2020 Grid Energy Storage Technology Cost and Performance Assessment

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Foreword

The Department of Energy's (DOE) Energy Storage Grand Challenge (ESGC) is a comprehensive program to accelerate the development, commercialization, and utilization of next-generation energy storage technologies and sustain American global leadership in energy storage. The ESGC is organized around five cross-cutting pillars (Technology Development, Manufacturing and Supply Chain, Technology Transitions, Policy and Valuation, and Workforce Development) that are critical to achieving the ESGC's 2030 goals. Foundational to these efforts is the need to fully understand the current cost structure of energy storage technologies and to identify the research and development opportunities that can impact further cost reductions. This report represents a first attempt at pursuing that objective by developing a systematic method of categorizing energy storage costs, engaging industry to identify theses various cost elements, and projecting 2030 costs based on each technology's current state of development. This data-driven assessment of the current status of energy storage technologies is essential to track progress toward the goals described in the ESGC and inform the decision-making of a broad range of stakeholders.

Not all energy storage technologies could be addressed in this initial report due to the complexity of the topic. For example, thermal energy storage technologies are very broadly defined and cover a wide range of potential markets, technology readiness levels, and primary energy sources. In other areas, data scarcity necessitates a greater understanding of future applications and emerging science. Future efforts will expand the list of energy storage technologies covered while providing regular updates to the data presented in this report and on https://www.pnnl.gov/ESGC-cost-performance.

Finally, numerous complementary analyses are planned, underway, or completed that will provide a deeper understanding of the specific technologies covered in this report. Many of these have been cited herein.

PNNL and the entire ESGC looks forward to working with industry, external researchers, and other stakeholders to improve our understanding of energy storage cost and performance.

Executive Summary

As growth and evolution of the grid storage industry continues, it becomes increasingly important to examine the various technologies and compare their costs and performance on an equitable basis. As part of the Energy Storage Grand Challenge, Pacific Northwest National Laboratory (PNNL) is leading the development of a detailed cost and performance database for a variety of energy storage technologies that is easily accessible and referenceable for the entire energy stakeholder community. This work is based on previous storage cost and performance research at PNNL funded by the U.S. Department of Energy (DOE) HydroWIRES initiative (Mongird et al., 2019). This work aims to: 1) update cost and performance values and provide current cost ranges; 2) increase fidelity of the individual cost elements comprising a technology; 3) provide cost ranges and estimates for storage cost projections in 2030; and 4) develop an online website to make energy storage cost and performance data easily accessible and updatable for the stakeholder community. This research effort will periodically update tracked performance metrics and cost estimates as the storage industry continues its rapid pace of technological advancement.

Phase 1 of this initiative includes cost and performance metrics for most commercially available energy storage technologies across various energy-to-power ratios:

- Lithium-ion: lithium-ion iron phosphate (LFP) batteries
- Lithium-ion: lithium-ion nickel manganese cobalt (NMC) batteries
- Lead-acid batteries
- Vanadium redox flow batteries (RFBs)
- Compressed-air energy storage (CAES)
- Pumped storage hydro (PSH)
- Hydrogen energy storage system (HESS) (bidirectional)

Additional storage technologies will be incorporated in later phases of this research effort to capture more nascent technologies of interest to DOE and other stakeholders.

In addition to current cost estimates and projections, the research team aimed to develop a cohesive organization framework to organize and aggregate cost components for energy storage systems (ESS). This framework helps eliminate current inconsistencies associated with specific cost categories (e.g., energy storage racks vs. energy storage modules). A framework breaking down cost components and definitions was developed to help provide clarity and enable apples-to-apples comparisons, while using data from different industry participants across multiple technologies. The breakdown of these components and definitions was reviewed by various experts across numerous national laboratories and is provided in the next section.

Cost and performance information was compiled for the defined categories and components based on conversations with vendors and stakeholders, literature, commercial datasets, and real-world storage costs for systems deployed across the US. A range of detailed cost and performance estimates are presented for 2020 and projected out to 2030 for each technology. Current cost estimates provided in

this report reflect the derived point estimate based on available data[1] from the reference sources listed above with estimated ranges for each studied technology. In addition to ESS costs, annualized costs and a levelized cost of energy (LCOE) of each technology are also provided to better compare the complete cost of each ESS over the duration of its usable life. Annualized cost measures the cost to be paid each year to cover all capital and operational expenditures across the usable life of the asset while also accounting for additional financial parameters such as taxes and insurance. The unit energy or power annualized cost metric is derived by dividing the total annualized cost paid each year by either the rated energy to yield $/rated kilowatt-hour (kWh)-year or by rated power to yield $/rated kilowatt (kW)-year, where the kWh and kW are rated energy and power of the ESS, respectively. LCOE, on the other hand, measures the price that a unit of energy output from the storage asset would need to be sold at to cover all expenditures and is derived by dividing the annualized cost paid each year by the annual discharge energy throughput[2] of the system.

For battery energy storage systems (BESS), the analysis was done for systems with rated power of 1, 10, and 100 megawatts (MW), with duration of 2, 4, 6, 8, and 10 hours. For PSH, 100 and 1,000 MW systems at 4- and 10-hour durations were considered. For CAES, in addition to these power and duration levels, 10,000 MW was also considered. For HESS, only 100 MW at a 10-hour duration was evaluated. These power and duration choices for each technology represent the commercially available or representative levels. In addition to costs for each technology for the power and energy levels listed, cost ranges were also estimated for 2020 and 2030.

Key findings from this analysis include the following:

- The dominant grid storage technology, PSH, has a projected cost estimate of $262/kWh for a 100 MW, 10-hour installed system. The most significant cost elements are the reservoir ($76/kWh) and powerhouse ($742/kW).
- Battery grid storage solutions, which have seen significant growth in deployments in the past decade, have projected 2020 costs for fully installed 100 MW, 10-hour battery systems of: lithium-ion LFP ($356/kWh), lead-acid ($356/kWh), lithium-ion NMC ($366/kWh), and vanadium RFB ($399/kWh). For lithium-ion and lead-acid technologies at this scale, the direct current (DC) storage block accounts for nearly 40% of the total installed costs.
- CAES is estimated to be the lowest cost storage technology ($119/kWh) but is highly dependent on siting near naturally occurring caverns that greatly reduces overall project costs. Figures Figure ES-1 and Figure ES-2 show the total installed ESS costs by power capacity, energy duration, and technology for 2020 and 2030.
- Looking at total installed ESS cost for a 4-hour duration, CAES may still provide the lowest cost option, showing the potential impact of low cavern costs. Lithium-ion and lead-acid have

[1] Depending on technology and category, the derived point estimate corresponds to the average after removing outliers (lithium-ion storage block, CAES, PSH), professional judgment (balance of system), single estimate (lead-acid module), or consensus values (power conversion system). Hence, whether the value is average, median, or point estimate depends on the cost category and technology. We have therefore used “derived point estimate” since no single word can describe what the estimates represent. Point estimates within this document refer to the value residing within the upper and lower bounds of the cost range as the most representative cost.

[2] Annual discharge energy throughput is the total energy discharged each year and is simply the product of rated energy, number of cycles per year, and the depth of discharge (DOD), accounting for assumed downtime.

similar costs, with the slightly higher storage block cost for the lithium-ion chemistries compensated by the need for a DC-DC converter for the lead-acid system. RFBs and PSH have the highest capital costs, primarily due to greater impact of stacks and powerhouse, respectively.

- There is a demonstrated effect of power-related scaling for fixed duration, shown in Figure ES-1 and Figure ES-2. This also shows how various technologies switch places in installed cost ranking based on duration, with PSH showing the lower capital cost at 10-hour duration, and higher cost at 4-hour duration. Technologies with independent power and energy costs and low energy costs, like CAES, are only marginally impacted in terms of unit power costs by changes in discharge duration.
- On an annualized cost basis (Figure ES-3), for 10-hour duration systems, CAES and PSH are projected to have the most cost-effective position for 2020 ($29/kWh and $36/kWh, respectively, for a 100 MW system). HESS, in spite of lower capital cost, is nearly tied with redox flow when considered on an annualized basis ($56/kWh and $65/kWh, respectively) due to the higher round-trip efficiency (RTE) of the RFB. While capital cost for lithium-ion LFP was only marginally lower than lithium-ion NMC, its annualized cost is significantly lower ($93/kWh vs. $140/kWh) due to its higher cycle life. For the same reasoning, lithium-ion LFP is higher than redox flow on an annualized cost basis for the 100 MW, 10-hour system, even though its capital cost is lower. Lead-acid batteries, with a capital cost on par with lithium-ion, have an annualized cost nearly three times higher due to their lower cycle life, DOD, and round-trip efficiency.
- Looking at the annualized costs for 100 MW, 4-hour duration systems, CAES, PSH, and RFB systems benefit from much higher cycle life compared to the remaining systems. Lead-acid batteries are significantly impacted by the lower allowable DOD and lower round-trip efficiency at the 4-hour rate in the current modular configuration. Single-cell string configurations may offer significant performance improvements for lead acid. Overall, the annualized cost results show the importance of the performance metrics such as round-trip efficiency, DOD, and cycle life.
- The 2020 installed cost ranges were determined for most technologies using factors of 0.9 and 1.1, the only exception being salt cavern costs, which exhibit a wide range of costs depending on cavern type.
- The 2030 scenario installed cost estimates were obtained by using higher learning rates[3] for lithium-ion and redox flow storage blocks, with the same learning rates used for the rest of the cost categories. For 2030 projections, CAES remains the most cost-effective ESS on a total installed cost basis as well as an annualized cost basis for a 100 MW, 10-hour system. A steep drop in HESS price, as provided by Hunter et al. (In Press), could enable these systems to be competitive with CAES in future scenarios. At the higher learning rates, lithium-ion BESS, may be more cost competitive with PSH by 2030 for 10-hour duration.
- Regarding 2030 installed ESS cost for 100 MW, 4-hour systems, higher learning rate scenarios (e.g., 12-16%) could allow lithium-ion LFP ($299/kWh) and lithium-ion NMC ($300/kWh) to be

[3] Learning rate is percent cost decrease for doubling of cumulative capacity

more competitive with CAES ($291/kWh). Similar learning rates applied to redox flow ($414/kWh) may enable them to have a lower capital cost than PSH ($512/kWh) but still greater than lead-acid technology ($330/kWh).

Major findings from this analysis are shown in Figures Figure ES-1 and Figure ES-2. Values presented show the derived point estimates for total installed ESS cost by technology, power capacity (MW), and energy duration (hr). Figure ES-1 provides estimates for 2020, while Figure ES-2 shows estimates for2030. A figure showing ranges in addition to point estimates for 100 MW, 10-hour systems and 100 MW, 4-hour systems is provided in the Comparative Results section later in this report. Additional cost ranges, while shown in the technology-specific sections of this report, will be provided in comparative figures in the online database for each technology, year, power capacity, and energy duration combination analyzed in this report. Annualized cost and LCOE ranges for 100 MW, 10-hour and 100 MW, 4-hour systems are shown in Figure ES-3 and provided in the Annualized Cost of Storage and Levelized Cost of Energy section.

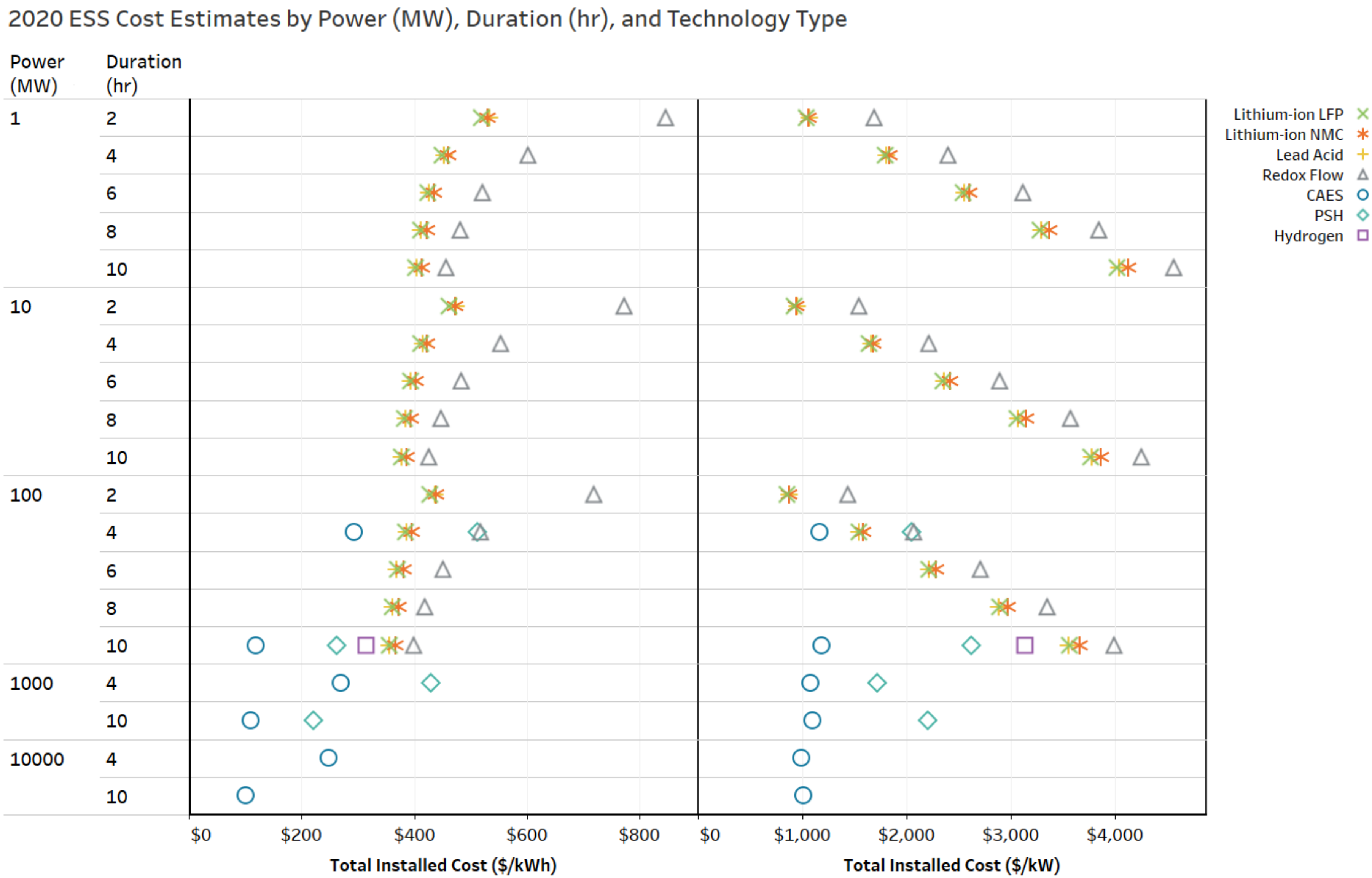

Figure ES-1. Comparison of Total Installed ESS Cost Point Estimates by Technology, 2020 Values

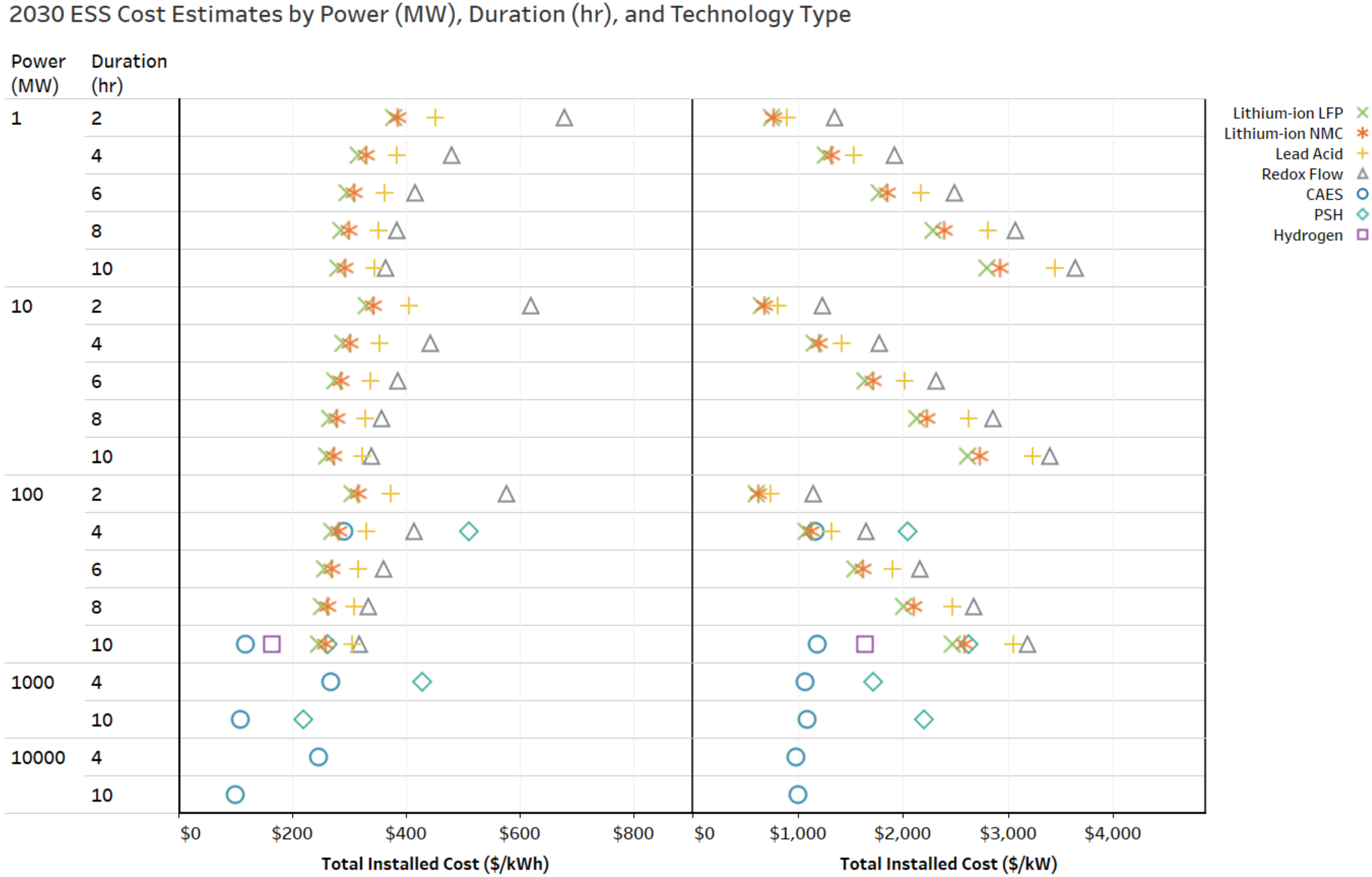

Figure ES-2. Comparison of Total Installed ESS Cost Point Estimates by Technology, 2030 Values

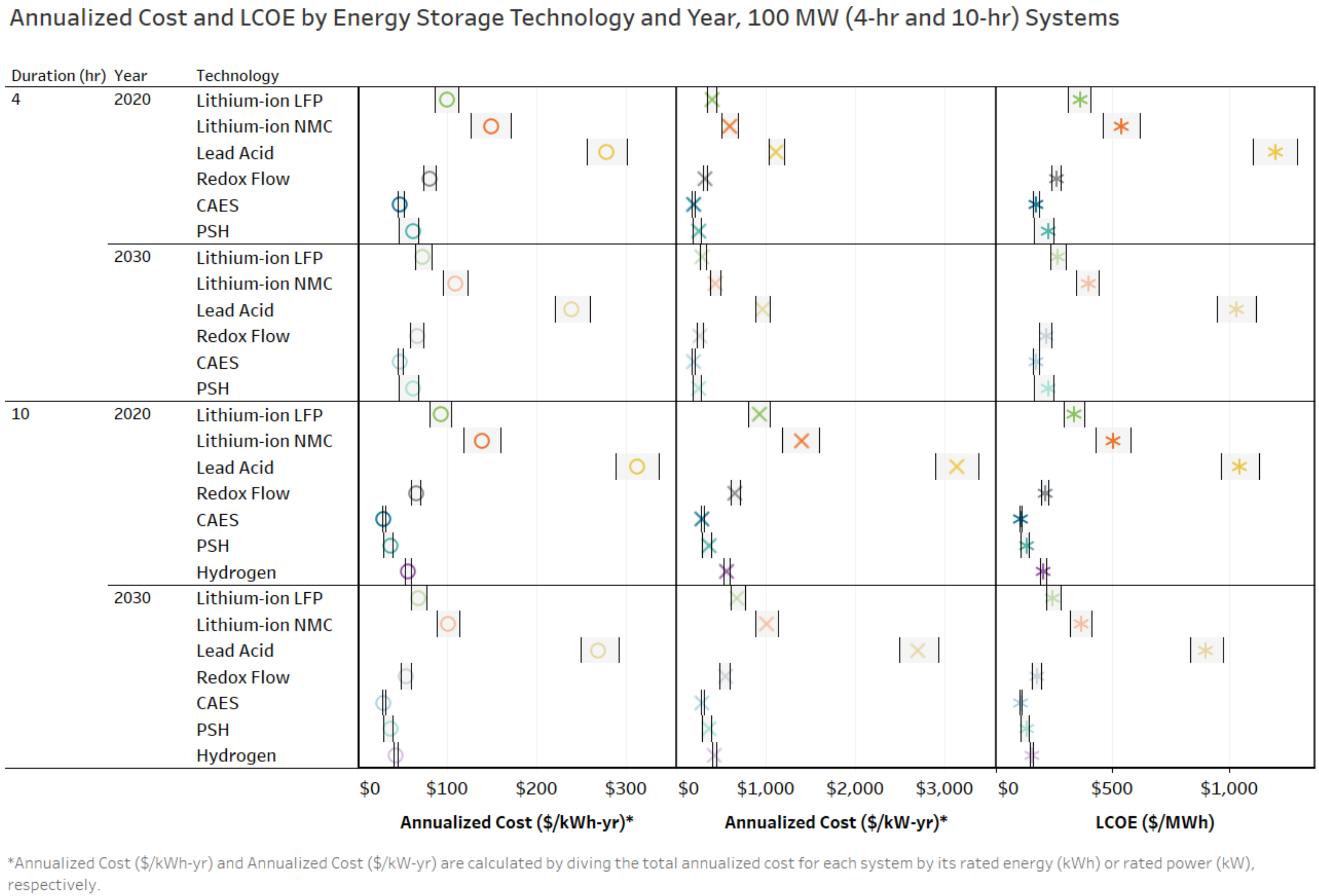

Figure ES-3. Comparison of Annualized Costs and LCOE by Technology, Duration, and Year

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Acronyms

AC	alternating current
Ah	ampere-hour
BESS	battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BMS	battery management system
BOP	balance of plant
BOS	balance of system
C&C	controls & communication
C&I	civil and infrastructure
CAES	compressed-air energy storage
DC	direct current
DOD	depth of discharge
DOE	U.S. Department of Energy
E/P	energy to power
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
ESGC	Energy Storage Grand Challenge
ESS	energy storage system
EV	electric vehicle
GW	gigawatts
HESS	hydrogen energy storage system
hr	hour
HVAC	heating, ventilation, and air conditioning
kW	kilowatt
kWe	kilowatt-electric
kWh	kilowatt-hour
LCOE	levelized cost of energy
LFP	lithium-ion iron phosphate
MW	megawatt
MWh	megawatt-hour
NHA	National Hydropower Association
NMC	nickel manganese cobalt
NRE	non-recurring engineering
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PCS	power conversion system
PEM	polymer electrolyte membrane
PNNL	Pacific Northwest National Laboratory
PSH	pumped storage hydro
PV	photovoltaic
R&D	research & development
RFB	redox flow battery
RTE	round-trip efficiency

SB	storage block
SBOS	storage balance of system
SCADA	sensors, supervisory control, and data acquisition
SM	storage module
SOC	state of charge
USD	U.S. dollars
V	volt
Wh	watt-hour

2020 Grid Energy Storage Cost and Performance Assessment

Introduction

Energy storage and its impact on the grid and transportation sectors have expanded globally in recent years as storage costs continue to fall and new opportunities are defined across a variety of industry sectors and applications. Electrification of the transportation sector is being driven by the availability of lower cost, higher performance lithium-ion batteries for electric vehicles and is being actively tracked and advanced by the U.S. Department of Energy's (DOE's) Energy Efficiency and Renewable Energy Vehicle Technologies Office and other commercial entities. Grid-scale energy storage, however, lacks the stringent power and weight constraints of electric vehicles, enabling a multitude of storage technologies to compete to provide current and emerging grid flexibility services. As growth and evolution of the grid storage industry continues, it becomes increasingly important to examine the various technologies and compare their costs and performance on an equitable basis. As part of the Energy Storage Grand Challenge (ESGC), Pacific Northwest National Laboratory (PNNL) is leading the development of a detailed cost and performance database for a variety of energy storage technologies that is easily accessible and referenceable for the entire energy stakeholder community. This work is based on previous storage cost and performance research at PNNL funded by DOE's HydroWIRES Initiative (Mongird et al., 2019). This work aims to: 1) provide a detailed analysis of the all-in costs for energy storage technologies, from basic storage components to connecting the system to the grid; 2) update and increase fidelity of the individual cost elements comprising a technology; 3) provide cost ranges and estimates for storage cost projections in 2030; and 4) develop an online website to make energy storage cost and performance metrics easily accessible and updatable for the stakeholder community. This research effort will periodically update tracked performance metrics and cost estimates as the storage industry continues its rapid pace of technological advances

The analysis was done for energy storage systems (ESS) across various power levels and energy-to-power (E/P) ratios. The power levels and durations for each technology were selected based on availability. For battery energy storage systems (BESS), the power levels considered were 1, 10, and 100 megawatt (MW), with durations of 2, 4, 6, 8, and 10 hours. For pumped storage hydro (PSH), 100 and 1000 MW systems with 4- and 10-hour durations were considered for comparison with BESS. For compressed-air energy storage (CAES), 10,000 MW plants were also considered. For hydrogen energy storage systems (HESS), as per Hunter et al. (In Press), a 100 MW plant was analyzed, with duration of 10 hours for comparison with other technologies. Phase 1 of this initiative includes cost and performance metrics for the following energy storage technologies across various E/P ratios:

- Lithium-ion: lithium-ion iron phosphate (LFP) batteries
- Lithium-ion: lithium-ion nickel manganese cobalt (NMC) batteries
- Lead-acid batteries
- Vanadium redox flow batteries (RFBs)
- CAES
- PSH
- HESS (bidirectional)

Additional storage technologies will be incorporated in future phases to capture more nascent technologies of interest to DOE and other stakeholders.

In addition to cost estimates and projections, the research team aimed to develop a cohesive framework to organize and aggregate cost components for ESS. This framework helps eliminate current inconsistencies associated with specific cost categories (e.g., energy storage racks vs. energy storage modules). A framework breaking down cost components and definitions was developed to help provide clarity and enable apples-to-apples comparisons while using data from different industry participants across multiple technologies. The breakdown of these components and definitions was reviewed by various experts across numerous national laboratories and is provided in the next section.

Cost and performance information was compiled for the defined categories and components based on conversations with vendors and other stakeholders, literature, commercial datasets, and real-world storage costs for selected storage systems deployed across the US. Detailed cost and performance estimates are presented for 2020 and projected out to 2030 for each technology. Current cost estimates in this report reflect the derived point estimate[4] cost taken from the reference sources listed above. Provided ranges reflect the variability of the sources. In addition to ESS costs, annualized costs and a levelized cost of energy (LCOE) of each technology are also provided to better compare the complete cost of each ESS over the duration of their individual usable lives.

[4] Depending on technology and category, the derived point estimate corresponds to the average after removing outliers (lithium-ion storage block, CAES, PSH), professional judgment (balance of system), single estimate (lead-acid module), or consensus values (power conversion system). Hence, whether the value is average, median, or point estimate depends on the cost category and technology. We have therefore used “derived point estimate” since no single word can describe what the estimates represent. Point estimates within this document refer to the value residing within the upper and lower bounds of the cost range as the most representative cost.

Terminology

Organization and Categorization of Cost Categories

The research team compiled information on various cost components for a range of energy storage technologies and produced a cohesive breakdown of items that is consistent and tractable across multiple storage types. Figure 1 displays the schematic of the proposed cost and performance categorization that resulted from this effort.

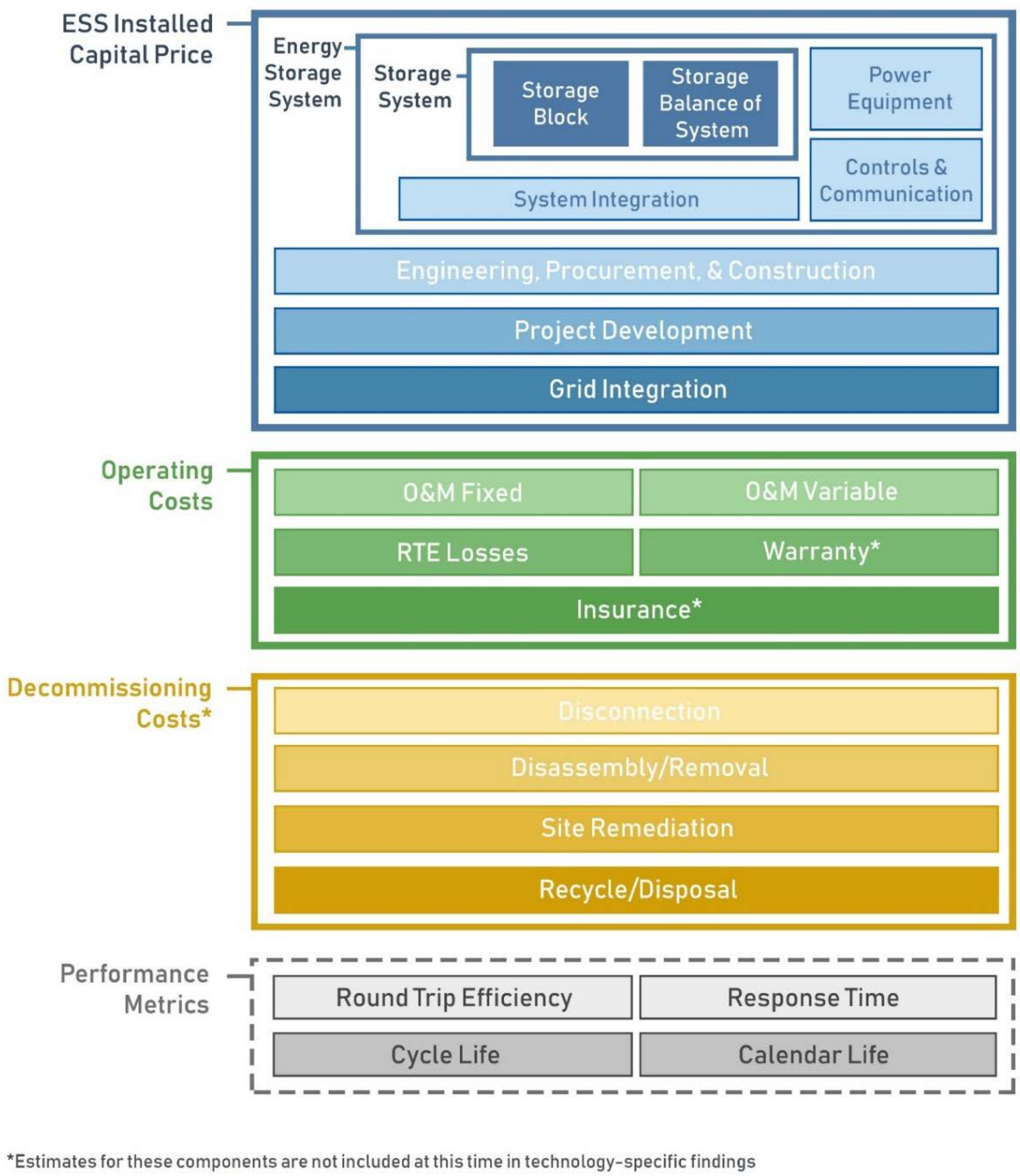

Figure 1. Energy Storage Subsystems and Performance Metrics

It should be noted that this schematic has been designed to capture the most practical level of granularity for the costs of ESS. For BESS, the storage block (SB) and storage balance of system (SBOS) can be used to track impacts of cost reductions to the cell and balance of system (BOS) components. For other technologies, like PSH and CAES plants, these cost elements (SB and SBOS) are aggregated to capture the costs associated with reservoirs and caverns. For PSH/CAES type systems, additional cost elements such as power equipment, controls & communication (C&C), and system/grid integration corresponding to electromechanical equipment/powertrain and powerhouse/power island construction can be aggregated to provide some additional resolution of cost. For HESS, the SB is represented by the electrolyzer, stationary fuel cell, and cavern, while the BOS is represented by compressor, humidifiers, and air and fuel delivery system.

The various cost items for PSH, CAES, and HESS are separately identified later in this report within the estimates for those specific technologies.

Definitions of Cost Components and Performance Metrics

Defining cost component parameters is necessary to effectively break down system costs in a consistent way. Failing to do so leads to inconsistent results and a misunderstanding of the estimates being produced. The list below aims to provide clarity and defines each of the cost items that appear in Figure 1 above. For categories and parameters for non-BESS technologies, information is included in the individual technology sections analysis.

