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Battery Storage in the United States: An Update on Market Trends

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List of Acronyms

AEO	*Annual Energy Outlook*
AK/HI	Alaska and Hawaii
CAES	Compressed-air energy storage
CAISO	California Independent System Operator
CPUC	California Public Utility Commission
CSP	Concentrated solar power
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
IOU	Investor-owned utilities
ITC	Investment Tax Credit
IPP	Independent power producer
IRP	Integrated resource plan
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kW	Kilowatt
kWh	Kilowatthour
LADWP	Los Angeles Department of Water and Power
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatthour
NEMS	National Energy Modeling System
NYISO	New York Independent System Operator
PGE	Pacific Gas and Electric
PJM	PJM Interconnection
PPA	Power purchase agreement
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDGE	San Diego Gas and Electric
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool

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Executive Summary

Electric power markets in the United States are undergoing significant structural change that we believe, based on planning data we collect, will result in the installation of the ability of large-scale battery storage to contribute 10,000 megawatts to the grid between 2021 and 2023—10 times the capacity in 2019.

Energy storage plays a pivotal role in enabling power grids to function with more flexibility and resilience. In this report, we provide data on trends in battery storage capacity installations in the United States through 2019, including information on installation size, type, location, applications, costs, and market and policy drivers. The report then briefly describes other types of energy storage.

This report focuses on data from EIA survey respondents and does not attempt to provide rigorous economic or scenario analysis of the reasons for, or impacts of, the growth in large-scale battery storage.

Growth across U.S. electric power market regions

The number and total capacity of large-scale battery storage systems continue to grow in the United States, and regional patterns strongly influence the nation-wide market structure:

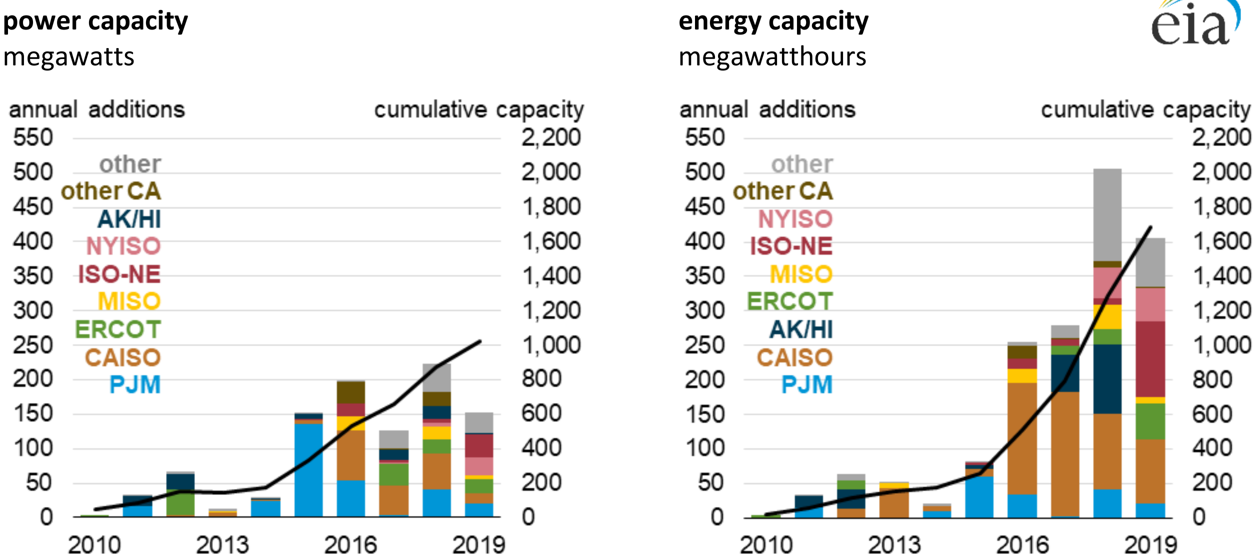
- At the end of 2019, 163 large-scale battery storage systems were operating in the United States, a 28% increase from 2018. The maximum energy that could be stored at these sites (energy capacity) was 1,688 megawatthours (MWh), and the maximum power that could be provided to the grid from these sites at any given moment (power capacity) was 1,022 megawatts (MW).

- As of the end of 2019, more than 60% of the large-scale battery system capacity to store energy or provide power to the grid in the United States was located in areas covered by regional grid operators PJM Interconnection (PJM) and California Independent System Operator (CAISO). Historically, these areas attracted capacity additions because of favorable market rules promoting energy storage.

- Starting in 2017, regions outside of PJM and CAISO have also seen installations of large-scale battery energy storage systems, in part as a result of declining costs.

- A breakout of installed power and energy capacity of large-scale battery by state is attached as Appendix C.

Figure ES1. Large-scale battery storage capacity by region (2010–2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Small-scale battery storage

Small-scale battery storage also continues to grow, especially in California, but also in other regions of the United States:

- In 2019, 402 MW of small-scale total battery storage power capacity existed in the United States.
- California accounts for 83% of all small-scale battery storage power capacity.
- The states with the most small-scale power capacity outside of California include Hawaii, Vermont, and Texas.

Lower installed costs

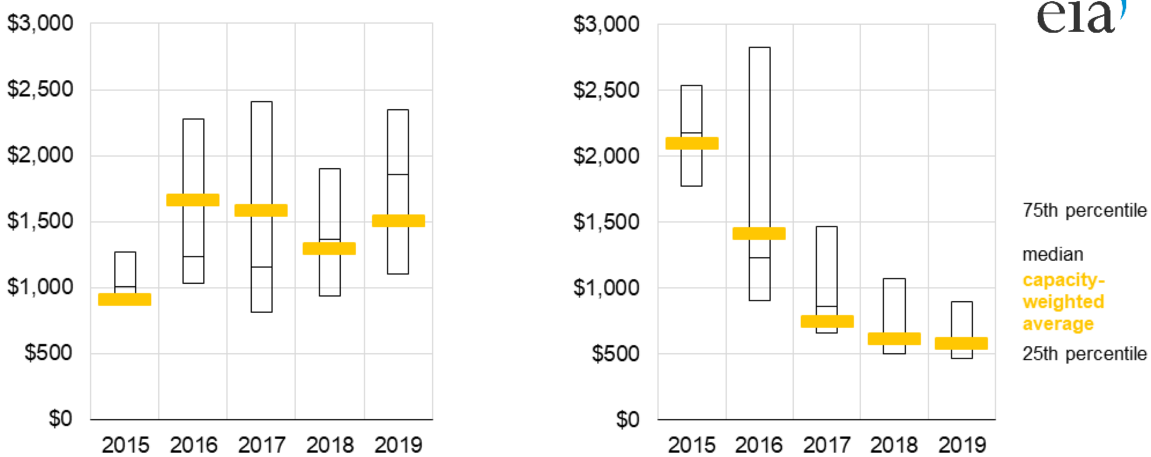
The costs of installing and operating large-scale battery storage systems in the United States have declined in recent years.

- Average battery energy storage capital costs in 2019 were $589 per kilowatthour (kWh), and battery storage costs fell by 72% between 2015 and 2019, a 27% per year rate of decline.
- These lower costs support more capacity to store energy at each storage facility, which can increase the duration that each battery system can last when operating at its maximum power.

Figure ES2. Total installed cost of large-scale battery storage systems by year

power capacity costs
dollars per kilowatt

energy capacity costs
dollars per kilowatthour



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

More direct support from solar power

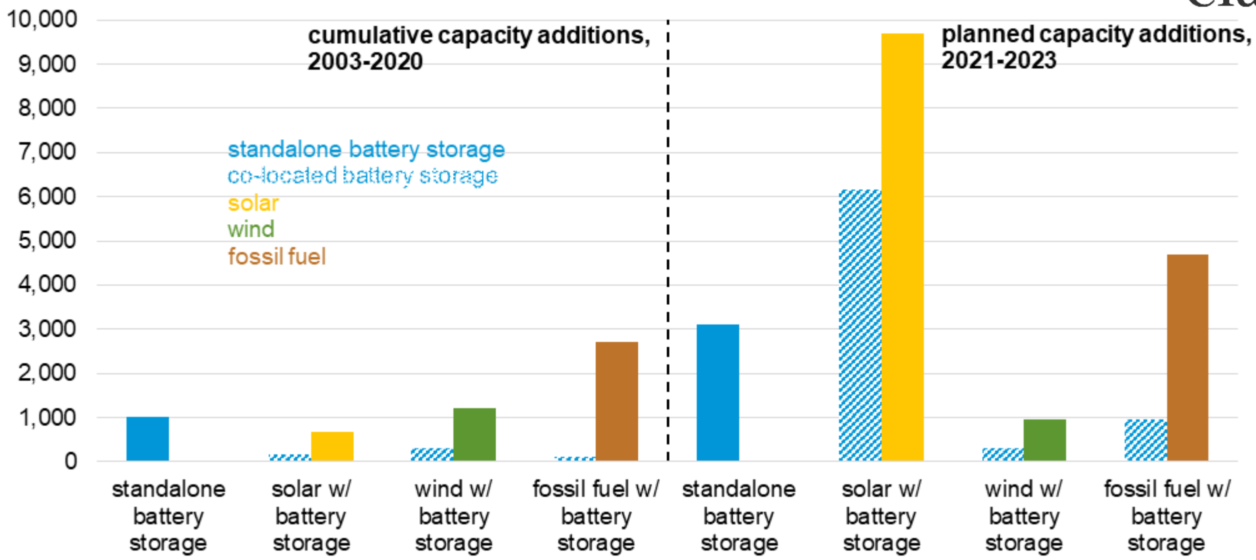
Most large-scale battery energy storage systems we expect to come online in the United States over the next three years are to be built at power plants that also produce electricity from solar photovoltaics, a change in trend from recent years.

- As of December 2020, the majority of U.S. large-scale battery storage systems were built as standalone facilities, meaning they were not located at sites that generate power from natural resources. Only 38% of the total capacity to generate power from large-scale battery storage sites was co-located with other generators: 30% was co-located specifically with generation from renewable resources, such as wind or solar PV, and 8% was co-located with fossil fuel generators.

- We expect the relationship between solar energy and battery storage to change in the United States over the next three years because most planned upcoming projects will be co-located with generation, in particular with solar facilities. If all currently announced projects from 2021 to 2023 become operational, then the share of U.S. battery storage that is co-located with generation would increase from 30% to 60%.

Figure ES3. U.S. large-scale battery storage power capacity additions, standalone and co-located

megawatts



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Note: Solid yellow, green, and brown bars indicate generating total capacity of solar, wind, and fossil fuels that have battery storage on-site.

Additional accelerated growth

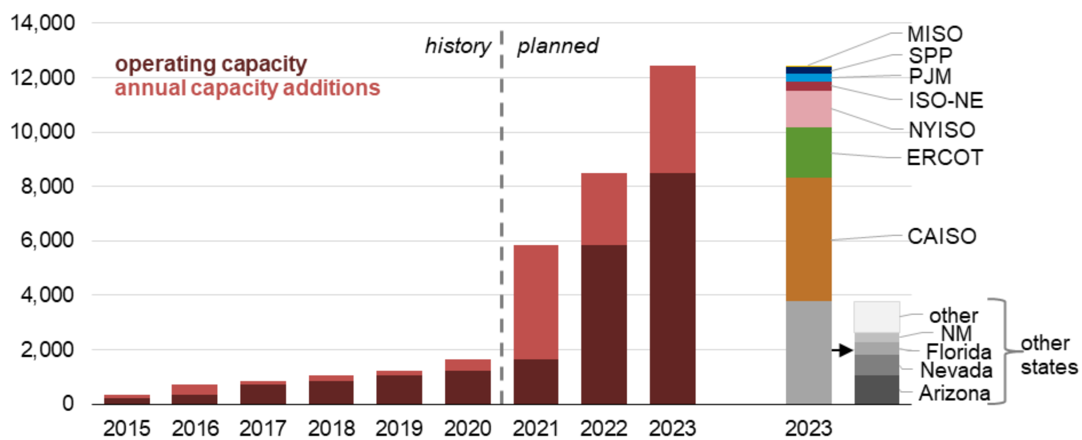
Based on planning data we collect, an additional 10,000 megawatts of large-scale battery storage's ability to contribute electricity to the grid is likely to be installed between 2021 and 2023 in the United States—10 times the total amount of maximum generation capacity by all systems in 2019.

Almost one-third of U.S. large-scale battery storage additions will come from states outside of regional grid operators PJM and CAISO, which led in initial development of large-scale battery capacity.

Figure ES4. Large-scale battery storage cumulative power capacity, 2015–2023

power capacity

megawatts



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Large-Scale Battery Storage Trends

The first large-scale[1] battery storage installation reported to us in the United States that was still in operation in 2019 entered service in 2003. Only 50 MW of power capacity from large-scale battery storage systems was installed between 2003 and 2010. However, the prevalence of these systems has grown in recent years. Between 2010 and 2019, power capacity from large-scale battery storage increased by a net of 972 MW, and 1,022 MW of battery storage power capacity was operational by the end of 2019.

