily operation. Extremely low installed capital costs in the range of 2 – 80 \$/kWh are required to meet the per cycle cost targets. The key message from this scaling analysis is that capital costs must decrease for a given system as durations are scaled beyond those typically utilized for daily cycling. The cost curve shown here establishes a new "dynamic" metric that is distinct from "static" capital cost targets set by ARPA-E and others (green circle in Figure 2A).