- **Energy Storage System (ESS) Installed Cost Components**

  i) **Storage Block (SB)** ($/kilowatt-hour [kWh]) – this component includes the price for the most basic direct current (DC) storage element in an ESS (e.g., for lithium-ion, this price includes the battery module, rack, and battery management system, and is comparable to an electric vehicle (EV) pack price).

  ii) **Storage - Balance of System (SBOS)** ($/kWh) – includes supporting cost components for the SB with container, cabling, switchgear, flow battery pumps, and heating, ventilation, and air conditioning (HVAC).

  iii) **Storage System** ($/kWh) – this cost is the sum of the SB and SBOS costs and is an appropriate level of granularity for some studies.

  iv) **Power Equipment** ($/kilowatt [kW]) – this component includes bidirectional invertor, DC-DC converter, isolation protection, alternating current (AC) breakers, relays, communication interface, and software. This is the power conversion system for batteries, the powerhouse for PSH, and the power island/powertrain for CAES.

  v) **Controls & Communication (C&C)** ($/kW) – this includes the energy management system for the entire ESS and is responsible for ESS operation. This may also include annual licensing costs for software. The cost is typically represented as a fixed cost scalable with respect to power and independent of duration.

  vi) **System Integration** ($/kWh) - price charged by the system integrator to integrate sub-components of a BESS into a single functional system. Tasks include procurement and shipment to the site of battery modules, racks with cables in place, containers, and power equipment. At the site, the modules and racks are containerized with HVAC and fire suppression installed and integrated with the power equipment to provide a turnkey system.

vii) **Engineering, Procurement, and Construction (EPC)** ($/kWh) – includes non-recurring engineering costs and construction equipment as well as shipping, siting and installation, and commissioning of the ESS. This cost is weighted based on E/P ratio.

viii) **Project Development** ($/kW) – costs are associated with permitting, power purchase agreements, interconnection agreements, site control, and financing.

ix) **Grid Integration** ($/kW) – direct cost associated with connecting the ESS to the grid, including transformer cost, metering, and isolation breakers. For the last component, it could be a single disconnect breaker or a breaker bay for larger systems.

- **Operating Costs**

i) **Fixed Operations & Maintenance (O&M)** ($/kW-year) – includes all costs necessary to keep the storage system operational throughout the duration of its economic life that do not fluctuate based on energy throughput, such as planned maintenance, parts, and labor and benefits for staff. This also includes major overhaul-related maintenance which depends on throughput.

ii) **Basic Variable O&M** ($/megawatt-hour [MWh]) – includes usage impacted costs associated with non-fuel consumables necessary to operate the storage system throughout its economic life.

iii) **Round Trip Efficiency (RTE) Losses** ($/kWh) – Round trip efficiency is simply the ratio of energy discharged to the grid to the energy received from the grid to bring the ESS to the same state of charge. RTE for is < 1 due to losses related to thermal management, electrochemical losses, power conversion losses, powertrain-related losses, energy conversion losses, evaporation, or gas/air leakage losses. This value for RTE losses is estimated through the cost of the additional electricity purchased or fuel required per unit kWh of energy discharged due to the losses described.

iv) **Warranty** ($/kWh) – fees to the equipment provider for manufacturability and performance assurance of designated lifespan.

v) **Insurance** ($/kWh) – insurance fees to hold a policy to cover unknown and/or unexpected risks. The terms of this cost may depend on vendor reputation and financial strength.

- **Decommissioning Costs**

i) **Disconnection** ($/kW) – costs associated with the removal of ESS interconnection from grid.

ii) **Disassembly/removal** ($/kW) – includes deconstruction of ESS and components for disposal or recycle.

iii) **Site Remediation** ($/kW) – costs required to return the ESS site to either a brownfield or greenfield state.

iv) **Recycle/Disposal** ($/kW) – costs associated with separating out recyclable components, shipping to a recycling plant, and recycling the material in the plant.

- **Performance Metrics**
  i) **RTE** (%) –the ratio of net energy that is discharged to the grid (after removing auxiliary load consumption) to the total energy used to charge the ESS (after including the auxiliary load consumption). Note that RTE for any technology depends on operating conditions.
  ii) **Response Time -** (sec or min) – measured as the time for an ESS to go from 0 to 100% rated power.
  iii) **Cycle Life** (#) – the cycle life for an ESS is a function of depth of discharge (DOD) and measures the total number of cycles that an ESS can provide over its life.
  iv) **Calendar Life** (years) – defined as the maximum life of the system regardless of operating conditions. For batteries, calendar life depends on the ambient temperature and state of charge (SOC).
  v) **Duration Corresponding to Cycle Life** (years) – calculated by dividing the cycle life by the number of cycles per year, accounting for downtime.

It should be noted that some of the above items have not been separately estimated in this analysis due to current availability of data. Warranty, insurance, and decommissioning costs are not well documented in the literature and their specific values cannot be parsed out with substantial accuracy at this time. Some of the costs associated with these items may have been partially included in other cost estimates (e.g., part of the cost of decommissioning may be embedded in a capital cost quoted by a vendor), but the capability to estimate them on their own is not available at this time. For this reason, they have been included in Figure 1 above, as they are important components of the overall cost of an ESS, but are not specified in the results discussed later. Estimates for these components will be pursued in later phases of this continued research effort as more information becomes available. Additionally, future efforts will attempt to expand the list of performance characteristics tracked (e.g., PSH generation and discharge response times, mode switching time) to provide a more complete assessment of each technology's capabilities.

Results by Technology

Lithium-ion Batteries

Capital Costs

Cost data for each technology came from a variety of sources including literature and discussions with battery vendors, power conversion systems (PCS) vendors, systems integrators, EPC firms, and project developers as well as estimates produced by energy research firms. Costs were adjusted to 2020 US dollars (USD) using producer price index data for the electric power distribution industry from the U.S. Bureau of Labor Statistics (BLS) (U.S. BLS, 2020). Where value year is not specified, 2020 values should be assumed.

The cost categories developed for this report was socialized with industry stakeholders (Black & Veatch, 2020; Industry Stakeholder, 2020b) and national laboratory experts who provided additional insight and clarity. For example, these discussions yielded insights on the role of the system integrator who receives storage modules, containerizes them, installs HVAC and fire suppression, and integrates with PCS to provide a turnkey system. BESS installation and interconnection with the grid is done through an EPC contract (Industry Stakeholder, 2020b).

For both lithium-ion NMC and LFP chemistries, the SB price was determined based on values for EV battery pack and storage rack, where the storage rack includes the battery pack cost along with cost for racks with cables in which the battery packs are located. To translate from EV to stationary storage context, adjustments related to grid-specific battery product aspects, stationary system integration, and scaling were applied with respect to power and energy capacity (Black & Veatch, 2020; Frith, 2020a; Goldie-Scot, 2019; Wood Mackenzie, 2020b). This overcomes the limitations where discounts or premiums are applied with respect to power capacity, but no adjustments are made for fixed power as the E/P ratio changes (Wood Mackenzie, 2020b). For EV battery pack price data, a 30% premium was added to make the values comparable to stationary systems by accounting for racking costs (additional cabling, labor, etc.) along with advantages related to scaling for EV battery packs vs. stationary energy storage battery racks (Baxter, 2020a; Frith, 2020a, 2020b; Goldie-Scot, 2019). Historical learning rates[5] for the SB range from 14-16%, while SBOS ranges from 8-9%, PCS from 13-14%, and C&C between 11-13% (Goldie-Scot, 2019; Lisa-Hsieha, Panb, Chiang, & Green, 2019; Wood Mackenzie, 2020b).

Typically, technologies are able to sustain higher learning rates during the initial scale-up and manufacture but can experience a 50% reduction as the technology achieves a sufficient state of maturity. For this study, we have based 2030 price projections on a learning rate of 10% which assumes the technology has reached manufacturing maturity. Should the technology continue to achieve the 14-16% learning rates of the past decade, the 2030 cost projections would be significantly lower. For example, at a 14% learning rate, the SB cost is estimated at $78/kWh for a 100 MW, 10h LFP system, with a total installed cost of $216/kWh; the corresponding numbers for NMC are $83/kWh and $222/kWh respectively. A pathway to $200/kWh of installed cost could be achieved by an increase in the learning rates for the SB to 16%, along with marginal increase in learning rates for other components. Learning rates are discussed in greater detail later in this section.

The SBOS for the lithium-ion systems was estimated to be approximately 23-30% of the SB cost found in the literature (Frith, 2020a; Goldie-Scot, 2019; Wood Mackenzie, 2020b). The lower end of this range was used to provide the estimates in this analysis, resulting in higher/more conservative cost projections. Since rack costs were already accounted for in the SB price, the price of a container with cables, contactors, HVAC, and fire suppression is estimated to be 23% for this study with other costs already contained in system integration.

The SBOS cost is determined by both the energy and power capacity of the system. For systems with a higher power-to-energy ratio, higher currents associated with high-power levels require thicker cabling and contactors/fuses with higher current ratings, while systems with higher E/P ratio require more racks/containers with associated rack-to-rack cabling. HVAC sizing is related to power flow, while fire suppression and safety depend more on total energy content with some dependence on power flow. Different weights were assigned for power and energy based on data from Frith (2020a) and the $/kW and $/kWh components of SBOS were derived. Scaling was applied with respect to both energy and power to separately estimate the $/kW and $/kWh components of the SBOS. This approach allows

[5] Learning rate is the percentage drop in price for each doubling of cumulative deployed power or energy capacity.

estimation of SBOS price for any E/P ratio and any power and energy level. A 7% learning rate was applied to SBOS for the 2030 projected cost.

For power equipment, the PCS cost estimate for lithium-ion was found to follow trends in solar photovoltaic (PV) inverter cost after discussions with various experts and representatives from energy research firms (Baxter, 2020a; Ramasamy, 2020; Vartanian, 2020; Wood Mackenzie, 2020a). Solar PV inverter cost, however, typically underestimates PCS cost by approximately 20% (Baxter, 2020a; Vartanian, 2020). Discussions with a PCS vendor indicated a typical cost of $45/kW for utility-scale PCS at low volume (Austin, 2020). Typically, PCS costs do not include additional hardware such as safety disconnects since these are site dependent. PCS price estimate with and without additional hardware was obtained from conversation with multiple vendors (Baxter, 2020a). The number without additional hardware aligned with prices reported by BloombergNEF (Goldie-Scot, 2019) at the 20-50 MW level and Wood Mackenzie (2020b) at the 10 MW level, but was higher at low power levels and lower at higher power levels. This is because the discount applied by the Wood Mackenzie study is steeper at higher power levels and the premium is less at low power levels. A 3% adder was applied for National Electrical Manufacturer Association-rated housing for outdoor installation (Austin, 2020).

C&C includes non-recurring engineering (NRE) costs for the energy management system software and establishing the data pipeline, along with associated hardware costs for computers, controls, sensors, supervisory control and data acquisition (SCADA), and data storage (Baxter, 2020d). While it is difficult to quantify NRE costs, it is assumed that as project MW capacity increases by an order of magnitude, the investment in engineering and design staff time will increase marginally to ensure the asset is being used optimally. This analysis assumes a doubling of staff labor for every 10x increase in MW capacity, based on our inference during stakeholder discussions that labor does not scale linearly with MW capacity level since some of it is fixed and benefits from scale. Since the battery management system (BMS) feeds the detailed DC parameters to the central or master BMS computer and the safety hardware is already incorporated in SBOS costs it is assumed that the computers needed for the energy management system to communicate with the master BMS have significant room for the parts count to decrease with scaling. Similarly, the hardware associated with SCADA transmits the same number of parameters such as market price and grid conditions, while hardware associated with data pipeline has a sunk cost with marginal increases associated with system MW capacity. Hence, these costs are assumed to double with every 10x increase in MW capacity. Since the parts count does not increase proportionately with system capacity, it is assumed that the cost of integration increases only 50% for every 10x increase in power from 1-10 MW and 33% from 10-100 MW.

Grid integration consists of a transformer, busbars, safety breakers, meters, and installation/integration of these components. Transformers receive nominal scaling with respect to power capacity (Baxter, 2020b), while for busbars and safety breakers the disconnects scale marginally with power capacity. As described earlier, for C&C hardware we have assumed the meter cost is expected to double for every 10x increase in power. Assigning nominal labor hours required, installation is found to be 3-7% of the total cost and scales with power capacity.

Estimates for systems integration, EPC, and project development costs were determined from conversations with an energy storage expert (Richard Baxter, Mustang Prairie Energy) and the PNNL research team (Baxter, 2020b). Systems integration assigns a markup to SB, SBOS, and PCS hardware, and applies an estimated profit margin to the entire ESS cost including C&C. The EPC contractor applies markup and profit on all costs including system integration, while the project developer applies markup and profit on all costs including EPC. A combined markup and profit range of 20-30% was provided, for 2020 the markup and profit are set to 20% combined, with this number increasing to 25% in 2030.[6] Hardware is primarily where prices are expected to drop by 2030 (Baxter, 2020b, Pre-publication). To provide an estimated price range for 2020, low and high values were set to 0.9 to 1.1 times the nominal values for each category. Table 1 provides a detailed category cost breakdown for a 10 MW, 40 MWh lithium-ion NMC BESS, with a comprehensive reference list for each category.

The learning rates for the SB range from 14-16%, while the SBOS ranges from 8-9%, PCS from 13-14%, and C&C between 11-13% (Goldie-Scot, 2019; Wood Mackenzie, 2020b). For the SB , this was estimated to be a 10% learning rate. To realize the higher learning rate for the SB, significant advancements must occur including cheaper raw materials, higher energy density and specific energy, manufacturing improvements, high plant utilization, and commoditization of lithium-ion technologies. However, the 2020 price used does not leave much room for improvement (Baxter, 2020b). Additionally, recent safety incidents have triggered significant actions related to adding more safety requirements for BESS. Some of these include new National Fire Protection Association requirements and additional certification testing (such as UL 9540A). NFPA 855 and the International Fire Code require the ESS to be listed to UL 9540. This triggers many safety-related protections and measures for an ESS and is a minimum product safety standard. The overall product standard UL 9540 is critical to ensure all components function safely together. The NFPA 9540a fire test is in its infancy, as demonstrated by the fourth edition in a short period of time. Nevertheless, this test methodology is critical to determine how a particular battery will perform under thermal runaway conditions, identify if a location is safe for installation, and decide how best to protect exposure equipment and structure (Paiss, 2020). These testing and safety requirements are expected to add to the cost of both the SB and SBOS (Baxter, 2020c). Hence, a 10% learning rate is used for DC SB, weighing the positives associated with lower cost materials, higher specific energy, utilization, and superior manufacturing practices against higher costs related to safety. The price range was established using learning rates of 7% and 14%.

For SBOS, a 7% learning rate was applied since most of the components (cables, disconnects, containers, HVAC) have little room for improvement and cost reductions opportunities are limited to more efficient processes to containerize the DC system, coupled with higher safety-related costs. The price range was established using learning rates of 4% and 10%. For power equipment, the learning rates used by the literature are considered to be very steep at 13-14% (Goldie-Scot, 2019; Wood Mackenzie, 2020b). The PCS prices are already quite low for utility-scale systems; therefore, the learning rate is expected to be only 3% over this time period, with some opportunity for price reduction based on novel developments for PCS and leveraging on solar PV developments for the DC-DC converter. Lastly, C&C has an estimated learning rate of 7%, lower than the 13-14% used in aforementioned reports.

[6] Markup and profits as a percentage are expected to grow in order to keep the total markup and profits constant, since hardware costs are expected to drop.

Table 1. Price Breakdown for Various Categories for a Lithium-ion NMC BESS

Cost Category	Nominal size	2020 Price	Content	Additional Notes	Source(s)
Escalation Rate			Provides escalation rate	Costs adjusted to 2020 USD using producer price index data for electric power distribution industry from BLS	U.S. BLS (2020)
Cost Category Validation			System integrators provided agreement on cost categories		Black & Veatch (2020); Industry Stakeholder (2020b)
SB	40 MWh	$185/kWh	SB price obtained from multiple reports and a system integrator	30% premium applied to EV battery pack price available from reports	Baxter (2020a); Frith (2020a); Frith (2020b); Goldie-Scot (2019)
BOS	10 MW	$9.9/kW	BOS cost as percent of SB cost	BOS cost is 23-30% of SB cost; lower end of range used in this study to get $/kW component	Frith (2020a); Goldie-Scot (2019); Wood Mackenzie (2020b)
BOS	60 MWh	$32.7/kWh	BOS cost as percent of SB cost	BOS cost is 23-30% of SB cost; used lower end of range and PNNL approach to get $/kWh component	Frith (2020a); Goldie-Scot (2019); Wood Mackenzie (2020b)
BOS			Additional safety requirements that may impact BOS cost		Baxter (2020c); Paiss (2020)
PCS	10 MW	$73/kW	PCS cost estimate for lithium-ion follows trends in solar PV inverter cost and includes cost for additional equipment such as safety disconnects which are site specific	Cost aligns with numbers provided by PCS vendor for utility scale	Austin (2020); Baxter (2020a); Goldie-Scot (2019); Ramasamy (2020); Vartanian (2020); Wood Mackenzie (2020a)
C&C	10 MW	$7.8/kW	Source provides estimate for C&C	This study approach for scaling across various power levels	Baxter (2020d)
System Integration		10% markup on hardware and 10% profit on sum of above rows	System integration cost as percent of line items above		Baxter (2020b)
EPC		15% markup and 5% profit on sum of above rows	EPC cost as percent of line items above		Baxter (2020b)

Cost Category	Nominal size	2020 Price	Content	Additional Notes	Source(s)
EPC tasks			System integrator indicates BESS installation and interconnection with grid is done through EPC contract		Industry Stakeholder (2020b)
Project Development		5% markup and 15% profit on sum of above rows	Project development cost as percent of line items above		Baxter (2020b)
Grid Integration	10,000 kW	$24.9/kW	Source provides estimate for grid integration	Study approach for scaling across various power levels	Baxter (2020b)
Fixed O&M			Source started research projects to determine O&M		Minear (2020)
Fixed O&M			Provided O&M range		Aquino, Zuelch, and Koss (2017)
Fixed O&M			Provided O&M cost for lead-acid battery system		Raiford (2020a)
Fixed O&M			Provided O&M cost as percent of capital cost for zinc-bromine flow battery system		Sapien (2020)
Basic variable O&M			Provided variable basic O&M cost		Aquino et al. (2017); Black & Veatch (2012); Hunter et al. (In Press); Mongird et al. (2019); Raiford (2020a); S. Wright (2012)
Performance metrics			Cycle life as a function of DOD		DiOrio, Dobos, and Janzou (2015); Greenspon (2017)
Performance metrics			RTE		Aquino et al. (2017); DiOrio et al. (2015); Greenspon (2017); EASE (2016)
Learning rates			Learning rates for various cost categories		Goldie-Scot (2019); Wood Mackenzie (2020b)
Learning rates				2020 pricing structures may leave less room for aggressive learning rates	Baxter (2020b)

The hardware related items such as meters, computers, and sensors are not expected to drop significantly in price, leaving only the NRE costs for software development for cost reduction. The learning rates used were the same as for SBOS. A nominal 4% learning rate was assigned to system integration, EPC, project development, and grid integration, with 6% and 2% to establish the range. Table 2 shows the learning rates used to establish price ranges for year 2030.

Table 2. Learning Rates Used to Establish Lithium-ion 2030 Capital Cost and Fixed O&M Ranges

Component	Low Price	Point Estimate Price	High Price
DC SB ($/kWh)	14%	10%	7%
DC SBOS ($/kWh)	10%	7%	4%
DC-DC converter ($/kW)	7%	3%	2%
PCS ($/kW)	7%	3%	2%
C&C ($/kW)	10%	7%	4%
System integration ($/kWh)	6%	4%	2%
EPC ($/kWh)	6%	4%	2%
Project Development ($/kWh)	6%	4%	2%
Grid Integration ($/kW)	6%	4%	2%
Fixed O&M ($/kW-year)	6%	4%	2%

Regarding cost differences between LFP and NMC systems, while LFP batteries use cheaper cathode raw materials, their lower specific ampere-hour (Ah) and watt-hour (Wh) capacity require more passive elements for cell manufacture per unit Wh capacity. This results in a marginal decrease in the cell and module cost. Due to the need for more racks and associated cabling, the DC SB cost difference between LFP and NMC for stationary systems is lower than for EV packs. Additionally, due to the need for more containers, inter-rack cables, fuses to accommodate the larger footprint of LFP DC system relative to NMC, and the DC system cost difference between the two chemistries is negligible.

O&M Costs

O&M cost data for battery systems is currently limited, although multiple groups have recently started research projects in this area (Minear, 2020).[7] Aquino et al. (2017) estimated that the fixed O&M cost lithium-ion to be in the range of $7-14/kW-year. A fixed O&M cost for lead-acid batteries provided by Raiford (2020a) was found to be $8/kW-year, which corresponds to 0.86% of the direct capital cost for a 4-hour system. Zinc-bromine batteries, on the other hand, which require significant maintenance in terms of periodic full discharges to mitigate zinc dendrite nucleation and growth, have a fixed O&M cost of 2% of capital cost (Sapien, 2020). While there are limited data availability for fixed O&M details for other battery technologies, for this study the fixed O&M was set to 0.43% of direct capital cost, about 25% of the zinc-bromine battery system. The actual value, specific to each technology, will depend on the capital cost; hence, the reported fixed O&M varies with power capacity and E/P ratio. Note that while labor-related costs are not expected to change with duty cycles, deep repair and refurbishment costs may depend on how the BESS is operated. The fixed O&M range for the year 2020 was set to 0.9 to 1.1 times the nominal values for each category. The fixed O&M learning rate was in the 2-6% range.

[7] EPRI Energy Storage Integration Council is working toward releasing information on O&M costs that will include a range of costs for service agreements, slated for publication in 2020.

For basic variable O&M, there is inconsistent nomenclature regarding what this category consists of. Due to the lack of detailed justification regarding what comprises basic variable O&M for each technology, this work sets the basic variable O&M to be $0.5125/MWh and is derived here based on the average across various technologies (Table 3). Depending on duty cycle, the energy throughput will vary, thus affecting total basic variable O&M costs.

Table 3. Variable O&M Estimate Calculation for Energy Storage Systems

Reference(s)	Technology	Value ($/MWh)
Raiford (2020a)	Lead Acid	1
Hunter et al. (In Press)	Hydrogen	0.5
Aquino et al. (2017); S. Wright (2012); Black & Veatch (2012)	CAES	0.25
Mongird et al. (2019)	Non-specific	0.30
	Average	**0.5125**

Performance Metrics

A range of cycle estimates was provided throughout the literature for lithium-ion of up to nearly 6,000 cycles with lower DOD (DiOrio et al., 2015; Greenspon, 2017). The analysis conducted here estimates that lithium-ion LFP can typically provide 2,000 cycles at 80% DOD, while NMC systems provide 1,200 cycles for the same DOD, due to positive electrode dissolution and associated increased capacity loss at the negative electrode. In the next phase, more detailed cycle life data for LFP and NMC chemistries will be obtained. For example, based on 70% capacity at end of life, lithium-ion batteries have demonstrated a cycle life of approximately 8,000 cycles at 80% DOD (R. B. Wright & Motloch, 2001).

The calendar life of lithium-ion batteries ranges with some stating > 5 years or as high as 20 years (R. B. Wright & Motloch, 2001) and others in the range of 5-15 years (Dubarry, Qin, & Brooker, 2018). This report estimates a 10-year calendar life at 80% DOD, also assuming 5% of that time will also be allocated to downtime. A cycle life of 2,000 cycles for LFP and 1,200 for NMC is assumed with a 5% increase in total cycles each by 2030.

With respect to RTE, the literature typically provided estimates between 77-98% (Aquino et al., 2017; DiOrio et al., 2015; EASE, 2016; Greenspon, 2017). PNNL testing of grid-scale batteries in the past yielded an AC-AC RTE of 83–87% over 1.5 years of testing, while RTE for a battery > 5 years old was only 81%. A system RTE of 86% was used in this work.

Based on an extensive literature review and testing of lithium-ion systems conducted by the research team, the response times for the DC portion of the ESS contained in this report were assumed to be < 1 second. However, it has been shown that inverter response times can range from approximately 1-4 seconds to reach the rated power which affects the estimated overall response time of the system. Therefore, the response time assumed here for lithium-ion systems is assumed to be between 1-4 seconds.

Performance metrics are expected to remain relatively stable through 2030 for both lithium-ion chemistries. A marginal increase in RTE is assumed at 88%, along with a 5% increase in cycle life at 80% DOD for both chemistries.

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and the RTE. The cost due to loss is determined to be $0.005/kWh for 2020 and $0.004/kWh for 2030.

Results

Figure 2 provides cost component estimates for 1, 10, and 100 MW lithium-ion LFP and NMC systems with a 4-hour duration for 2020 and 2030. Additional estimates for 2-, 6-, 8-, and 10-hour systems at the three power capacities listed above are included in the appendix as well as in the ESGC cost and performance tracking database (https://www.pnnl.gov/ESGC-cost-performance).

Category	Parameter	Units	Lithium-ion LFP						Lithium-ion NMC					
			1 MW / 4 hr		10 MW / 4 hr		100 MW / 4 hr		1 MW / 4 hr		10 MW / 4 hr		100 MW / 4 hr	
			2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[164 - 200] 182	[87 - 128] 109	[156 - 191] 174	[83 - 122] 104	[149 - 182] 165	[79 - 116] 99	[175 - 213] 194	[93 - 136] 116	[166 - 203] 185	[89 - 129] 111	[158 - 194] 176	[84 - 123] 106
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[38 - 47] 42	[25 - 35] 30	[36 - 44] 40	[24 - 33] 28	[35 - 42] 38	[23 - 32] 27	[30 - 45] 37	[22 - 30] 26	[29 - 43] 35	[21 - 29] 25	[27 - 41] 34	[20 - 28] 24
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[76 - 93] 85	[59 - 77] 73	[66 - 80] 73	[51 - 66] 63	[57 - 69] 63	[44 - 57] 54	[76 - 93] 85	[59 - 77] 73	[66 - 80] 73	[51 - 66] 63	[57 - 69] 63	[44 - 57] 54
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[36 - 44] 40	[24 - 33] 28	[7 - 9] 8	[5 - 6] 5	[1 - 2] 2	[1 - 1] 1	[36 - 44] 40	[24 - 33] 28	[7 - 9] 8	[5 - 6] 5	[1 - 2] 2	[1 - 1] 1
ESS Installed Cost / Energy Storage System	System Integration	$/kWh	[37 - 56] 50	[37 - 46] 36	[35 - 52] 47	[35 - 42] 33	[33 - 49] 44	[33 - 40] 31	[38 - 58] 51	[38 - 47] 42	[36 - 54] 48	[35 - 44] 39	[34 - 51] 45	[33 - 41] 37
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[48 - 74] 61	[45 - 56] 50	[44 - 68] 56	[42 - 51] 46	[42 - 64] 53	[39 - 48] 43	[49 - 77] 63	[46 - 57] 51	[45 - 71] 58	[43 - 52] 47	[42 - 67] 54	[40 - 49] 44
ESS Installed Cost	Project Development	$/kWh	[57 - 90] 73	[54 - 67] 60	[52 - 83] 67	[50 - 61] 55	[49 - 78] 63	[47 - 58] 52	[58 - 94] 75	[56 - 68] 62	[53 - 87] 69	[51 - 63] 57	[50 - 81] 65	[48 - 59] 53
ESS Installed Cost	Grid Integration	$/kW	[28 - 34] 31	[23 - 28] 25	[22 - 27] 25	[18 - 23] 20	[18 - 22] 20	[15 - 18] 16	[28 - 34] 31	[23 - 28] 25	[22 - 27] 25	[18 - 23] 20	[18 - 22] 20	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[1517 - 2040] $1,793**	**[1105 - 1460] $1,266**	**[1389 - 1868] $1,643**	**[1008 - 1334] $1,156**	**[1302 - 1752] $1,541**	**[944 - 1249] $1,081**	**[1537 - 2122] $1,838**	**[923 - 1239] $1,089**	**[1408 - 1947] $1,685**	**[1031 - 1365] $1,204**	**[1320 - 1827] $1,581**	**[965 - 1279] $1,128**
	Total ESS Installed Cost*	**$/kWh**	**[379 - 510] $448**	**[276 - 365] $317**	**[347 - 467] $411**	**[252 - 333] $289**	**[326 - 438] $385**	**[236 - 312] $270**	**[384 - 531] $459**	**[231 - 310] $272**	**[352 - 487] $421**	**[258 - 341] $301**	**[330 - 457] $395**	**[241 - 320] $282**
Operating Costs	Fixed O&M	$/kW-yr	[3.96 - 4.84] 4.40	[3.26 - 4] 3.61	[3.63 - 4.43] 4.03	[2.98 - 3.67] 3.30	[3.41 - 4.16] 3.79	[2.8 - 3.44] 3.10	[4.06 - 4.96] 4.51	[3.34 - 4.1] 3.70	[3.72 - 4.55] 4.13	[3.06 - 3.76] 3.39	[3.5 - 4.27] 3.89	[2.88 - 3.54] 3.19
Operating Costs	Variable O&M	$/MWh	0.5125		0.5125		0.5125		0.5125		0.5125		0.5125	
Operating Costs	System RTE Losses ($/kWh)	$/kWh	0.005	0.004	0.005	0.004	0.005	0.004	0.005	0.004	0.005	0.004	0.005	0.004
Performance Metrics	Round Trip Efficiency	%	86%	88%	86%	88%	86%	88%	86%	88%	86%	88%	86%	88%
Performance Metrics	Response Time	sec	1-4		1-4		1-4		1-4		1-4		1-4	
Performance Metrics	Cycle Life	#	2,000	2,100	2,000	2,100	2,000	2,100	1,200	1,260	1,200	1,260	1,200	1,260
Performance Metrics	Calendar Life	yrs	10		10		10		10		10		10	
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	5.77	6.06	5.77	6.06	5.77	6.06	3.46	3.63	3.46	3.63	3.46	3.63

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Figure 2. Lithium-ion LFP and NMC Cost and Performance Estimates by Power Capacity for 2020 and 2030

R&D Trends in Lithium-ion Batteries

Price reduction for lithium-ion batteries is enabled by a combination of inexpensive raw material prices, higher energy density, efficient manufacturing and efficiencies of scale (Frith, 2020c). Rapid developments in lithium-ion battery research and development (R&D) are enabled by collaboration between EV manufacturers and R&D organizations (Industry Stakeholder, 2020a). Research areas include improving material properties, cell design, manufacturing improvements and safety. R&D trends in various areas are captured below.

Cathode

There is an R&D trend to reduce cobalt content in lithium-ion batteries because of expected resource constraints and humanitarian issues in its extraction in the world's major production region (Lefebvre, 2020), and due to increasing nickel content (Industry Stakeholder, 2020a). Shifting toward nickel-heavy batteries could generate new hurdles as batteries using more nickel are less stable and require more advanced material engineering (Industry Stakeholder, 2020a). Tesla has already announced plans to eliminate cobalt in its cells (Lyons, 2020).

The stability of the cathode and electrolyte at high voltages is an important area of research (Lefebvre, 2020). Layered cathodes destabilize at > 4.2 volt (V) vs. lithium (Dahn, 2020; Lefebvre, 2020; H. Li et al., 2019). The presence of cobalt helps to stabilize the layered structure, while the inclusion of manganese and aluminum provides chemical stability (Industry Stakeholder, 2020a; Lefebvre, 2020). However, Dahn (2020) showed that 5% cobalt did not suppress phase distortion, while aluminum, manganese, and magnesium did. However, these dopants reduce initial capacity by 10-15%. Avoiding this capacity reduction may be a promising area of research.

Toward the goal of removing dependence on cobalt and nickel, cation-disordered rock salt transition metal oxides, a new class of materials,[8] is being actively researched. This class of promising compounds opens up a wide mix of transition metal choices and some offer notably higher capacities than incumbent layer oxides, although they do possess challenges that require further study (Cle´ment, Lun, & Ceder, 2020; Lefebvre, 2020).

Cost reduction and an increase in specific energy may also be facilitated by using stabilized lithium-metal powder or other methods that introduce extra lithium inventory without complicating the requirements for the manufacturing environment. Since the cathode usually is the source of lithium inventory in the cell, less cathode material may be needed, reducing cost and weight (Industry Stakeholder, 2020a). Such methods may also shorten the cell formation duration, which is a cost-saving opportunity.

Anode

The negative electrode comprises a lower percentage of cell cost at approximately 10% (Schrooten, 2020a). The use of synthetic graphite in lithium-ion batteries has a higher coulombic efficiency and better rate capability (Schrooten, 2020a, 2020b). Use of natural graphite has the potential to decrease cost further. Using silicon instead of graphite anodes is being explored under a collaboration between Daimler and Sila Nanotechnologies (Industry Stakeholder, 2020a; Sila Nanotechnologies Inc., 2020). Its engineered design gives with volume buffering to accommodate expansion (Lefebvre, 2020) and allows

[8] Not layered.

easy drop-in integration into conventional manufacturing processes (Lefebvre, 2020). However, material fatigue due to expansion and contraction is still expected to be an issue.