Before last year, the largest annual battery power capacity addition in the United States occurred in 2018, when a record 222 MW of large-scale battery storage was added. In 2019, 152 MW of battery power capacity was installed, 32% less than in 2018. Preliminary data for 2020 show a 458 MW increase in battery power capacity, more than double the previous record and 66% more than total power capacity additions for 2019.

Independent power producers (IPPs) installed most of the U.S. battery storage power capacity that was operational in 2019 in the PJM Interconnection (PJM), which coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Investor-owned utilities (IOUs) in the California Independent System Operator (CAISO) territory have procured significant amounts of storage capacity as well.

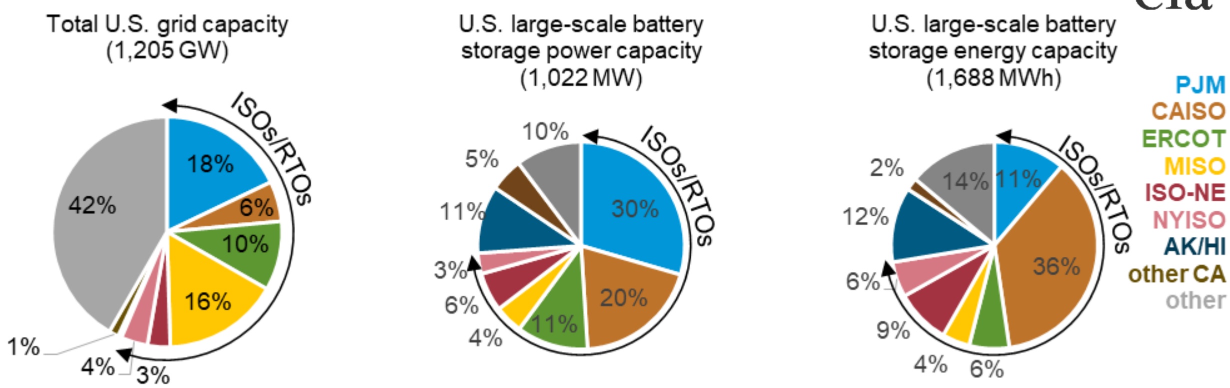
Although Alaska and Hawaii represent a significant share of current U.S. battery storage capacity, their utilization patterns are unique in that batteries need to provide a wider range of additional services and engineering support than is commonly used in the Lower 48 states; therefore, these two states are grouped together in this report.

Regional trends

About 74% of large-scale battery storage power capacity and 72% of energy capacity in the United States is installed in areas covered by independent system operators (ISOs) or regional transmission organizations (RTOs) (Figure 1).[2] The ISOs and RTOs account for 58% of total grid capacity in the United States and have the largest shares of storage power capacity relative to their shares of installed grid capacity (Figure 2). The disproportionate share of battery storage across ISOs and RTOs may result from differences in market design and policies compared to the utilities that integrate generation and distribution themselves which prevail elsewhere (Market and Policy Drivers).

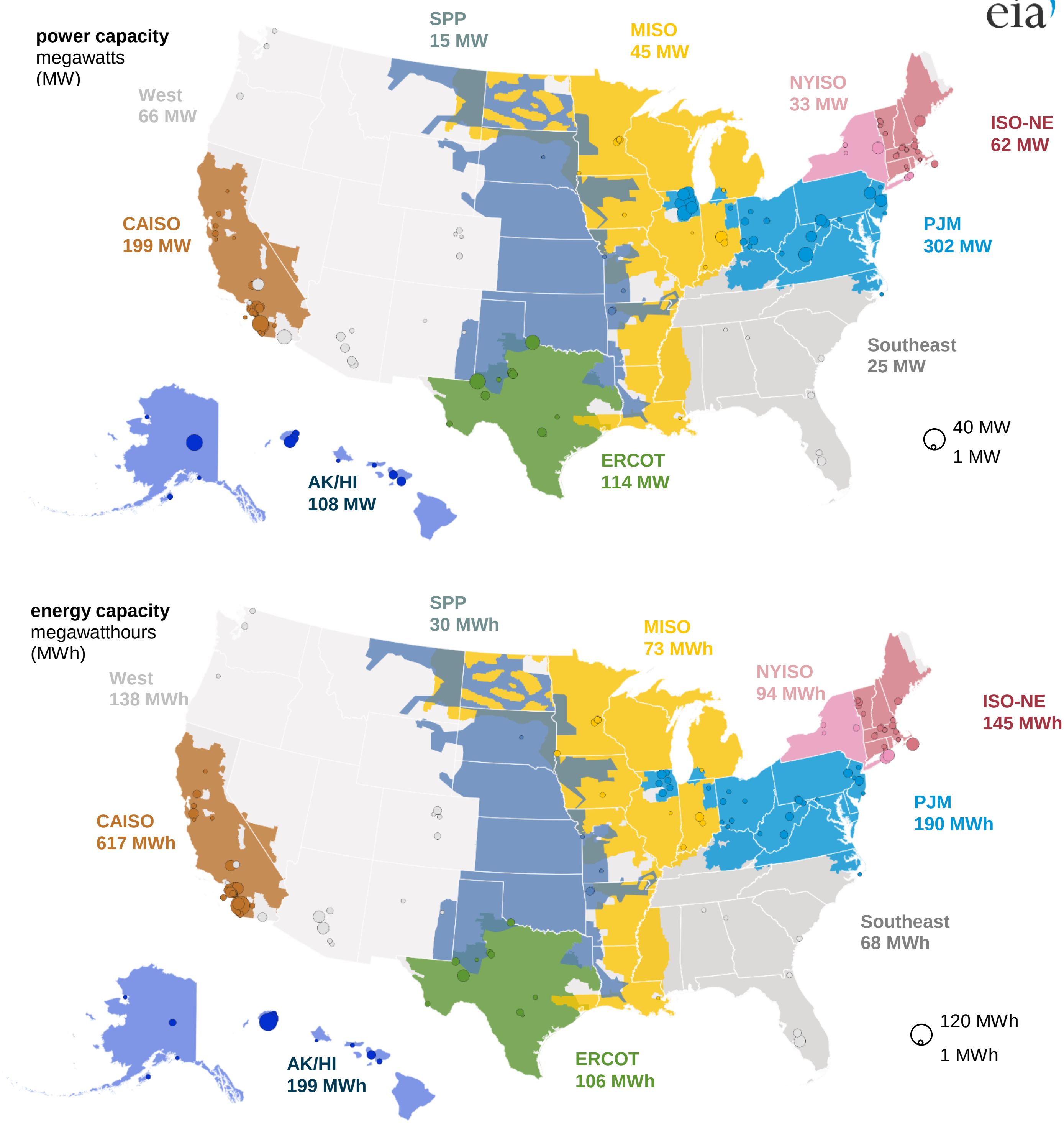
[1] Large-scale refers to systems that are grid connected and have a nameplate power capacity greater than 1 MW.
[2] ISOs and RTOs are independent, federally regulated non-profit organizations that ensure reliability and optimize supply and demand bids for wholesale electric power.

Figure 1. Large-scale power and energy capacity by region (2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Figure 2. Large-scale battery storage installations by region (2019)

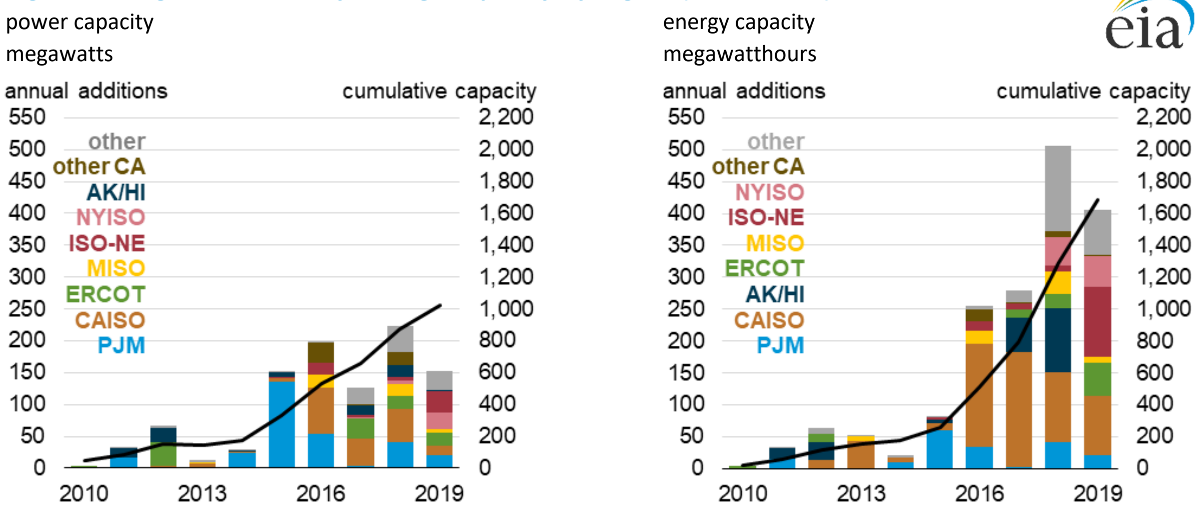


Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*
Note: Energy capacity data for large-scale battery storage installed in 2019. Gray regions are not covered by RTO/ISO's.

Between 2003 and 2019, 1,044 MW (22 MW of which is now retired) of large-scale battery storage power capacity (as part of 168 individual projects) was installed in the United States, 82% of which was installed between 2015 and 2019. The region with the most power capacity, PJM Interconnection (Figure 3), makes up 30% of existing large-scale battery storage power capacity, most of which was built from 2014 to 2016. This period of growth in large-scale battery storage power capacity in PJM most likely resulted from changes in PJM's market for frequency regulation (a grid service that helps balance momentary differences between electricity demand and supply within the transmission grid) in 2012, which created a specific requirement for fast-response resources, such as batteries. In 2015, PJM capped the market share for fast-responding resources as a result of grid reliability concerns,[3] and PJM has had relatively less storage growth since these changes occurred.

Existing installations in PJM tend to be power-oriented with larger capacities but shorter durations to serve frequency regulation applications. In 2019, large-scale battery storage installations in PJM had an average power capacity of 10.8 MW, an average energy capacity of 6.8 MWh, and an average duration of 45 minutes. This average duration is the same as the average duration was in 2017 and 2018 for PJM.

Figure 3. Large-scale battery storage capacity by region (2010–2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

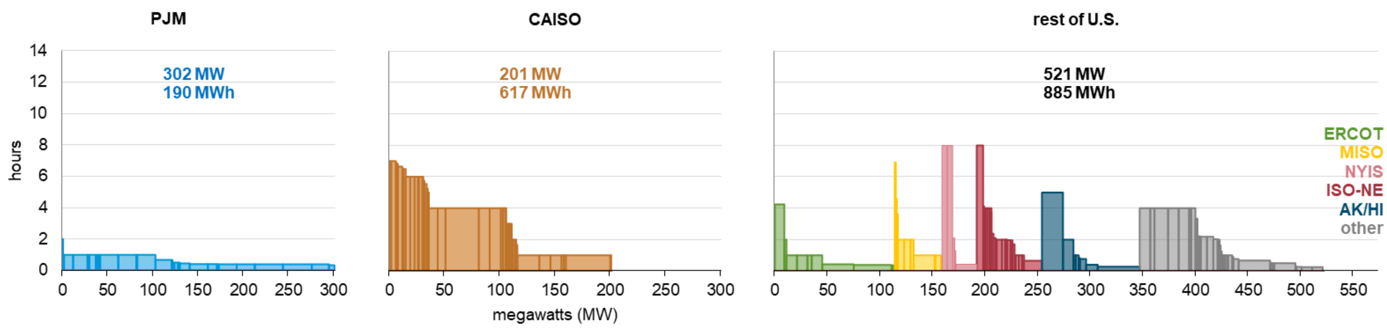
In 2019, installations in CAISO accounted for 20% of existing large-scale battery storage power capacity in the United States, but they accounted for 36% of existing energy capacity. California uses battery storage for reliability purposes, so large-scale battery storage installations tend to be energy-oriented with small power capacities and long durations.

In 2019, operating large-scale battery storage systems in CAISO had an average power capacity of 4.7 MW, an average energy capacity of 14.4 MWh, and an average duration of 4.0 hours. This duration is longer than the 2018 average of 3.5 hours for battery systems in CAISO and the 2019 national average of

[3] FERC Docket No. ER19-1651-000, PJM Interconnection ORDER ON CONTESTED SETTLEMENT, https://www.pjm.com/-/media/documents/ferc/orders/2020/20200326-er19-1651-000.ashx

2.3 hours for all operating large-scale batteries. Other markets show a mix of power- and energy-oriented battery installations (Figure 4). The California Public Utilities Commission (CPUC) requires generation resources to provide at least four hours of output to contribute to reliability reserves. As a result, large-scale battery storage installations in California tend to need larger energy capacities to qualify as reliability resources. The Market and Policy Drivers section provides more information on California's activities related to energy storage.

Figure 4. Power capacity and duration of large-scale battery storage by region (2019)



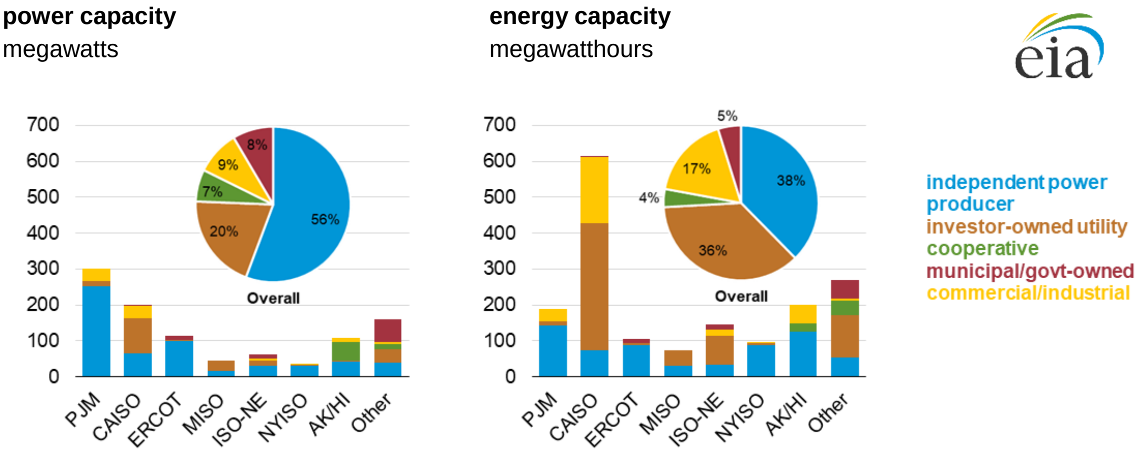
Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*
Note: We calculate duration by dividing nameplate energy capacity (in megawatthours [MWh]) by nameplate power capacity (in megawatts [MW]).

Ownership trends

At the end of 2019, IPPs owned slightly more than half (56%) of the existing power capacity of large-scale battery storage in the United States, and IOUs owned only 20% (Figure 5). In terms of large-scale battery storage energy capacity, IPPs owned 38%, and IOUs owned 36%. This ownership structure reflects the dominance of IPPs in PJM and PJM's power-oriented storage applications. It also reflects the prevalence of IOU ownership of energy-oriented reliability assets in CAISO.

The differences in ownership resulted from market and state policy incentives pursued in both areas. Initially, PJM had rules that compensated batteries that participated in its market region, but later redacted these rules. California passed state laws that required utilities to accept project bids and install a certain amount of batteries on their systems. These requirements led to more battery ownership in CAISO by IOUs and not IPPs. PJM took a market approach, while CAISO reflected the policy of the state in which it operates.

Figure 5. Large-scale battery storage capacity by region and ownership type (2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Although half of all large-scale battery storage power capacity operates inside of PJM and CAISO, some noteworthy points emerge in other regions. IPPs own more than 87% of the power capacity in the Electric Reliability Council of Texas (ERCOT), which is regulated by the Public Utility Commission of Texas. Of the 45 MW of battery storage power capacity in Midcontinent Independent System Operator (MISO), IOUs own 67%. In Alaska, IPPs own most large-scale battery storage energy capacity, but the power capacity is split between cooperatives and IPPs. State-owned utilities in the United States own 8.5% of large-scale battery storage power capacity, led by two large installations in Southern California that are owned by the Imperial Irrigation District (30 MW power capacity/20 MWh energy capacity) and the Los Angeles Department of Water and Power (LADWP) (20 MW power capacity/10 MWh energy capacity).

Chemistry Trends

Chemistry descriptions

Battery storage technologies use several different battery chemistries. The most common with large-scale deployment[4,5,6] in the United States include:

- **Lithium-ion** technology was used in more than 90% of the installed power and energy capacity of large-scale battery storage operating in the United States at the end of 2019. Lithium-ion batteries have high-cycle efficiency (they don't lose much energy between recharge and discharge) and fast response times. In addition, their high energy density (stored energy per unit of weight) makes them the current battery of choice for most portable electronic and electric vehicle applications.
- **Nickel-based** batteries were used in some of the earliest large-scale battery storage installations in the United States, including a 2003 system added in Fairbanks, Alaska. Since then, the deployment of this battery chemistry has been limited. Nickel-based batteries typically have

[4] Akhil, Abbas A., et al. *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*. January 2015. http://www.sandia.gov/ess/publications/SAND2015-1002.pdf

[5] Chen, Haisheng, et al. *Progress in electrical energy storage system: A critical review*. Progress in Natural Science, March 2009.

[6] Luo, Xing, et al. Overview of current development in electrical energy storage technologies and the application potential in power system operation. Applied Energy, January 2015.

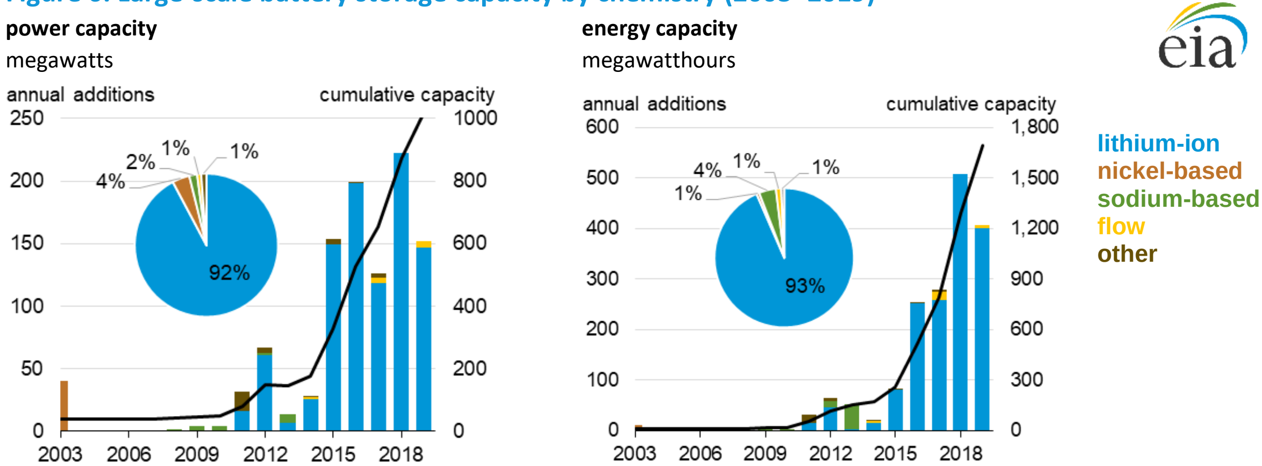
high energy density and reliability but a relatively short cycle life (fewer recharge and discharge cycles before performance degrades below useful levels).

- **Sodium-based** battery storage was used in 2% of the installed large-scale power capacity and 4% of the installed large-scale energy capacity in the United States at the end of 2019. Sodium-based battery storage is an established technology based on abundant materials with a long cycle life suitable for long-discharge applications. These systems require high operating temperatures (about 300°C) because they use molten sodium to operate.
- **Lead acid** is one of the oldest forms of battery storage and was developed in the mid-1800s. It is widely used as a starter battery in vehicles. Lead acid accounted for less than 1% of large-scale battery storage power capacity installed at the end of 2019 in the United States and has seen limited large-scale deployment because of relatively low energy density and a short cycle life.
- **Flow battery** systems have one or more chemical components that dissolve in a liquid solution. The chemical solutions are typically stored in tanks and separated by a membrane. Tank size determines the overall battery capacity, and these systems can be expanded to meet different applications. They have a long cycle life and a long operational lifetime. At the end of 2019, flow batteries were used in 1% of the installed power and energy capacity of large-scale battery storage in the United States.

Chemistry trends

The earliest large-scale battery storage installations in the United States used nickel-based and sodium-based chemistries (Figure 6). However, since 2011, most installations have opted for lithium-ion batteries, including retrofits of older systems that initially relied on different chemistries. For example, in 2012, Duke Energy added 36 MW of lead-acid battery storage to its Notrees wind power facility in West Texas. When the lead-acid batteries were first installed, the battery system participated in the region's frequency regulation market, which required rapid charging and discharging that significantly degraded the batteries. In 2016, Duke Energy replaced the original lead-acid batteries with better-performing lithium-ion batteries.[7]

Figure 6. Large-scale battery storage capacity by chemistry (2003–2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

[7] Duke Energy, *Duke Energy to upgrade its Notrees Energy Storage System*, June 2015, https://news.duke-energy.com/releases/duke-energy-to-upgrade-its-notrees-energy-storage-system

Flow batteries are an emerging energy storage technology. In 2016, Avista Utilities installed the first large-scale flow battery storage system in the United States, which is located in Washington State. Electric utilities in Washington and California each installed flow battery projects in 2017. The vanadium-based electrolyte used in these flow battery systems is stored in large tanks and pumped through a connected but separate electrode system. This configuration provides greater energy capacity at a lower price, but it lowers the round-trip efficiency[8] of the stored electricity as a result of the energy consumed to operate the pumps.[9] Other battery storage chemistries and technologies are in different phases of development but have yet to have significant deployment in large-scale grid applications in the United States.

[8] Round-trip efficiency is the battery system efficiency over one cycle, measured as the amount of energy discharged to a specified depth over the amount of energy consumed to bring the system back up to its specified initial state of charge.
[9] Amerseco, Inc., *Demonstrating the Benefits of Long-Duration, Low-Cost Flow Battery Storage in a Renewable Microgrid*, December 2019, https://www.serdp-estcp.org/Program-Areas/Installation-Energy-and-Water/Energy/Microgrids-and-Storage/EW19-5312

Current Applications

Batteries have both physical and operational constraints, such as power output and discharge duration. These constraints affect individual battery technology choices that are often made to optimize the delivery of certain types of services or provide specific applications to the electricity grid. In some cases, different applications can, or sometimes must, be combined to maximize the value of the system. For a more complete discussion, refer to DNV-GL's *Recommended Practices: Safety, operation and performance of grid-connected energy storage systems*.

Application descriptions

The various types of battery applications[10] include:

- **Frequency regulation** helps balance momentary differences between electricity demand and supply within the transmission grid, often in order to help maintain interconnection frequencies close to 60 hertz.
- **Spinning reserve** is the unused but dispatchable generating capacity of online assets that provides grid frequency management and may be available to use during a significant frequency disturbance, such as during an unexpected loss of generation capacity. This reserve ensures undisrupted system operation and power availability. Dispatchable generators are those that can be turned on or off to meet immediate needs of the system.
- **Voltage or reactive power support** ensures the quality of delivered power by maintaining the local voltage within specified limits by serving as a source, or sink, of reactive power (the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment).
- **Load following** supplies (discharges) or absorbs (charges) power to compensate for load variations—this application is a power balancing application, also known as a form of ramp rate control.
- **System peak shaving** reduces or defers the need to build new central generation capacity or purchase capacity in the wholesale electricity market, often during times of peak demand.
- **Arbitrage** occurs when batteries charge during periods when electrical energy is less expensive and discharge when prices for electricity are high, also referred to as electrical energy time-shift.
- **Load management** provides a demand-side customer-related service. Load management services include managing power quality, power reliability (grid-connected or microgrid operation), retail electrical energy time-shift, demand charge management, and renewable power consumption maximization. Renewable power consumption maximization refers to charging the battery storage system during periods when renewable energy is greatest to consume the maximum renewable energy from the battery system, or in other words, charging with solar during the day or charging with wind during high wind periods.
- **Storing excess wind and solar generation** reduces the rate of change for power output from a non-dispatchable generator to maintain compliance with local grid requirements related to grid stability or to prevent over production or over-production penalties. Non-dispatchable generators cannot be turned on or off to meet immediate needs and are often intermittent

[10] DNV-GL, *Recommended Practices: Safety, operation and performance of grid-connected energy storage systems*, September 2017, https://rules.dnvgl.com/docs/pdf/DNVGL/RP/2017-09/DNVGL-RP-0043.pdf?_ga=2.80787476.2095102769.1516371272-888917498.1516371272

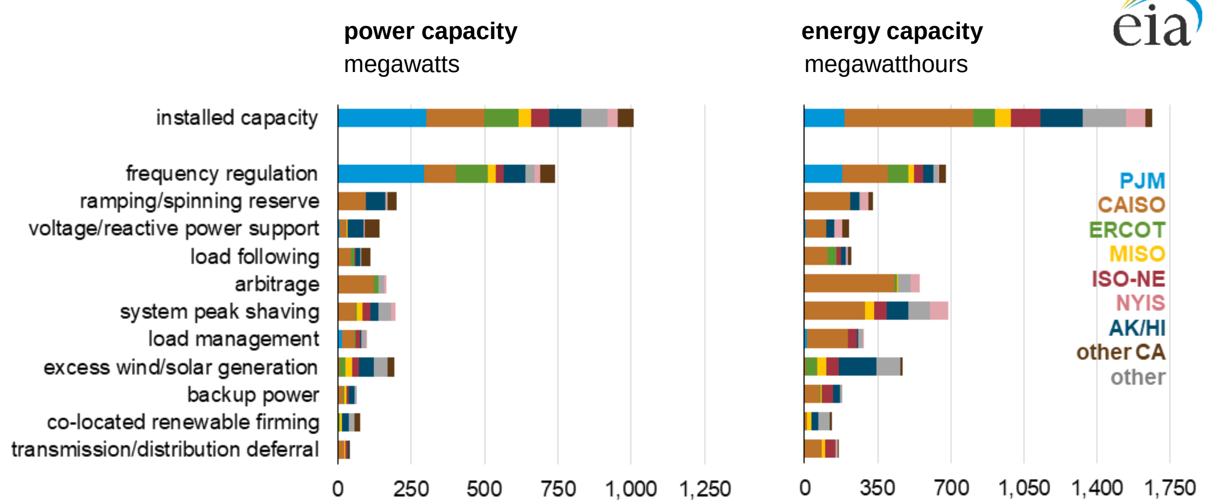
resources (generators with output controlled by the natural variability of the energy source, for example, wind and solar).