Electrolyte

As discussed earlier in the cathode section, electrolytes that are stable across a wide operating range are being explored. Developers are also trying to move away from $LiPF_6$ salt to LiFSI salt in spite of their lower conductivity and higher viscosity (Lefebvre, 2020) due to the latter's superior stability in the presence of water, thus improving cycle life by avoiding electrolyte and cathode degradation (Choi, 2020; Kaschmitter, 2020).

Cell Design and DC Storage Module Architecture

The choice of cell size and format can determine cost, performance, and safety. Small cells are better for heat dissipation, while increasing parts count and hence module assembly cost. Tesla recently switched from 18650 (18 mm diameter, 65 mm height) cells to 21700 (21 mm diameter, 70 mm height) cells and subsequently to 4680 (46 mm diameter, 80 mm height) cells (Lyons, 2020) in an attempt to balance heat dissipation vs. parts count and energy density. The series/parallel configuration of cells within a module can further affect module cost; connecting cells in series followed by connecting the strings in parallel requires monitoring all the individual cell voltages, while connecting the cells in parallel reduces the monitoring points substantially.

Separators

There are multiple vendors for separators that keep price competitive. Ceramic coatings on various cell components are often used to improve safety of high-energy cells but may add additional costs to the cell (Industry Stakeholder, 2020a). Specifically, ceramic coating on one or both sides of the separator is used to improve safety (Industry Stakeholder, 2020a; Lefebvre, 2020). Development of separators with proven safety is expected to be an area of continued R&D.

Manufacturing

Cathodes and anodes are made using a slurry method and need expensive solvents such as n-methyl-pyrrolidone, which is difficult to recover (Industry Stakeholder, 2020a), making dry coating processes attractive. Tesla bought Maxwell Technologies (Maxwell Technologies Inc., 2020) to acquire their dry coating process and announced a tables design that is expected to speed up manufacturing while improving performance (Lyons, 2020). Innovations in tab-to-cell connection can further improve cell reliability (Boyle, 2020).

Part of cell cost that may not be fully accounted for is formation, which is expensive. Right now, each battery manufacturer has their own formation process that involves, as an example, waiting for a prolonged time at certain temperatures following formation (Industry Stakeholder, 2020a). Streamlining of formation procedure can further reduce costs.

Recycling

It is unclear if waste treatment costs for used lithium-ion cells are incorporated in the price. In this study we have not factored in decommissioning costs, which can run quite high to ship hazardous material for suitable disposal.

Recycling reduces demand for raw materials, reduces imports, reduces material processing carbon footprint when recycling is done near cell manufacturing sites, and avoids waste treatment costs (De-Leon, 2020). Globally, there are 38 companies that recycle lithium-ion cells, with 16 providing automation equipment (De-Leon, 2020); however, these are mainly for recovery of copper, aluminum, and cathode materials. Since only 6% of lithium-ion cells are being recycled, there is significant room for improvement in this area. Beyond cost, material processing conditions and cell design affect chemical, structural, and electrical stability. Modification of processes to use recycled materials is expected to be a key to more environmentally sustainable lithium-ion cell manufacturing.

While 54% of graphite used is synthetic, 39% of all anodes are natural graphite (Kaschmitter, 2020). Synthetic graphite uses dirty feedstock from refineries, with a high carbon footprint, so recycling is expected to gain more prominence as focus shifts to making the manufacturing process greener (Deveney, 2020).

Lithium-Metal Batteries

Lithium-metal batteries have a higher specific energy and energy density. In the late 20th century, fire and explosions associated with lithium-metal telecommunications batteries halted work in this area (Lefebvre, 2020). Solid-state battery R&D is currently tailored toward developing lithium-metal batteries. One hurdle in its development is that high-voltage cathodes also require electrolytes with a stable voltage window but not all solid-state electrolytes are stable at high voltage (Lefebvre, 2020). Solid-state electrolytes work well with graphite and lithium-metal anodes in principle, but manufacturing will need to be reinvented to make it a plausible option.

Lead-Acid Batteries

Capital Cost

While lead-acid battery technology is considered mature, recent industry R&D has focused on improving the performance required for grid-scale applications. Lead-acid battery life is highly dependent on DOD where typically the battery is cycled between 50% and 80%. The reason the battery must operate within this stated range is that the Ah and Wh capacity for most lead-acid batteries are rated at the 50- to 100-hour rate, hence cycling them at 100% DOD would require a discharge duration of 50 to 100 hours. However, only about 50% of the energy capacity is available at the 1-hour rate and 80% of the energy capacity is available at the 10-hour rate.

Lead-acid batteries also do not typically operate at low SOC, and the SOC is generally prevented from going below 20% when an extended battery life is desired. Table 4 shows the energy capacity in Wh and the corresponding DOD obtained from a 12 V, 200 Ah (2,400 Wh) battery at various discharge durations (C&D Technologies Inc., Undated). A separate calculation to find the adjusted DOD limitations accounting for battery degradation of 5% is provided as a separate column in Table 4. The number of cycles at each adjusted DOD is obtained from Figure 3 using information provided from conversation with a lead-acid battery expert (Raiford, 2020a). Note that since single-cell cycle life was much higher than for assembled modules or packs, this study uses cycle life data obtained from modules.

Table 4. Energy Capacity by Duration of Lead-Acid Batteries

Duration (hrs)	Watts/cell	Wh	DOD	Degradation	# Cycles
1	206	1,236	51.5%	48.9%	1,030
2	122	1,464	61.0%	58.0%	862
3	89.4	1,609	67.1%	63.7%	781
4	70.6	1,694	70.6%	67.1%	739
5	59.2	1,776	74.0%	70.3%	704
6	51.3	1,847	77.0%	73.1%	675
8	40.8	1,958	81.6%	77.5%	635
10[(a)]		2,070	86.3%	81.9%	599

(a) Watts/cell was not provided for a 10-hour system

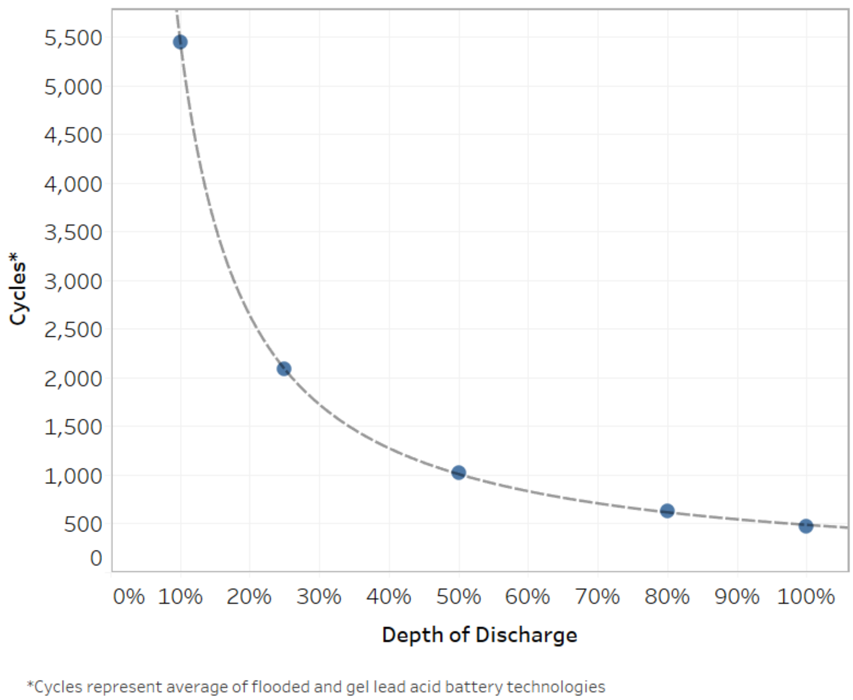

Figure 3. Cycles by DOD for 12 V Lead-Acid Battery Modules

In the literature, lead-acid battery prices are reported as low as $200-220/kWh (Aquino et al., 2017; G. J. May, Davidson, & Monahov, 2018; PowerTech Systems, 2015). Cost information was provided for a 10 MW, 50 MWh system for a utility-scale BESS installed in Europe and is shown in Table 5 (Raiford, 2020a). The SB cost based on rated energy was $236/kWh. Note that the power component of lead-acid batteries in Table 5 includes converters, rectifiers, internal cabling, and piping. The SBOS costs are estimated by subtracting DC-DC converter and PCS costs from the power component costs and was 23% of SB cost. No attempt was made to differentiate the cost between valve-regulated and flooded lead-acid batteries.

Table 5. Costs by Category for a 10 MW, 50 MWh Lead-Acid Battery

Category	Value
DC battery ($/kWh)	236

Power component ($/kW) [(a)]	675
Fixed O&M ($/kW-year)	8.0
Variable O&M ($/MWh)	1.0
RTE (%)	84
Cycles at 50% DOD	5,500
Cycles at 100% DOD	3,000
Shelf life (years)	12

(a) Includes converters, rectifiers, internal cabling, and piping

Table 6 summarizes the capital cost and performance metrics for a 1, 10, and 100 MW, 5-hour lead-acid battery system. The 10 MW system cost was provided by vendors directly and estimates for the 1 MW and 100 MW system were calculated using a cost decrease for 10x increase in MW capacity, where 10 MW is used as the baseline (Raiford, 2020b). Conversely, cost increases for a 10x decrease in MW was also employed for this study. Additional capital costs provided by another energy storage expert have also been included for lead-acid and lead-carbon batteries at a 1 MW power capacity (Baxter, 2020e) and shows a wide range of data depending on the different battery designs being considered. Cost associated with system integration, EPC, and project development were determined using the same approach used for lithium-ion batteries described previously in this report, but with a reduction of markup and profit changed to 15% instead of 20%. The primary reason for the lower markup and profit is that there are generally fewer safety-related issues associated with lead-acid batteries. The SBOS for the Raiford (2020a) system has been estimated by removing PCS (assumed equivalent to PCS cost for lithium-ion) and DC-DC converter prices (Wood Mackenzie, 2020b) from the total power component cost as stated earlier. Note that the SBOS per the European example (Raiford, 2020a) was 23% of SB cost; slightly higher than other studies referenced in this report. For this study, the SBOS was set at 20% of SB cost, in line with lithium-ion BOS.

Table 6. Capital Costs and Performance Metrics for Lead-Acid Systems Across Various Capacities

	Raiford (2020a)	Raiford (2020a)		Baxter (2020e)	
Power capacity (MW)	10	1	100	1	1[(a)]
Energy capacity (MWh)	50	5	500	4	4
DC SB ($/kWh)	471	495	447	183	349
DC-DC converter ($/kW)	60	70	52		
PCS ($/kW)	73	85	63	24	24
SBOS ($/kWh)	108	114	103	44	44
Energy management system ($/kW)	8	40	2		
System integration ($/kWh)	83	88	78	38	42
EPC ($/kWh)	93	99	88	58	92
Project development ($/kWh)	118	125	111		
Grid integration ($/kW)	25	31	20		
Total ESS installed costs ($/kWh)	**906**	**965**	**855**	**347**	**551**

[(a)] Lead-carbon system

Note that the capital cost information provided from Raiford (2020a) corresponds to $/kWh of available energy at 50% DOD for lead-acid BESS comprised of single cells, which are more expensive but have a higher cycle life. To be consistent with other BESS, the SB capital cost is represented as $/kWh of rated energy in this study and is $236/kWh for BESS comprised of single cells, with rack cost estimated at $70/kWh (30% of SB cost). The 12 V battery module costs are estimated at $100/kWh (Raiford, 2020c), resulting in SB cost of $170/kWh regardless of DOD. The DOD corresponding to each duration is determined from Table 4, while the cycle life corresponding to DOD is determined from Figure 3. Table 7 provides a detailed category cost breakdown for a 10 MW, 40 MWh, lead-acid BESS with a comprehensive reference list for each category.

Table 7. Price Breakdown for Various Categories for a 10 MW, 40 MWh, Lead-Acid Battery

Cost Category	Nominal. Size	2020 Price	Content	Additional Notes	Source(s)
SB	40 MWh	\$171/kWh	\$/kWh cost for SB	Lead-acid battery module price of \$100/kWh (Raiford, 2020a) used along with \$70/kWh for racking the modules	Baxter (2020a); Frith (2020a); Frith (2020b); Goldie-Scot (2019); Aquino et al. (2017); G. J. May et al. (2018); PowerTech Systems (2015); Raiford (2020a)
BOS	40 MWh	\$47/kWh	\$/kWh cost for BOS	Obtained by subtracting DC-DC converter and PCS price from power component price of Aquino et al. (2017), works out to be 20% of SB cost based on single-cell strings	Raiford (2020a)
DC-DC converter	10,000 kW	\$60/kW	DC-DC converter cost		Wood Mackenzie (2020b)
PCS	10 MW	\$73/kW	PCS cost	Includes cost for additional equipment such as safety disconnects that are site-specific, cost aligns with numbers provided by PCS vendor for utility scale	Austin (2020); Baxter (2020a); Goldie-Scot (2019); Vartanian (2020); Wood Mackenzie (2020a)
C&C	10 MW	\$7.8/kW		Source provides estimate for C&C, PNNL approach for scaling across various power levels	Baxter (2020d)
System integration	N/A	7.5% markup on hardware and 7.5% profit on sum of above rows		Lowered from 10% markup and 10% profit for lithium-ion due to lower safety concerns	Baxter (2020b)
EPC	N/A	15% markup + profit on sum of above rows		Lowered from 15% markup and 5% profit for lithium-ion due to lower safety concerns	
Project development	N/A	15% markup + profit on sum of above rows		Lowered from 5% markup and 15% profit for lithium-ion due to lower safety concerns	
Grid integration	10 MW	\$24.9/kW		Source provided estimate for C&C, PNNL approach for scaling across various power levels	
O&M			Fixed O&M		Aquino et al. (2017); Raiford (2020a)
Performance metrics			DOD at various discharge durations		C&D Technologies Inc. (Undated)
Performance metrics			Cycles as a function of DOD		Anuphappharadorn, Sukchai, Sirisamphanwong, and Ketjoy (2014); BAE Batteries (2016); DiOrio et al. (2015); Raiford (2020a)
Performance metrics			Calendar life		C&D Technologies Inc. (2015); G. J. May et al. (2018)
Performance metrics			RTE		Anuphappharadorn et al. (2014); G. May (2020); Raiford (2020a)

The price range for 2020 was 0.9 to 1.1 times the nominal values for each category. For the 2030 price, the learning rate for the SB was set at 1.5%, with the low and high end of the price range having learning rates of 2.5% and 0.5% respectively. The learning rates for other categories are the same as for the lithium-ion system and are shown in Table 8.

Table 8. Learning Rates Used to Establish 2030 Lead-Acid Capital Cost and Fixed O&M Ranges

Component	Low Price	Nominal Price	High Price
DC SB ($/kWh)	2.50%	1.50%	0.50%
DC SBOS ($/kWh)	10%	7%	4%
DC-DC converter ($/kW)	7%	3%	2%
PCS ($/kW)	7%	3%	2%
C&C ($/kW)	10%	7%	4%
System integration ($/kWh)	6%	4%	2%
EPC ($/kWh)	6%	4%	2%
Project development ($/kWh)	6%	4%	2%
Grid integration ($/kW)	6%	4%	2%
O&M ($/kW-year)	6%	4%	2%

O&M Costs

There are not many examples in the literature of O&M costs specific to lead-acid systems. Aquino et al. (2017) estimated that the fixed O&M cost for an advanced lead-acid battery combined with an asymmetric supercapacitor to be in the range of $7-15/kW-year, and that the variable cost for the same system is estimated to be $0.0003/kWh ($0.3/MWh). Raiford (2020a) places fixed O&M costs closer to the low end of the range at $8/kW-year, which corresponds to 0.86% of the direct capital cost for a 4-hour duration. As described in the lithium-ion section, fixed costs were assumed to be 0.43% of SM capital cost for all BESS. The fixed O&M range for the year 2020 was 0.9 to 1.1 times the nominal values for each category. The fixed O&M learning rate was in the 2 to 6% range.

For basic variable O&M, there is inconsistent nomenclature regarding what this category consists of and, as mentioned previously, is derived here based on averages across various technologies and literature estimates at $0.5125/MWh (Table 3).

Performance Metrics

Lead-acid batteries typically have a shorter cycle life compared to lithium-ion systems and are primarily used for resource adequacy and capacity applications (Aquino et al., 2017). The lead-acid battery cycle life depends highly on DOD, hence its operating life depends on the number of cycles needed per year at the desired DOD along with cycle life at the desired DOD (Anuphappharadorn et al., 2014; BAE Batteries, 2016; DiOrio et al., 2015). Therefore, operating life can be limited to 1-5 years depending on chosen DOD. Other sources estimate lead-acid systems to be capable of a much longer calendar life (15-20 years), which, as defined earlier, is the maximum life of a battery under specified ambient temperature, regardless of operating conditions (C&D Technologies Inc., 2015; G. J. May et al., 2018). Raiford (2020a) is consistent with the lower end of the cycle range specified in the literature with an estimate of 675 cycles and a calendar life of 12 years. The calendar life is assumed to be consistent with that of Raiford (2020a) in this analysis along with a varying cycle life based on assumed number of cycles per day and DOD corresponding to the values in Table 4.

The RTE of lead-acid systems is typically estimated to fall between 75-84% but is dependent on the chosen operation of the system where operating at a higher duration corresponds with a higher RTE (Anuphappharadorn et al., 2014; G. J. May et al., 2018; Raiford, 2020a). Taking the average of the values provided in the literature gives an RTE of 82% and is the value assumed in this analysis for 6-hour duration, with 77% RTE for 2-hour duration and 85% RTE for 10-hour duration.

Response time estimation for lead-acid systems follows the same methodology as that of lithium-ion. That is, the time to go from rest to rated power is determined by the inverter selection and the overall system design. A specific PCS or DC stack design can be chosen so that the system can respond at the desired rate for the chosen application. Here, response time is assumed to be between 1-4 seconds for lead-acid systems.

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and the RTE corresponding to each duration. For example, for a 6-hour duration with RTE of 82%, the cost due to RTE losses is $0.007/kWh for the lead-acid system.

Results

Figure 4 provides cost estimates for 1, 10, and 100 MW lead-acid batteries with a 4- and 10-hour duration for both 2020 and 2030. Additional estimates for 2-, 6-, and 8-hour systems of the same power capacities are provided in the appendix.

Lead Acid
2020 & 2030 Cost & Performance Estimates

Category	Parameter	Units	1 MW				10 MW				100 MW			
			4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
			2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[169 - 190] 180	[160 - 176] 167	[169 - 190] 180	[160 - 176] 167	[161 - 181] 171	[152 - 168] 159	[161 - 181] 171	[152 - 168] 159	[153 - 172] 162	[145 - 159] 151	[153 - 172] 162	[145 - 159] 151
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[46 - 52] 49	[30 - 41] 35	[46 - 52] 49	[30 - 41] 35	[44 - 50] 47	[28 - 39] 33	[44 - 50] 47	[28 - 39] 33	[42 - 47] 45	[27 - 37] 31	[42 - 47] 45	[27 - 37] 31
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[146 - 164] 155	[108 - 141] 133	[146 - 164] 155	[108 - 141] 133	[125 - 141] 133	[93 - 121] 114	[125 - 141] 133	[93 - 121] 114	[108 - 122] 115	[80 - 104] 99	[108 - 122] 115	[80 - 104] 99
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[38 - 42] 40	[24 - 33] 28	[38 - 42] 40	[24 - 33] 28	[7 - 8] 8	[5 - 6] 5	[7 - 8] 8	[5 - 6] 5	[1 - 2] 2	[1 - 1] 1	[1 - 2] 2	[1 - 1] 1
ESS Installed Cost / Energy Storage System	System Integration	$/kWh	[45 - 50] 47	[35 - 43] 39	[41 - 46] 43	[32 - 40] 36	[41 - 47] 44	[33 - 40] 36	[38 - 43] 41	[30 - 37] 34	[39 - 44] 41	[31 - 38] 34	[36 - 41] 39	[29 - 35] 32
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[49 - 55] 52	[39 - 47] 43	[45 - 50] 47	[35 - 43] 39	[46 - 52] 49	[36 - 45] 40	[42 - 48] 45	[33 - 41] 37	[43 - 49] 46	[34 - 42] 38	[40 - 45] 43	[32 - 39] 35
ESS Installed Cost	Project Development	$/kWh	[63 - 71] 67	[49 - 61] 55	[57 - 65] 61	[45 - 56] 50	[58 - 65] 62	[46 - 56] 51	[54 - 61] 57	[42 - 52] 47	[54 - 61] 58	[43 - 53] 47	[51 - 57] 54	[40 - 49] 44
ESS Installed Cost	Grid Integration	$/kW	[29 - 33] 31	[23 - 28] 25	[29 - 33] 31	[23 - 28] 25	[23 - 26] 25	[18 - 23] 20	[23 - 26] 25	[18 - 23] 20	[19 - 21] 20	[15 - 18] 16	[19 - 21] 20	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[1658 - 1956] $1,808**	**[1405 - 1673] $1,538**	**[3707 - 4365] $4,040**	**[3175 - 3750] $3,449**	**[1520 - 1792] $1,657**	**[1296 - 1538] $1,415**	**[3472 - 4086] $3,780**	**[2981 - 3516] $3,235**	**[1419 - 1672] $1,544**	**[1211 - 1436] $1,322**	**[3273 - 3852] $3,558**	**[2812 - 3315] $3,050**
	Total ESS Installed Cost*	**$/kWh**	**[414 - 489] $452**	**[351 - 418] $385**	**[371 - 436] $404**	**[317 - 375] $345**	**[380 - 448] $414**	**[324 - 384] $354**	**[347 - 409] $378**	**[298 - 352] $324**	**[355 - 418] $386**	**[303 - 359] $330**	**[327 - 385] $356**	**[281 - 331] $305**
Operating Costs	Fixed O&M	$/kW-yr	[5.59 - 6.3] 5.94	[4.4 - 5.41] 4.87	[12.78 - 14.41] 13.60	[10.06 - 12.37] 11.15	[5.11 - 5.76] 5.43	[4.02 - 4.94] 4.45	[11.96 - 13.49] 12.72	[9.42 - 11.58] 10.43	[4.8 - 5.42] 5.11	[3.78 - 4.65] 4.19	[11.32 - 12.76] 12.04	[8.91 - 10.95] 9.87
Operating Costs	Variable O&M	$/MWh	0.5125				0.5125				0.5125			
Operating Costs	System RTE Losses	$/kWh	0.008		0.005		0.008		0.005		0.008		0.005	
Performance Metrics	Round Trip Efficiency	%	79.0%		85.0%		79.0%		85.0%		79.0%		85.0%	
Performance Metrics	Response Time	sec	1-4				1-4				1-4			
Performance Metrics	Cycle Life	#	739		599		739		599		739		599	
Performance Metrics	Calendar Life	yrs	12				12				12			
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	2.13		1.73		2.13		1.73		2.13		1.73	

* Does not include any additional transmission costs that may be required or decommissioning costs
** Assumes various depths of discharge, one cycle/day, and 5% downtime

Figure 4. Lead-Acid Battery Cost and Performance Estimates by Power Capacity and Energy Duration for 2020 and 2030

R&D Trends in Lead-Acid Batteries

Lead-acid batteries are quite complex and come in two main categories: flooded and valve-regulated. Flooded lead-acid batteries have different charge procedures compared to valve-regulated lead acid batteries. Flooded lead-acid batteries use Pb-Sb grids to improve cyclability. Sb improves castability of grids and reduces resistance of the positive grid corrosion layer while also improving positive active material cycle life by promoting interparticle contact (Pavlov, 2017c). However, Sb results in increased oxygen generation at the positive and especially increased hydrogen generation at the negative, requiring frequent topping off of water. This results in very low shelf life for flooded batteries with Pb-Sb alloy grids. To avoid a high self-discharge rate, battery manufacturers use Pb-Ca grids, which increase the shelf life and reduce or eliminate the need for topping off with water. However, absence of Sb led to premature capacity loss related to formation of high resistance layer of PbO between positive grid and active material and high resistance between positive active material particles, in addition to poor castability. Alloying Pb-Ca with Sn mitigated this premature capacity. Some manufactures use low Sb alloy grid for the positive and Pb-Ca-Sn alloy for the negative to take advantage of the positive effects of Sb on positive active material cyclability. However, this results in Sb ion transport to the negative, where it promotes self-discharge via hydrogen evolution (Pavlov, 2017c).

The modes and causes of degradation for lead-acid batteries are:

- Positive grid corrosion to high resistance oxide – mitigated by Sb or Sn alloy (Pavlov, 2017c).
- Premature capacity loss for the positive – mitigated by Sb or Sn alloy (Pavlov, 2017c).
- Passivation of negative electrode with continuous film of lead-sulfate crystals.
  - Mitigated by addition of expanders such as carbon black, activated carbon, barium sulfate, and lignocellulose (Pavlov, 2017a).
  - Carbon has two purposes: to increase conductivity and provide suitable pore structure (Pavlov, 2017a).
    - Carbon black has high surface area but low pore size – pores too small for Pb^{+2} and HSO_4- ion transport.
    - Activated carbon has lower surface area, but sufficiently large pores for transport of Pb^{+2} and HSO4- ions.
  - $BaSO_4$ promotes nucleation of $PbSO_4$, avoiding crustal growth and passivation of active material (Boden, 1998).
  - Lignocellulose provides the desired pore structure to form $PbSO_4$ crystals during discharge of the right size such that they dissolve and reprecipitate on the electrode, in equilibrium with dissolved $PbSO_4$ near the electrode. Upon charge the dissolved lead sulfate gets reduced to Pb. As $PbSO_4$ gets consumed more $PbSO_4$ dissolved near the electrode is reduced (Pavlov, 2017a).

  - The correct choice of expander depends on application; therefore, it is anticipated that there will be a focus on mapping the available expanders to batteries developed for various grid services.

- Improper balance between electrolyte and negative and positive active material utilization – balance between initial capacity and cycle life (Pavlov, 2017b).
- High temperature during formation that leads to macrocracks between grid and active material resulting in poor contact and high resistance (Pavlov, 2017d).
- Excessively high sulfuric acid concentration during formation that leads to a higher amount of undesired α-PbO_2 (Pavlov, 2017b).
- Electrolyte stratification resulting in sulfation at the bottom which can result in permanent capacity loss (Pavlov, 2017b). This is not a factor for valve-regulated lead-acid batteries, especially if the battery is placed horizontally.
- High temperature during operation that promotes water decomposition and cell dry out, positive grid oxidation from evolved oxygen, expander degradation resulting in negative electrode passivation with lead sulfate (Pavlov, 2017a).
- Improper choice of grid for the application (Pavlov, 2017c):
  - Deep cycle application would require more Sb or Sn at the positive and suitable expander composition.
  - Valve-regulated batteries for deep cycling would be a challenge since Sb used to increase cycle life promotes gassing and water loss.

The utilization of electrolyte is typically designed as the limiting factor, with excess positive and negative active material. This results in low DOD for the positive and negative electrode at the rated capacity (Pavlov, 2017b). Increasing the DOD without adversely affecting cycle life would be a substantial achievement for lead-acid batteries. Module cycle life typically is 2x lower than single-cell cycle life as reported earlier (Raiford, 2020a). However, it would be reasonable to assume that, in addition to poorer cell-to-cell temperature and voltage uniformity for modules, the above factors may also play a role. Modules are typically lower value products used in starting, lighting and ignition, and other commodity applications. Whereas, single cells connected in series/parallel are used in stationary applications in substations and have a robust design, which may take the above factors into account in greater detail.

Based on the above information, to narrow the wide range of cycle life observed in battery cells and modules, the trends in lead-acid battery energy storage R&D are expected to be:

- Improving cycle life for valve-regulated cells/modules at high DOD
- Identification of grid alloy that promotes further oxidation of highly resistive PbO without increasing self-discharge
- Further understanding the mechanism of role of expander on negative active material performance
- Increasing DOD such that rated capacity is based on higher DOD than the current ~ 50% DOD

- Designing cells to fit the grid service by proper choice of electrolyte, positive and negative utilization, and grid composition
- Replacing negative grid with copper for improved performance
- Having a standardized formation procedure conducive to intended grid service
- Addressing electrolyte stratification with nonintrusive ways to circulate the electrolyte
  - Baffles
  - Reverse pulses
  - Micropumps
- Finding a suitable substitute for Sb at the positive grid to avoid highly resistive PbO layer and promoting interparticle conductive among PbO_2 active material particles
- Improving stability of expanders at higher temperature to mitigate degradation at high temperature
- Understanding the mechanism of additives to electrolytes for increasing battery life.

Vanadium Redox Flow Batteries

Capital Cost

A redox flow battery (RFB) is a unique type of rechargeable battery architecture in which the electrochemical energy is stored in one or more soluble redox couples contained in external electrolyte tanks (Yang et al., 2011). Liquid electrolytes are pumped from the storage tanks through electrodes where the chemical energy in the electrolyte is converted to electrical energy (discharge) or vice versa (charge). The electrolytes flowing through the cathode and anode are often different and referred to as catholyte and anolyte, respectively. Between the anode and cathode compartments is a membrane (or separator) that selectively allows cross-transport of a charge-carrying species (e.g., H+, Cl-) to maintain electrical neutrality and electrolyte balance. In traditional battery designs like lithium-ion, the stored energy is directly related to the amount of electrode material and increasing the power capacity of these systems also increases the energy capacity as more cells are added. In RFB systems the power and energy capacity can be designed separately. The power (kW) of the system is determined by the size of the electrodes and the number of cells in a stack, whereas the energy storage capacity (kWh) is determined by the concentration and volume of the electrolyte. Both energy and power can be easily adjusted for storage from a few hours to days, depending on the application. This flexibility makes RFBs an attractive technology for grid-scale applications where both high-power and high-energy services are being provided by the same storage system. Sufficient data are not currently available to estimate the life of RFB stack components, such as membranes and electrodes, with a proposed lifetime of 10 years.

There is not a substantial amount of capital cost data available for redox flow systems. Price information was primarily provided by discussions with an energy storage expert, an RFB manufacturer, and from past research conducted by PNNL. Estimates for a 1 MW and 10 MW redox flow system from Baxter (2020e) are shown in Table 9. Both estimates are for 4-hour systems.

Table 9. Cost Estimates for 1 MW and 10 MW Redox Flow Battery Systems

	1 MW/4 MWh System		10 MW/40 MWh System	
Estimate Year	2020	2030	2020	2030
DC system (with SB and container costs) ($/kWh)	$367	$299	$341	$278
PCS ($/kWh)	$22	$17	$17	$13
PCS markup ($/kW)	$2.2	$1.7	$2	$1
ESS equipment total ($/kWh)	**$391**	**$318**	**$360**	**$292**
Integrator margin ($/kWh)	$58	$48	$36	$29
Complete ESS equipment total ($/kWh)	**$449**	**$365**	**$396**	**$321**
EPC ($/kWh)	$101	$82	$79	$64
AC Installed Cost ($/kWh)	**$551**	**$447**	**$475**	**$386**

Estimates from past PNNL research of RFBs provided additional cost information and were adjusted based on an objective function that lowered total capital cost for systems of various E/P ratios (A. Crawford et al., 2015; V. Viswanathan et al., 2014). It is assumed that stacks for flow batteries would be run at various power densities depending on E/P ratio. That means for a high E/P ratio, since electrolyte costs dominate, the power density would be adjusted lower to improved efficiency and thus reduce electrolyte cost. This results in a lower $/kWh for the energy component (electrolyte) and a higher $/kW for the power component (stacks). For this work, the $/kW for stacks and $/kWh for electrolyte and tanks were averaged across the durations studied (1, 4, and 10 hours). It is also assumed the numbers calculated correspond to a 10 MW system. The optimization approach also lends itself to a greater DOD for higher E/P ratio to save on electrolyte cost. The optimized DOD at 1-, 4- and 10-hour durations was found to be 78%, 85%, and 85%, respectively. In other words, no change in DOD was observed between 4 and 10 hours, while the 1-hour DOD was 78%. With the assumption that the 2-hour DOD would be a third of the way between the 1- and 4-hour DODs, the DOD for a 2-hour system was estimated to be 80.3%. The average DOD for 2-, 4-, and 10-hour systems was found to be 83.4%.

Conversation with an RFB manufacturer indicated that oversizing the electrolyte in the tank can achieve an effective DOD of 75% (Cipriano, 2020b). The BMS adjusts the SOC such that, at 75% DOD, the SOC registers 0% (and at full charge, SOC registers 100%). The DOD for this study was set as the average of the PNNL estimate described previously (83.4%) and the 75% value provided by the redox flow manufacturer (Cipriano, 2020b) to get 79.2% DOD. After these adjustments, the unit power cost of the DC SB was estimated to be $351.5/kW, while the energy-related cost for the SB was $177.7/kWh.

The SBOS for the RFB system is assumed to be in line with lithium-ion and lead-acid BESS at 20% of SB cost. While flow battery SBOS is expected to be slightly greater than lead-acid due to lower specific energy and energy density, some of the SBOS elements such as pumps are already included in the SB capital cost. Table 10 shows results for various durations at 10 MW from the previous PNNL analysis (A. Crawford et al., 2015; V. Viswanathan et al., 2014) as well as the total DC system cost for the 10 MW, 4-hour system provided by Baxter (2020e) for comparison.