- **Backup power**, following a catastrophic failure of a grid, provides an active reserve of power and energy that can energize transmission and distribution lines, provide start-up power for generators, or provide a reference frequency.
- **Transmission and distribution deferral** keeps the loading of the transmission or distribution system equipment below a specified maximum. This application allows for delays in transmission upgrades, avoids the need to upgrade a transmission system completely, or avoids congestion-related costs and charges.
- **Co-located generator firming** provides constant output power over a certain period of time for a combined generator and energy storage system. Often the generator in this case is for non-dispatchable renewable generation (for example, wind or solar).

Applications by region

Each year, operators report on Form EIA-860 all use case applications that their batteries can serve. A battery's number and types of uses varies significantly across regions (Figure 7). For example, battery storage in PJM is primarily for one application (frequency regulation). In contrast, batteries installed in CAISO are used for several reasons (2.5 applications on average) but primarily provide system peak shaving and load management. MISO has a widely dispersed set of use cases, and almost the same number of batteries provide peak shaving as do frequency regulation. Batteries in ISO New England (ISO-NE), like those in CAISO, primarily provide peak shaving and store excess wind and solar generation, but New England batteries also significantly support frequency regulation.

Figure 7. Applications served by large-scale battery storage (2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*
Note: This figure is based on information provided by Form EIA-860 survey respondents regarding their market region and the applications that battery storage systems provided in 2019. Survey respondents could select more than one application for each battery system.

Different factors affect battery storage investment decisions in different regions. These factors depend on state policies and both existing and future market characteristics and needs. Batteries that are intended primarily to serve frequency response have different design characteristics than those intended to serve peak shaving. However, because most batteries serve more than one function, most of the RTO markets and regions have batteries that serve all the use case applications despite regional or market bias.

Batteries installed in Alaska and Hawaii are used more diversely (4.3 applications on average). Because these states lack interconnected operating systems, batteries need to provide a wider range of additional services and engineering support than commonly needed in the Lower 48 states.

Figure 7 illustrates the total amount of power and energy capacity that was available for each application in the United States in 2019. Nearly 73% of large-scale battery storage power capacity provided frequency regulation, which helps electrical grids quickly balance unexpected differences in electricity supply and demand. Installations in PJM are driven by the need for fast-ramping frequency regulation, a need that has led many independent power producers to rapidly deploy large-scale battery storage. As of 2019, CAISO installations served a wider array of applications than PJM applications because regulated utilities in CAISO systems served multiple applications without necessarily being directly compensated for each application through market mechanisms.

Battery Storage Costs

Costs for battery storage technologies depend on technical characteristics such as the power capacity and energy capacity of the battery system.

Cost background

This discussion of costs is divided into three main categories based on the nameplate duration of the battery storage system, which is the ratio of nameplate energy capacity to nameplate power capacity:

- The short-duration battery storage category includes systems with less than 0.5 hours of nameplate duration.
- The medium-duration battery storage category includes systems with nameplate durations ranging between 0.5 hours and 2.0 hours.
- The long-duration battery storage category includes all systems with more than 2.0 hours of nameplate duration.

Table 1 summarizes the average characteristics of the categorized sample data. Battery duration is a key determinant of system characteristics such as cost. Even when using the same cells and inverters, a system intended to provide long duration discharge will optimize its design to minimize energy cost (in dollars per kilowatthour), whereas a system intended to provide a short-duration injection of power into the grid will minimize power cost (dollars per kilowatt).

For costs reported between 2013 and 2019, short-duration battery storage systems had an average power capacity of 12.4 MW, medium-duration systems had 6.4 MW, and long-duration battery storage systems had 4.7 MW. The average energy capacity for the short- and medium-duration battery storage systems were 4.7 MWh and 6.6 MWh, respectively. The average for the long-duration battery storage systems was 21.2 MWh, between three and five times more than the average energy capacity of short- and medium-duration battery storage systems.

Table 1. Sample characteristics of capital cost estimates for large-scale battery storage by duration (2013–2019)

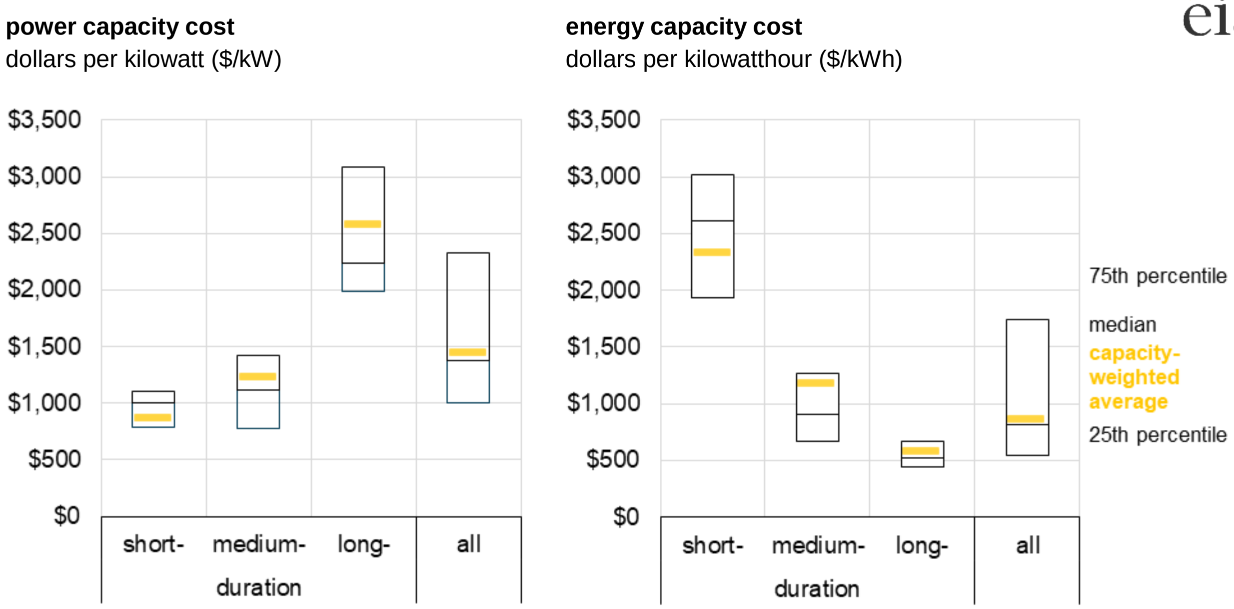
	Short-duration	**Medium-duration**	**Long-duration**
	<0.5 hours	**0.5–2 hours**	**>2 hours**
Number of battery systems with reported costs available	24	52	45
Average of nameplate power capacity, megawatts	12.4	6.4	4.7
Average of nameplate energy capacity, megawatthours	4.7	6.6	21.2
Average of nameplate duration, hours	0.4	1.2	4.6
Capacity-weighted cost per unit power capacity, dollars per kilowatts	872	1,224	2,575
Capacity-weighted cost per unit energy capacity, dollars per kilowatthour	2,329	1,178	575

Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*
Note: The reported capital cost values are from large-scale battery storage systems installed across the United States between 2013 and 2019 and include multiple reported battery chemistries.

Cost results

Based on costs reported between 2013 and 2019, battery systems with shorter durations typically had lower normalized power capacity costs measured in dollars per kilowatt ($/kW) than batteries with longer nameplate durations (Figure 8). The opposite was generally true when examining normalized energy capacity costs measured in dollars per kilowatthour ($/kWh) because total system costs for longer-duration systems are spread out over more stored energy. Technological and site-specific requirements also contribute to the range of normalized cost values, especially within a given duration category.

Figure 8. Total installed cost of large-scale battery storage systems by duration (2013–2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Normalized energy capacity costs (in dollars per kilowatthour) have decreased over time (Table 2 and Figure 9). The energy capacity-weighted average installed cost fell by 72% between 2015 and 2019 for an average five-year annual decrease of 27%. The capacity-weighted average installed cost of large-scale batteries fell by 33% from $2,102/kWh in 2015 to $1,417/kWh in 2016. This trend continued into 2017 when installed costs decreased by 47% to $755/kWh. This fall in energy capacity costs carried through 2017 and 2019, but at a slower rate, when the capacity-weighted average installed cost fell by 17% to $625/kWh in 2018 and by 5.7% to $589/kWh in 2019.

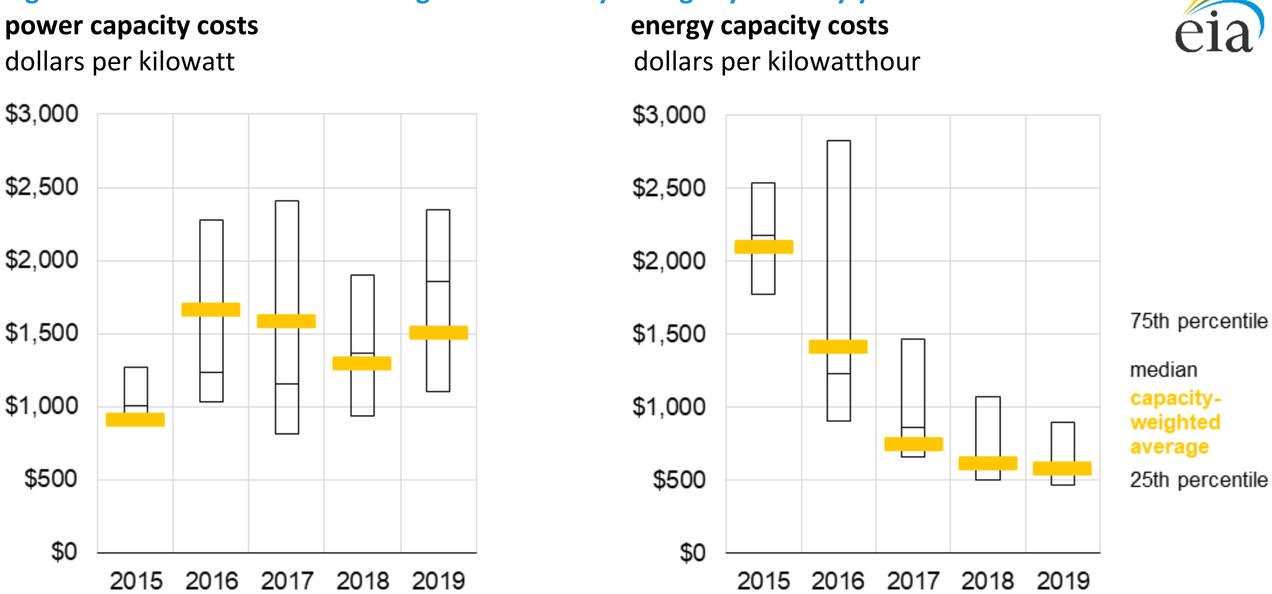
From 2015 to 2019, power capacity costs have remained relatively stable and within an average cost range of $913/kW and $1,664/kW. The trends of declining costs in terms of energy capacity and of relatively stable costs in terms of power capacity result from the increasing durations and larger energy capacities over time. The average nameplate energy capacity of the batteries in these cost samples increased at an average annual rate of 16% between 2015 and 2019, while duration increased at an annual rate of 56% for that same time period. In contrast, the average nameplate power capacity decreased at an average annual rate of 26% between 2015 and 2019.

Table 2. Sample characteristics of capital cost estimates for large-scale battery storage by year

	2015	2016	2017	2018	2019
Number of battery systems with reported costs available	10	21	22	26	37
Average of nameplate power capacity, megawatts	12.7	10.4	5.6	7.8	3.8
Average of nameplate energy capacity, megawatthours	5.5	12.2	11.7	16.1	9.8
Average of nameplate duration, hours	0.5	1.5	1.8	2.4	3.2
Capacity-weighted cost per unit power capacity, dollars per kilowatt	913	1,664	1,587	1,300	1,511
Capacity-weighted cost per unit energy capacity, dollars per kilowatthour	2,102	1,417	755	625	589

Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Figure 9. Total installed cost of large-scale battery storage systems by year



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*
Note: Cost observations for installation years 2013 and 2014 are not in this figure because the sample sizes for those years are too small.

Unlike other energy sources, battery storage can supply and consume energy at different times of the day, creating a combination of cost and revenue streams that makes it challenging to directly compare storage with generation-only technologies. Batteries are not standalone generation sources and must procure electricity supplied by generators to recharge and cover the round-trip efficiency losses they have during cycles of charging and discharging.