Table 10. Cost Estimates for Various Durations for RFBs

E/P	DCSB Cost ($/kWh)	SBOS Cost ($/kWh)	Total DC System Cost ($/kWh) [a]	Total DC System Cost ($/kWh) [b]
2	353	71	424	
4	266	53	319	341
6	236	47	283	
8	222	44	266	
10	213	43	255	

[a] A. Crawford et al. (2015); V. Viswanathan et al. (2014)
[b] Baxter (2020e)

Comparing the total DC system cost from A. Crawford et al. (2015); V. Viswanathan et al. (2014), and Baxter (2020e) finds them to be similar for the 4-hour duration. Taking the average of the total cost across both estimates gives $330/kWh, which is 1.035 times the PNNL number. To obtain estimates for the remaining durations, the PNNL numbers for the 2-, 6-, 8-, and 10-hour systems were multiplied by this ratio with results shown in Table 11.

Table 11. Cost Estimates for a 10 MW RFB Across Various Durations

E/P	DC SB Cost ($/kWh)	SBOS Cost ($/kWh)	Total DC System Cost ($/kWh)
2	366	73	439
4	275	55	330
6	245	49	293
8	229	46	275
10	220	44	264

To obtain cost estimates for various power capacities, a 5% premium was added for a 1 MW system and a 5% discount was included for a 100 MW system, also including PCS, C&C, and grid integration cost estimates obtained from the lithium-ion reference literature. The system integration, EPC, and project development costs as a percentage of previous line items were kept at 15%, the same as for lead-acid, due to higher capital costs compared to the lithium-ion system and lower safety-related issues. Table 12 provides a detailed category cost breakdown for a 10 MW, 100 MWh vanadium redox flow BESS, with a comprehensive reference list for each category. Note that the SB has power and energy cost components. The power cost is associated with stack, pumps, and piping, while energy costs are associated with electrolyte and tank costs.

Table 12. Price Breakdown for Various Categories for a 10 MW, 100 MWh Vanadium RFB

Cost Category	Nominal Size	2020 Price	Content	Additional Notes	Source(s)
SB	100 MWh	\$352/kW for power \$178/kWh for energy			Baxter (2020e); Cipriano (2020a); A. Crawford et al. (2015); V. Viswanathan et al. (2014)
BOS		\$44/kWh		Used same 20% of SM cost as for lead-acid	Raiford (2020a)
DC-DC converter	10 MW	\$60/kW	DC-DC converter cost		Wood Mackenzie (2020b)
PCS	10 MW	\$73/kW	PCS cost	Includes cost for additional equipment such as safety disconnects that are site-specific, cost aligns with numbers provided by PCS vendor for utility scale	Austin (2020); Baxter (2020a); Goldie-Scot (2019); Vartanian (2020); Wood Mackenzie (2020a)
C&C	10 MW	\$7.8/kW	C&C cost	PNNL approach for scaling across various power levels	Baxter (2020d)
System integration	N/A	7.5% markup on hardware + 7.5% profit on sum of above rows	System integration cost	Lowered from 10% markup and 10% profit for lithium-ion due to lower safety concerns	Baxter (2020b)
EPC	N/A	15% markup + profit on sum of above rows	EPC cost	Lowered from 15% markup and 5% profit for lithium-ion due to lower safety concerns	
Project Development	N/A	15% markup + profit on sum of above rows	Project development cost	Lowered from 5% markup and 15% profit for lithium-ion due to lower safety concerns	
Grid Integration	10 MW	\$24.9/kW	Grid integration cost	PNNL approach for scaling across various power levels	
O&M			O&M fixed costs		Aquino et al. (2017); DNV GL (2016)
Performance metrics			Calendar life		Aquino et al. (2017); EASE (2016); G. J. May et al. (2018)
Performance metrics			Cycle life		Aquino et al. (2017); Greenspon (2017); EASE (2016); G. J. May et al. (2018)
Performance metrics			RTE		Aquino et al. (2017); EASE (2016); G. J. May et al. (2018); Uhrig, Koenig, Suriyah, and Leibfried (2016)

The price range for 2020 was 0.9 to 1.1 times the nominal values for each category. For the year 2030, the learning rate for SB was set at 4.5%, with the low and high end of the price range having learning rates of 9% and 2% respectively. The learning rates for other categories are set to be the same as for the lithium-ion system and are shown in Table 13.

Table 13. Learning Rates Used to Establish 2030 Redox Flow Capital Cost and Fixed O&M Ranges

Component	Low Price	Low Price	Nominal Price	High Price
DC SB ($/kWh)	14%	9%	4.50%	2%
DC SBOS ($/kWh)	10%	10%	7%	4%
DC-DC converter ($/kW)	7%	7%	3%	2%
PCS ($/kW)	7%	7%	3%	2%
C&C ($/kW)	10%	10%	7%	4%
System Integration ($/kWh)	6%	6%	4%	2%
EPC ($/kWh)	6%	6%	4%	2%
Project Development ($/kWh)	6%	6%	4%	2%
Grid Integration ($/kW)	6%	6%	4%	2%
O&M ($/kW-year)	6%	6%	4%	2%

O&M Costs

Fixed O&M costs for battery systems appear in the range of $6–$20/kW-year within the literature, with most in the $7-16/kW-year range (Aquino et al., 2017; DNV GL, 2016). As with lithium-ion and lead-acid, there are not many examples in the literature of O&M costs that provide substantial clarity for RFB systems. For this study, the fixed O&M is set to 0.43% of direct capital cost, as described in the lithium-ion section. The actual value specific to each technology will depend on the capital cost. The fixed O&M range for the year 2020 was 0.9 to 1.1 times the nominal values for each category. The fixed O&M learning rate was in the 2- 6% range

For variable O&M, there is similarly inconsistent nomenclature regarding what this category consists of for battery systems. Due to the lack of detailed justification regarding what comprises variable O&M for each technology, this work sets the basic variable O&M to be $0.5125/MWh and is based on the average across various technologies (Table 3).

Performance Metrics

Compared to other electrochemical battery systems, RFBs typically have longer lifespans due to being insensitive to temperature and avoiding the stress experienced by other battery systems during cycling. The typical calendar life of these systems typically falls between 10 and 20 years, though most estimates place it in the middle of those two values (Aquino et al., 2017; EASE, 2016; G. J. May et al., 2018). It should be noted that the electrolyte essentially does not degrade, while stack components such as membranes and electrodes may need replacement every 10 years (V. Viswanathan et al., 2014) and pumps may need replacement every 15 to 20 years (Elsey, 2016; ITT Industries, Undated). With regards to cycle life, the literature provided a small range of estimates, but with almost all estimating its capability at 10,000 cycles and above (EASE, 2016; Greenspon, 2017; G. J. May et al., 2018). Only one estimate placed its capability as low as 5,000 cycles for an unknown DOD for a vanadium system (Aquino et al., 2017). While RFB systems use non-degradable electrolyte under proper usage, as the system is used the stack may need replacement. Assuming a calendar life of 15 years and one cycle per day, with 5% of that time allocated to downtime, this corresponds to a total cycle life of 5,201 cycles.

The literature places the RTE for RFB systems between 65% and 80% (Aquino et al., 2017; EASE, 2016; G. J. May et al., 2018; Uhrig et al., 2016). PNNL testing in the past has shown that 4-hour systems typically reflect the lower end of this range at closer to 65% RTE. Past analysis also found that there exists an optimum operational regime that changes depending on design of stacks, the E/P (h) ratio, and the SOC (A. J. Crawford, Viswanathan, Vartanian, Alam, et al., 2019; A. J. Crawford, Viswanathan, Vartanian, Mongird, et al., 2019; V. V. Viswanathan et al., 2018). For this analysis, a 67.5% RTE is assumed for 2020 and expected to rise to 70% by 2030 due to innovations in the technology.

Losses from RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 68% for 2020 and 70% for 2030. Following these two items, it can be determined that the cost is $0.014/kWh for 2020 and $0.013/kWh for 2030 for the RFB system.

Results

Final cost and performance estimates for the redox flow battery for 1 MW, 10 MW, and 100 MW systems at 4- and 10-hour durations are provided in Figure 5. Estimates for durations of 2, 4, 6, 8, and 10 hours across the same power capacities can be found in the appendix.

Vanadium Redox Flow
2020 & 2030 Cost & Performance Estimates

	Parameter	Units	1 MW				10 MW				100 MW			
			4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
			2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[260 - 317] 289	[183 - 263] 231	[208 - 254] 231	[147 - 210] 185	[247 - 302] 275	[175 - 250] 220	[198 - 242] 220	[140 - 200] 176	[235 - 287] 261	[166 - 238] 209	[188 - 230] 209	[133 - 190] 167
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[52 - 63] 58	[35 - 47] 40	[42 - 51] 46	[28 - 38] 32	[49 - 60] 55	[33 - 45] 38	[40 - 48] 44	[26 - 36] 31	[47 - 57] 52	[31 - 43] 37	[38 - 46] 42	[25 - 34] 29
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[139 - 170] 155	[108 - 141] 133	[139 - 170] 155	[108 - 141] 133	[120 - 146] 133	[93 - 121] 114	[120 - 146] 133	[93 - 121] 114	[103 - 126] 115	[80 - 104] 99	[103 - 126] 115	[80 - 104] 99
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[36 - 44] 40	[24 - 33] 28	[36 - 44] 40	[24 - 33] 28	[7 - 9] 8	[5 - 6] 5	[7 - 9] 8	[5 - 6] 5	[1 - 2] 2	[1 - 1] 1	[1 - 2] 2	[1 - 1] 1
ESS Installed Cost / Energy Storage System	System Integration	$/kWh	[50 - 61] 55	[41 - 50] 45	[39 - 47] 43	[32 - 39] 35	[46 - 56] 51	[38 - 47] 42	[36 - 44] 40	[30 - 37] 33	[43 - 53] 48	[35 - 44] 39	[34 - 41] 38	[28 - 34] 31
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[57 - 69] 63	[47 - 57] 52	[45 - 55] 50	[37 - 45] 41	[53 - 64] 58	[43 - 53] 48	[42 - 51] 46	[34 - 42] 38	[49 - 60] 54	[40 - 49] 45	[39 - 47] 43	[32 - 39] 35
ESS Installed Cost	Project Development	$/kWh	[72 - 88] 80	[59 - 73] 66	[57 - 70] 64	[47 - 58] 52	[66 - 81] 73	[54 - 67] 60	[53 - 64] 59	[43 - 53] 48	[61 - 75] 68	[50 - 62] 56	[49 - 60] 54	[40 - 49] 45
ESS Installed Cost	Grid Integration	$/kW	[28 - 34] 31	[23 - 28] 25	[28 - 34] 31	[23 - 28] 25	[23 - 28] 25	[19 - 23] 21	[23 - 28] 25	[19 - 23] 21	[18 - 22] 20	[15 - 18] 16	[18 - 22] 20	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[2163 - 2644] $2,404**	**[1614 - 2163] $1,922**	**[4111 - 5025] $4,568**	**[3062 - 4112] $3,645**	**[1995 - 2438] $2,216**	**[1488 - 1996] $1,773**	**[3832 - 4684] $4,258**	**[2852 - 3835] $3,399**	**[1863 - 2277] $2,070**	**[1388 - 1864] $1,656**	**[3595 - 4393] $3,994**	**[2673 - 3597] $3,187**
	Total ESS Installed Cost*	**$/kWh**	**[541 - 661] $601**	**[403 - 541] $480**	**[411 - 502] $457**	**[306 - 411] $365**	**[499 - 609] $554**	**[372 - 499] $443**	**[383 - 468] $426**	**[285 - 383] $340**	**[466 - 569] $517**	**[347 - 466] $414**	**[359 - 439] $399**	**[267 - 360] $319**
Operating Costs	Fixed O&M	$/kW-yr	[6.11 - 7.47] 6.79	[5.03 - 6.18] 5.57	[11.5 - 14.05] 12.77	[9.45 - 11.62] 10.47	[5.65 - 6.91] 6.28	[4.65 - 5.71] 5.15	[10.77 - 13.17] 11.97	[8.86 - 10.89] 9.82	[5.3 - 6.48] 5.89	[4.36 - 5.36] 4.83	[10.17 - 12.43] 11.30	[8.36 - 10.28] 9.26
Operating Costs	Variable O&M	$/MWh	0.5125				0.5125				0.5125			
Operating Costs	System RTE Losses	$/kWh	0.014		0.013		0.014		0.013		0.014		0.013	
Performance Metrics	Round Trip Efficiency	%	68%		70%		68%		70%		68%		70%	
Performance Metrics	Response Time	sec	1-4				1-4				1-4			
Performance Metrics	Cycle Life	#	5,201				5,201				5,201			
Performance Metrics	Calendar Life	yrs	15				15				15			
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	15				15				15			

* Does not include warranty, insurance, or decommissioning costs
** Assumes 90% depth of discharge, one cycle/day, and 5% of calendar life allocated to downtime

Figure 5. RFB Cost and Performance Estimates by Power Capacity and Energy Duration for 2020 and 2030

R&D Trends in Redox Flow Batteries

Typical flow batteries are composed of two tanks of electrolyte solution, one for the cathode and the other for the anode. The technology is still in the early phases of commercialization compared to more mature battery systems such as lithium-ion and lead-acid. However, scalability due to modularity, ability to change energy and power independently, and long electrolyte cycle and calendar life are attractive features of this technology. The basic RFB design is also flexible in the chemistries and architectures it can accommodate. Any multivalent element that can be dissolved in a solution can potentially be used in RFB designs and several hybrid designs may eliminate/augment one flowing electrolyte in favor of metal anode in which the electrochemical species is plated during charge.

To date, vanadium-based and hybrid zinc-bromine flow batteries have achieved the most commercial success, with other technologies based on iron-chrome and polysulfide-bromine having been demonstrated but falling short of commercialization. Vanadium flow batteries use the ability of vanadium to exist in four distinct electrically charged species to serve as both the anolyte and catholyte, limiting the impact of species crossover on battery performance. The technology was first demonstrated in the 1980s by Maria Skyllas-Kazacos at the University of New South Wales, with various generations of the technology having attempted field demonstrations and commercialization. In the past decade, the technology has re-emerged as a candidate for grid-scale storage applications due to its long cycle life and effective use of available SOC range. Replacing the flowing anolyte with a metal electrode (e.g., zinc in Zn-Br2 and iron in Fe/Fe2+ technologies) increases the number of chemistries available for use, but also couples power and energy which reduces operational flexibility. Zinc-based hybrid flow batteries are one of the more promising systems for medium- to large-scale energy storage applications, with advantages in safety, cost, cell voltage, and energy density. Zinc-hybrid systems have the highest energy content due to the high solubility of zinc ions (> 10 M) and the solid negative electrode (B. Li et al., 2015).

While vanadium flow batteries have achieved initial commercial deployment, further R&D efforts are needed to push the technology to lower cost. Efforts supported by DOE are focused on increasing performance and reducing the cost of advanced systems by replacing vanadium with lower cost raw materials to approach the $100/kWh targets required for wider scale deployment of energy storage. One pathway is to replace vanadium with lower cost, easy to synthesize, redox active-organic molecules. A critical design aspect is ensuring these organic redox systems use existing RFB manufacturing capabilities necessitating that new technologies are water soluble with similar concentrations, viscosities, and performance to today's RFBs. Designing these new organic systems to be soluble in water—called aqueous soluble organics—not only ensures these systems are compatible with existing RFB infrastructure but also provide inherent fire safety. Additional efforts to use Earth-abundant zinc and iron electrodes for the anode in hybrid flow battery designs also offer a pathway to lower cost systems.

Compressed-Air Energy Storage

Capital Cost

CAES involves using electricity to compress air and store it in underground caverns. When electricity is needed, the compressed air is released and expands, passing through a turbine to generate electricity. There are various types of this technology including adiabatic systems and diabatic systems. The difference between these two configurations is that adiabatic systems capture and store the heat generated through the compression process to re-use later in the air expansion process in order to generate a larger amount of power output. For diabatic systems, the heat generated during compression is simply released. Newer applications of this technology include the development of isothermal CAES. This technology attempts to use a different process by removing heat across multiple stages of compression in order to reach a temperature closer to ambient, making it easier and more economic to store.

CAES is designed to fill markets where longer duration (12-24 hours) is needed, especially in regions with higher variable renewable energy penetrations (Farley, 2020d). For example, in Texas renewable generation is dominated by wind and curtailment is as high as 7% of total production. The curtailment is related to 1) a transmission bottleneck and 2) price going to zero. For these reasons, the average duration for wind integration in Texas needs to be around 8 hours. While CAES has been demonstrated to deliver longer duration storage, its cost effectiveness is limited by the availability and design of the caverns used for compressed-air storage.

While CAES technology has been demonstrated on a large scale, there are several reasons why early deployments did not keep pace with PSH, and why the future may be brighter:

- Hydropower generation is a mature and proven form of generation, allowing PSH plants to leverage upon the available knowledge base in hydraulic turbine design, installation and operation (Bailie, 2020d; Naeve, 2020). CAES technology, on the other hand, requires a unique design for the compressors and expanders. While compression equipment is a mature technology in chemical processing, compressor design has multiple variables such as molecular weight of gas and desired discharge pressure and investments have only been recently made to develop compressor technology for this specific application. Similar developments are being made for high pressure expanders based on steam turbines, with redesign needed to account for the molecular weight difference between air and steam (Naeve, 2020).
- CAES systems were designed as an optimized gas turbine (Baxter, 2020f). Low natural gas prices made it difficult for CAES to compete with natural gas-powered plants in the past. Migration towards long duration storage of greater than 24 hours is expected to favor CAES, since salt cavern costs are lower than PSH reservoir costs (Farley, 2020a).
- Major turbine manufacturers have started to invest in CAES turbines only recently, since they didn't have an incentive to do this in the past due to high demand for conventional turbines (Ridge Energy Storage, Undated).
- The performance of CAES process equipment for compression and expansion has improved considerably, along with a drop in price (Farley, 2020a).
- While low cost storage in suitable salt formations is a reality, the electric utility industry has limited experience with the design, development and operation of underground gas storage caverns (Naeve, 2020).
- The high cost of disposing salt brine coupled with risk of locations being unsuitable geologically (Seltzer, 2017) prevented deployment for shorter duration systems. However, recovery of chemicals such as sodium, chlorine, potassium and magnesium from brine may provide some benefits to defray this high cost, especially for locations that are far from the ocean (Delgado, Beach, & Luzzadder-Beach, 2020).

Power Island Capital Costs

There are only two CAES plants currently in operation internationally: the 290 MW plant in Huntorf, Germany, and the 110 MW McIntosh Plant in Alabama, USA. The 270 MW Iowa Stored Energy Park (estimated at a total cost of $1,480/kW), which would have been the third CAES plant, was discontinued in 2011 due to the storage reservoir ultimately being unsuitable for the envisioned scale of the project (Aquino et al., 2017; Schulte, 2011).

The McIntosh Plant was deployed in 1991 and cost $591/kW at installation, which corresponds to $1,068/kW in 2020 USD; however, external funding was provided so the actual cost estimate may be higher. When improvements in performance of the powertrain for the McIntosh Plant are factored into the provided estimate, the total installed cost amounts to $1,200/kW. This cost includes additional permitting requirements over 1991 regulations along with selective catalyst reduction of nitrogen oxide costing a combined $90/kW in 2020 USD (HDR Inc., 2014). Additional site-specific costs for the substation and switchgear[9] as well as a 5-mile transmission line[10] were added and resulted in a total cost of $1,348/kW if the plant was built today (S. Wright, 2012).

The Electric Power Research Institute (EPRI) conducted an analysis of CAES plants at two different power levels (135 MW and 405 MW) as well as for a low fuel CAES system, hiring an EPC company to provide costs for installation and balance of plant (BOP) and a geologic company to provide air storage costs. Storage type in the analysis included a salt dome, bedded storage, depleted natural gas cavern, and an aquifer. The salt dome cost was noted to decrease with increase in depth in the report. Hence, even as duration increased, using a deeper cavern, the $/kW decreased. This made it difficult to parse out the individual $/kWh cost for the salt cavern. For bedded storage, the correlation of $/kW capital cost was found to be weak as a function of duration and therefore, $/kWh could also not be easily estimated. The total system cost for depleted natural gas caverns was the lowest, thus demonstrating these are the most cost-effective storage options (S. Wright, 2012). Table 14 has been adapted from the EPRI report (S. Wright (2012) and shows a detailed breakdown of costs of the 110 MW McIntosh Plant from 1991 as well as the same values adjusted to 2020 USD, including the additional substation/switchgear and transmission costs described earlier. The same report also provided a detailed cost breakdown for a 316 MW CAES system based on the Siemens SGT6-3000E. The total 2020 direct cost was $871/kW, while indirect costs added 21%, bringing the total to $1,052/kW. Adding $150/kW for substation and 5 miles of transmission brings the estimated 2020 cost to $1,202/kW.

Table 14. CAES Cost Component Breakdown

Cost Component	$/kW (1991 USD)	$/kW (2020 USD)
Major equipment, power island: Compression, expansion, motor-generators recuperator	$468	$520
Mechanical, electrical, and control procurement and construction	$175	$194
Civil procurement and construction	$116	$129
Indirects: EPC fees, engineering, heavy hauls, commissioning, and training	$218	$242
Air storage in domal salt (26 hours)	$101	$112
Storage ($/kWh)	$3.9	$4

[9] $91/kW (2012 USD)
[10] Assumes $1.2M/mile for 138 kV ($44/kW in 2012 USD)

Cost Component	$/kW (1991 USD)	$/kW (2020 USD)
Subtotal ($/kW)	**$1,078**	**$1,198**
Substation/switchgear ($12M for 138 kV/150 kVA)	$91	$101
Transmission (5 miles at $1.2M/mile 138 kV)	$44	$49
Grand total ($/kW)	**$1,213**	**$1,348**

For comparison, a report by Black & Veatch broke down the cost for a 262 MW, 15-hour plant as shown in Table 15 (Black & Veatch, 2012). The $1,091/kW (2020 USD) cost is on the lower side, likely due to low EPC (3.7% of direct costs) and owner's cost (7.1% of direct costs). The cavern cost of $29/kWh, obtained by dividing the reported $/kW by the duration, is on the higher side, while the powerhouse costs appear to be lower compared to other estimates. This highlights the complexity in cost assessment and breakdown of CAES. Adding $150/kW for substation/switchyard development and a 5-mile transmission line to the numbers in Table 15 brings the total cost to $1,241/kW in 2020 USD.

Table 15. Cost Component Breakdown for a 262 MW, 15-hour CAES Plant

Cost Component	$/kW (2012 USD)	$/kW (2020 USD)	$/kWh (2020 USD)	Percent of Direct Costs (%)	Percent of Total Cost (%)
Turbine	$270	$327			30.0%
Compressor	$130	$158			14.4%
BOP	$50	$61			5.6%
Cavern	$360	$436	$29		40.0%
EPC management	$30	$36		3.7%	3.3%
Owners' cost	$60	$73		7.1%	6.7%
Subtotal ($/kW)	**$900**	**$1,091**			
Substation/switchgear ($12M for 138 kV/150 kVA)	$91	$101			
Transmission (five miles at $1.2M/mile 138 kV)	$44	$49			
Grand total ($/kW)	**$1,213**	**$1,241**			

Siemens provided cost metrics for a CAES plant with numbers on the low end of the range investigated that were interpreted as future target costs, and have been reproduced in Table 16. These values provide additional insight into the individual cost share of categories. The target cost range was indicated to be between $875-1,375/kW (2020 USD) and, for the purposes of this study, the lower end of this range was not included in final estimate calculations for the reason described (Bailie, 2020a). The higher end of the range was assumed to include transmission interconnection costs. Bailie (2020h) indicated that a turnkey CAES plant will cost anywhere from $850-$1,250/kW depending on configuration and location-related factors. With typical durations < 24 hours, the $/kWh is < $50/kWh, assuming "a high-pressure holding reservoir can be used to store air (salt, depleted gas field, aquifers, hard rock mines)."

Table 16. CAES Cost Component Breakdown – Target Estimates

Cost Component	Description	Low Estimate ($/kW)	High Estimate ($/kW)
Power Island	Powertrain and equipment build	$400	$600

Cost Component	Description	Low Estimate ($/kW)	High Estimate ($/kW)
BOP/EPC	Location, labor rates, building/site permitting, transmission interconnection, natural gas pipeline, construction contingency	$425	$575
Reservoir	Salt cavern, aquifer, or hard rock mine	$50	$150
	Total	**$875**	**$1,325**

The same Siemens reference also provided values representing currently achievable estimates and have been reproduced in Table 17. The total project cost is 13 to 1.5x the previously mentioned target costs, which appears more realistic. Note that the cavern cost, which is discussed in more detail after capital cost, is considered to be on the high side at $14-22/kWh (Bailie, 2020a).

Table 17. CAES Cost Component Breakdown – Achievable Estimates

Cost Category	10-hour Duration (Low)	30-hour Duration (High)	20-hour Duration (Average)
160 MW expansion train ($/kW)	$309	$378	$344
115 MW compression train ($/kW)	$197	$241	$219
Core powertrain equipment total ($/kW)	**$506**	**$619**	**$563**
BOP ($/kW) including engineering, procurement, transmission interconnection, natural gas pipeline, and permitting	$159	$216	$188
Construction ($/kW) including labor, construction, and contingency to house powertrain	$375	$563	$469
Power island total ($/kW)	$1,097	$1,341	$1,219
Salt dome cavern ($/kW)	$219 ($22/kWh)	$406 ($14/kWh)	$313 ($16/kWh)
Total project cost ($/kW)	**$1,316**	**$1,747**	**$1,531**
Total project cost ($/kWh)	**$132**	**$58**	**$77**

The cost breakdown for the Bethel Energy Center 324 MW, 48-hour CAES plant was provided by Farley (2020d) and is shown in Table 18. Project development cost was 1.9% of direct cost, while estimated substation and 5-mile transmission line cost was $150/kW. At $131/kW, the substation and transmission amounted to 12.4% of costs including project development and was in line with the $150/kW estimated by (S. Wright, 2012).

Table 18. Capital Cost Breakdown for a 324 MW CAES Plant

Cost Category	Value ($/kW)
Above ground power island ($/kW)	1038
Project development ($/kW)	20
Powerhouse total ($/kW)	**1058**
Substation/switchgear and 5 miles of transmission	131
Powerhouse total + substation and five miles of transmission ($/kW)	**1189**
Salt dome cavern ($/kW)	131 ($2.73/kWh)

Final capital cost for this analysis was estimated based on an average of those found in the literature described above and was $1,153/kW. Values for highly specific technologies, such as low fuel CAES and those considered to be outliers or target costs, were excluded from the estimation process. Table 19 provides a summary of the capital costs found in the literature and details which values were included in the estimation process to achieve the final result. Note that for most sites, all-in costs were provided without substation/switchyard or 5 miles of transmission line costs. For additional reference, the final capital cost estimate for CAES with the addition of the substation/switchyard and transmission, estimated at $150/kW (S. Wright, 2012), would be $1,303/kW.

Table 19. Summary of CAES Capital Cost Estimates from Literature

Reference	Site/System	MW	Duration (hours)	Study Year	$/kW Capital Cost (Study Year USD)	$/kW Capital Cost (2020 USD) [(a)]
Aquino et al. (2017)	McIntosh Plant	110	26	1991	$1,068	$1,218
S. Wright (2012)	McIntosh Plant	110	26	1991	$1,198	$1,348
		136	26	2012	$1,042	$1,189
	Dresser-Rand SMARTCAES	135	8-24	2012	$1,204	$1,354
	Dresser-Rand SMARTCAES	405	8-16	2012	$983	$1,133
	Low fuel CAES	369	8-16	2012	$1,311	$1,461[(b)]
HDR Inc. (2014)	ADELE – Adiabatic CAES for Electricity Supply, Germany	90		2014	$712	$762[(c)]
		300-500	10	2014	1,758	$1,882[(d)]
Bailie (2020a)	Siemens	400-600		2020		$9,500[(c)]
		160	10-30	2020		$1,381

[(a)] Inclusive of substation/switchgear and five-mile transmission costs.
[(b)] Excluded from average calculation – special technology case.
[(c)] Excluded from average calculation – target cost estimate or low outlier.
[(d)] Excluded from average calculation – high outlier.

CAES plants may require a substation and transmission line to be built due to potential plant locations being located away from existing lines. For a 168 MW, 48-hour plant in Texas, these additional costs add up to $40-45 million (Farley, 2020b). These values are consistent with the numbers from Black & Veatch (2012). In Texas, the utility builds these costs into the rate base and the project owner has to put down collateral during construction in case of project incompletion. There is inconsistency in the literature as to whether these costs were included in estimated totals and additional substation/switchgear costs were integrated into those for which it was not explicitly included. Therefore, estimates from references that do not explicitly state whether these costs are included are arrived at by including these additional substation and transmission costs.

Information on scaling for CAES with respect to power capacity is not commonly available and has been adapted for this analysis based on estimates for scaling for PSH using data from the literature (Davitti, 2018). For PSH a 16% drop in system cost in $/kW for every 10x increase in power was estimated. An assumption has been made that the drop in system cost with scaling for CAES is approximately half that of PSH at 8%, since PSH benefits more from scaling due to the nature of the excavation and requirements for underground powerhouse expansion. The scaling factor for various power levels was determined by setting a 100 MW value to 1. For the CAES cavern, the scale was set to 1 for 800 MWh of storage based on data provided in the literature, with a similar 8% drop in price for every 10x increase in storage MWh capacity (Davitti, 2018).

Cavern Costs

Salt dome caverns are typically the most cost-effective option for CAES based on the fact they are both deep and wide, while bedded caverns, which have a shallower depth, are more expensive. The compressed-air storage pressure increases with depth and has an associated decrease in $/kWh (Farley, 2020b). For example, at 3,500 feet deep, 3,000 pounds per square inch is attained. With the right depth and width of salt domes, the cavern cost can be as low as $2/kWh, but oftentimes differs based on geology and region. Caverns in West Texas, for example, typically have shallow depth and need more wells for the same amount of storage, thus increasing cost. Caverns in Michigan, Arizona, and Colorado are bedded salt caverns, with costs > $10/kWh (Farley, 2020b).

Most salt caverns are 800 to 900 feet deep with a typical diameter of 70 to 85 feet. The maximum storage pressure is measured in pounds per square inch and is calculated as 0.8 multiplied by the cavern depth when the typical diameter range mentioned previously is assumed. Examining this type of cavern is relevant as midstream oil companies (those responsible for processing, transporting, and marketing oil) in the US often own salt caverns[11] and if natural gas were to be replaced by hydrogen over time, these caverns may be repurposed for both CAES and hydrogen storage. Experts in this field estimate that there are enough existing caverns to meet CAES and hydrogen storage needs in the future following these assumptions. For this analysis, natural gas fuel supplied from pipes is considered but the costs are not explicitly stated in any report; hence, it is assumed that these costs are accounted for in BOP, EPC, and owner's cost (Bailie, 2020b). Bailie (2020h) noted that salt, depleted gas fields, aquifers, and hard rock mines are all different types of potential reservoirs that can be used for CAES. The "pressure holding capability" of the reservoir determines its storage capacity and cost. For gas fields, it is important to minimize any remaining entrained hydrocarbons.

For CAES using salt caverns, the cost is initially estimated to be $3.5-4/kWh (Bailie, 2020c), although a cavern cost of $2/kWh was estimated in a 2012 report by EPRI (S. Wright, 2012). A detailed breakdown of the 110 MW McIntosh Plant in the same report, however, showed a cavern cost of $4.3/kWh, which is in line with the number provided by Siemens (Bailie, 2020c). It is unclear if this also includes the cost of dissolving existing salt and disposing of the resultant brine. To be conservative, a 50% adder is used in this analysis to arrive at a total estimated cavern cost of $6/kWh, which is midway between the $2-10/kWh estimated by Luo et al. (Luo, Wang, Dooner, Clarke, & Krupke, 2014), while cavern cost was estimated at $2.7/kWh for the for the 324 MW, 15500 MWh Bethel Energy Center plant of 48-hours duration (Farley, 2020d). Note that this study does not consider bedded salt caverns, which are more expensive. Cavern costs for salt domes were estimated in the $2-4/kWh range, while they were expected to be > $10/kWh for bedded salt caverns. The cost depends on depth of the cavern, since higher compression pressures are possible at increasing depth, and also on the salt formation thickness or width (Farley, 2020b). Hunter et al. (In Press) reported $2/kWh for salt caverns. While the cavern cost for 24-hour storage was estimated at $4.50/kWh, this dropped to $3.5/kWh for 48-hour storage (Bailie, 2020f). One of the cost drivers is solution mining. For caverns that already are solution mined, the costs can drop further (Bailie, 2020g).

[11] These caverns are predominantly located on the gulf coast of the US.

An average of these numbers ($6/kWh, $3/kWh, and $2/kWh) yields $3.66/kWh for salt dome caverns and is the final estimate for cavern cost provided in this analysis. For historical comparison, an estimate from the 1980s placed CAES cavern cost at $18/kWh (Willett, 1981). It is unclear if this is due to significant decrease in cavern costs or simply to site-specific issues. Table 20 provides a detailed category cost breakdown for a 100 MW, 1,000 MWh CAES plant, with a comprehensive reference list for each category.