Two major challenges exist in determining the profitability and cost of battery storage systems. First, we must consider the individual markets in which the storage technology will be used and what revenue opportunities exist for the technology. Second, we must consider degradation of the system over time, which is the lasting and continuous decrease in either a battery's power or energy performance, or both, which is linked to use or age of a battery component or system.

A battery's power or energy performance can be characterized by the full-cycle power input and output at an agreed-on charge and discharge rate. Two general options can ensure reliable performance during a storage system's lifetime:

- **Overbuilding**: adding more storage or discharge capacity behind the inverter than is needed so that as the system ages, it will maintain a capacity at or above the contracted capacity required of the system.
- **Continual upgrades**: replacing some portion of the storage system to maintain the agreed-on performance during its lifetime.

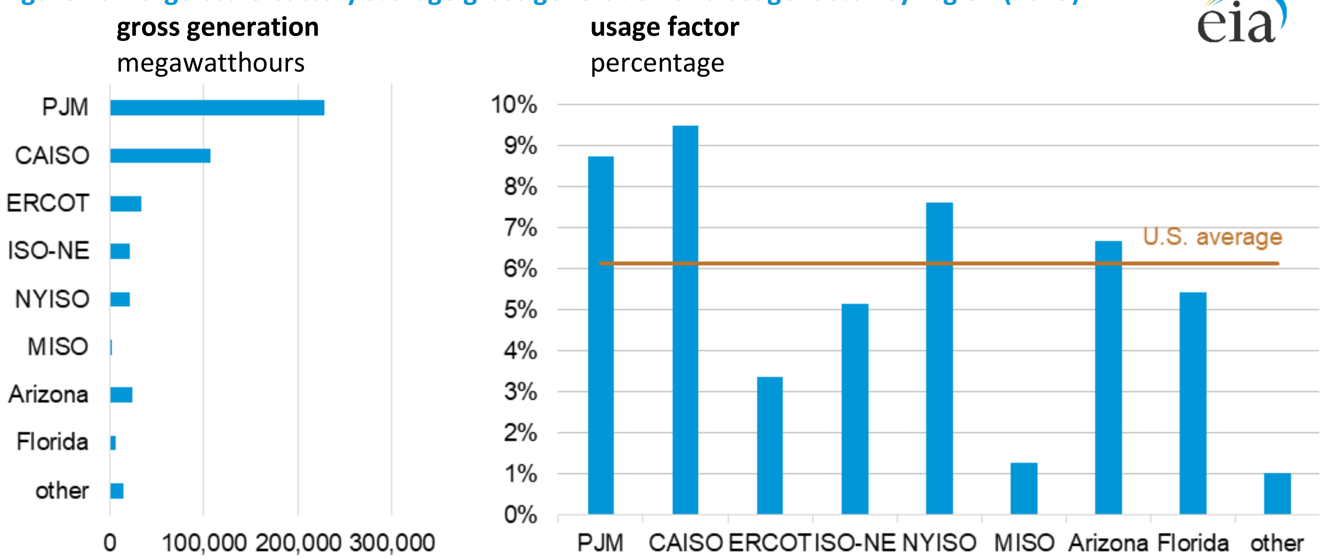
The two approaches to meet performance requirements affect the installed capital costs of the system. Overbuilding storage capacity leads to a higher initial installed capital cost, and continual upgrades lead to higher operation and maintenance costs throughout the lifetime of the storage facility. Therefore, comparing only the normalized capital cost of various battery systems does not capture the variation in the lifetime costs (Figure 8). Full understanding of this trade-off between capital and operating costs requires additional data collection and analysis as the industry continues to mature and as the operating batteries age through their expected long-term maintenance cycles.

Battery Utilization Trends

In addition to generator capacity data collected from Form EIA-860, we also collect power discharge and charging data from respondents at the power plant level on Form EIA-923, *Power Plant Operations Report*. Battery storage sites absorb electricity from the power grid while charging, and they supply electricity to the grid when discharging. Power absorbed by charging a battery can either be a system cost or system value (a revenue stream in a power market or simply a value recognized by the system operator in a vertically integrated balancing authority). In most cases, value or revenue is always produced when supplying electricity from stored energy to the grid.

Because of the efficiency loss between charging and discharging a battery, batteries are a net consumer of electricity. Of the 150 plants (1,022 MW) that reported operating battery storage capacity on Form EIA-860 in 2019, 109 plants (850 MW) also reported electricity generation and consumption data on Form EIA-923 in 2019. These 109 plants reported a total of 458,169 MWh of gross discharge and 553,705 MWh of gross charge in 2019 (an average round-trip efficiency of 85%). About half of the reported gross discharge was PJM serving its frequency regulation market (Figure 10).

Figure 10. Large-scale battery storage gross generation and usage factor by region (2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-923, *Power Plant Operations Report*
Note: Not all plants with battery storage systems reported generation to EIA in 2019.

For most electric generators, the capacity factor measures the actual useful output (net generation) of the plant (or resource) divided by the maximum potential output of the plant if it were operating at its full notional capability (normally the full rated power capacity for 24 hours per day, 365 days a year). Energy storage systems can generate revenue, or system value, through both discharging and charging of electricity; however, at this time our data do not distinguish between battery charging that generates system value or revenue and energy consumption that is simply part of the cost of operating the battery. Therefore, the usage factor detailed in Figure 10 is calculated using solely gross discharge. However, because of the strong relationship between charge and discharge, in cases where the storage unit provides system value or revenue from both charge and discharge, its bi-directional system value would be linearly related to its usage factor.[11]

Usage factors using only discharge cannot, however, be directly compared to usage factors for generation because batteries can provide value to the grid both when charging and discharging, unlike generating units which only provide recognized value when generating.

In 2019, the average usage factor of the 109 U.S. plants reporting generation to EIA in 2019 was 6%. Battery systems in PJM and CAISO were nearly 9%, well above the national average, while systems in ERCOT were well below the average at 3%. Systems outside the regions specified in Figure 10, including Hawaii, Alaska, and the parts of California not included in CAISO, had an average usage factor of under 1%.

[11] Specifically, a battery over any extended period will need to recharge (consume) as much energy as it discharged (generated), plus additional recharge to compensate for losses. If the usage factor of an 85% efficiency battery is 10%, then its average consumption would be 12% of its total capacity over a period of time, and its bi-directional energy flow would be about 22% of its total capacity over a period of time. Because a battery must recharge a bit more than it is discharged, its maximum annual usage factor is limited to about 43% (for an 85% efficient unit); that is, it can only generate 43% of the electricity that a unit of that size could were it able to generate 24 hours per day for 365 day a year.

Small-Scale Energy Storage Trends

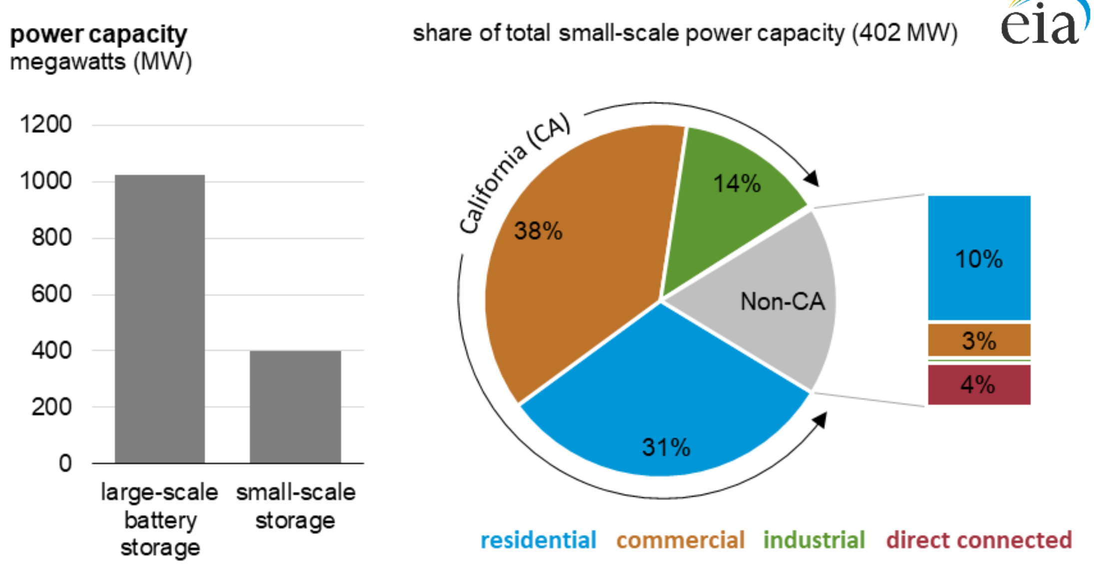
Small-scale battery storage is a significant part of developing energy storage in the United States. Small-scale battery storage refers to storage at facilities that have less than 1 MW of generating capacity. Electric utilities connected to these units report the small-scale storage data to us through Form EIA-861. Small-scale storage data differs from the detailed large-scale storage data that battery operators report. Utilities, through their interconnection data, provide summaries of the total capacity of small-scale storage connected to their systems but do not report detailed performance and design data.

In 2019, utilities reported 402 MW of existing small-scale storage power capacity in the United States. About 41% of this capacity was installed in the commercial sector, 41% was installed in the residential sector, and 14% was installed in the industrial sector. The remaining 4% was directly connected to the distribution grid, such as a utility at its own distribution substation.

Small-scale storage trends in California

As shown in Figure 11, in 2019, 83% of reported small-scale storage power capacity in the United States was in California. Of the small-scale storage power capacity in California, 97% was installed in three electric utility service territories: Southern California Edison (SCE), Pacific Gas and Electric (PGE), and San Diego Gas and Electric (SDGE). In 2019, most installations of small-scale storage in the commercial sector in California were in SCE's territory (68% of such capacity) and SDGE's territory (23%). Most installations (94%) of small-scale storage in the industrial sector in California were in PGE's territory.

Figure 11. Small-scale energy storage capacity by sector (2019)



Source: U.S. Energy Information Administration, Form EIA-861, *Annual Electric Power Industry Report*
Note: Data collected on small-scale storage may include forms of energy storage other than batteries. Direct-connected storage may not be located at an ultimate customer's site but is in front of the meter or connected directly to a distribution system or both. Direct-connected storage in California and industrial storage outside of California account for less than 1% of the total and are therefore not depicted in the figure.

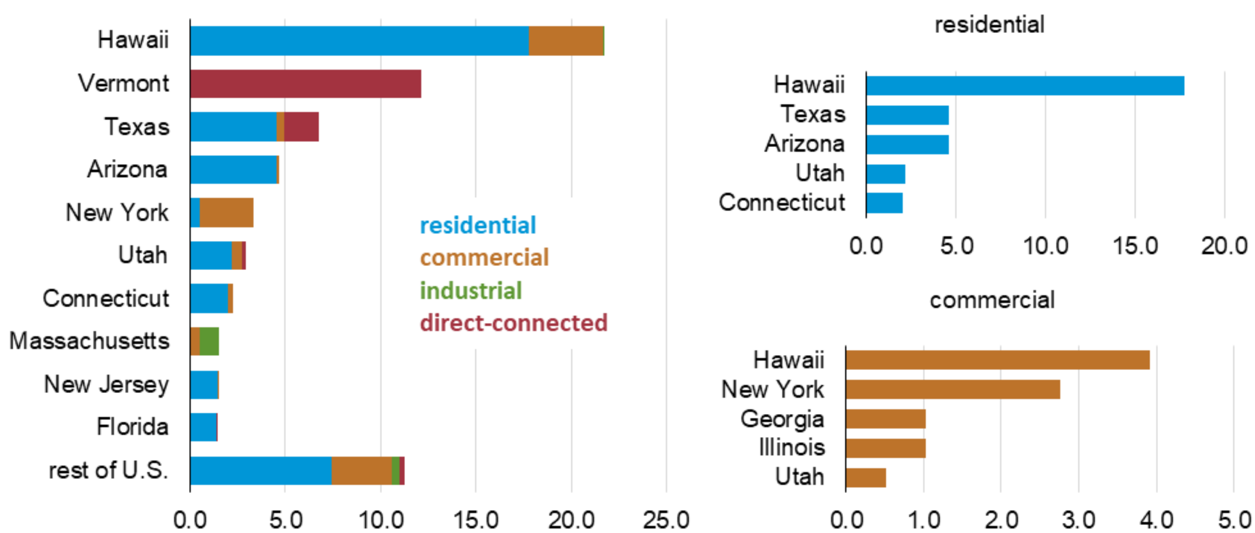
California's large share of small-scale energy storage power capacity can be attributed to the state's Self-Generation Incentive Program (SGIP), which provides financial incentives for installing customer-sited distributed generation. Installations receiving rebates through SGIP contribute to California's 2013 energy storage regulation (Assembly Bill 2514), which requires 200 MW of customer-sited energy storage to be installed by 2024. In May 2017, the CPUC implemented Assembly Bill 2868 and ordered SCE, PGE, and SDGE to procure up to an additional 500 MW of distributed energy storage, including no more than 125 MW of customer-sited energy storage.

Small-scale energy storage trends in the rest of the United States

After California, the states with the most reported small-scale storage power capacity in 2019 were Hawaii, Vermont, and Texas, and much of this capacity was installed in the residential sector (Figure 12). Only minimal small-scale storage power capacity in the industrial sector existed outside of California. In the commercial sector, small-scale storage was mostly reported in Hawaii and New York, as well as other states, notably in Georgia, Illinois, and Utah.

Figure 12. Small-scale energy storage capacity outside of California by sector (2019)

power capacity
megawatts



Source: U.S. Energy Information Administration, 2019 Form EIA-861, *Annual Electric Power Industry Report*

End users typically own small-scale energy storage systems. Direct-connected storage systems are installations not located at an ultimate customer's site but rather in front of the meter[12] or connected directly to a distribution system, or both. In Vermont, Green Mountain Power Corporation reported the largest amount of direct-connected battery storage power capacity. Green Mountain operated front-of-the-meter battery storage systems for customers, which totaled 12.1 MW of power capacity in 2019. The second-largest reported direct-connected battery storage power capacity was in Texas, operated by the Farmers Electric Cooperative, which totaled 1.85 MW.

[12] Front of the meter describes systems that provide power from an offsite location where the electricity must travel from the system through a meter to reach the home or business.

Market and Policy Drivers

As discussed earlier in this report, battery storage is technologically capable of serving many applications, each with benefits for one or more participants in the electricity system, including transmission and distribution system operators, power producers, and consumers. However, the functional ability of storage to serve these applications can be limited if regional policies or market rules do not acknowledge the value added. Still, market operators and policy makers can be hesitant to draft new legislation or market rules for relatively new technologies, such as storage, that may not have enough historical data to easily show value added to the system. This situation has begun to change as deployment of battery storage has increased and as industry stakeholders in some regions have gained experience financing, procuring, and operating storage installations.

Wholesale market rules

ISOs and RTOs are independent, federally regulated, non-profit organizations that ensure reliability and optimize supply and demand bids for wholesale electric power. They are currently regulated to be technology neutral and must ensure market rules do not unfairly preclude any resources from participating (in other words, ensure markets don't favor existing technologies and preclude new technologies from fairly competing for power generation market share), as enforced by the Federal Energy Regulatory Commission (FERC). Many existing market rules may not take into account the unique operating parameters and physical constraints of battery storage as both a consumer and a producer of electricity. However, recent actions by FERC, as well as by ISOs and RTOs, have begun to carve a path for storage to participate in individual markets.

A notable example of this trend is FERC Order 755, issued in 2011, which requires ISO and RTO markets to compensate for resources that can provide faster-ramping frequency regulation. As a result of Order 755, PJM split its frequency regulation market into a fast-ramping service and a slower-ramping service. By the end of 2015, more than 180 MW of large-scale battery storage power capacity had come online in the PJM territory.

However, in 2015, PJM began observing operational issues, including over cycling of large power generation units such as hydro plants and combustion turbines, which resulted from overdependence on the duration limitations of the fast-ramping regulation service. The fast-ramping service mainly consists of resources with duration restrictions, such as batteries, as opposed to the slower-ramping service, which generally consists of resources that could operate much longer, but take longer to come online.[13] Therefore, PJM changed its frequency regulation signals to decrease its ratio of fast-ramping to slow-ramping resources, delaying installations of large-scale battery storage in the region.

Other system operators have also implemented relevant changes to market rules. Some have developed unique asset classes for storage that allow them to be treated differently than other generating technologies. System operators then can specify participation models for these new asset classes, allowing one facility to serve and generate revenue from several markets. Some operators have lowered the minimum size requirements, allowing relatively smaller energy storage facilities to generate revenue

[13] PJM, *Fast Response Regulation (RegD) Resources Operational Impact*, July 1, 2017.

in markets usually reserved for bigger power plants. Some operators have defined duration requirements for assets to provide different grid services, allowing energy storage investors to plan accordingly. Although these rules spurred energy storage deployment to varying levels in these regions, energy storage participation has been inconsistent in each market.

In February 2018, FERC issued Order No. 841, which required system operators to remove barriers for electric storage resources to participate in the capacity, energy, and ancillary services markets. Each ISO and RTO under FERC jurisdiction was required to revise its tariff to include market rules that recognize the physical and operational characteristics of electric storage resources and to implement the revisions after FERC approves them. As of March 2021, FERC had approved the changes made by all ISOs and RTOs, but several RTOs, including MISO, ISO-NE, and SPP, are still working on implementing the approved changes.

In November 2020, FERC approved Order No. 2222, which requires RTOs and ISOs to create financial mechanisms for distributed energy resources (DERs) to compete to provide services normally reserved for large-scale systems. DERs are small-scale systems located close to the power load. They are usually connected to the distribution network and help to decrease the load on the transmission grid. This requirement could allow more economic deployment of small-scale battery storage systems, which could potentially be connected through virtual power plants. Grid operators must file compliance filings by late 2021, and the resulting rules may take effect in early 2022 or later.

Federal-level policy actions

Other than the FERC activities described in the previous section, federal policies involving energy storage have been limited. One exception is the Investment Tax Credit (ITC), which is a credit to income tax liability proportional to the capital expenditures originally intended for certain renewable energy technologies, including solar and wind. Energy storage installed at a solar or wind facility can be considered part of the energy property of the facility and can receive a portion of the tax credit, given that at least 75% of the power used to charge the battery comes from the co-located renewable asset.

State-level policy actions

Most policy actions involving energy storage have been at the state level and include setting procurement requirements, establishing incentives, and requiring that storage is incorporated into long-term planning mechanisms.

Policy actions in California

California has introduced several measures related to energy storage. In 2013, the California Public Utility Commission (CPUC) implemented Assembly Bill 2514, which requires its investor-owned utilities (IOUs) to procure 1,325 MW of differing levels of large-scale and small-scale energy storage by 2020 and to have the energy storage operational by 2024. As of December 2020, California had 520 MW of operational large-scale battery storage.

In May 2017, CPUC implemented Assembly Bill 2868, which requires IOUs to procure up to an additional 500 MW of distributed energy storage, including no more than 125 MW of customer-sited energy storage. The Self-Generation Incentive Program, which provides financial incentives for installing customer-sited distributed generation, has designated $48.5 million in rebates for residential storage systems of 10 kW or smaller and $329.5 million for storage systems larger than 10 kW.

Press reports in 2017 indicated that 100 MW, or about 19%, of existing battery storage power capacity in California was installed in response to a leak at the Aliso Canyon natural gas storage facility outside of Los Angeles in October 2015.[14] According to these reports, in May 2016, to help address reliability risks resulting from constraints on natural gas supply, the CPUC authorized the SCE electric utility to hold an expedited solicitation for energy storage. As a result, 62 MW of battery storage power capacity was added to the system in December 2016. In addition, the CPUC expedited SDGE's ongoing procurement of 38 MW of battery storage, which was installed in early 2017.

Policy actions in the rest of the United States

As of May 2021, five states besides California have also set energy storage requirements or targets:

- **Oregon**: Passed House Bill 2193 in 2015, allowing the two largest utilities in the state, Portland General Electric and Pacific Power, to each procure 5 MWh of storage energy capacity by January 2020. Although neither utility had achieved the 5 MWh of operational battery storage as of December 2020, both announced projects that are scheduled to come online in upcoming years, such as the Wheatridge Renewable Energy Facility.
- **Massachusetts**: Enacted House Bill 4857 (An Act to Advance Clean Energy) in August 2018, directing the Massachusetts Department of Energy Resources to set an energy storage target of 1,000 MWh by 2025.
- **New York**: In October 2018, New York announced a target of 3,000 MW of energy storage by 2030.
- **New Jersey:** In May 2018, New Jersey enacted the Clean Energy Act, P.L. 2018, which set a target of 2,000 MW of energy storage by 2030.
- **Virginia**: In February 2020, Virginia passed House Bill 1526, which set a 3,100 MW energy storage goal by 2035.

In addition, some states, such as Nevada, allow storage systems to be included in state-level renewable portfolio standards. Aside from targets, some states have provided financial incentives for energy storage installations, including grants, support for pilot projects, and tax incentives. For example, in 2018, Maryland passed Senate Bill 758, offering a tax credit of 30% on the installed costs for residential and commercial storage systems.

Many states require utilities to produce integrated resource plans (IRPs) that demonstrate each utility's ability to meet long-term demand projections using a combination of generation, transmission, and energy efficiency investments, while minimizing costs. Incorporating storage into IRPs can be a challenge because storage is different from conventional electricity generators and demand-side resources. For example, storage:

- Has unique operational constraints

[14] Green Tech Media, "Tesla, Greensmith, AES Deploy Aliso Canyon Battery Storage in Record Time," January 31, 2017, https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green#gs.bvJdDKY

- Can be interconnected at various points throughout the system
- Can serve a variety of applications
- Has policy and regulatory uncertainty that may affect system profitability

Nonetheless, some states have begun requiring utilities to include storage in integrated resource plans, including:

- Arizona
- California
- Connecticut
- Colorado
- Florida
- Indiana
- Kentucky
- Massachusetts
- New Mexico
- North Carolina
- Oregon
- Utah
- Virginia
- Washington

New York and Vermont already include storage in their state energy plans.[15]

[15] PV Magazine, "Utilities are increasingly planning for energy storage," December 7, 2017, https://pv-magazine-usa.com/2017/12/07/utilities-are-increasingly-planning-for-energy-storage-w-charts/

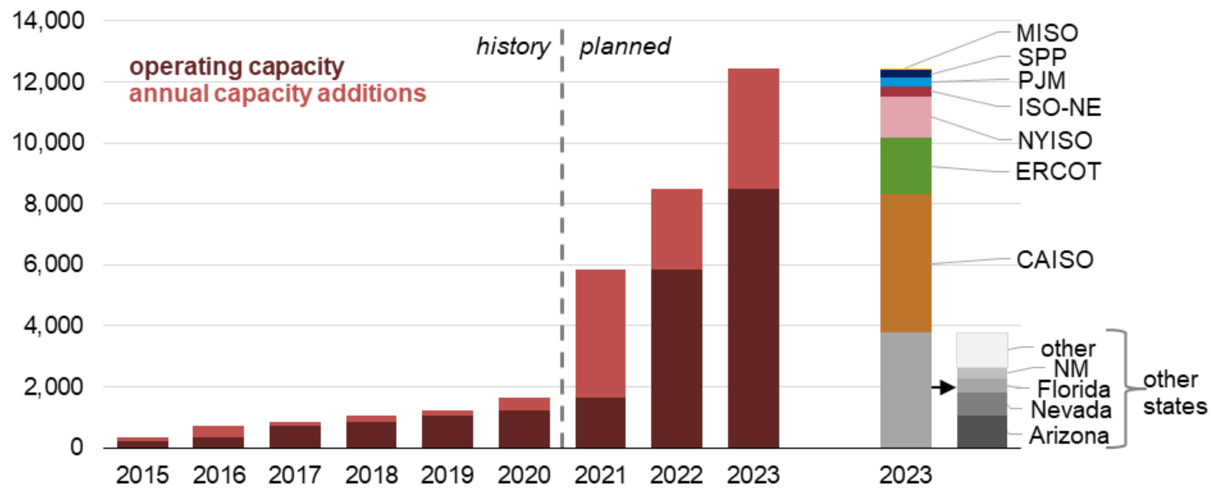
Ongoing Trends

In the near term, we assess future battery capacity installation trends using planned additions reported by project developers, both for standalone battery storage systems and for those co-located with other electricity generating technologies such as solar or wind. For the long term, we provide projections on future battery capacity installations in our *Annual Energy Outlook*.

Near-term planned capacity additions (2020–2023)

As of December 2020, project developers reported to us that they planned to install over 10 gigawatts (GW) of large-scale battery storage power capacity in the United States between 2021 and 2023, which would represent more than a 1000% increase from the 1 GW of operating storage power capacity in 2019. Given the short planning period required to install a storage facility, the reported planned capacity does not necessarily reflect all the possible builds during this period, but it can be used to indicate trends.