Table 20. Price Breakdown for Various Categories for a 100 MW, 1,000 MWh CAES

Cost Category	Nominal Size	2020 Price	Component	Additional Notes	Source(s)
Power island and BOP	100 MW	$1,153/kW	Power island and BOP capital cost	Includes powertrain, labor, permitting, transmission interconnection, natural gas pipeline, construction contingency	Aquino et al. (2017); Bailie (2020a); Bailie (2020h); Black & Veatch (2012); Farley (2020b, 2020d); HDR Inc. (2014); S. Wright (2012)
Cavern	1000 MWh	$3.66/kWh	Cavern capital cost	Salt dome	Bailie (2020b, 2020c, 2020f, 2020g, 2020h); Farley (2020b, 2020c); S. Wright (2012); Hunter et al. (In Press)
Indirect costs (owner, engineering, construction management, contingencies)		45% of direct costs, included in above numbers		All prices referenced include indirect costs; reference is from 1981, hence probably needs to be updated	Aquino et al. (2017); Bailie (2020g)
O&M		$10.30/kW-year	Fixed O&M cost		Aquino et al. (2017); Farley (2020b); HDR Inc. (2014); Industry Stakeholder (2020b); S. Wright (2012)
Performance metrics			Calendar life		Aquino et al. (2017); EASE (2016); G. J. May et al. (2018)
Performance metrics			RTE		Aquino et al. (2017); EASE (2016); G. J. May et al. (2018); Bailie (2018);Black & Veatch (2012); J. Li et al. (2017)

To determine the 2020 price range, the powertrain-related costs are multiplied by 0.9 and 1.1, respectively, to get the low and high end of the price range, with cavern cost of $2/kWh and $10/kWh, respectively. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and caverns.

There is a trend in Europe to replace natural gas usage in CAES with green hydrogen produced by renewables. A current Siemens CAES project in Denmark uses hydrogen produced by renewables as fuel instead of natural gas. It is worth noting that the country has a larger interest in using hydrogen in all gas turbines, not just CAES, and is pushing for 100% conversion to hydrogen by the year 2030. The European Union is also making a push for green electricity generation by incentivizing renewable-generated hydrogen for storage, including CAES. In discussion with Siemens, it was noted that for fossil-fuel-free CAES using hydrogen storage, 10 gigawatts (GW) with 30 hours of storage was the suggested system size (Bailie, 2020b).

CAES plants that use hydrogen instead of natural gas can store the gas in cylindrical salt caverns, so there is no reason to assume the hydrogen cavern cost would be different from cavern cost for compressed air.

EPC and Owner's Cost

Total plant cost for CAES is typically heavily influenced by non-trivial components including the choice of design, procurement of the BOP, construction and installation, contingency fees, and specific costs associated with both the site and owner. These components can oftentimes be the most dominating costs, even over major plant equipment. Additionally, costs associated with EPC fees, overhead, construction, and contingencies are typically multipliers or percentages of other costs. If other cost items are overestimated or if equipment costs are increased, these costs will rise as well (Aquino et al., 2017).

Design choices play a large role in determining EPC fees and contingencies due to perceived risks in a less prominent technology. Project management is argued to be of crucial importance and helps to achieve higher cost effectiveness for CAES investment. Oftentimes, risk and responsibility for EPC can be split between the plant owner, the EPC contractor, and various engineers, contractors, and construction management firms under contract. If the project is not well-designed prior to contracting an EPC, costs may increase as alterations are made or risk increases (Aquino et al., 2017).

EPC is estimated to be approximately 20% of overall project costs. Fees and overhead make up 7%, contingency is 6%, and the remaining 7% includes profit (Aquino et al., 2017). In this model, EPC is not controlled by the plant owner. In other models, the plant owner takes more control over project execution, with the EPC managing specific contracts. The plant owner may also choose to have total control over project execution by handing out prime contracts to multiple contractors. This gives a range of project management approaches that may be useful for cost reduction and shifting risk.

An EPRI report from 1981 looking at the design of underground CAES shows the breakdown for indirect cost as percentage of total direct cost provided in Table 21 (Willett, 1981). Based on these numbers there is significant room for cost adjustment.

Table 21. Percent of Total Direct Costs by CAES Cost Component

Cost Component	% of Direct Cost
Owner's cost	15%
Engineering	5%
Construction management	10%
Contingencies	15%
Total	**45%**

O&M Costs

Fixed O&M, measured in $/kW-year, for CAES typically includes labor, safety, site maintenance, communications, training, office and administration, and other similar expenses. A plant will typically require two to three full-time staff depending on the size (referred to here as labor-related fixed O&M) and major maintenance, which is dependent on the number of operating hours each year and can vary year to year (referred to as maintenance-related fixed O&M). Variable O&M costs, measured in $/MWh, include chemical treatment and makeup water for the cooling tower, catalyst replacement, and other non-fuel consumables (S. Wright, 2012).

Estimates for both fixed and variable O&M components are typically not provided in great detail in the literature. General estimates place total fixed O&M in the range of $12.3-$20.1/kW-year and variable O&M costs to be in the range of $1.7-2.5/MWh (Aquino et al., 2017; Black & Veatch, 2012; HDR Inc., 2014). EPRI conducted a detailed analysis of O&M costs for CAES, described in higher detail later in this section, and estimated basic non-fuel variable O&M to be slightly lower than the other literature at $1.6/MWh (S. Wright, 2012). Conversation with a CAES developer indicated that basic variable cost was $0.25/MWh. Note that, to remain consistent across technologies in this report, the basic variable O&M was determined from the average of multiple values reported in the literature (described in detail in the lithium-ion section) and is set to $0.5125/MWh for all technologies in this analysis.

Table 22 provides O&M information from a few CAES sites found in the literature where the size of the plant was included. Note that fixed O&M in this table is inclusive of both labor-related fixed O&M costs and maintenance-related fixed O&M costs. More granularity for labor and maintenance-related O&M costs was found in an EPRI study (S. Wright, 2012), details are shown in Table 23.

Table 22. Fixed and Variable CAES O&M Costs from Various Literature Sources

Reference	Estimate Year	MW	Duration (hours)	Fixed O&M ($/kW-year) [(a)]	Variable O&M ($/MWh) [(a)]	Fixed O&M ($/kW-year) (2020 USD)	Variable O&M ($/MWh) (2020 USD)
Aquino et al. (2017)	2017	100		$19	$2.3	$18.38	$2.22
Black & Veatch (2012)	2017	262	15	$11.6	$1.55	$12.89	$1.72
HDR Inc. (2014)	2014	300-500	10	$18.78	$2.3	$20.08	$2.46

[(a)] Values measured in study year USD

As previously mentioned, there is also an annual fixed O&M cost that is associated with maintenance required for a plant and is determined as a function of the plant's total energy generated each year. The literature reported this as a non-annual cost, unlike in this analysis, and provided an estimate of $3.7/MWh (2012 USD) for this component (S. Wright, 2012). From the total number of plant starts per year and the hours required per start, the capacity factor was calculated to be 45.6%. Conversation with a CAES developer indicated that long-term service contracts are typically acquired for maintenance and that, for a system with a 130 MW compressor train and 324 MW generator train, the hourly rate is typically $168/hour for generation and $43/hour for the compressor (Farley, 2020b). Depending on operating power during generation, this translates to different $/MWh, with increasing values at lower power levels. The average $/MWh for generation power in the 41-100% range corresponds to $1.71/MWh, while the average for compression was found to be $0.39/MWh. For every 1 MWh generated, only 0.56 MWh of electricity is needed for compression on average (Farley, 2020b) so the charging maintenance O&M is $0.22/MWh generated. Adding values for generation and compression, and applying a 45.6% capacity factor, the maintenance O&M is estimates to be $4.32/MWh. This value is in line with the estimate provided in S. Wright (2012). Since maintenance cost is a fixed hourly cost, the $/MWh value is converted to $/kW-year taking power generation into account at 60% of maximum output. Using an average value of $4.21/MWh, the maintenance-related O&M comes out to $10.30/kW-year. The numbers were verified from the long-term service agreement hourly rate for generation and compression, incorporating the capacity factor and generation power. For this study, the $10.30/kW-year estimated is used for annual fixed O&M cost related to maintenance.

Note that the compressor and generator efficiencies vary with power, affecting fuel and air costs and the RTE. In other words, for CAES the operating conditions significantly affect RTE, which makes RTE-related losses relevant for the annualized cost analysis included at the end of this report. Heat rate and air compression costs as a function of generator output were provided from discussions with a CAES developer (Farley, 2020c). At the average generation of 41% of maximum output range, the costs added up to $14.4/MWh, assuming a 82% discount of electricity prices net of spinning reserves credit, close to the $15.1/MWh provided (Farley, 2020b). The discrepancy can be attributed to the fact that the heat rate and air consumption per unit energy output varies with output power.

Fixed O&M overall, including both labor and maintenance components, was provided in the literature for two CAES plants: a 100 MW system and a 408 MW system (S. Wright, 2012). Details from this report are reproduced in Table 23. It is assumed that the smaller plant requires two full-time staff and three are required for the larger. The labor component of fixed O&M is estimated at $6/kW-year for the 100 MW system and $2.2/kW-year for the 408 MW system in 2012 USD based on information shown (S. Wright, 2012).

Table 23. O&M Costs and Operational Parameters for Multiple CAES Plants

O&M Cost Component	Parameter	100 MW Plant	408 MW Plant
Variable O&M ($/MWh)		1.78	1. 78
Maintenance-related fixed O&M	Major maintenance cost ($/MWh)	4.10	4.10
	Operation hours per year	4,000	4,000
	Plant starts per year	350	350
	Hours per start	11.43	11.43
	MWh annual	400,000	1,632,000
	Total maintenance-related fixed O&M ($/year)	1,476,000	6,022,080
	Total ($/kW-year) (2012 USD)	14.76	14.76
	Total ($/kW-year) (2020 USD)	16.40	16.40
Labor-related fixed O&M	Labor (persons per shift)	2	3
	Shifts per day	3	3
	Total labor per day (persons x shifts)	6	9
	Salary per persons	$100,000	$100,000
	Total labor cost	$600,000	$900,000
	Labor-related fixed O&M ($/kW-year) (2012 USD)	6	2.21
	Labor-related fixed O&M ($/kW-year) (2020 USD)	6.67	2.45
Total fixed O&M	**Total Fixed O&M ($/kW-year) (2012 USD)**	**20.76**	**16.97**
	Total Fixed O&M ($/kW-year) (2020 USD)	**23.07**	**18.85**

Note that the EPRI study increases labor required by 50% when plant capacity increases from 100 MW to 408 MW. For our study, similar to the PSH labor-related O&M approach, an assumption has been made that labor costs double for every order of magnitude increase in plant power. This yields labor-related fixed O&M costs of $6/kW-year at 100 MW, $1.2/kW-year at 1,000 MW, and $0.48/kW-year at 10,000 MW.

Table 24 shows the final estimated O&M costs across various plant sizes for this analysis. The costs were assigned 0.9 and 1.1 multiples to establish the range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and caverns.

Table 24. Fixed and Variable O&M CAES Cost Estimates by Power Capacity

Component	100 MW System	1,000 MW System	10,000 MW System
Full-time staff	2	4	8
Total labor cost ($M)	$600,000	$1,200,000	$4,800,000
Labor-related fixed O&M ($/kW-year)	6	1.2	0.48
Maintenance-related fixed O&M ($/kW-year)	10.30	10.30	10.30
Total fixed O&M ($/kW-year)	16.30	11.50	10.78
Total variable O&M ($/MWh)	0.5125	0.5125	0.5125

Performance Metrics

Resources from the literature that provided calendar life and total cycle life for CAES systems estimated they are capable of 10,000 cycles and have an approximate 30-year usable life (Aquino et al., 2017; EASE, 2016; G. J. May et al., 2018). Assuming a calendar life of 30 years, with 5% of that time allocated to downtime, this corresponds to a total cycle life of 10,403 cycles.

With regards to RTE, the stated range from the literature was typically between 50% and 70%, with higher estimates being more common (Aquino et al., 2017; Bailie, 2018; Black & Veatch, 2012; J. Li et al., 2017; G. J. May et al., 2018). For adiabatic systems specifically, RTE is estimated to be higher (> 70%) due to not having to reheat the cavern as the heat generated from compression is reutilized (Aquino et al., 2017; EASE, 2016). Conversations with Dresser-Rand/Siemens provided a method to estimate the RTE by dividing the electrical output of the system by the sum of the electrical input to the compressor and the energy that could have been alternatively generated through the natural gas used. This calculation assumes a 49% conversion efficiency when going from natural gas to electricity. Following this methodology, if heat capture in the compression cycle is assumed, the RTE is expected to be 74.6%. However, if the same system instead utilizes the actual lower heating value of the natural gas fuel, the RTE is calculated to be lower at approximately 52%. This analysis assumes the lower RTE value to be a more accurate representation as, if one were to compare the same system to a combustion turbine unit, the lower heating value would be used to determine efficiency (Bailie, 2018).

Conversations with representatives from Siemens provided a range of response times for CAES systems between 3.33 and 10 minutes depending on mode change (Siemens Energy, 2018). These values are shown in detail in Figure 6.

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 52%. Following these two items, it can be determined that the cost due to RTE losses is $0.028/kWh for CAES.

Results

Figure 6 provides cost estimates for 10, 100, and 1000 MW CAES systems at 4- and 10-hour durations each. Given the maturity level of the technology, values are not expected to change significantly by 2030, so the same cost estimate is provided across both years.

Compressed Air Energy Storage
2020 & 2030 Cost & Performance Estimates

			100 MW				1,000 MW				10,000 MW			
			4 hr		10 hr		4 hr		10 hr		4 hr		10 hr	
	Parameter	Units	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
ESS Cost	Capital Cost Related to Turbine, Compressor, BOP, and EPC Mangement	$/kW	[1038 - 1268] 1153		[1038 - 1268] 1153		[955 - 1167] 1061		[955 - 1167] 1061		[878 - 1073] 976		[878 - 1073] 976	
ESS Cost	Cavern Capital Cost	$/kWh	[2 - 10] 3.66	[2 - 10] 3.09	[2 - 10] 3.66	[2 - 10] 3.09	[2 - 9] 3.37	[2 - 9] 2.85	[2 - 9] 3.37	[2 - 9] 2.85	[1 - 7] 3.10	[1 - 7] 2.62	[1 - 7] 3.10	[1 - 7] 3.00
	Total ESS Installed Cost*	**$/kW**	**[1046 - 1308] $1,168**	**[1044 - 1302] $1,165**	**[1058 - 1368] $1,190**	**[1055 - 1353] $1,184**	**[962 - 1204] $1,074**	**[961 - 1198] $1,072**	**[973 - 1259] $1,094**	**[970 - 1245] $1,089**	**[885 - 1107] $988**	**[884 - 1102] $986**	**[895 - 1158] $1,007**	**[893 - 1145] $1,002**
	Total ESS Installed Cost*	**$/kWh**	**[261 - 327] $292**	**[261 - 326] $291**	**[106 - 137] $119**	**[105 - 135] $118**	**[241 - 301] $269**	**[240 - 299] $268**	**[97 - 126] $109**	**[97 - 124] $109**	**[221 - 277] $247**	**[221 - 276] $247**	**[90 - 116] $101**	**[89 - 115] $100**
Operating Costs	Fixed O&M	$/kW-yr	[14.51 - 17.73] 16.12				[8.84 - 10.8] 9.82				[7.87 - 9.61] 8.74			
Operating Costs	Variable O&M	$/MWh	0.5125				0.5125				0.5125			
Operating Costs	System RTE Losses	$/kWh	0.0005				0.0005				0.0005			
Performance Metrics	Round Trip Efficiency	%	52%				52%				52%			
Performance Metrics	Response Time	sec												
Performance Metrics	Cycle Life	#	10,403				10,403				10,403			
Performance Metrics	Calendar Life	yrs	30				30				30			
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	30				30				30			

Scenario	Response Time
Cold start to full generation	10 min
Online to full power	5 min
Full speed (no load) to full load	3.33 min
Offline to full load	4 min

* Does not include decommissioning costs

** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Figure 6. CAES Cost and Performance Estimates by Power Capacity and Energy Duration for 2020 and 2030

R&D Trends in CAES

Future focus areas for CAES are expected to be the following:

- Improvements in powertrain performance are expected to lower unit power costs. For example, the 110 MW McIntosh Plant capacity was upgraded to 136 MW using the same powertrain (S. Wright, 2012).
- To increase operational flexibility, specifically ramp rate, independent operation of compressors and expanders enable 33% higher ramp rate (Bailie, 2020a; Farley, 2020b). Development and refinement of control systems that enable such operation while taking into account impact on system efficiency and O&M costs are expected to be an area of continued investment.
- Improving system efficiency by lowering heat rate and improvements in heat recuperation over a wide range of operating conditions are also expected to be focus areas for the future.
- Using electricity generated by renewables for air compression.
- Existing natural gas caverns are a logical choice for compressed-air storage, hence technology for removal of entrained natural gas may become important.
- Salt caverns with the optimal depth and width cost $2/kWh, while bedded salt caverns, prevalent in Michigan, Arizona and Colorado, cost > $10/kWh due to lack of depth (Farley, 2020b). In areas such as Texas, where wind dominates, 12-24 hour storage is needed to avoid curtailment related to transmission bottleneck or electricity price going to $0, with utilities preferring combustion turbines at lower duration. Therefore, efforts to reduce the cost of storage via engineering design are expected to gain traction.
- As long-duration energy storage (diurnal and seasonal) becomes more relevant, it is important to quantify cost for incremental storage in the cavern. The incremental cost for CAES storage is estimated to be $0.12/kWh. For example, the cavern for the 324 MW, 16,000 MWh Bethel Energy Center project has a capacity of 4 million barrels. To increase the size by 20%, a 63-day leaching at 3,000 gallons per minute is needed, estimated to cost $383,000 including electricity, water, and labor (Naeve, 2020), which amounts to $0.12/kWh, or $1.2/kW for the 324 MW plant. Hence, as long duration storage becomes prevalent, increasing the storage capacity of existing salt domes by solution mining is expected to gain traction due to its cost-effectiveness.
- The largest existing cavern has a volume of 17 million barrels (Naeve, 2020), which corresponds to about 64,000 MWh of storage. The Bethel Energy Center cavern can be expanded to 10 million barrels, while ATMOS Energy is developing a 10-million-barrel cavern on the west of the existing Bethel dome, corresponding to nearly 40,000 MWH of storage. As demand for long-term storage increases, it is expected that caverns of similar size will be developed.
- There are about 130 caverns at Mt. Belview constructed on a large salt done, with web thickness between caverns much less than the 250 to 300 ft required today. For large projects, it is expected that multiple caverns within a single salt dome will be developed and connected in parallel.

- Long-term service contracts are based on number of operating hours; therefore, operating the system at low power levels where efficiency may be higher increases O&M costs. The efficiency for compression and generation depends on operating power level. Flattening the efficiency curve such that high efficiency is obtained in a wider operating range would be useful and is expected to be a priority.
- Migration to green hydrogen produced from renewables to replace natural gas is a trend in Europe, while in the US natural gas prices are low. If there are regulations that account for carbon footprint in the overall cost, green hydrogen may dominate in the US as well. Hence, locating CAES plants near electrolyzer plants powered by renewables and coupled with hydrogen storage in salt or natural gas caverns may gain traction (Bailie, 2020f).

Pumped Storage Hydropower

PSH is a mature technology that includes pumping water from a lower reservoir to a higher one where it is stored until needed. When released, the water from the upper reservoir flows back down through a turbine and generates electricity. There are various configurations of this technology, including open-loop (one or more of the reservoirs are connected to a natural body of water) and closed loop (reservoirs are separate from natural waterways). Existing turbine technologies also offer different features and capabilities, including fixed speed, advanced speed, and ternary.

Indirect vs. Direct Costs

The average MW capacity level for PSH plants has increased from 600 MW in 1973, to 1,400 MW in 1991, to > 2,000 MW today, with the current largest plant in the US being 3,000 MW (Bath County Pumped Storage Station, Virginia). Several factors may be responsible for this trend, the main ones being permitting for location and size, and possibly the extent of variable renewable penetration on the grid.

Fixed-speed PSH units are the most commonly deployed type, with frequency regulation ancillary service provided only in the generation mode and spinning reserve in both generation and pumping mode. Adjustable-speed units, on the other hand, provide ancillary services in both pumping and generation mode, and cost about 25-30% more than fixed-speed units (Key, 2011). Ternary units offer higher operational flexibility in terms of faster switching between charge and discharge (Miller, 2020b). However, ternary units cannot match the ramp rates needed for load following and frequency regulation offered by variable-speed units with modern power electronics. Since most regions in the US need switching between pumping to generation mode in < 10 minutes, the fast switching speed offered by ternary units is not needed in the US. There are two PSH plants using ternary units in Europe, where the grids do not offer much flexibility in terms of generation sources, increasing the need for fast switching between modes (Miller, 2020b). While ternary units are known for their fast switching of < 30 seconds, switching times of < 10 minutes are sufficient for the US, with a greater need for fast ramping capability related to load following and frequency regulation, which adjustable-speed units offer. Despite the advanced features described above, no adjustable-speed or ternary units are in operation in the US today and only two adjustable-speed units internationally, and it has been stated that regional transmission organizations are less interested in this technology as there is enough flexibility in generation to meet the needs of the US system (Miller, 2020a).

A hypothetical 1,000 MW PSH system is made up of four units, each rated at 250 MW, with operating range of 125-250 MW. While durations in the past have been 10-20 hours with weekend recharge, going forward, PSH plant duration is expected to be between 8-10 hours with daily recharge (Miller, 2020a). However, there is renewed interest in long-duration storage of > 24 hours.

Capital cost for PSH plants is typically split between direct and indirect costs, also referred to as contingency (HDR Inc., 2014; Manwaring, Mursch, & Erpenbeck, 2020; Miller, 2020a). Indirect costs are typically considered to be 15-33% of direct costs (HDR Inc., 2014; Manwaring et al., 2020; Miller, 2020a). Table 25 shows what is typically included under each of these two categories (HDR Inc., 2014).

Escalation rates corresponding to the Electric Power Distribution for Industrial Electric Power Index were used to get 2020 prices from historical data. In the next phase, escalation factors specific to categories such as civil and infrastructure (C&I), construction material, and powertrains will be used to estimate 2020s price from historical data (Key, 2011).

Table 25. Direct and Indirect PSH Cost Components

Direct Costs	Indirect Costs
Materials	Preliminary engineering and studies (planning studies, environmental impact studies, and investigations)
Construction of project features (tunnels, caverns, dams, roads, etc.)	License and permit applications and processing
Equipment cost	Detailed engineering and studies
Labor for construction of structures	Construction management, quality assurance, and administration
Supply and installation of permanent equipment	Bonds, insurances, taxes, and corporate overheads
Procurement of water rights for reservoir spill and make up water	

The direct capital component of a conventional PSH facility includes two water reservoirs, a waterway to connect them, and a power station with one or more pumps/turbines. Reservoir costs can consist of various components including roller-compacted concrete, cleaning, emergency spillways, excavation and grout, and inlet/outlet structures and accessories (Bailey, 2020). Reservoir costs are addressed in greater detail in the next section.

Placing indirect costs in the range of 15-33% of direct costs from HDR is consistent with information provided from Absaroka Energy, the developer of the 400 MW, 3,400 MWh Gordon Butte PSH Project (Bailey, 2020). The electromechanicals were $1,044/kW and C&I was $1,666/kW for a total of $2,710/kW direct cost. Indirect costs comprised engineering and construction management, financial costs such as project contingency and insurance, and development costs including permitting, licensing, and site acquisition. Indirect costs amounted to 24% of direct cost (Bailie, 2020e) and included preliminary engineering studies as well as engineering and design management as part of their total estimated indirect costs. Regardless of nomenclature for specific items, indirect costs are expected to fall somewhere in the stated range and differ between the upper and lower values based on project complexity.

It should be noted that land price is typically not considered within O&M costs, since land cost varies depending on who owns the land. PSH O&M costs are estimated in the section that follows reservoir costs.

Capital Costs

A 2012 report from Black & Veatch estimated a wide total cost range of $1,349/kW to $4,048/kW for PSH and gave an average cost of $2,698/kW for a 500 MW, 10-hour plant in 2010 USD (Black & Veatch, 2012). The breakdown of costs in the report has been reproduced in Table 26. Note that, in order to provide both upper and lower reservoir costs in the table, the upper reservoir cost of $520/kW (2020 USD) was doubled to account for the lower reservoir since its cost was not explicitly provided (Black & Veatch, 2012) and that if there is an existing reservoir, the total reservoir cost will be half of the costs used in this study.

Table 26. Breakdown of PSH Capital Cost Components for a 500 MW, 10-hr Duration Project, Adapted from Black & Veatch (2012)

Cost Component	$/kW (2010 USD)	$/kW (2020 USD)	Percent of Total Direct Costs	Percent of Total Installed Cost
Upper and lower Reservoir	840	1,016		32.2%
Tunnels	135	163		5.1%
Powerhouse excavation	80	97		3.0%
Powerhouse structure, equipment, BOP	835	1,010		31.3%
Total direct costs	**1,910**	**2,311.12**		**71.5%**
EPC management services (project management, construction management, and contingency fees)	390	472	20.4%	14.6%
Owners' cost	370	448	34.4%	13.9%
Total indirect costs	**756**	**915**	**54.8%**	**28.5%**
Total installed cost	**2,650**	**3,07**		

For a 10-hour plant, the reservoir cost was found to be $104/kWh, higher than the $77/kWh without contingency fee and very close to the $103/kWh inclusive of contingency fees obtained from conversations with a PSH developer (Miller, 2020a).

The cost for tunnels as well as powerhouse excavation shown in Table 26 are each a small percentage of total installed cost at approximately 5% and 3%, respectively. Powerhouse structure and electromechanical equipment, on the other hand, which include costs related to tunnels, excavation, structure, and electromechanicals, is higher at 31% of total cost. This amount is in line with estimates provided by Miller (2020a); however, EPC and owner's costs combined are higher than Miller's estimates at approximately 55% of direct costs and 28.5% of total installed costs (Manwaring et al., 2020; Miller, 2020a).

In the same 2012 report, the authors additionally provided a more detailed breakdown of costs for a similar 500 MW PSH plant where the costs for each category were shown to be 89% of those in Table 26. Table 27 shows the breakdown details. The indirect costs in the additional estimates were found to be only 25% of direct costs, thus showing a wide range of indirect costs as a percent of direct cost (25-55% in the 2012 report). Indirect costs in the additional plant analysis include project management and design engineering at 5% of direct cost, construction management and startup support at 5%, and contingency at 15%. Due to lower direct and indirect costs, the total project cost of $2,565/kW was found to be only 85% of the cost shown in Table 26. This range of $2,565/kW to $3,231/kW provided by the two analyses within the same report gives an idea of how costs can vary in one study (Black & Veatch, 2012), based on assumptions of direct and indirect costs.

Table 27. Cost Breakdown for a Representative 500 MW, 10 hour PSH Plant, Adapted from Black & Veatch (2012)

	Value	Value ($/kW)
Rated capacity (MW)	500	
Duration (h)	10	
Total reservoir cost ($M, 2020 USD)	457	
Reservoir cost ($/kWh) (without contingency)	91	
Tunnels ($M)	73	145
Powerhouse excavation	42	85
Powerhouse structure, equipment, and BOP	454	908
Total direct project cost ($M)	1,026	2,052
Project management and design engineering at 5% of total direct cost ($M)	51	103
Construction management and startup support at 5% of total direct cost ($M)	51	103
Contingency at 15% of total direct cost ($M)	154	308
Total project cost ($M)	**1,283**	**2,565**

Conversations with HDR Engineering provided a breakdown of costs for PSH in both 8-10 hour and 18-20 hour duration ranges as shown in Table 28 (Miller, 2020a). Note that minor adjustments made to individual component costs allow values to sum to the total costs provided.

Table 28. Low and High PSH Cost Estimates by Category, Adapted from Miller (2020a)

Cost Category	Low Estimate ($/kW)	High Estimate ($/kW)
Total cost	$2,500	$3,500
Electromechanical cost	$585	$659
C&I	$1,915	$2,841
Contingency fees (25% of total cost)	$625	$875
Total cost without contingency fees	$1,875	$2,625

In order to also estimate the reservoir cost from the above values, it was assumed that the lower $2,500/kW total cost corresponds to a project with an average of the lower duration range (9 hours) while the higher $3,500/kW total cost corresponds to a project at the average of the higher duration range (18 hours). Following this assumption, the $/kWh reservoir cost with contingency was calculated to be $103/kWh based on the relationship between the total cost and the assumed duration of each system. This value is in line with earlier estimates for reservoir cost of $104/kWh (Black & Veatch, 2012).

Subtracting the estimated $103/kWh reservoir cost from the total C&I cost, the powerhouse-related C&I cost was estimated at $988/kW. The sum of the powerhouse C&I and electromechanical costs comes out to $1,500/kW and is greater than the $1,260/kW reported in the 2012 Black & Veatch report, but the total project cost is similar as the latter assumed indirect costs to be 55% of direct costs (Black & Veatch, 2012). Note that these costs include a 33% contingency fee on direct costs (or 25% of project total). Table 29 shows the cost breakdown for individual components without contingency fee added.

Table 29. PSH C&I Cost Components without Contingency Fees

Cost Component	Value
Reservoir cost ($/kWh)	77

Cost Component	Value
Electromechanical cost ($/kW)	467
C&I for powerhouse ($/kW)	742
Contingency fees (% of above costs)	33%

According to Miller (2020a), the non-civil electromechanical part costs $550 to $650/kW depending on head. The greater the head, the smaller the electromechanical components need to be to provide same power. It should be noted that the head also affects C&I costs. The higher the head, the smaller the reservoir needed to get the same energy output. The smaller electromechanical size lends itself to lower C&I for powerhouse. The Goldendale Energy Storage Project has a head of 2,400 feet and is expected to cost $1,800/kW for C&I. Higher head for the project also reduced tunnel excavation costs due to the fact the pump/turbine centerline depth below the lower reservoir bottom decreased with increasing head (Miller, 2020a).

HDR Engineering performed an analysis in 2014 of three PSH projects: Swan Lake North, JD Pool, and Black Canyon (HDR Inc., 2014). Plant details and costs estimated by both the original project developer and HDR's own estimates for the specific plants have been reproduced in Table 30.

Table 30. Project Details and Cost Estimates for Three PSH Plants, Adapted from HDR Inc. (2014)

Component	Swan Lake North	JD Pool	Black Canyon
Head (feet)	1,253	2,000	1,063
Power capacity (MW)	600	1,500	600
Energy duration (hours)	8.8	11	9.5
Energy capacity (MWh)	5,280	12,100	5,700
Project developer cost estimate ($/kW) (2014 USD)	$2,300	$2,100	$1,500
HDR cost estimate ($/kW) (2014 USD)	$2,250	$2,500	$2,150
HDR cost estimate ($/kW) (2020 USD)	$2,406	$2,674	$2,299

An estimate of reservoir cost was derived from the information provided in Table 30. The relationship between total $/kW plant cost and plant duration was examined across the three sites. It is assumed that the change in total cost for an increase in duration is a good proxy for determining the $/kWh reservoir cost for a plant given that increasing duration consists of increasing reservoir size. This calculation gave an estimated $142/kWh for reservoir cost using this data set. Ultimately, this estimate was determined to be a high outlier when compared to reservoir costs estimated or provided from other sources and was excluded from the overall calculation in this analysis. Note that reservoir costs are affected by head and duration. Higher head lends itself to lower reservoir size for the same amount of stored energy, while longer duration benefits from scale, as the fixed costs related to equipment procurement and planning becomes less important, with incremental cost for additional stored energy dominating. It should be noted that, due to limited data availability, the relationship would likely be more robust with estimates from additional projects with a wide range of durations. From the data available, for an 8-11 hour duration range, the total plant cost was estimated to be between $2,300 and $2,637/kW following the relationship established. Assuming these costs do not include substation/switchgear and transmission lines, the total costs are at the lower end of the $2,500 to 3,500/kW range provided in conversations with developers (Manwaring et al., 2020; Miller, 2020a).

An analysis by Black and Veatch for the same three sites analyzed in the 2014 HDR report, except with adjusted MW capacities, showed total project cost to be in a much tighter range of $2,844-2,954/kW compared to the range estimated above (Black & Veatch, 2016). An earlier HDR analysis from 2010 of representative PSH projects, on the other hand, gave a higher total project cost range of $3,025-3,307/kW, inclusive of an assumed 5-mile transmission line. Excluding the transmission line cost the range amounted to a total project cost of $2,915-3,217/kW.

Scaling for PSH with respect to MW capacity was completed using data from Davitti (2018). This resulted in a 35% drop in system cost for every 10x increase in power. The scale factor was adjusted to reflect a 16% drop in system cost in $/kW for every 10x increase in power to be conservative and not overestimate the effect of scaling. This is because there are several factors that affect cost, including tunnel length to storage head ratio, storage head, geology of the location. The scaling factor for various power levels was determined by setting the 100 MW value to 1. For PSH, the capital cost and is multiplied by 0.9 and 1.1 respectively to get the low and high end of the year 2020 price range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrains.

Using drilling techniques from the oil industry, vertical shafts are drilled to house the submersible pump-turbine, eliminating excavation costs for the powerhouse, with associated reduction in contingency fees for pumphouse construction. This offers a potential 33% cost reduction.

Reservoir Cost

The estimated reservoir cost of $142/kWh derived from the values provided in in Table 30 is higher than the $104/kWh cost found in the 2012 Black & Veatch report, inclusive of contingency (Black & Veatch, 2012). Note that both the reservoir cost from the 2014 HDR study in Table 30 and the reservoir cost from Miller (2020a) in Table 28 are derived from cost differences between projects of various durations. The reservoir cost from Miller (2020a), however, involves even more assumptions, where, as noted previously, the lower end of the total project cost range was assigned to 9-hour storage and the upper end to 18-hour storage, since storage durations were grouped into 8-10 hour and 18-20 hours (Miller, 2020a). Eliminating the high outlier reservoir cost range estimate of $142/kWh from the 2014 HDR report, reservoir costs were assumed to be $100/kWh, in line with the literature and conversations with developers (Black & Veatch, 2012; Miller, 2020a).

As with the power-scaling factor, for the reservoir to be conservative, the scale was adjusted using data from Davitti (2018). Scale was set to 1 for 800 MWh of storage, with a 16% drop in price for every 10x increase in storage MWh capacity (Davitti, 2018).

Table 31 shows the summary of capital and reservoir costs from various sources, and the costs assumed for this work. Note that some sites provide contingency fees as a percentage of total project cost, while others provide breakdown of contingency fees into categories such as EPC management services, project management, construction management, and contingency. In the generic PSH example, the term contingency refers only to construction management, while in this study contingency fees are used as a catch-all category that includes items such as EPC management services, project management, construction management, and other components. While indirect costs and contingency fees can be grouped together, Key (2011) assigns 15-30% of direct costs as indirect costs, which include planning studies, licensing and permitting, design, and construction management. An additional 20-25% contingency fee was also recommended for unanticipated costs.

Table 31. Summary of Cost Estimates from Literature and Developer Interviews

	Generic PSH Site	Generic PSH Site	Swan Lake North[a]	JD Pool[a]	Black Canyon[a]	Generic PSH Site	Generic PSH Site	Generic PSH Site
Reference	Black & Veatch (2012)		HDR Inc. (2014)			HDR Inc. (2010)		Manwaring et al. (2020)
Power (MW)	500	500	600	1,100	600	1,050	1136	1,000
Duration (h)	10	10	8.8					10
Reservoir ($/kWh)	104	91.5						77
Reservoir ($/kW)	1,040	915						770
Tunnels ($/kW)	163	145						
Powerhouse excavation ($/kW)	97	85						
Tunnels, excavation, powerhouse structure, and BOP ($/kW)								742
Powerhouse structure, BOP electromechanical ($/kW)	1,010	908						
Electromechanical ($/kW)								467
Total ($/kW)	**2,310**	**2,053**						**1,979**
EPC management services (project management, construction management, contingency) ($/kW)	472	513						653.07
Owner's cost ($/kW)	448	513						
Total with EPC and owner's cost ($/kW)	**3,230**	**3,079**	**2,406**	**2,674**	**2,299**	**2,603**	**2,121**	**2,632**
Contingency as percentage of total project cost	28%	33%	15-30%	15-30%	15-30%			25%

(a) Unspecified if indirect costs are included in estimates

Since the costs in Table 31 are in agreement, the detailed breakdown provided in Table 29 has been used, coupled with the scaling described earlier, to arrive at system costs for various power and durations shown in the PSH summary figure included at the end of this section (Figure 7). Table 32 provides a detailed category cost breakdown for a 100 MW, 1,000 MWh PSH plant, with references for each category.

Table 32. Price Breakdown for Various Categories for a 100 MW, 1000 MWh PSH

Cost Category	Nominal Size	2020 Price	Content	Additional Notes	Source(s)
Electromechanical powertrain	100 MW	$467/kW		Direct costs	Black & Veatch (2012); Davitti (2018);

Cost Category	Nominal Size	2020 Price	Content	Additional Notes	Source(s)
Powerhouse C&I	100 MW	$742/kW	Electromechanical and powerhouse C&I costs		HDR Inc. (2014); Manwaring et al. (2020); Miller (2020a)
Reservoir	1000 MWh	$76/kWh	Direct costs	Assumes need for upper and lower reservoirs	Bailey (2020); Black & Veatch (2012); Davitti (2018); Miller (2020a)
Contingency	100 MW, 1000 MWh	$656/kW	Indirect costs	33% of direct costs	Bailie (2020e); Key (2011); Miller (2020a)
O&M		$30.4/kW-year	Fixed O&M	Deep repair and refurbishments every 20 years	Aquino et al. (2017); Black & Veatch (2016); Manwaring et al. (2020); Miller (2020a); R. Shan and O'Connor (2018); Uría-Martínez, Johnson, and O'Connor (2018)
Performance metrics			Calendar life of 50 years	Assumed 40-year life	G. J. May et al. (2018)
Performance metrics			RTE 70-87%	Assumed 80%	Aquino et al. (2017); G. J. May et al. (2018); R. Shan and O'Connor (2018)
Performance metrics			Ramp rates 12-50 MW/s per unit	Ramp rate decreases by 2X when one tunnel serves two units	Fisher et al. (2012); General Electric (2018); Koritarov et al. (2013); Manwaring (2018); R. Shan and O'Connor (2018)

For PSH, the capital cost is multiplied by 0.9 and 1.1 respectively to get the low and high end of the 2020 price range. No learning rates were assigned for 2030 due to maturity of the technology related to reservoirs.

O&M Costs

O&M costs were described in Miller (2020a) for a 1,000 MW plant consisting of four 250 MW units. Table 33 shows the various O&M labor-related costs. Note that labor costs do not change significantly as MW capacity increases, resulting in a lower $/kW-year, while parts and refurbishments have a constant $/kW-year. O&M costs were assigned 0.9 and 1.1 multipliers to establish the range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and reservoirs.

Table 33. Estimated Labor Required for a 1,000 MW PSH Plant, Adapted from Miller (2020a)

Labor Component	Staff Required
Electromechanical controls	6
Electronics-related repair	3

Rotary equipment repair	3
HVAC, smoke and heat rejection	3
Outdoor maintenance of dams, roads	15
Supervisors	8

Variable O&M for PSH plants consist of multiple components including parts and overhaul of pumps/turbines. Parts are estimated at 40% of labor costs and are a constant $/kW across all power levels. Overhauls are expected to be required every 10 years at a cost of $16/kW-year ($40 million per 250 MW unit) and is not expected to be a function of plant size.

There is not a substantial amount of data available on adjustable-speed units in the US given that deployed units are fixed-speed technology. It is projected that O&M costs for adjustable-speed units may be either the same or less than for fixed speed. For fixed O&M, labor would typically require 25 operators to cover a 24/7 operation schedule. For variable O&M, the same source estimated that repairs are required every five years and should be assumed to cost 1% of electromechanical cost (Manwaring et al., 2020).

A deeper repair, in which the turbine is pulled out and seals are replaced, is required every 10 years. This repair is labor-intensive, and the bearings and gaskets will often be replaced as well. This can require the plant to be shut down for about a month and costs 5% of electromechanical cost (Manwaring et al., 2020). Lastly, every 20 years parts like the rotor must be replaced and the stator rewired. These changes can cost between 10-20% of the electromechanical cost (Manwaring et al., 2020). These numbers align with details provided in Key (2011).

The fixed O&M defined by Miller and the National Hydropower Association (NHA) (Manwaring et al., 2020) corresponds to yearly fixed labor costs, while variable O&M corresponds to deep repair and refurbishments.. However, both costs are related to labor, maintenance, and repair, and have been denoted as total fixed O&M in this study. The O&M costs combining Miller (2020a) and Manwaring et al. (2020) are shown in Table 34. Note that labor costs are assumed to double for every 10x increase in power.

Table 34. PSH O&M Costs by Category

Component	100 MW System	1,000 MW System
Duration (hrs)	10	10
Labor-related fixed O&M ($/kW-year)	15.7	3.1
Parts-related fixed O&M ($/kW-year)	5.6	5.6
Refurbishment-related fixed O&M ($/kW-year)	9.0	9.0
Total fixed O&M ($/kW-year)	30.4	17.8
Percentage of capital cost	2.0%	1.4%

The O&M costs for PSH plants, measured in $/year, have typically been estimated using the following relationship (Black & Veatch, 2016):

$$O\&M\ Cost = 34{,}730\ \times P^{0.32}\ \times\ AE^{0.33} \qquad [1]$$

Where,
P = plant capacity (MW)

AE = annual energy throughput (MWh)

Note that the choice of capacity factor affects results. Also, it is assumed that this formula accounts for charge energy as well, based on the known RTE. For a 1,000 MW plant operating at a capacity factor of 25% (Aquino 2017), fixed O&M is estimated to be $8.29 million which corresponds to $8.29/kW-year and puts it in line with the above result of $8.7/kW-year at 1,000 MW. However, at a lower power capacity level of 100 MW, this formula does not adequately account for a larger contribution of labor at this lower power capacity level with a fixed O&M of $18.6/kW-year, much lower than $78.7/kW-year from Table 34. The same study also set aside $280,000 every two years for repairs, which corresponded to $0.14/kW-year. Costs associated with overhaul such as restoration of bushings and bearings in the wicket gate operation, rehabilitation of servomotors, pump-turbine bearings, and similar amounted to $0.32/kW-year. The sum of these numbers is much lower than the $9/kW-year estimated in Table 34. The O&M costs are in line with the literature values (Aquino et al., 2017; R. Shan & O'Connor, 2018; Uría-Martínez et al., 2018). However, the numbers in Table 34 provide more realistic estimates as a function of PSH MW capacity.

To remain consistent, the basic variable O&M was determined from the average of values reported in the literature and, as shown in Table 3, is equal to $0.5125/MWh for all technologies this analysis.

Performance Metrics

G. J. May et al. (2018) estimate that a PSH unit is capable of having a calendar life of 50 years with up to 20,000 cycles with deep repair and refurbishments needed after 20 and 40 years (Aquino et al., 2017; R. Shan & O'Connor, 2018). Assuming a calendar life of 40 years, with 5% of that time allocated to downtime, this corresponds to a total cycle life of 13,870 cycles for one cycle per day.

The RTE found in the literature typically ranges from a low of 70% to a high of 87% for the technology (Aquino et al., 2017; G. J. May et al., 2018; R. Shan & O'Connor, 2018). A middle-ground estimate of 80% RTE is assumed for this analysis.

Typical ramp rates for PSH systems are estimated at 25 to 50 MW/s (Manwaring, 2018). Unlike other storage technologies, the ramp rate is a function of tunnel design to move water between reservoirs. Configuration can also play a significant role in ramp rates and response times. For a four-unit PSH plant with one tunnel per unit, the ramp rate is estimated to be 200 MW/s. However, in configurations where one tunnel has the capability to serve two units, ramp rates decrease to 12 to 25 MW/s per unit (General Electric, 2018; R. Shan & O'Connor, 2018). For spinning in air to full generation, the ramp rate for fixed-speed systems ranges from 1.4 to 20% of rated power per second, while it is 1.7% of rated power per second for adjustable-speed systems. The ramp rate from spinning in air to full load is 1.3 to 2% of rated power per second for fixed-speed systems, while it is 1.4% of rated power per second for adjustable-speed systems.

The time for various mode changes also depends on the choice of turbine. For ternary PSH, which uses a separate turbine and pump on a single shaft, mode changes are quicker (Koritarov et al., 2013). For fixed-speed unit, which are only capable of pumping water in non-adjustable “blocks” of power, pumping is done at fixed-load consumption, thus, ramp rate is not applicable in pumping mode, while for generation mode they can take 5 to 15 seconds to reach rated power from online status (NHA, 2017). Figure 7 shows the response times across various mode changes for fixed-speed, adjustable-speed, and ternary based on the literature and conversations with PSH experts and developers (Fisher et al., 2012; General Electric, 2018; R. Shan & O'Connor, 2018).

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 80%. Following these two items, it can be determined that the cost due to RTE losses is $0.0075/kWh for PSH.

Results

Figure 7 provides cost estimates for 100 and 1,000 MW PSH systems across both 4-hour and 10-hour durations. Based on industry feedback, significant reductions in costs for current PSH technology were not expected to change by 2030; therefore, the same cost estimate is provided across both years for this report. However new R&D in PSH, as detailed later in this report, may offer substantial improvements in installed and annualized costs for the technology. Escalation factors specific to categories such as C&I, construction material, and powertrains have been found to be higher than the rates used in this work (Key, 2011) which could increase costs.

Values in parentheses represent the full estimated cost range while the single value below each range provides the point estimate for that cost component.

Pumped Storage Hydro
2020 & 2030 Cost & Performance Estimates

	Parameter	Units	100 MW				1,000 MW			
			4 hr		10 hr		4 hr		10 hr	
			2020	2030	2020	2030	2020	2030	2020	2030
ESS Cost	Reservoir Construction & Infrastructure	$/kWh	[73 - 89] 81		[68 - 83] 76		[61 - 75] 68		[57 - 70] 64	
ESS Cost	Powerhouse Construction & Infrastructure	$/kW	[321 - 817] 742		[321 - 817] 742		[270 - 686] 623		[270 - 686] 623	
ESS Cost	Electro-mechanical	$/kW	[420 - 513] 467		[420 - 513] 467		[353 - 431] 392		[353 - 431] 392	
	Total ESS Installed Cost*	**$/kW**	[1034 - 1688] **$1,534**		[1424 - 2164] **$1,967**		[868 - 1417] **$1,288**		[1195 - 1817] **$1,651**	
	Total ESS Installed Cost*	**$/kWh**	[259 - 422] **$384**		[142 - 216] **$197**		[217 - 354] **$322**		[120 - 182] **$165**	
	Total ESS Installed Cost + Contingency Fee*	**$/kW**	[1301 - 2250] **$2,046**		[1792 - 2885] **$2,623**		[1093 - 1889] **$1,717**		[1504 - 2422] **$2,202**	
	Total ESS Installed Cost + Contingency Fee*	**$/kWh**	[325 - 563] **$511**		[179 - 289] **$262**		[273 - 472] **$429**		[150 - 242] **$220**	
Operating Costs	Fixed O&M	$/kW-yr	[27.36 - 33.44] 30.40				[16.02 - 19.58] 17.80			
Operating Costs	Variable O&M	$/MWh	0.5125				0.5125			
Operating Costs	System RTE Losses	$/kWh	0.0075				0.0075			
Performance Metrics	Round Trip Efficiency	%	80%				80%			
Performance Metrics	Response Time(s)	sec	see table below							
Performance Metrics	Cycle Life	#	13,870				13,870			
Performance Metrics	Calendar Life	yrs	40				40			
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	40				40			

Response Time(s), sec:

Scenario	Fixed Speed	Variable Speed	Ternary
Spinning-in-air to full-load generation	5-70	60	20-40
Shutdown to full generation	75-120	90	65-90
Spinning-in-air to full load	50-80	70	25-30
Shutdown to full load	160-360	230	80-85
Full load to full generation	90-220	280	25-60
Full generation to full load	240-500	470	25-45

* Does not include any additional transmission costs that may be required or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Figure 7. PSH Cost and Performance Estimates by Power Capacity and Energy Duration for 2020 and 2030

R&D Trends in PSH

The following trends are anticipated for PSH power plants:

- Migration to adjustable-speed technology. The power electronics cost has decreased over the last few decades, with cost for adjustable-speed electromechanicals and powerhouse about 20% higher than fixed-speed technology (Manwaring et al., 2020; Miller, 2020c). The higher efficiency, superior load following, and ability to provide frequency regulation ancillary service in pumping mode make an adjustable-speed option more attractive.
- Migration to ternary technology is not anticipated due to higher cost and sufficient flexible generation present in the US grid (Miller, 2020b). The fast switching time of approximately 30 seconds is not needed since load following requires switching time of not faster than 10 minutes (Miller, 2020d).
- The PSH plant capacity has been trending higher over the last two decades and this trend is expected to continue (Manwaring et al., 2020; Miller, 2020b).
- The duration is region-dependent, with trend to 12-24 hour storage in regions where renewable generation is dominated by wind (Farley, 2020d).
- Quantification of the effects of head and tunnel length to head ratio on system cost and performance for a fixed rated power level. Currently, the relationship developed does not account for differences in power levels. Hence there is a need to perform multilinear regression to relate capital cost to parameters such as power capacity, duration, head, and tunnel length to head ratio. For example, higher head lowers reservoir volume needed for a fixed amount of stored energy. Higher head also reduces the depth below lower reservoir level for the electromechanicals, lowering powerhouse construction cost.
- As long-duration energy storage (diurnal and seasonal) becomes more relevant, it is important to quantify the cost for incremental storage in the reservoir. Estimation of this incremental cost for storage beyond a certain duration such as 10 hours would be useful in addressing long-duration energy storage needs.
- Work is ongoing to adapt oil well drilling techniques to drop in the powertrain, saving powerhouse construction costs and reducing associated contingency fees (Obermeyer, George, & Wells, 2019; Stark, 2020).
- Escalation factors specific to categories such as C&I, construction material, and powertrains have been found higher than the rates used in this work (Key, 2011) and could increase costs.
- Deep repair and refurbishment costs are estimated as fixed costs every 5, 10, or 20 years. There is a need to estimate these costs as a function of operating conditions such as percent of rated power, capacity factor, and cumulative energy throughput.

Hydrogen

There are multiple hydrogen energy storage (HESS) configurations that may be useful in different use cases. The configuration analyzed in this report is bidirectional utilizing fuel cells. This configuration further involves using a polymer electrolyte membrane (PEM) electrolyzer to generate hydrogen from water with an electrical current (releasing oxygen as a byproduct) before compressing and storing the hydrogen in underground salt caverns until needed. The hydrogen is later re-electrified using the fuel cells to produce electricity.

Capital Cost

Hydrogen generation using electrolyzers can monetize variable energy sources and enable long-duration storage of energy that would otherwise be curtailed (Hunter et al., In Press). Hydrogen can be blended with natural gas in gas turbines to generate electricity and has the potential to replace natural gas as the fuel in these systems to offer a cleaner alternative (Lindstrand, 2019).

As an example of commercially deployable electrolyzers, Siemens has a 17.5 MW electrolyzer, the Silyzer 300, consisting of 24 modules and generating a maximum of 2,000 kg of hydrogen per hour at an efficiency of 75% (Siemens AG, 2018). When these are connected in parallel, electrolyzer systems rated at several hundred MWs can be deployed. Siemens has electrolyzer plants in Germany, Dubai, and other locations, with multiple projects in Europe (H2Future, 2020a, 2020b; HYBRIT Development, 2020). The Silyzer plant operates at atmospheric pressure which provides a variety of benefits such as a direct reduction of iron in steel plants, while other electrolyzers operate at 8-30 bars (Schlesog, 2020). While this work currently only examines bidirectional use of hydrogen, use in other industries such as steel making, fertilizer, glass manufacture, and microchips is expected to provide economies of scale for electrolyzers moving forward (U.S. DOE, 2020).

HESS consists of three major components:

- Charging system includes electrolyzer modules, BOP, water-handling units, mass flow controllers, electrolyzer management system, compressor, and rectifier.
- Discharging system is comprised of stationary fuel cell modules, BOP, gas-handling units, blowers, mass flow controllers, fuel cell management system, and inverter.
- Storage system typically includes pipes or a cavern.

Electrolyzer hardware capital costs consist of stacks and BOP. The life of the BOP is expected to be 20-25 years, corresponding to life of compressors and air and fuel delivery systems (Purchasing, Undated; Rundle, 2012), while the life of the electrolyzer depends on operating profile. The capital costs for hydrogen systems, along with EPC and O&M costs, are project-specific and can vary substantially.

Bidirectional usage for hydrogen is not limited to electricity generation by fuel cells; gas turbines or engines can also be used. Though there are various hydrogen technology configurations, the one included in this report is a stationary bidirectional HESS that uses a PEM electrolyzer, a salt cavern for storage, and stationary fuel cells. Cost estimates and projections for this technology were based on extensive literature review and analysis reported in Information on response time capability was provided from the literature regarding dynamic modeling and validation of electrolyzers (Hovsapian, Kurtz, Panwar, Medam, & Hanson, 2019).

To reconcile cost metrics in Hunter et al. (In Press)with the methodology used for other storage technologies in this report, the following categories were estimated for HESS using lithium-ion BESS values for categories where information was unavailable:

- C&C added $1.5/kW, same as for 100 MW lithium-ion battery system.
- Systems integration included in 50% markup.

- EPC included in 50% markup and 25% installation.
- Project development included in 50% markup and 25% installation.
- Grid integration including transformers, meters, safety disconnects, and nominal labor costs added at $19.89/kW, same as for 100 MW lithium-ion battery system.

Table 35 shows input values for capital cost obtained from Hunter et al. (In Press) for a 100 MW, 120-hour HESS. These costs include 50% markup and 25% installation and are assumed equivalent to system integration, EPC, and project development combined.

Table 35. Hydrogen Energy Storage Costs by Component – 2018 and 2030 Values, Adapted from Hunter et al. (In Press)

Mode	Component	2018 Assumption	2030 Estimate
Charging	PEM electrolyzer (kilowatt Electric [kWe])	$1,500	$440
	Rectifier cost (kW)	$130	$100
	Compressor cost (kW)	$40	$40
Discharging	Stationary PEM fuel cell (kW)	$1,320	$1,000
	Inverter (kW)	$67	$45
Storage	Hydrogen salt caverns (kWh)	$2	$1.69

Cavern cost for hydrogen systems has been estimated to be between $2-10/kWh based on previous efforts developing caverns for CAES systems. Discussions with a CAES developer indicated that, based on depth and salt thickness, cavern cost of $2/kWh can be realized. However, where caverns are not very deep and salt thickness is lower, the cost can be as high as $10/kWh, with bedded salt caverns costing even higher (Farley, 2020b). For more information on cavern costs, see the detailed discussion in the CAES section.

Table 36 provides a detailed cost breakdown for various categories and performance metrics, with references for each category.

Table 36. Price Breakdown for Various Categories and Performance Metrics for HESS

Cost Category	Nominal Size	2018 Price	Content	Additional Notes	Source(s)
Electrolyzer	100 MW	$1503/kWe	Estimated 2018 capital cost	Part of SB	Hunter et al. (In Press)
Rectifier	100 MW	$130/kW	Estimated 2018 capital cost	Part of power equipment	
Compressor	See notes	$32.7/kWh	Estimated 2018 capital cost	Part of BOP or BOS, compressor rating to support 100 MW electrolyzer hydrogen output	
Stationary PEM fuel cell	100 MW	$1,320/kW	Estimated 2018 capital cost	Part of SB	
Inverter	100 MW	$67/kW	Estimated 2018 capital cost	Part of power equipment.	
Cavern	1,000 MWh[(a)]	$3.66/kWh	Cavern capital cost	Salt dome	Bailie (2020b, 2020c, 2020f, 2020g, 2020h); Farley (2020b, 2020c); S. Wright (2012); Hunter et al. (In Press)
C&C	100 MW	$1.5/kW	Source estimate for C&C	PNNL approach used for scaling across various power levels	Baxter (2020d)
Grid integration	100 MW	$19.9/kW	Source estimate for grid integration	PNNL approach for scaling across various power levels	Baxter (2020b)
Fixed O&M for electrolyzer	100 MW	$14.5/kW-year	Estimate for fixed O&M	Includes $0.8/MWh for parts replacement converted to $1.7/kW-year	Hunter et al. (In Press)
Fixed O&M for stationary fuel cell	100 MW	$13.4/kW-year	Estimate for fixed O&M	Includes $0.8/MWh for parts replacement converted to $0.63/kW-year	
Fixed O&M for cavern storage	100 MW	$0.60/kW-year	Estimate for fixed O&M	2.1% of cavern capital cost	

Cost Category	Nominal Size	2018 Price	Content	Additional Notes	Source(s)
Basic variable O&M	100 MW, 10 hour	$0.51/MWh	Variable basic O&M cost	Average of basic variable O&M costs from sources	Aquino et al. (2017); Black & Veatch (2012); Hunter et al. (In Press); Mongird et al. (2019); Raiford (2020a); S. Wright (2012)
Performance metrics – RTE	100 MW	35%	RTE for a 100 MW system		Hunter et al. (In Press)
Performance metrics – electrolyzer calendar life	100 MW	30 years	Electrolyzer calendar life in years		
Performance metrics – electrolyzer durability (hours)	100 MW	60,000 hours	Electrolyzer durability in hours		
Performance metrics – electrolyzer calendar life	100 MW	30 years	Electrolyzer calendar life in years		
Performance metrics – electrolyzer durability (hours)	100 MW	40,000 hours	Electrolyzer durability in hours		
Performance metrics – response time	100 MW	< 1 second	HESS response time ion seconds		Hovsapian et al. (2019)

[a] For this study, we are using a maximum of 10 hours of storage. Hence, for a 100 MW system, the cavern size happens to be 1,000 MWh. Hunter et al. (In Press) uses 120 hours of storage, and, therefore, they use 12,000 MWh. The use of 1,000 MWh is necessary for us to do a comparison across technologies for the same 10-hour duration.

Table 37 provides breakdown for a 100 MW, 10-hour HESS system, calculated from the estimates provided in Hunter et al. (In Press) with additional cost components and adjustments described previously. In addition to calculating estimates using the provided low cavern cost ($2/kWh), the estimates have also used a moderate $3.66/kWh cavern cost to match that of CAES following the average of various estimates described in that section. For HESS, the low, nominal, and high end for cavern costs used $2/kWh, $3.66/kWh, and $10/kWh, respectively. Additionally, multipliers of 0.9 and 1.1 were used to establish the low and high ranges for other components. For 2030 cavern costs, the NREL number was changed proportionately based on 2020 cavern costs used to establish the price range.

Table 37. Costs by Component for a 100 MW, 10-hour HESS System, Adapted from (Hunter et al., In Press)

Category	Cost Component	Low 2020 Values	Low 2030 Values	Moderate 2020 Values	Moderate 2030 Values	High 2020 Values	High 2030 Values
PEM electrolyzer	Capital cost ($/kW)	1,353	393	1,503	437	1,653	481
	Rectifier cost ($/kW)	117	84	130	94	143	103
	Compressor cost ($/kW)	35	35	39.3	39.3	43	43
Storage	Storage ($/kWh)	2	1.69	3.66	3.09	10	8.45
	Storage DOD (%)	70%	70%	70%	70%	70%	70%
	Effective storage ($/kWh)	2.86	2.4	5.23	4.44	14.29	12.10
Stationary fuel cell	Capital cost ($/kW)	1,188	854	1,320	949	1,452	1,044
	Inverter ($/kW)	60	41	67	45	74	50
C&C ($/kW)		1.35	0.95	1.5	1.06	1.65	1.16
Grid integration ($/kW)		18	15	19.89	16.3	22	18
Grand total ($/kW)		**2,793**	**1,440**	**3,117**	**1,612**	**3,488**	**1,824**
Grand total ($/kWh)		**279**	**144**	**312**	**161**	**349**	**182**

O&M Costs

Table 38 shows O&M values for a HESS from the long-duration energy storage study in Hunter et al. (In Press). It should be noted that Hunter et al. incorporates property tax, insurance, licensing, and permitting costs into hydrogen O&M estimates. To remain consistent with the methodology of the other technologies considered in this report, O&M costs without these additional additives are considered. Both values are provided in Table 38. Correspondence with a CAES developer indicated that incorporating these cost items into CAES O&M is not uncommon (Farley, 2020b).

Table 38. HESS O&M Costs by Category, Adapted from Hunter et al. (In Press)

O&M Cost Category	Electrolyzer	Stationary PEM Fuel Cell	Storage
Fixed O&M - including property tax, insurance, licensing, and permitting ($/kW-year)	47.9	37.6	
Fixed O&M - without property tax, insurance, licensing, and permitting ($/kW-year)	12.8	12.8	
Stack replacement-related variable O&M ($/MWh)	0.8	0.8	
Storage O&M (% of storage capital cost)			2.1%
Basic variable O&M ($/kWh)	$0.0005	$0.0005	

While there is limited information available for basic variable O&M cost of HESS, these costs are assumed to be similar to CAES where basic variable O&M involves water, lubrication oil, and miscellaneous items. For the electrolyzer and fuel cells, these costs may also include spare parts and compressor/blower lubrication.

Additional variable O&M costs consists of those required for stack replacement. Both basic variable O&M and stack replacement variable O&M costs depend on cumulative energy throughput. Throughput was calculated for the electrolyzer and fuel cell from the desired capacity factor and calendar life. For the electrolyzer, using a design capacity factor of 24%, the 60,000-hour durability stated in Hunter et al. (In Press) is reached in 28.5 years, less than the estimated 30-year calendar life. Hence, the cumulative energy throughput was calculated using a 60,000-hour durability at 24% capacity factor and was found to be 6,000 GWh. For the fuel cell, at the design capacity factor of 9%, the 40,000-hour durability provided in Hunter et al. (In Press) is reached only after 50 years, surpassing the stated calendar life of 30 years. Therefore, the cumulative energy is calculated using a 9% capacity factor for 30 years and was estimated to be 2,370 GWh.

Table 39 shows the individual O&M cost for each component in $/kW-year with totals in the final column. The fixed O&M range for 2020 was 0.9 to 1.1 times the nominal values for each category. To remain consistent, the variable O&M was determined from the average of values reported in the literature across multiple technologies and, as shown in Table 3, is equal to $0.5125/MWh for all technologies in this analysis.

Table 39. HESS O&M Costs by Component, Adapted from Hunter et al. (In Press) and PNNL Assumptions[(b) (c)]

O&M Cost Category	Electrolyzer	Stationary Fuel Cell	Storage	Total
Fixed O&M ($/kW-year)	12.8	12.8		25.6
Stack replacement-related O&M[(a)] ($/kW-year)	1.68	0.63		2.31
Storage O&M[(b)] ($/kW-year)			0.60	0.6
Total fixed O&M ($/kW-year)	**14.48**	**13.43**	**0.60**	**28.51**
Baseline variable O&M[(c)] ($/kWh)	0.0005125	0.0005125		0.001

(a) $1.3/MWh charged or discharged, (b) Based on 2.1% of storage capital expenditure, (c) $0.0005/kWh charged or discharged

Performance Metrics

System efficiency depends on compression needs, storage type, and auxiliary load such as cooling. According to Hunter et al. (In Press), the total RTE for the hydrogen system considered in this analysis is approximately 35%.

The calendar life for hydrogen is estimated to be 30 years (Hunter et al., In Press). Note that the calendar life for the electrolyzer and fuel cell stacks should not be confused with the 20-25 year life for BOP components such as compressors and air and fuel delivery systems mentioned earlier. This corresponds to a cycle life of approximately 10,400 cycles when one cycle per day and 5% downtime are assumed. The response time for hydrogen is estimated to be < 1 second, as provided in Hovsapian et al. (2019)

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 35%. Following these two items, it can be determined that the cost due to RTE losses is $0.056/kWh.

Results

Figure 8 provides cost estimates for a 100 MW, 10-hour hydrogen system using a PEM electrolyzer, salt cavern, and stationary fuel cells.