Figure 13. Large-scale battery storage cumulative power capacity, 2015–2023
megawatts

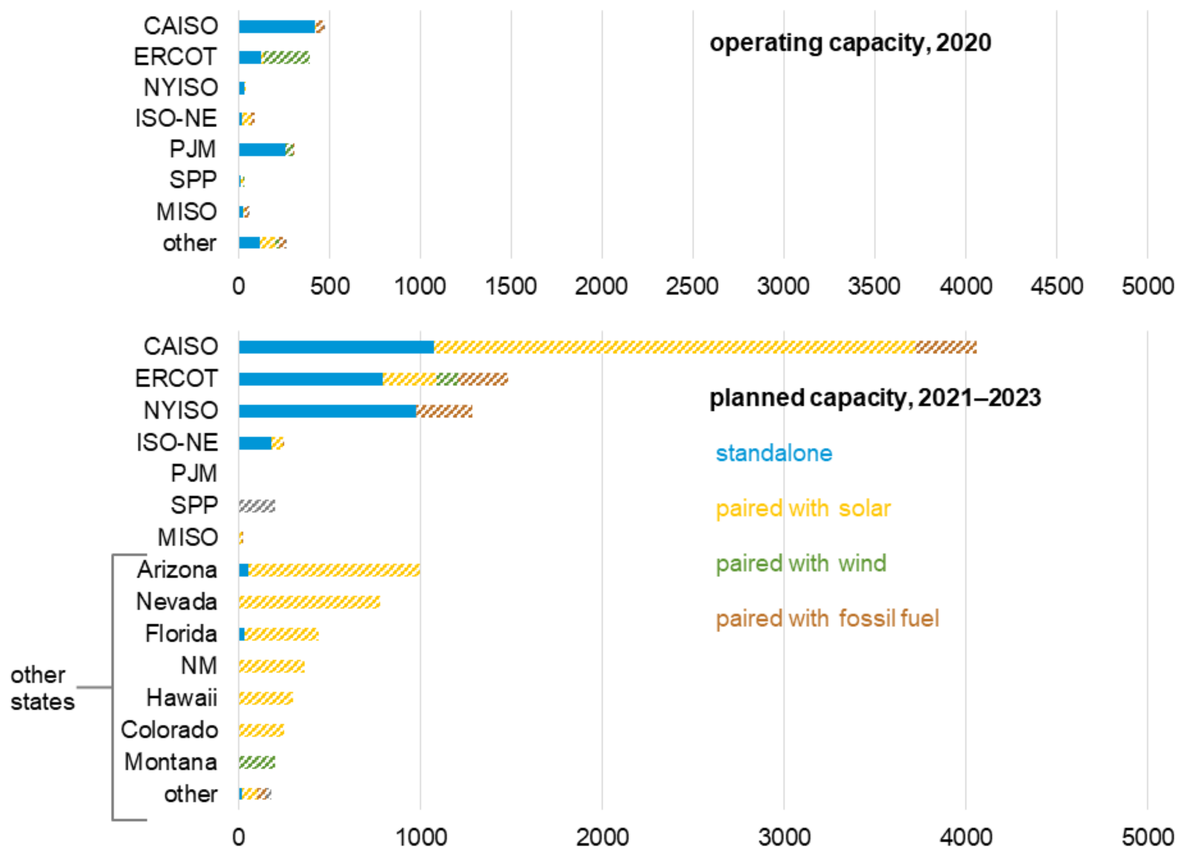


Source: U.S. Energy Information Administration, December 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

California accounted for 40% of battery storage power capacity planned for installation between 2021 and 2023 and reported as of December 2020. These planned additions put California in line to meet its energy storage requirement (Assembly Bill 2514), which is that IOUs install 1,325 MW of energy storage by 2024. New York and Massachusetts also have state requirements for energy storage and companies have planned battery storage projects in the upcoming years. Virginia and New Jersey have requirements, but no companies have reported any planned energy storage builds to us. The Market and Policy Drivers section has information on this topic.

Several states without policy requirements show relatively strong growth in large-scale battery storage in the upcoming years, including Texas, Arizona, Nevada, New Mexico, Florida, Hawaii, Colorado, and Montana. Strong forecasted growth in the Southwest highlights an increase in battery storage in states outside of RTO and ISO regions as well. Lower battery costs, in addition to lessons learned from previous storage deployment in regions with market rules or state requirements, may have led to increased investment of battery storage in the regions new to battery storage.

Figure 14. Large-scale battery storage power capacity by region and co-located generator, operating and planned
megawatts



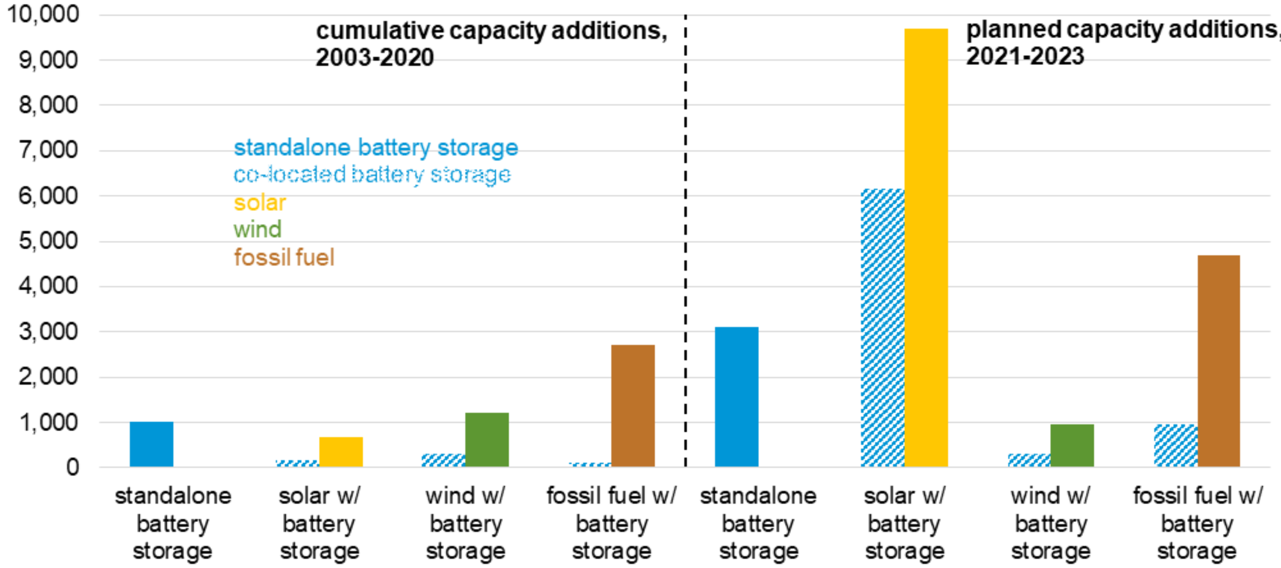
Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

The four RTO and ISO regions of CAISO, ERCOT, NYISO, and ISO-NE will host 97% of the 3,315 MW of standalone battery storage power capacity (not located at a power plant with another generating resource such as solar or wind) planned to come online between 2021 and 2023. During the same period, 2,508 MW of battery storage power capacity outside of the RTO and ISO regions plan to come online, the majority of which will be co-located at plants with solar power generators (Figure 14).

Co-located battery storage projects

Pairing power generating technologies, especially solar, with on-site battery energy storage will be the most common trend over the next few years for deploying energy storage, according to projects announced to come online from 2021 to 2023. Between 2011 and 2020, 92 power plants with co-located battery storage systems came online with a combined power capacity of 628 MW. Data reported for proposed projects show an additional 7,689 MW (100 plants) with co-located battery storage systems are planned to come online between 2021 and 2023, compared with 3,115 MW of standalone storage (59 plants).

Figure 15. U.S. large-scale battery storage power capacity, standalone and co-located
megawatts



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*
Note: Solid yellow, green, and brown bars indicate total generating capacity of solar, wind, and fossil fuels that have battery storage co-located on-site.

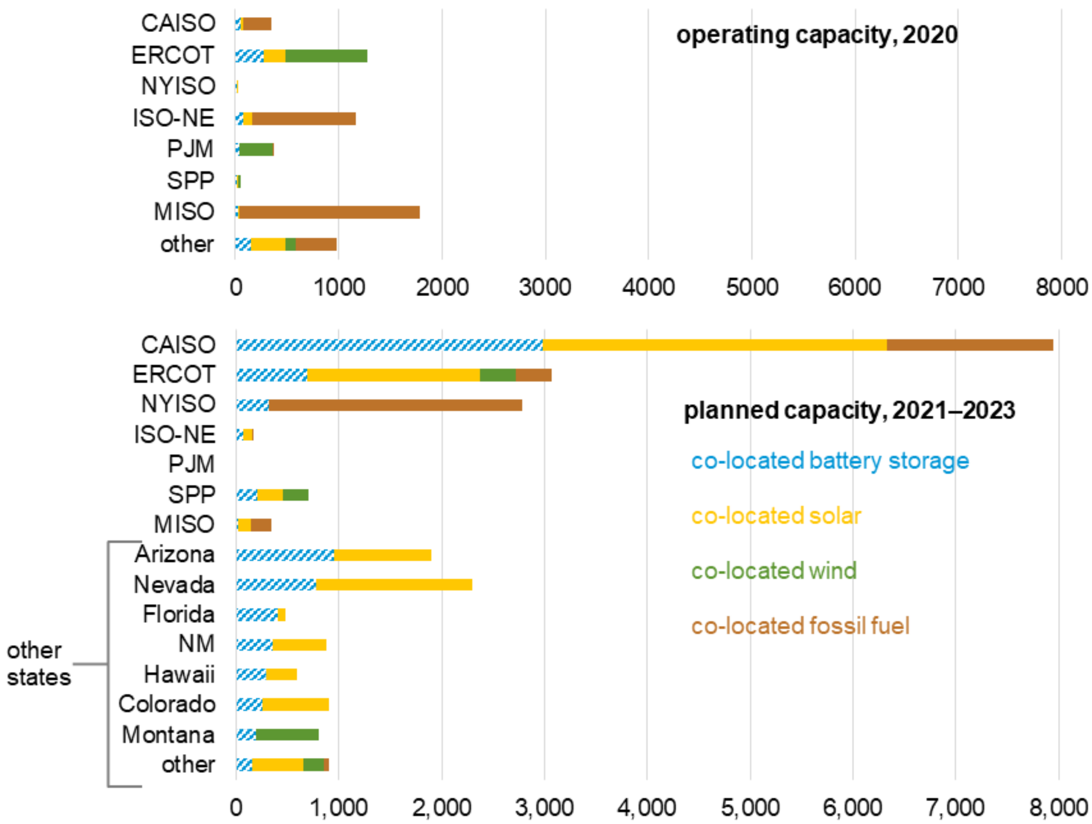
These co-located projects offer an arbitrage application, which allows common on-site infrastructure to store renewable-generated energy produced during periods of low electricity prices and low demand. The infrastructure later supplies stored energy to the grid when both demand and electricity prices are higher. Solar generators can particularly benefit from battery storage because of their relatively predictable generation patterns.

The benefits of pairing battery storage with any generator can also be realized even after the power plant has initially begun operating. As of December 2020, more than 25 power plants had added battery storage systems after their original operation date. Another key advantage of pairing batteries with renewable generators is the ability to take advantage of tax incentives such as the Investment Tax Credit (ITC), which is common in solar projects.

As of December 2020, about 50% of operating co-located battery storage power capacity was paired with wind turbines, and the rest was split between solar and fossil fuel generation (Figure 15). This trend is set to change significantly; 80% of co-located battery storage power capacity that is planned to come online between 2021 and 2023 will be paired with solar. Over 75% of this planned battery storage power capacity co-located with solar comes from the CAISO and the Southwest (Arizona, New Mexico, and Nevada) regions. Nearly 25% of all planned solar photovoltaic (PV) capacity will include co-located storage, compared with under 2% of existing solar PV capacity as of December 2020.

The ratio of battery storage to co-located resource power capacity is scheduled to significantly increase over the next few years. On average, existing co-located projects have a 1:10 battery storage power capacity to co-located generator capacity on a power rating basis, while planned projects have a ratio of 1:2. Projects paired with fossil fuel on-site, such as those in NYISO, MISO, and ISO-NE, have a smaller ratio than those paired with solar, such as those in CAISO, ERCOT, Arizona, and Nevada (Figure 16).

Figure 16. Large-scale co-located battery storage and generator power capacity by region
megawatts



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Long-term projected capacity additions (2020–2050)

In the *Annual Energy Outlook 2021* (AEO2021), we provide projections to 2050 on the supply and demand needs for energy markets in the United States. The AEO2021 Reference case, which assumes implementation of current U.S. laws and policies, projects large-scale battery storage energy capacity to grow to 235 GWh (59 GW power capacity of four-hour duration systems) in 2050 (Figure 17), including 82 GWh (21 GW) of standalone storage and 153 GWh (38 GW) of storage paired with solar PV.[16]

AEO2021 includes alternative scenarios (cases) that examine the sensitivity of results to changes in the costs of renewables and the availability of oil and natural gas resources. All cases have a projected baseline total of 64 GWh of battery storage from historical builds, announced projects, and state policy

[16]AEO projections assume all battery storage capacity defined as co-located with PV will charge solely from its on-site PV generation through a DC coupled system.

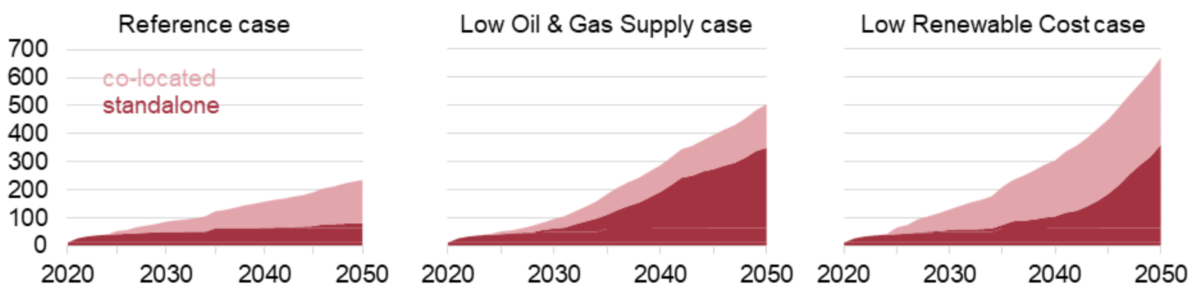
requirements. Our National Energy Modeling System (NEMS) determines how much additional storage to add to a case, based on the input assumptions for each case in order to minimize costs of meeting U.S. power demand through 2050.