Hydrogen (Bi-directional)
2020 and 2030
Cost & Performance Estimates

	Parameter	Units	100 MW, 10 hr: 2020	100 MW, 10 hr: 2030
ESS Installed Cost	Electrolyzer Capital Cost	$/kW	[1353 - 1653] 1,503	[393 - 481] 437
ESS Installed Cost	Rectifier	$/kW	[117 - 143] 130	[84 - 103] 94
ESS Installed Cost	Compressor	$/kW	[35 - 43] 39.30	[35 - 43] 39.30
ESS Installed Cost	Cavern Storage	$/kWh	[2 - 10] 3.66	[2 - 8] 3.09
ESS Installed Cost	Stationary Fuel Cell Capital Cost	$/kW	[1188 - 1452] 1,320	[854 - 1044] 949
ESS Installed Cost	Inverter	$/kW	[60 - 74] 67	[41 - 50] 45
ESS Installed Cost	Controls & Communication	$/kW	[1.35 - 1.65] 1.50	[.95 - 1.16] 1.06
ESS Installed Cost	Grid Integration	$/kW	[18 - 22] 19.89	[15 - 18] 16.30
	Total ESS Installed Cost*	**$/kW**	**[2793 - 3488] $3,117**	**[1440 - 1824] $1,612**
	Total ESS Installed Cost*	**$/kWh**	**[279 - 349] $312**	**[144 - 182] $161**
Operating Costs	Fixed O&M	$/kW-yr	[26.02 - 31.80] 28.51	
Operating Costs	Variable O&M	$/MWh	0.5125	
Operating Costs	System RTE Losses	$/kWh	0.056	
Performance Metrics	Round Trip Efficiency	%	35%	
Performance Metrics	Response Time	sec	<1	
Performance Metrics	Cycle Life	#	10,403	
Performance Metrics	Calendar Life	yrs	30	
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	30	

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Figure 8. Hydrogen (bidirectional) Cost and Performance Estimates for 2020 and 2030

R&D Trends in Hydrogen Energy Storage Systems

While high capital costs and low RTE have been a roadblock to HESS deployment in the past, there is opportunity for reduction in PEM electrolyzer and fuel cell costs with R&D to improve performance and cost of catalysts and membranes, coupled with economies of scale. The following focus areas for R&D are anticipated:

- Currently, the design life for fuel cells used in busses is 20,000 operating hours, while for stationary energy storage is expected to be 40,000 hours (Hunter et al., In Press). However, considering HESS are expected to have a discharge capacity factor of 5-10%, this translates to 13,000-26,000 operating hours for a desired 30-year calendar life. Hence, HESS can leverage the developments in transportation fuel cells, much as lithium-ion BESS leverages developments in EV batteries. Additionally, R&D in heavy-duty vehicle PEM fuel cells is focused on a price target of $60/kW which offers opportunities for significant price reduction from HESS.
- Salt caverns with the desired depth and width cost $2/kWh, while bedded salt caverns, prevalent in Michigan, Arizona, and Colorado, cost > $10/kWh due to lack of depth (Farley, 2020b). The required cavern size, and hence cost, is dependent on the regional generation mix. Therefore, efforts to reduce cost of storage via engineering design are expected to gain traction.
- As long-duration energy storage (diurnal and seasonal) becomes more relevant, it is important to quantify cost for incremental storage in the cavern. The incremental cost for CAES storage is estimated to be $0.12/kWh. The cavern for the 324 MW, 16000 MWh Bethel Energy Center project has a capacity of 4 million barrels. To increase the size by 20%, a 63-day leaching at 3000 gallons per minute is needed, estimated to cost $383,000 including electricity, water and labor (Naeve, 2020), which amounts to $0.12/kWh, or $1.2/kW for the 324 MW plant. Hence, as long duration storage becomes prevalent, increasing the storage capacity of existing salt domes by solution mining is expected to gain traction due to its cost-effectiveness.
- The largest existing cavern has a volume of 17 million barrels (Naeve, 2020), which corresponds to about 64,000 MWh of storage. The Bethel Energy Center cavern can be expanded to 10 million barrels, while ATMOS Energy is developing a 10-million-barrel cavern on the west of the existing Bethel dome, corresponding to nearly 40,000 MWh of storage. As demand for long-term storage increases, it is expected that caverns of similar size will be developed.
- There are about 130 caverns at Mt. Belview constructed on a large salt done, with web thickness between caverns much less than the 250 to 300 ft required today. For large projects, it is expected that multiple caverns within a single salt dome will be developed and connected in parallel.

Comparative Results

Figure 9 shows total installed ESS cost including ranges for 100 MW, 4-hour and 100 MW, 10-hour systems. It should be noted that the PSH, CAES, and HESS total installed costs shown are inclusive of contingency fees, while for BESS, the system integration, EPC, and project development costs include associated contingency fees. Comparisons across a wider set of power and energy durations will be included in the online database.

Figure 10 shows the total installed cost point estimates for each technology, excluding ranges, by power and energy duration combination for 2020. Figure 11 show the same information for 2030. While this does not include the cost ranges for each technology shown in the previous figures, it provides a high-level comparison across various power capacity and energy durations.

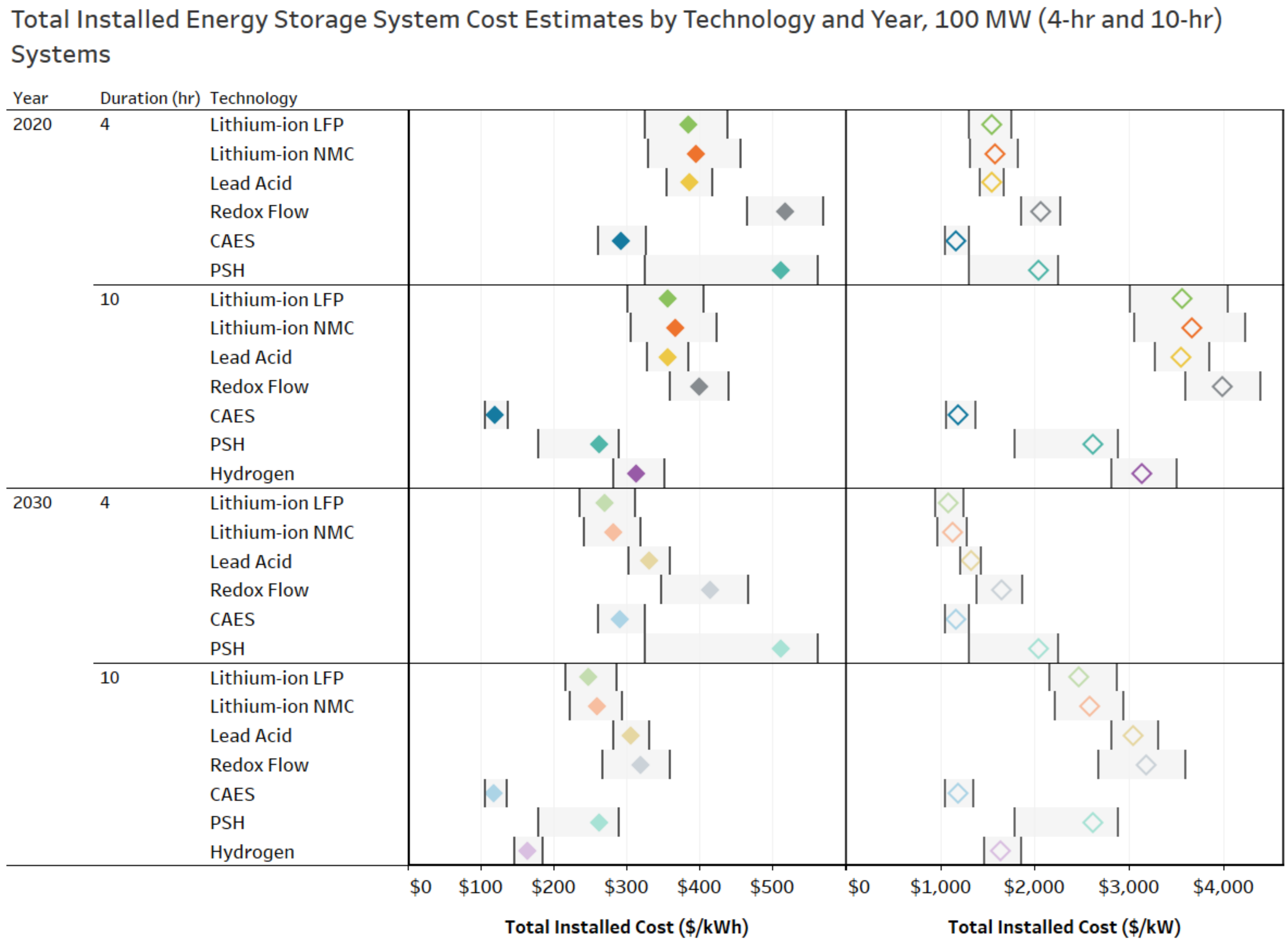

Figure 9. Comparison of Total Installed ESS Cost Ranges by Year and Technology, 100 MW (4-hr and 10-hr) Systems

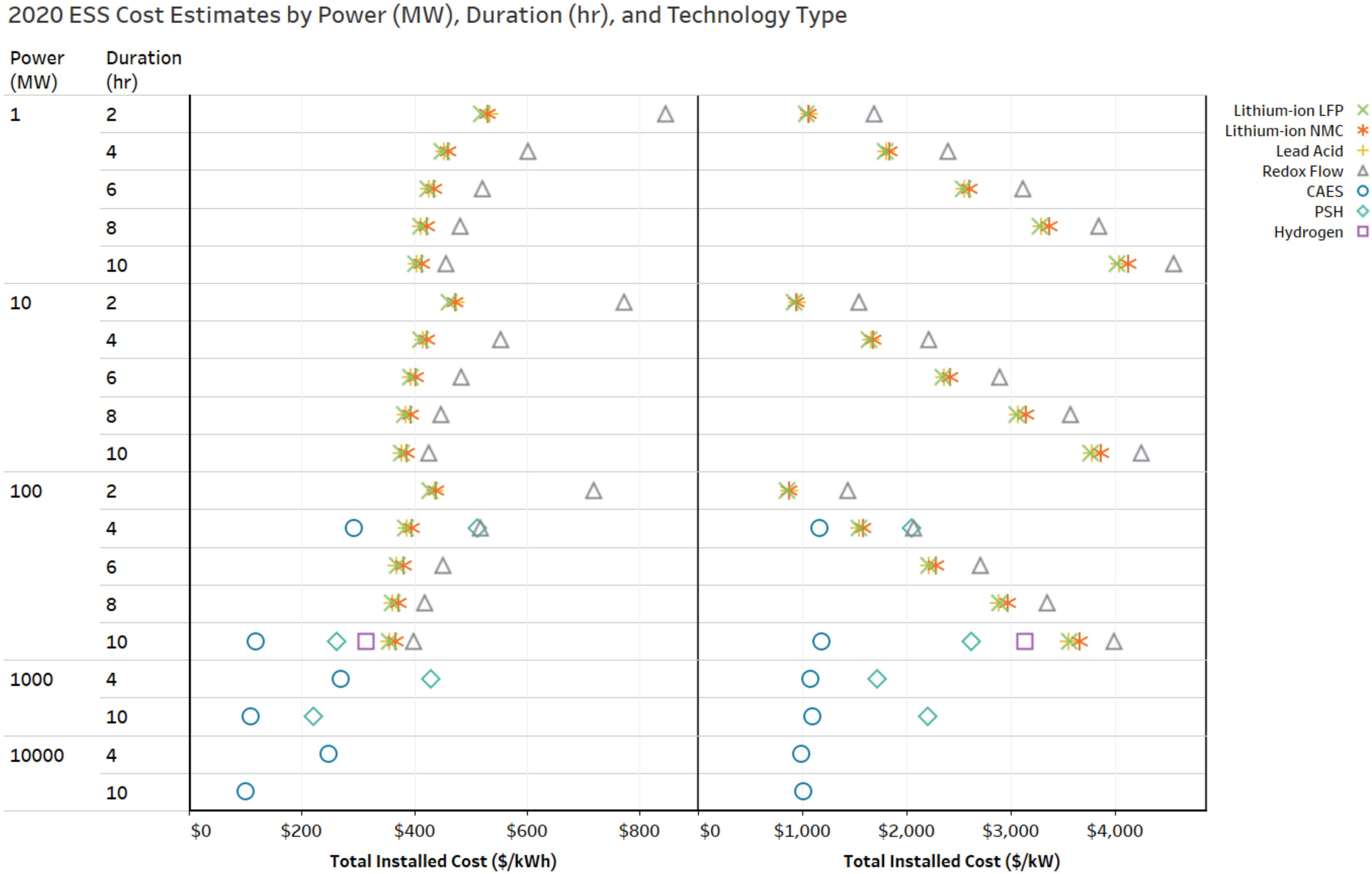

Figure 10. Comparison of Total Installed ESS Cost Point Estimates by Technology, 2020 Values

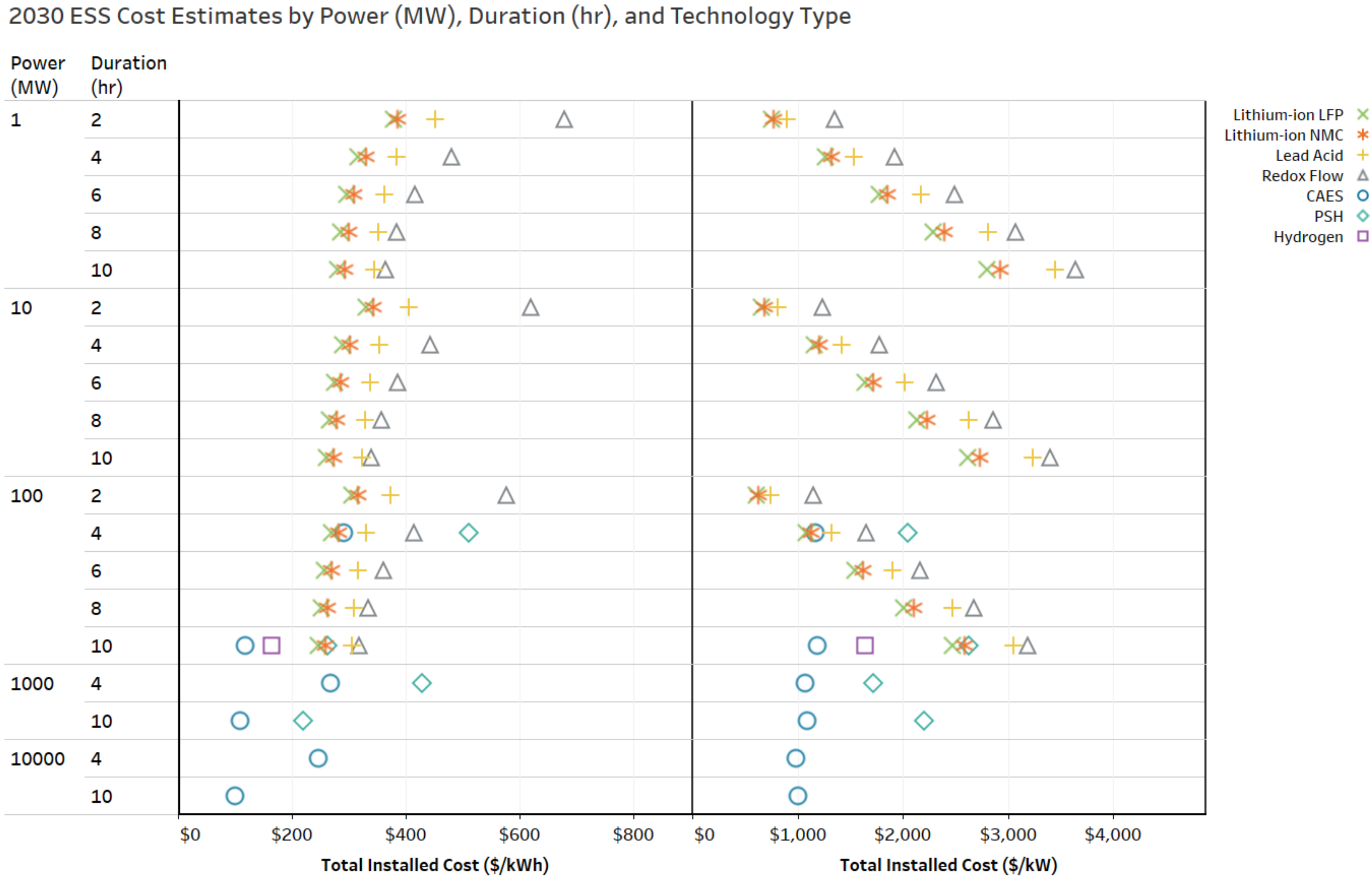

Figure 11. Comparison of Total Installed ESS Cost Point Estimates by Technology, 2030 Values

Annualized Cost of Storage and Levelized Cost of Energy

Methodology

To achieve a comparable annualized cost, technology-specific findings for installed ESS costs and estimated operating costs are run through a pro forma that incorporates assumptions surrounding the required costs of financing a project over the duration of its usable life. This total long-run revenue requirement is then evaluated as an annualized payment in 2020 USD based on an assumed weighted cost of capital for discounting. By conducting an annualized calculation, we can compare across technologies to get a better understanding of cost components and the economics of each system. Dividing the annualized cost by the annual energy discharge throughput yields the LCOE.[12] Both components depend on calendar life, cycle life, DOD, and assumptions on electricity price.

The assumptions listed in Table 40 were adapted from previous PNNL storage valuation of a battery storage project located in the Pacific Northwest (Balducci, Mongird, Alam, Yuan, & Wu, 2018). These values are representative of a typical storage system within the US. Generally accepted accounting principles were used to achieve the annualized results. Inflation is assumed to equal the 2019 inflation rate from U.S. Congressional Budget Office (Shakleton, 2020).

Table 40. Financial Parameters and Assumptions

Parameter	Value
Inflation rate (%)	1.4%
Nominal discount rate (%)	7.60%
Combined state and federal tax rate (%)	24.873%
Tax depreciation method	Modified accelerated cost recovery system, half-year convention
Property tax (%)	0.56%
Insurance rate (%)	0.48%
Electricity cost ($/kWh)	$0.03[a]

[a] While this report assumes a fixed electricity cost, future research phases will explore varying this input as well other financial parameters to observe impacts on results.

LCOE calculates the $/MWh value that the discharged electricity would need to be sold to breakeven on the overall storage lifecycle costs (capital and operational expenditures) across its usable life. The LCOE is calculated by dividing the total annualized cost of storage ($) by the annual throughput of the system (kWh). Annual discharge energy throughput is the product of rated energy capacity of the storage system, DOD, and the number of cycles per year. The annual discharge (kWh/yr) for each technology by power capacity, energy duration, and estimate year is provided in Appendix 4. Comparison of annualized cost for two identical BESS operated for the same number of cycles but at different DOD is expected to yield lower annualized cost for the lower DOD, while the LCOE values are reflective of which operating mode is more cost-effective. The choice of DOD depends on several factors including desired cycle life, calendar life related limitations, and the grid service being provided.

Most batteries have extra Ah/Wh capacity built in such that at reported 0% SOC, there is still some capacity left. Conversation with a flow battery vendor showed that they build in 25% excess capacity to

[12] LCOE is also derived by dividing the total cost over ESS life by the cumulative discharge energy throughput over ESS life.

ensure a 100% DOD discharge is enabled. However, the amount of extra capacity varies by vendor and possibly varies with technology.

The cycle life of conventional batteries depends on DOD. Lead-acid batteries, for example, have poor cycle life at high DOD and therefore are operated at approximately 50% DOD to ensure the cycle life target is met. Lithium-ion batteries' energy throughput does not vary significantly with DOD; hence, they can be operated at high DOD. However, to ensure the desired energy is obtained at the rated power throughout the design life, lithium-ion batteries are typically cycled at < 80% DOD to account for degradation, with charging done to <100% SOC to avoid premature positive (layered) electrode degradation and minimize loss of lithium-related capacity loss. For flow batteries, cycle life does not depend on DOD so it makes sense to discharge them at high DOD. Depending on extra electrolyte capacity, stack design, and the effective amperes/unit area at rated power, flow batteries may deliver the full rated energy at rated power. There is a push for flow battery vendors to provide their power and energy ratings such that rated energy is available at rated power. Hence, it is assumed that flow batteries deliver 90% of rated energy at rated power, corresponding to 90% DOD. Table 41 shows the DOD assumptions used in the annualization calculation for each technology and energy duration combination.

Table 41. DOD Assumptions by Storage Technology and Duration

Technology	Energy Duration (hr)	DOD
Lithium-ion LFP	All	80%
Lithium-ion NMC	All	80%
Lead acid	2	58%
	4	67%
	6	73%
	8	78%
	10	82%
Vanadium redox flow	All	90%
CAES	All	80%
PSH	All	80%
Hydrogen	All	80%

The capital cost in $/kWh is provided per unit rated energy in this study. In the LCOE analysis DOD was incorporated for annual discharge energy throughput adjustment to account for this.

Figure 12 shows the annualized cost ranges in $/kWh-year and $/kW-year as well as the LCOE ranges for each technology. Values shown in Figure 12 are for 100 MW, 4-hour and 100 MW, 10-hour systems.

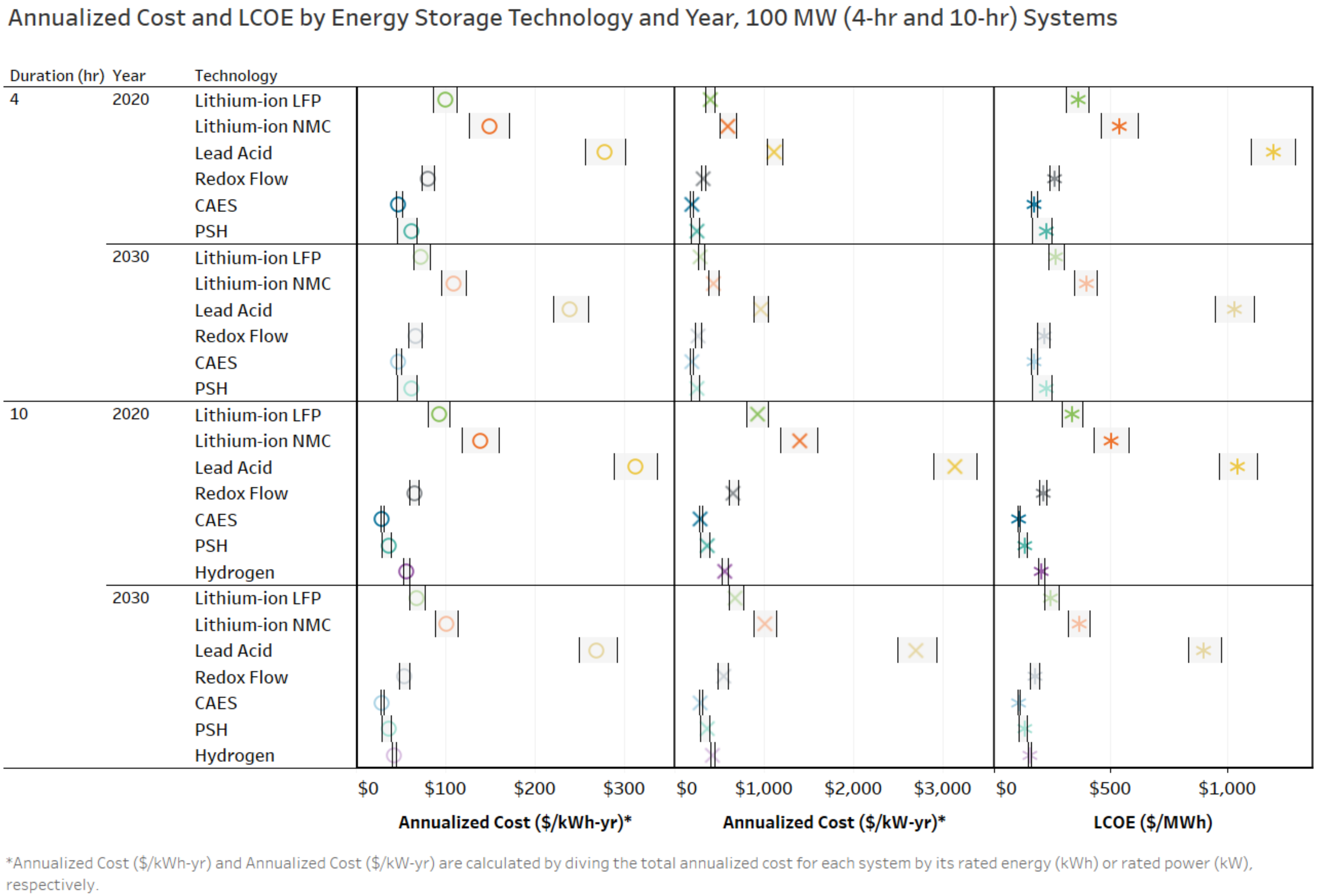

Figure 12. Annualized Cost and LCOE Ranges by Energy Storage Technology and Year, 100 MW (4-hour and 10-hour) Systems

Conclusion

This report has provided detailed cost and performance metrics for the following energy storage technologies across a range of E/P ratios.[13] While the preferred E/P ratio varies for each technology, this report provides a common 100 MW, 10-hour cost projection for each technology to enable comparison. A more detailed comparison of technologies at different E/P ratios will be addressed in future updates. The following technologies were compared:

- Lithium-ion LFP batteries
- Lithium-ion NMC batteries
- Lead-acid batteries
- Vanadium RFBs
- CAES
- PSH
- HESS (bidirectional)

Technologies selected for the initial iteration of the report were based on availability of current data from multiple sources and/or specific interest from industry stakeholders. Current focus was on technologies capable of providing bidirectional electrical capabilities (electrons in – electrons out) but future updates will expand to include other storage technologies providing heat or other valuable outputs. Additional efforts will also focus on capturing multiple output vectors of certain technologies, like hydrogen, where outputs like transportation fuel or chemical synthesis provide more valuable services over electricity generation.

The cost projections provided here represent an initial attempt at accurately defining and capturing the entire cost structure of these storage systems. The cost and performance data were compiled for the defined categories and components based on conversations with vendors and stakeholders, literature, and costs of systems procured at sites across the US. Detailed cost, cost ranges, and performance estimates are presented for 2020 and projected out to 2030 for each of the technologies described.

In addition to expanding the number of technologies tracked, future updates will be focused on refining and updating the current and 2030 cost and performance values based on stakeholder feedback. These values will be regularly updated on the ESGC Cost and Performance website (currently at https://www.pnnl.gov/ESGC-cost-performance) which has been established to make the energy storage cost and performance metrics both accessible to a wide audience and easily updatable as costs change over time.

Additional areas for research that may be explored in additional phases of this initiative include:

- Establishing additional fidelity on cycle life for all BESS at various DOD with associated RTE to facilitate technology selection across a suite of grid services.

[13] Note that for comparison across all technologies, 100 MW 10-hour duration was used. This was the only power and energy level common to all technologies.

- Developing a standardized way of estimating O&M costs for ESS through expert collaboration and discussion.
- Gathering additional input and feedback from industry stakeholders to update and firm up cost numbers and performance metrics.
- Collecting information and data to develop costs related to decommissioning of ESS.

This project has also developed a standardized framework of the cost components for ESS in order to establish a method to accurately compare costs from different industry participants. Terminology is often applied inconsistently resulting in confusion over which components are associated with specific cost categories. The standardized framework will hopefully enable an equitable way to compare across technologies.

This effort provides an agile resource for industry to understand the current cost and performance metrics of different technologies while providing a standardized framework to track longer term cost projections. The standardized methodology and long-term cost projections can be used to identify valuable R&D areas that DOE and industry can address to lower the overall cost of each technology and provide a suite of cost-competitive storage options that industry can choose from.

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Appendix 1: Lithium-ion (LFP and NMC) Battery Cost Table Across all Durations

Lithium-ion LFP
2020 Cost & Performance Estimates

				1 MW					10 MW					100 MW				
		Parameter	**Units**	**2hr**	**4hr**	**6hr**	**8hr**	**10hr**	**2hr**	**4hr**	**6hr**	**8hr**	**10hr**	**2hr**	**4hr**	**6hr**	**8hr**	**10hr**
ESS Installed Cost	Energy Storage System / Storage System	Storage Block	$/kWh	[166 - 203] 185	[164 - 200] 182	[163 - 199] 181	[162 - 198] 180	[161 - 197] 179	[159 - 194] 176	[156 - 191] 174	[155 - 189] 172	[154 - 188] 171	[153 - 187] 170	[151 - 185] 168	[149 - 182] 165	[148 - 180] 164	[147 - 179] 163	[146 - 179] 162
ESS Installed Cost	Energy Storage System / Storage System	Storage Balance of System	$/kWh	[41 - 50] 46	[38 - 47] 42	[37 - 45] 41	[36 - 45] 41	[36 - 44] 40	[39 - 48] 43	[36 - 44] 40	[35 - 43] 39	[35 - 42] 39	[34 - 42] 38	[37 - 45] 41	[35 - 42] 38	[34 - 41] 37	[33 - 40] 37	[33 - 40] 36
ESS Installed Cost	Energy Storage System	Power Equipment	$/kW	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63
ESS Installed Cost	Energy Storage System	Controls & Communication	$/kW	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2
ESS Installed Cost	Energy Storage System	Systems Integration	$/kWh	[42 - 63] 57	[37 - 56] 50	[35 - 53] 48	[35 - 52] 47	[34 - 51] 46	[38 - 57] 52	[35 - 52] 47	[33 - 50] 45	[32 - 48] 44	[32 - 48] 43	[36 - 53] 48	[33 - 49] 44	[31 - 47] 42	[31 - 46] 42	[30 - 45] 41
ESS Installed Cost		Engineering, Procurement, and Construction	$/kWh	[55 - 85] 70	[48 - 74] 61	[46 - 70] 58	[44 - 68] 56	[44 - 67] 55	[49 - 76] 62	[44 - 68] 56	[42 - 65] 54	[41 - 64] 53	[41 - 63] 52	[46 - 70] 58	[42 - 64] 53	[40 - 62] 51	[39 - 60] 50	[39 - 60] 49
ESS Installed Cost		Project Development	$/kWh	[65 - 103] 84	[57 - 90] 73	[54 - 86] 70	[52 - 83] 68	[51 - 82] 67	[58 - 92] 75	[52 - 83] 67	[50 - 80] 65	[49 - 78] 63	[48 - 77] 62	[54 - 86] 70	[49 - 78] 63	[47 - 75] 61	[46 - 74] 60	[46 - 73] 59
ESS Installed Cost		Grid Integration	$/kW	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20
		Total ESS Installed Cost*	**$/kW**	**[879 - 1180] $1,037**	**[1517 - 2040] $1,793**	**[2149 - 2891] $2,541**	**[2775 - 3735] $3,284**	**[3399 - 4575] $4,023**	**[781 - 1049] $922**	**[1389 - 1868] $1,643**	**[1990 - 2679] $2,355**	**[2587 - 3483] $3,063**	**[3181 - 4284] $3,767**	**[723 - 972] $854**	**[1302 - 1752] $1,541**	**[1875 - 2524] $2,220**	**[2444 - 3291] $2,894**	**[3010 - 4054] $3,565**
		Total ESS Installed Cost*	**$/kWh**	**[440 - 590] $519**	**[379 - 510] $448**	**[358 - 482] $424**	**[347 - 467] $410**	**[340 - 458] $402**	**[390 - 524] $461**	**[347 - 467] $411**	**[332 - 446] $393**	**[323 - 435] $383**	**[318 - 428] $377**	**[361 - 486] $427**	**[326 - 438] $385**	**[313 - 421] $370**	**[306 - 411] $362**	**[301 - 405] $356**
Operating Costs		Fixed O&M	$/kW-yr	[2.27 - 2.77] 2.52	[3.96 - 4.84] 4.40	[5.63 - 6.89] 6.26	[7.3 - 8.92] 8.11	[8.95 - 10.94] 9.95	[2.01 - 2.46] 2.24	[3.63 - 4.43] 4.03	[5.22 - 6.38] 5.80	[6.81 - 8.32] 7.56	[8.38 - 10.25] 9.31	[1.87 - 2.28] 2.08	[3.41 - 4.16] 3.79	[4.93 - 6.02] 5.47	[6.44 - 7.87] 7.15	[7.94 - 9.7] 8.82
Operating Costs		Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs		System RTE Losses	$/kWh	0.005					0.005					0.005				
Performance Metrics		Round Trip Efficiency	%	86%					86%					86%				
Performance Metrics		Response Time	sec	1-4					1-4					1-4				
Performance Metrics		Cycle Life	#	2,000					2,000					2,000				
Performance Metrics		Calendar Life	yrs	10					10					10				
Performance Metrics		Duration Corresponding to Cycle Life**	yrs	5.77					5.77					5.77				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Lithium-ion LFP
2030 Cost & Performance Estimates

Category	Parameter	Units	1 MW 2hr	1 MW 4hr	1 MW 6hr	1 MW 8hr	1 MW 10hr	10 MW 2hr	10 MW 4hr	10 MW 6hr	10 MW 8hr	10 MW 10hr	100 MW 2hr	100 MW 4hr	100 MW 6hr	100 MW 8hr	100 MW 10hr
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[89 - 129] 111	[87 - 128] 109	[87 - 127] 108	[86 - 126] 108	[86 - 125] 107	[85 - 123] 106	[83 - 122] 104	[83 - 121] 103	[82 - 120] 103	[82 - 119] 102	[81 - 118] 101	[79 - 116] 99	[79 - 115] 98	[78 - 114] 98	[78 - 114] 97
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[27 - 37] 32	[25 - 35] 30	[25 - 34] 29	[24 - 33] 28	[24 - 33] 28	[26 - 36] 30	[24 - 33] 28	[24 - 32] 27	[23 - 32] 27	[23 - 31] 27	[25 - 34] 29	[23 - 32] 27	[22 - 31] 26	[22 - 30] 26	[22 - 30] 25
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1
ESS Installed Cost / Energy Storage System	Systems Integration	$/kWh	[42 - 51] 46	[37 - 46] 36	[35 - 44] 33	[35 - 42] 32	[34 - 42] 32	[38 - 47] 38	[35 - 42] 33	[33 - 41] 31	[32 - 40] 30	[32 - 39] 30	[36 - 44] 35	[33 - 40] 31	[31 - 39] 30	[31 - 38] 29	[30 - 37] 28
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[52 - 64] 57	[45 - 56] 50	[43 - 53] 48	[42 - 51] 46	[41 - 50] 45	[46 - 57] 51	[42 - 51] 46	[40 - 49] 44	[39 - 48] 43	[38 - 47] 43	[43 - 53] 48	[39 - 48] 43	[38 - 46] 42	[37 - 45] 41	[36 - 45] 40
ESS Installed Cost	Project Development	$/kWh	[62 - 76] 69	[54 - 67] 60	[52 - 63] 57	[50 - 62] 56	[49 - 61] 55	[55 - 68] 61	[50 - 61] 55	[48 - 59] 53	[47 - 58] 52	[46 - 57] 51	[51 - 63] 57	[47 - 58] 52	[45 - 56] 50	[44 - 54] 49	[44 - 54] 48
ESS Installed Cost	Grid Integration	$/kW	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[650 - 854] $757**	**[1105 - 1460] $1,266**	**[1555 - 2059] $1,780**	**[2002 - 2654] $2,290**	**[2447 - 3245] $2,797**	**[575 - 757] $661**	**[1008 - 1334] $1,156**	**[1437 - 1905] $1,645**	**[1863 - 2471] $2,131**	**[2287 - 3035] $2,614**	**[531 - 699] $610**	**[944 - 1249] $1,081**	**[1353 - 1793] $1,547**	**[1758 - 2333] $2,010**	**[2162 - 2870] $2,471**
	Total ESS Installed Cost*	**$/kWh**	**[325 - 427] $378**	**[276 - 365] $317**	**[259 - 343] $297**	**[250 - 332] $286**	**[245 - 325] $280**	**[287 - 378] $330**	**[252 - 333] $289**	**[240 - 317] $274**	**[233 - 309] $266**	**[229 - 303] $261**	**[265 - 350] $305**	**[236 - 312] $270**	**[225 - 299] $258**	**[220 - 292] $251**	**[216 - 287] $247**
Operating Costs	Fixed O&M	$/kW-yr	[1.86 - 2.29] 2.07	[3.26 - 4] 3.61	[4.63 - 5.7] 5.13	[6 - 7.38] 6.65	[7.36 - 9.05] 8.16	[1.65 - 2.03] 1.83	[2.98 - 3.67] 3.30	[4.29 - 5.28] 4.76	[5.6 - 6.88] 6.20	[6.89 - 8.48] 7.64	[1.54 - 1.89] 1.70	[2.8 - 3.44] 3.10	[4.05 - 4.98] 4.49	[5.29 - 6.51] 5.86	[6.53 - 8.03] 7.23
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.004					0.004					0.004				
Performance Metrics	Round Trip Efficiency	%	88%					88%					88%				
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	2,100					2,100					2,100				
Performance Metrics	Calendar Life	yrs	10					10					10				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	6.06					6.06					6.06				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Lithium-ion NMC
2020 Cost & Performance Estimates