In our AEO2021 forecast, co-located storage was added to the model for the first time. Figure 17 shows the distribution of standalone storage versus co-located storage across different AEO2021 cases. When renewable and storage costs were lowered, the model preferred to add additional co-located storage compared with the Reference case. When natural gas prices were raised, the model preferred to add standalone storage.

Figure 17. AEO2021 diurnal energy storage capacity by case

energy capacity

gigawatthours

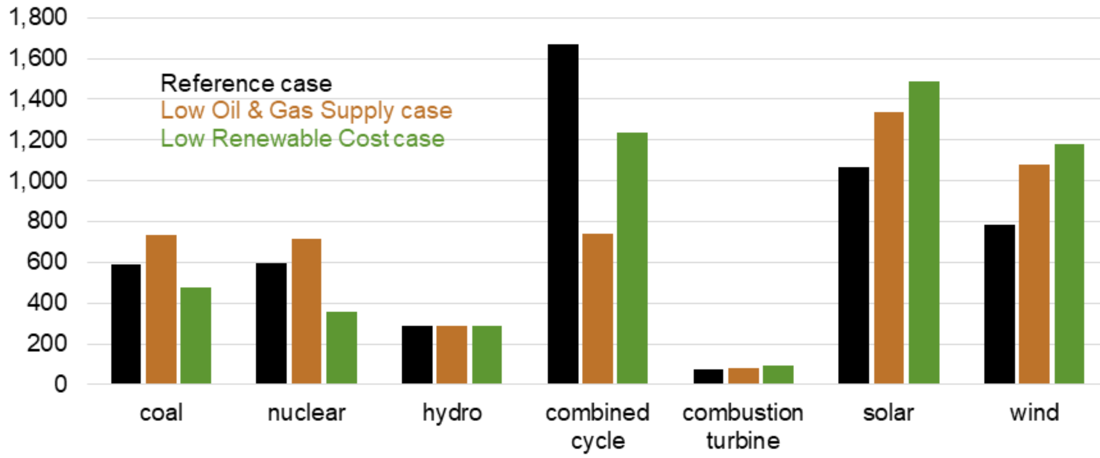


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2021*

In the AEO2021 Low Oil and Gas Supply case, which has higher natural gas prices compared with the Reference case, natural gas combined-cycle generation declines more than in the Reference case and is replaced by coal, nuclear, solar, and wind generation (Figure 18). To support this generation mix, an additional 270 GWh of standalone storage is built compared with the Reference case. Co-located storage deployment is the same as the Reference case, adding to the 504 GWh of battery storage operating in 2050.

In the AEO2021 Low Renewables Cost case, our added assumption of a 40% reduction in renewables and energy storage costs compared with the Reference case results in solar and wind generation replacing coal, nuclear, and natural gas combined-cycle generation in the Low Renewables Cost case. Similar to in the Low Oil and Gas Supply case, about 270 GWh of standalone storage is added in the Low Renewables Cost case compared with the Reference case; however, over 150 GWh of co-located energy storage energy capacity is also added for a total of 670 GWh diurnal storage operating in 2050.

Figure 18. AEO2021 power generation by technology and case, 2050
billion kilowatthours



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2021*

Modeling diurnal (daily cycling) energy storage systems requires high fidelity models that use high temporal and geographic resolution to capture the value of these systems. Because long-term planning models are designed to deliver multi-decade results with many complex interactions, modelers often have to simplify their modeling of energy storage technologies to avoid excessive processing times. One simplification we made that had significant consequences for energy storage technologies in AEO2021 is the temporal resolution of the NEMS model. Our AEO2021 included energy storage as a four-hour battery system that can avoid curtailments of excess solar- and wind-generated electricity, shift energy within a day, and help meet regional reliability requirements. However, modeling sub-hourly markets, such as battery systems participating in frequency response, remains a challenge. As a result, our AEO projections, as shown, do not represent all of the available storage technology options nor the full suite of applications that storage can serve. The list of possible applications for storage is outlined in the Current Applications section of this report.

We have been collaborating with other modeling entities on a multi-model comparison[17] to enhance the representation of technologies that challenge conventional long-term planning model design, such as wind, solar, and energy storage. Battery storage in the AEO will continue to develop as the markets and applications for energy storage evolve.

[17] Cole, Wesley, et al, *Variable Renewable Energy in Long-Term Planning Models: A Multi-Model Perspective*, November 2017, https://www.energy.gov/eere/analysis/downloads/variable-renewable-energy-long-term-planning-models-multi-model-perspective.

Appendix A: Data Concepts

Electrical, thermal, mechanical, and electrochemical technologies can store energy. This report focuses on electrochemical battery storage technologies, but Appendix B: Other Storage Technologies addresses other energy storage technologies.

We measure the capacity of battery storage in two ways: *power capacity* and *energy capacity*. Electrical generating technologies are often characterized in terms of power capacity, which is the maximum amount of power output possible at any instant, measured in this report in standard units of electrical power such as kilowatts (kW), megawatts (MW), or gigawatts (GW). However, batteries can sustain power output for only so long before they need to recharge. The *duration* of a battery is the length of time that a battery storage system can sustain power output at its maximum discharge rate, typically expressed in hours. The energy capacity of the battery storage system is defined as the total amount of energy that can be stored or discharged by the battery storage system and is measured in this report in standard units of electrical energy such as kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

This report explores trends in both large-scale and small-scale battery storage systems. We define large-scale systems as those synchronized to the grid that have a nameplate power capacity (the maximum rated output, usually indicated on a nameplate physically attached to the unit) of 1 MW or greater. Small-scale refers to systems that have less than 1 MW in power capacity and are typically connected to a distribution network (the portion of the electrical system that delivers electricity to end users).[18]

Although we release monthly updates of newly operating and planned large-scale battery storage generators *power capacity* on Form EIA-860M, we only report operational large-scale battery storage energy capacity data on our annual release of Form EIA-860. At the time of writing this report, we had only released energy capacity data through 2019 (the latest release of Form EIA-860). Therefore, any section of this report showing battery storage energy capacity data (the majority of the report) will only include information through the end of 2019. A notable exception is the Ongoing Trends section, which uses data through December 2020 from Form EIA-860M to display information of near-term planned builds power capacity.

[18] Large-scale and small-scale reporting conventions are derived from the reporting requirements of our *Electric Generators Report* (Form EIA-860) survey and our *Electric Power Industry Report* (Form EIA-861) survey. The reporting cut-offs for these surveys are based entirely on the power capacity of the facility.

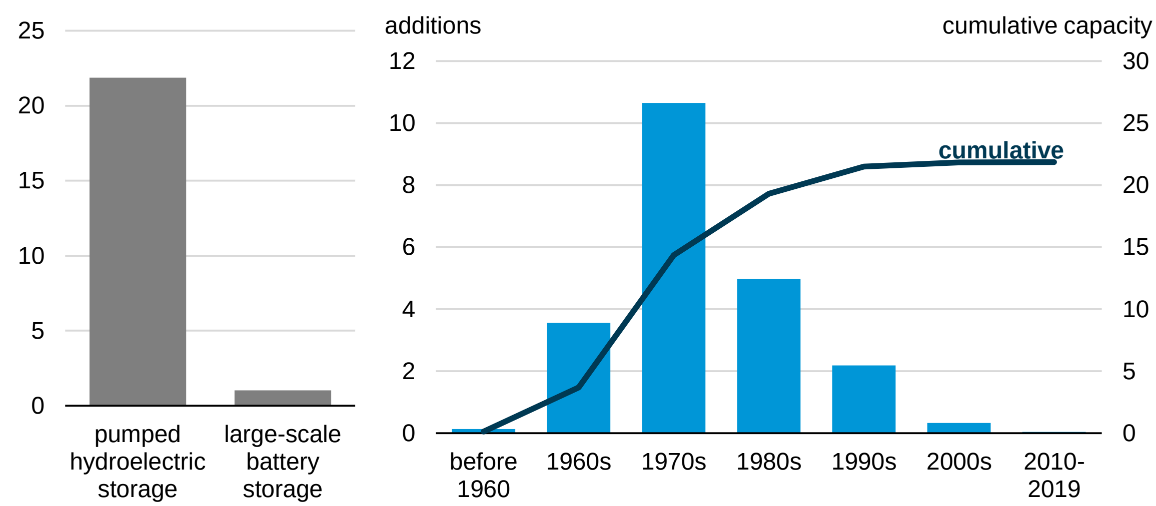
Appendix B: Other Storage Technologies

This report has focused primarily on electrochemical energy (or battery) storage; however, energy storage can use electrical, thermal, and mechanical technologies. Electrical energy storage includes capacitors and superconductors. Thermal storage includes water, ice, molten salts, and ceramics. Mechanical storage includes technologies such as hydroelectric pumped storage, flywheels, and compressed-air energy storage (CAES).

Hydroelectric pumped storage uses electricity to pump water into an elevated reservoir so it can be used to drive a hydroelectric turbine when electricity is needed. Although the United States has significantly more operating hydroelectric pumped storage capacity than battery storage capacity, most pumped storage was installed in the 1970s and early 1980s (Figure 19). California, Virginia, and South Carolina account for most of the existing hydroelectric pumped storage capacity. The largest single facility in the United States was installed in 1985 in Bath County, Virginia, and has a capacity of 3 GW.

Figure 19. Hydroelectric pumped storage capacity (1960–2019)

power capacity
gigawatts



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

Flywheels store energy by using an electric motor to speed up a spinning mass, which can be used later to spin a turbine to produce electricity. To reduce losses, the mass is spinning in a nearly frictionless enclosure. Flywheels are well suited to provide power-oriented applications that require many charge and discharge cycles. Three large-scale flywheel systems are currently operating in the United States: a 20 MW system in New York, a 20 MW system in Pennsylvania, and a 2 MW system in Alaska. One 5 MW standby flywheel system is in Texas.

CAES uses electricity to compress air and store it in an underground cavern. The air is then expanded through a turbine when electricity is needed. The only operable large-scale CAES system in the United States is a 110 MW system that was installed in Alabama in 1991 by PowerSouth Energy Cooperative.

The Apex Bethel Energy Center is a 317 MW CAES system in Texas that is expected to enter operation in late 2023.

Thermal storage systems take excess energy produced during the day to heat salt or other materials that can power a steam turbine. Thermal storage can also be used as a distributed energy resource, for example, by chilling water overnight to use for space cooling during summer days. All existing large-scale thermal energy storage in the United States uses concentrated solar power (CSP) technology. CSP reflects rays from the sun to a receiver to produce steam directly or to heat up alternative fluids, which are used to generate steam through a heat exchanger. The steam is run through a turbine to generate electricity. Some of these alternative heat transfer or storage fluids can store energy for long durations, and they can be used to generate steam and electricity at night using thermal solar energy gathered during the day. Of the eight CSP projects currently operating with a total capacity of 1,775 MW, only Arizona Solar One LLC’s 295 MW Solana Generating Station plant in Arizona and Tonopah Solar Energy LLC’s 110 MW Crescent Dunes Solar Energy plant in Nevada employ thermal storage systems.

Other energy storage technologies are in different phases of development but have yet to have significant deployment in large-scale grid applications.

Appendix C: Installed Power and Energy Capacity of Large-Scale Batteries by State

State	2019 Power capacity (MW)	2019 Energy capacity (MWh)	2020 Power capacity (MW)	2020 Energy capacity (MWh)
AK	45	16	45	16
AL	1	2	1	2
AR	12	26	12	26
AZ	42	93	42	101
CA	253	646	536	930
CO	11	28	9	27
CT	2	6	2	6
FL	19	60	29	100
GA	1	2	2	6
HI	63	183	63	183
IA	1	4	1	5
IL	133	66	133	66
IN	28	32	38	42
LA	1	1	1	1
MA	33	95	71	170
MD	13	6	11	5
ME	17	11	37	31
MI	1	1	1	1
MN	16	38	16	38
MO	2	3	2	3
NC	1	1	10	10
NJ	43	44	43	44
NM	2	2	2	2
NY	33	94	48	131
OH	33	19	33	19
OK	-	-	10	20
OR	5	1	5	1
PA	28	23	28	23
SC	4	4	4	4
SD	1	1	1	1
TX	114	106	223	232
VT	11	33	11	33
WA	6	13	5	9
WV	50	31	50	31

Source: U.S. Energy Information Administration, 2019 and early release of the 2020 Form EIA-860, *Annual Electric Generator Report*

Note: The data for year 2020 in this table are from the early release of the 2020 Form EIA-860, *Annual Electric Generator Report.* The 2019 data from this table use data from the final release of the 2019 Form EIA-860, *Annual Electric Generator Report*. MW = megawatts; MWh = megawatthours.