			1 MW					10 MW					100 MW				
	Parameter	Units	2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[177 - 216] 197	[175 - 213] 194	[173 - 211] 192	[172 - 210] 191	[171 - 209] 190	[169 - 206] 187	[166 - 203] 185	[165 - 202] 183	[164 - 200] 182	[163 - 199] 181	[161 - 196] 179	[158 - 194] 176	[157 - 192] 175	[156 - 191] 173	[155 - 190] 173
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[33 - 49] 40	[30 - 45] 37	[29 - 44] 36	[29 - 43] 35	[28 - 42] 35	[31 - 46] 38	[29 - 43] 35	[28 - 42] 34	[27 - 41] 34	[27 - 40] 33	[30 - 44] 37	[27 - 41] 34	[26 - 40] 33	[26 - 39] 32	[26 - 38] 32
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[76 - 93] 85	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[66 - 80] 73	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63	[57 - 69] 63
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2
ESS Installed Cost / Energy Storage System	Systems Integration	$/kWh	[43 - 66] 58	[38 - 58] 51	[37 - 56] 49	[36 - 54] 48	[35 - 53] 47	[39 - 60] 53	[36 - 54] 48	[34 - 52] 46	[34 - 51] 45	[33 - 50] 44	[37 - 56] 49	[34 - 51] 45	[32 - 49] 44	[32 - 48] 43	[31 - 48] 42
ESS Installed Cost	Engineering, Procurement, and Construction	$/kW	[56 - 88] 71	[49 - 77] 63	[46 - 73] 60	[45 - 71] 58	[44 - 70] 57	[50 - 79] 64	[45 - 71] 58	[43 - 68] 55	[42 - 67] 54	[41 - 66] 53	[46 - 73] 59	[42 - 67] 54	[41 - 64] 52	[40 - 63] 51	[39 - 62] 51
ESS Installed Cost	Project Development	$/kWh	[66 - 107] 86	[58 - 94] 75	[55 - 90] 72	[53 - 87] 70	[52 - 85] 68	[59 - 96] 77	[53 - 87] 69	[51 - 83] 66	[50 - 81] 65	[49 - 80] 64	[54 - 89] 71	[50 - 81] 65	[48 - 79] 63	[47 - 77] 62	[46 - 76] 61
ESS Installed Cost	Grid Integration	$/kW	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[22 - 27] 25	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20
	Total ESS Installed Cost*	$/kW	[889 - 1223] $1,060	[1537 - 2122] $1,838	[2179 - 3012] $2,608	[2816 - 3896] $3,372	[3450 - 4774] $4,132	[790 - 1090] $944	[1408 - 1947] $1,685	[2019 - 2794] $2,419	[2627 - 3636] $3,147	[3231 - 4473] $3,871	[731 - 1010] $875	[1320 - 1827] $1,581	[1903 - 2635] $2,280	[2481 - 3437] $2,974	[3057 - 4234] $3,664
	Total ESS Installed Cost*	$/kWh	[444 - 611] $530	[384 - 531] $459	[363 - 502] $435	[352 - 487] $421	[345 - 477] $413	[395 - 545] $472	[352 - 487] $421	[337 - 466] $403	[328 - 455] $393	[323 - 447] $387	[366 - 505] $437	[330 - 457] $395	[317 - 439] $380	[310 - 430] $372	[306 - 423] $366
Operating Costs	Fixed O&M	$/kW-yr	[2.32 - 2.83] 2.57	[4.06 - 4.96] 4.51	[5.78 - 7.07] 6.43	[7.49 - 9.16] 8.33	[9.2 - 11.24] 10.22	[2.06 - 2.52] 2.29	[3.72 - 4.55] 4.13	[5.36 - 6.56] 5.96	[6.99 - 8.55] 7.77	[8.62 - 10.53] 9.57	[1.92 - 2.34] 2.13	[3.5 - 4.27] 3.89	[5.06 - 6.19] 5.62	[6.62 - 8.09] 7.35	[8.16 - 9.97] 9.07
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.005					0.005					0.005				
Performance Metrics	Round Trip Efficiency	%	86%					86%					86%				
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	1,200					1,200					2,000				
Performance Metrics	Calendar Life	yrs	10					10					10				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	3.46					3.46					3.46				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Lithium-ion NMC
2030 Cost & Performance Estimates

Category	Parameter	Units	1 MW					10 MW					100 MW				
			2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr
ESS Installed Cost – Energy Storage System – Storage System	Storage Block	$/kWh	[94 - 138] 118	[93 - 136] 116	[92 - 135] 115	[92 - 134] 115	[91 - 133] 114	[90 - 131] 112	[89 - 129] 111	[88 - 128] 110	[87 - 127] 109	[87 - 127] 109	[86 - 125] 107	[84 - 123] 106	[84 - 122] 105	[83 - 121] 104	[83 - 121] 104
ESS Installed Cost – Energy Storage System – Storage System	Storage Balance of System	$/kWh	[24 - 33] 28	[22 - 30] 26	[22 - 30] 25	[21 - 29] 25	[21 - 29] 24	[23 - 31] 27	[21 - 29] 25	[21 - 28] 24	[20 - 28] 24	[20 - 27] 23	[22 - 30] 26	[20 - 28] 24	[20 - 27] 23	[19 - 26] 22	[19 - 26] 22
ESS Installed Cost – Energy Storage System	Power Equipment	$/kW	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[59 - 77] 73	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[51 - 66] 63	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54	[44 - 57] 54
ESS Installed Cost – Energy Storage System	Controls & Communication	$/kW	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1
ESS Installed Cost – Energy Storage System	Systems Integration	$/kWh	[43 - 53] 47	[38 - 47] 42	[36 - 45] 40	[35 - 44] 39	[35 - 43] 39	[39 - 48] 43	[35 - 44] 39	[34 - 42] 38	[33 - 41] 37	[33 - 40] 36	[37 - 45] 41	[33 - 41] 37	[32 - 40] 36	[32 - 39] 35	[31 - 38] 35
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[53 - 65] 59	[46 - 57] 51	[44 - 54] 49	[43 - 53] 48	[42 - 52] 47	[47 - 58] 52	[43 - 52] 47	[41 - 50] 45	[40 - 49] 44	[40 - 49] 44	[44 - 54] 49	[40 - 49] 44	[39 - 48] 43	[38 - 47] 42	[37 - 46] 41
ESS Installed Cost	Project Development	$/kWh	[63 - 78] 70	[56 - 69] 62	[53 - 65] 59	[52 - 63] 57	[51 - 62] 56	[57 - 70] 63	[51 - 63] 57	[49 - 61] 55	[48 - 59] 53	[47 - 58] 53	[53 - 65] 58	[48 - 59] 53	[46 - 57] 51	[46 - 56] 50	[45 - 55] 50
ESS Installed Cost	Grid Integration	$/kW	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[662 - 871] $771**	**[923 - 1239] $1,089**	**[1590 - 2108] $1,857**	**[2049 - 2718] $2,393**	**[2505 - 3325] $2,926**	**[586 - 773] $684**	**[1031 - 1365] $1,204**	**[1471 - 1951] $1,719**	**[1908 - 2533] $2,229**	**[2343 - 3111] $2,737**	**[542 - 714] $632**	**[965 - 1279] $1,128**	**[1385 - 1837] $1,618**	**[1801 - 2391] $2,105**	**[2215 - 2943] $2,589**
	Total ESS Installed Cost*	**$/kWh**	**[331 - 435] $386**	**[231 - 310] $272**	**[265 - 351] $310**	**[256 - 340] $299**	**[251 - 333] $293**	**[293 - 386] $342**	**[258 - 341] $301**	**[245 - 325] $286**	**[238 - 317] $279**	**[234 - 311] $274**	**[271 - 357] $316**	**[241 - 320] $282**	**[231 - 306] $270**	**[225 - 299] $263**	**[221 - 294] $259**
Operating Costs	Fixed O&M	$/kW-yr	[1.91 - 2.34] 2.11	[3.34 - 4.1] 3.70	[4.76 - 5.85] 5.27	[6.16 - 7.58] 6.83	[7.56 - 9.3] 8.38	[1.69 - 2.08] 1.88	[3.06 - 3.76] 3.39	[4.41 - 5.42] 4.89	[5.75 - 7.07] 6.37	[7.08 - 8.71] 7.85	[1.57 - 1.94] 1.75	[2.88 - 3.54] 3.19	[4.16 - 5.12] 4.61	[5.44 - 6.69] 6.03	[6.71 - 8.25] 7.44
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.004					0.004					0.004				
Performance Metrics	Round Trip Efficiency	%	88%					88%					88%				
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	1,260					1,260					1,260				
Performance Metrics	Calendar Life	yrs	10					10					10				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	3.63					3.63					3.63				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 80% depth of discharge, one cycle/day, and 5% downtime

Appendix 2: Lead-Acid Battery Cost Estimates Across all Durations

Lead Acid
2020 Cost & Performance Estimates

Category	Parameter	Units	1 MW 2hr	1 MW 4hr	1 MW 6hr	1 MW 8hr	1 MW 10hr	10 MW 2hr	10 MW 4hr	10 MW 6hr	10 MW 8hr	10 MW 10hr	100 MW 2hr	100 MW 4hr	100 MW 6hr	100 MW 8hr	100 MW 10hr
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[169 - 190] 180	[169 - 190] 180	[169 - 190] 180	[169 - 190] 180	[169 - 190] 180	[161 - 181] 171	[161 - 181] 171	[161 - 181] 171	[161 - 181] 171	[161 - 181] 171	[153 - 172] 162	[153 - 172] 162	[153 - 172] 162	[153 - 172] 162	[153 - 172] 162
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[46 - 52] 49	[46 - 52] 49	[46 - 52] 49	[46 - 52] 49	[46 - 52] 49	[44 - 50] 47	[44 - 50] 47	[44 - 50] 47	[44 - 50] 47	[44 - 50] 47	[42 - 47] 45	[42 - 47] 45	[42 - 47] 45	[42 - 47] 45	[42 - 47] 45
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[146 - 164] 155	[146 - 164] 155	[146 - 164] 155	[146 - 164] 155	[146 - 164] 155	[125 - 141] 133	[125 - 141] 133	[125 - 141] 133	[125 - 141] 133	[125 - 141] 133	[108 - 122] 115	[108 - 122] 115	[108 - 122] 115	[108 - 122] 115	[108 - 122] 115
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[38 - 42] 40	[38 - 42] 40	[38 - 42] 40	[38 - 42] 40	[38 - 42] 40	[7 - 8] 8	[7 - 8] 8	[7 - 8] 8	[7 - 8] 8	[7 - 8] 8	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2
ESS Installed Cost / Energy Storage System	Systems Integration	$/kWh	[51 - 57] 54	[45 - 50] 47	[42 - 48] 45	[41 - 47] 44	[41 - 46] 43	[46 - 52] 49	[41 - 47] 44	[40 - 45] 42	[39 - 44] 41	[38 - 43] 41	[43 - 48] 46	[39 - 44] 41	[37 - 42] 40	[37 - 41] 39	[36 - 41] 39
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[57 - 64] 60	[49 - 55] 52	[47 - 52] 50	[45 - 51] 48	[45 - 50] 47	[53 - 59] 56	[46 - 52] 49	[44 - 50] 47	[43 - 48] 46	[42 - 48] 45	[49 - 55] 52	[43 - 49] 46	[41 - 47] 44	[41 - 46] 43	[40 - 45] 43
ESS Installed Cost	Project Development	$/kWh	[72 - 81] 76	[63 - 71] 67	[60 - 67] 64	[58 - 66] 62	[57 - 65] 61	[65 - 73] 69	[58 - 65] 62	[56 - 63] 59	[55 - 62] 58	[54 - 61] 57	[60 - 67] 64	[54 - 61] 58	[52 - 59] 56	[51 - 58] 55	[51 - 57] 54
ESS Installed Cost	Grid Integration	$/kW	[29 - 33] 31	[29 - 33] 31	[29 - 33] 31	[29 - 33] 31	[29 - 33] 31	[23 - 26] 25	[23 - 26] 25	[23 - 26] 25	[23 - 26] 25	[23 - 26] 25	[19 - 21] 20	[19 - 21] 20	[19 - 21] 20	[19 - 21] 20	[19 - 21] 20
	Total ESS Installed Cost*	**$/kW**	**[975 - 1154] $1,065**	**[1658 - 1956] $1,808**	**[2341 - 2758] $2,552**	**[3024 - 3561] $3,296**	**[3707 - 4365] $4,040**	**[870 - 1028] $950**	**[1520 - 1792] $1,657**	**[2171 - 2557] $2,364**	**[2821 - 3322] $3,072**	**[3472 - 4086] $3,780**	**[801 - 946] $873**	**[1419 - 1672] $1,544**	**[2037 - 2398] $2,215**	**[2655 - 3125] $2,886**	**[3273 - 3852] $3,558**
	Total ESS Installed Cost*	**$/kWh**	**[488 - 577] $533**	**[414 - 489] $452**	**[390 - 460] $425**	**[378 - 445] $412**	**[371 - 436] $404**	**[435 - 514] $475**	**[380 - 448] $414**	**[362 - 426] $394**	**[353 - 415] $384**	**[347 - 409] $378**	**[401 - 473] $436**	**[355 - 418] $386**	**[339 - 400] $369**	**[332 - 391] $361**	**[327 - 385] $356**
Operating Costs	Fixed O&M	$/kW-yr	[3.19 - 3.59] 3.39	[5.59 - 6.3] 5.9	[7.98 - 9] 8.5	[10.38 - 11.71] 11.0	[12.78 - 14.41] 13.6	[2.82 - 3.18] 3.00	[5.11 - 5.76] 5.43	[7.39 - 8.33] 7.86	[9.68 - 10.91] 10.29	[11.96 - 13.49] 12.72	[2.63 - 2.97] 2.80	[4.8 - 5.42] 5.11	[6.97 - 7.87] 7.42	[9.15 - 10.31] 9.73	[11.32 - 12.76] 12.04
Operating Costs	Variable O&M	$/MWh			0.5125					0.5125					0.5125		
Operating Costs	System RTE Losses	$/kWh	0.009	0.008	0.007	0.006	0.005	0.009	0.008	0.007	0.006	0.005	0.009	0.008	0.007	0.006	0.005
Performance Metrics	Round Trip Efficiency	%	77.0%	79.0%	82.0%	83.5%	85.0%	77.0%	79.0%	82.0%	83.5%	85.0%	77.0%	79.0%	82.0%	83.5%	85.0%
Performance Metrics	Response Time	sec			1-4					1-4					1-4		
Performance Metrics	Cycle Life	#	862	739	675	635	599	862	739	675	635	599	862	739	675	635	599
Performance Metrics	Calendar Life	yrs			12					12					12		
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	2.49	2.13	1.95	1.83	1.73	2.49	2.13	1.95	1.83	1.73	2.49	2.13	1.95	1.83	1.73

* Does not include warranty, insurance, or decommissioning costs
** Assumes various depths of discharge, one cycle/day, and 5% downtime

Lead Acid
2030 Cost & Performance Estimates

	Parameter	Units	1 MW					10 MW					100 MW				
			2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr	2hr	4hr	6hr	8hr	10hr
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[160 - 176] 167	[160 - 176] 167	[160 - 176] 167	[160 - 176] 167	[160 - 176] 167	[152 - 168] 159	[152 - 168] 159	[152 - 168] 159	[152 - 168] 159	[152 - 168] 159	[145 - 159] 151	[145 - 159] 151	[145 - 159] 151	[145 - 159] 151	[145 - 159] 151
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[30 - 41] 35	[30 - 41] 35	[30 - 41] 35	[30 - 41] 35	[30 - 41] 35	[28 - 39] 33	[28 - 39] 33	[28 - 39] 33	[28 - 39] 33	[28 - 39] 33	[27 - 37] 31	[27 - 37] 31	[27 - 37] 31	[27 - 37] 31	[27 - 37] 31
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1
ESS Installed Cost / Energy Storage System	Systems Integration	$/kWh	[40 - 49] 44	[35 - 43] 39	[33 - 41] 37	[33 - 40] 36	[32 - 40] 36	[36 - 45] 40	[33 - 40] 36	[31 - 38] 35	[31 - 38] 34	[30 - 37] 34	[34 - 41] 37	[31 - 38] 34	[29 - 36] 33	[29 - 36] 32	[29 - 35] 32
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[45 - 55] 49	[39 - 47] 43	[37 - 45] 41	[36 - 44] 40	[35 - 43] 39	[41 - 51] 46	[36 - 45] 40	[35 - 43] 38	[34 - 42] 37	[33 - 41] 37	[39 - 48] 43	[34 - 42] 38	[33 - 40] 36	[32 - 39] 35	[32 - 39] 35
ESS Installed Cost	Project Development	$/kWh	[56 - 69] 63	[49 - 61] 55	[47 - 58] 52	[46 - 56] 51	[45 - 56] 50	[51 - 63] 56	[46 - 56] 51	[44 - 54] 49	[43 - 53] 48	[42 - 52] 47	[47 - 58] 52	[43 - 53] 47	[41 - 51] 46	[41 - 50] 45	[40 - 49] 44
ESS Installed Cost	Grid Integration	$/kW	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	**[816 - 981] $902**	**[1405 - 1673] $1,538**	**[1995 - 2365] $2,175**	**[2585 - 3058] $2,812**	**[3175 - 3750] $3,449**	**[734 - 879] $809**	**[1296 - 1538] $1,415**	**[1857 - 2197] $2,022**	**[2419 - 2856] $2,629**	**[2981 - 3516] $3,235**	**[678 - 810] $746**	**[1211 - 1436] $1,322**	**[1745 - 2062] $1,898**	**[2279 - 2688] $2,474**	**[2812 - 3315] $3,050**
	Total ESS Installed Cost*	**$/kWh**	**[408 - 491] $451**	**[351 - 418] $385**	**[332 - 394] $362**	**[323 - 382] $351**	**[317 - 375] $345**	**[367 - 439] $405**	**[324 - 384] $354**	**[310 - 366] $337**	**[302 - 357] $329**	**[298 - 352] $324**	**[339 - 405] $373**	**[303 - 359] $330**	**[291 - 344] $316**	**[285 - 336] $309**	**[281 - 331] $305**
Operating Costs	Fixed O&M	$/kW-yr	[2.51 - 3.08] 2.78	[4.4 - 5.41] 4.9	[6.29 - 7.73] 7.0	[8.17 - 10.05] 9.1	[10.06 - 12.37] 11.1	[2.22 - 2.73] 2.46	[4.02 - 4.94] 4.45	[5.82 - 7.16] 6.45	[7.62 - 9.37] 8.44	[9.42 - 11.58] 10.43	[2.07 - 2.55] 2.30	[3.78 - 4.65] 4.19	[5.49 - 6.75] 6.08	[7.2 - 8.85] 7.98	[8.91 - 10.95] 9.87
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.009	0.008	0.007	0.006	0.005	0.009	0.008	0.007	0.006	0.005	0.009	0.008	0.007	0.006	0.005
Performance Metrics	Round Trip Efficiency	%	77.0%	79.0%	82.0%	83.5%	85.0%	77.0%	79.0%	82.0%	83.5%	85.0%	77.0%	79.0%	82.0%	83.5%	85.0%
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	862	739	675	635	599	862	739	675	635	599	862	739	675	635	599
Performance Metrics	Calendar Life	yrs	12					12					12				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	2.49	2.13	1.95	1.83	1.73	2.49	2.13	1.95	1.83	1.73	2.49	2.13	1.95	1.83	1.73

* Does not include warranty, insurance, or decommissioning costs
** Assumes various depths of discharge, one cycle/day, and 5% downtime

Appendix 3: RFB Cost Estimates Across all Durations – 2020 and 2030

Vanadium Redox Flow
2020 Cost & Performance Estimates

Category	Parameter	Units	1 MW 2hr	1 MW 4hr	1 MW 6hr	1 MW 8hr	1 MW 10hr	10 MW 2hr	10 MW 4hr	10 MW 6hr	10 MW 8hr	10 MW 10hr	100 MW 2hr	100 MW 4hr	100 MW 6hr	100 MW 8hr	100 MW 10hr
ESS Installed Cost – Energy Storage System – Storage System	Storage Block	$/kWh	[346 - 423] 384	[260 - 317] 289	[231 - 282] 257	[217 - 265] 241	[208 - 254] 231	[329 - 402] 366	[247 - 302] 275	[220 - 269] 245	[206 - 252] 229	[198 - 242] 220	[313 - 382] 348	[235 - 287] 261	[209 - 256] 232	[196 - 240] 218	[188 - 230] 209
ESS Installed Cost – Energy Storage System – Storage System	Storage Balance of System	$/kWh	[69 - 85] 77	[52 - 63] 58	[46 - 56] 51	[43 - 53] 48	[42 - 51] 46	[66 - 80] 73	[49 - 60] 55	[44 - 54] 49	[41 - 50] 46	[40 - 48] 44	[63 - 76] 70	[47 - 57] 52	[42 - 51] 46	[39 - 48] 44	[38 - 46] 42
ESS Installed Cost – Energy Storage System	Power Equipment	$/kW	[139 - 170] 155	[139 - 170] 155	[139 - 170] 155	[139 - 170] 155	[139 - 170] 155	[120 - 146] 133	[120 - 146] 133	[120 - 146] 133	[120 - 146] 133	[120 - 146] 133	[103 - 126] 115	[103 - 126] 115	[103 - 126] 115	[103 - 126] 115	[103 - 126] 115
ESS Installed Cost – Energy Storage System	Controls & Communication	$/kW	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[36 - 44] 40	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[7 - 9] 8	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2	[1 - 2] 2
ESS Installed Cost – Energy Storage System	Systems Integration	$/kWh	[69 - 84] 76	[50 - 61] 55	[44 - 53] 48	[41 - 50] 45	[39 - 47] 43	[64 - 78] 71	[46 - 56] 51	[40 - 49] 45	[38 - 46] 42	[36 - 44] 40	[59 - 73] 66	[43 - 53] 48	[38 - 46] 42	[35 - 43] 39	[34 - 41] 38
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[78 - 96] 87	[57 - 69] 63	[50 - 61] 56	[47 - 57] 52	[45 - 55] 50	[73 - 89] 81	[53 - 64] 58	[46 - 57] 51	[43 - 53] 48	[42 - 51] 46	[68 - 83] 76	[49 - 60] 54	[43 - 53] 48	[40 - 49] 45	[39 - 47] 43
ESS Installed Cost	Project Development	$/kWh	[98 - 120] 109	[72 - 88] 80	[64 - 78] 71	[60 - 73] 66	[57 - 70] 64	[89 - 109] 99	[66 - 81] 73	[59 - 72] 65	[55 - 67] 61	[53 - 64] 59	[83 - 101] 92	[61 - 75] 68	[54 - 66] 60	[51 - 62] 57	[49 - 60] 54
ESS Installed Cost	Grid Integration	$/kW	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[28 - 34] 31	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20	[18 - 22] 20
	Total ESS Installed Cost*	**$/kW**	**[1523 - 1862] $1,693**	**[2163 - 2644] $2,404**	**[2811 - 3436] $3,123**	**[3461 - 4230] $3,845**	**[4111 - 5025] $4,568**	**[1391 - 1700] $1,546**	**[1995 - 2438] $2,216**	**[2606 - 3185] $2,895**	**[3219 - 3934] $3,576**	**[3832 - 4684] $4,258**	**[1294 - 1581] $1,438**	**[1863 - 2277] $2,070**	**[2439 - 2980] $2,710**	**[3016 - 3686] $3,351**	**[3595 - 4393] $3,994**
	Total ESS Installed Cost*	**$/kWh**	**[762 - 931] $846**	**[541 - 661] $601**	**[468 - 573] $521**	**[433 - 529] $481**	**[411 - 502] $457**	**[695 - 850] $773**	**[499 - 609] $554**	**[434 - 531] $483**	**[402 - 492] $447**	**[383 - 468] $426**	**[647 - 791] $719**	**[466 - 569] $517**	**[406 - 497] $452**	**[377 - 461] $419**	**[359 - 439] $399**
Operating Costs	Fixed O&M	$/kW-yr	[4.32 - 5.28] 4.80	[6.11 - 7.47] 6.79	[7.91 - 9.67] 8.79	[9.7 - 11.86] 10.78	[11.5 - 14.05] 12.77	[3.94 - 4.82] 4.38	[5.65 - 6.91] 6.28	[7.36 - 8.99] 8.18	[9.07 - 11.08] 10.07	[10.77 - 13.17] 11.97	[3.68 - 4.5] 4.09	[5.3 - 6.48] 5.89	[6.92 - 8.46] 7.69	[8.55 - 10.44] 9.49	[10.17 - 12.43] 11.30
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.0144					0.0144					0.0144				
Performance Metrics	Round Trip Efficiency	%	68%					68%					68%				
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	5,201					5,201					5,201				
Performance Metrics	Calendar Life	yrs	15					15					15				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	15					15					15				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 90% depth of discharge, one cycle/day, and 5% downtime

Vanadium Redox Flow
2030 Cost & Performance Estimates

Category	Parameter	Units	1 MW 2hr	1 MW 4hr	1 MW 6hr	1 MW 8hr	1 MW 10hr	10 MW 2hr	10 MW 4hr	10 MW 6hr	10 MW 8hr	10 MW 10hr	100 MW 2hr	100 MW 4hr	100 MW 6hr	100 MW 8hr	100 MW 10hr
ESS Installed Cost / Energy Storage System / Storage System	Storage Block	$/kWh	[244 - 350] 307	[183 - 263] 231	[163 - 234] 205	[153 - 219] 193	[147 - 210] 185	[232 - 333] 293	[175 - 250] 220	[155 - 223] 196	[146 - 209] 183	[140 - 200] 176	[221 - 316] 278	[166 - 238] 209	[148 - 211] 186	[138 - 198] 174	[133 - 190] 167
ESS Installed Cost / Energy Storage System / Storage System	Storage Balance of System	$/kWh	[46 - 63] 54	[35 - 47] 40	[31 - 42] 36	[29 - 39] 34	[28 - 38] 32	[44 - 60] 51	[33 - 45] 38	[29 - 40] 34	[28 - 38] 32	[26 - 36] 31	[42 - 57] 49	[31 - 43] 37	[28 - 38] 33	[26 - 36] 31	[25 - 34] 29
ESS Installed Cost / Energy Storage System	Power Equipment	$/kW	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[108 - 141] 133	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[93 - 121] 114	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99	[80 - 104] 99
ESS Installed Cost / Energy Storage System	Controls & Communication	$/kW	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[24 - 33] 28	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[5 - 6] 5	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1	[1 - 1] 1
ESS Installed Cost / Energy Storage System	Systems Integration	$/kWh	[57 - 70] 63	[41 - 50] 45	[36 - 44] 40	[33 - 41] 37	[32 - 39] 35	[52 - 64] 58	[38 - 47] 42	[33 - 41] 37	[31 - 38] 34	[30 - 37] 33	[49 - 60] 54	[35 - 44] 39	[31 - 38] 34	[29 - 36] 32	[28 - 34] 31
ESS Installed Cost	Engineering, Procurement, and Construction	$/kWh	[64 - 79] 71	[47 - 57] 52	[41 - 51] 46	[38 - 47] 43	[37 - 45] 41	[60 - 74] 67	[43 - 53] 48	[38 - 47] 42	[36 - 44] 39	[34 - 42] 38	[56 - 69] 62	[40 - 49] 45	[35 - 44] 39	[33 - 41] 37	[32 - 39] 35
ESS Installed Cost	Project Development	$/kWh	[81 - 99] 89	[59 - 73] 66	[52 - 65] 58	[49 - 60] 54	[47 - 58] 52	[73 - 90] 81	[54 - 67] 60	[48 - 59] 53	[45 - 56] 50	[43 - 53] 48	[68 - 84] 75	[50 - 62] 56	[45 - 55] 49	[42 - 51] 46	[40 - 49] 45
ESS Installed Cost	Grid Integration	$/kW	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[23 - 28] 25	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[18 - 23] 20	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16	[15 - 18] 16
	Total ESS Installed Cost*	**$/kW**	[1139 - 1523] **$1,356**	[1614 - 2163] **$1,922**	[2095 - 2811] **$2,495**	[2578 - 3461] **$3,070**	[3062 - 4112] **$3,645**	[1040 - 1393] **$1,240**	[1488 - 1996] **$1,773**	[1941 - 2608] **$2,314**	[2397 - 3221] **$2,856**	[2852 - 3835] **$3,399**	[967 - 1296] **$1,153**	[1388 - 1864] **$1,656**	[1815 - 2440] **$2,165**	[2244 - 3018] **$2,676**	[2673 - 3597] **$3,187**
	Total ESS Installed Cost*	**$/kWh**	[569 - 761] **$678**	[403 - 541] **$480**	[349 - 468] **$416**	[322 - 433] **$384**	[306 - 411] **$365**	[520 - 696] **$620**	[372 - 499] **$443**	[324 - 435] **$386**	[300 - 403] **$357**	[285 - 383] **$340**	[483 - 648] **$576**	[347 - 466] **$414**	[303 - 407] **$361**	[281 - 377] **$334**	[267 - 360] **$319**
Operating Costs	Fixed O&M	$/kW-yr	[3.55 - 4.37] 3.94	[5.03 - 6.18] 5.57	[6.5 - 8] 7.21	[7.98 - 9.81] 8.84	[9.45 - 11.62] 10.47	[3.24 - 3.99] 3.59	[4.65 - 5.71] 5.15	[6.05 - 7.44] 6.70	[7.45 - 9.17] 8.26	[8.86 - 10.89] 9.82	[3.02 - 3.72] 3.35	[4.36 - 5.36] 4.83	[5.69 - 7] 6.31	[7.03 - 8.64] 7.79	[8.36 - 10.28] 9.26
Operating Costs	Variable O&M	$/MWh	0.5125					0.5125					0.5125				
Operating Costs	System RTE Losses	$/kWh	0.0129					0.0129					0.0129				
Performance Metrics	Round Trip Efficiency	%	70%					70%					70%				
Performance Metrics	Response Time	sec	1-4					1-4					1-4				
Performance Metrics	Cycle Life	#	5,201					5,201					5,201				
Performance Metrics	Calendar Life	yrs	15					15					15				
Performance Metrics	Duration Corresponding to Cycle Life**	yrs	15					15					15				

* Does not include warranty, insurance, or decommissioning costs
** Assumes 90% depth of discharge, one cycle/day, and 5% downtime

Appendix 4: Annual Discharge Throughput by Technology, Power Capacity, Energy Duration, and Estimate Year

Technology	Year	Power Capacity (MW)	Energy Duration (hr)	Annual Energy Discharge (kWh/year)
Lithium-ion LFP	2020	1	2	554,800
			4	1,109,600
			6	1,664,400
			8	2,219,200
			10	2,774,000
		10	2	5,548,000
			4	11,096,000
			6	16,644,000
			8	22,192,000
			10	27,740,000
		100	2	55,480,000
			4	110,960,000
			6	166,440,000
			8	221,920,000
			10	277,400,000
	2030	1	2	554,800
			4	1,109,600
			6	1,664,400
			8	2,219,200
			10	2,774,000
		10	2	5,548,000
			4	11,096,000
			6	16,644,000
			8	22,192,000
			10	27,740,000
		100	2	55,480,000
			4	110,960,000
			6	166,440,000
			8	221,920,000
			10	277,400,000
Lithium-ion NMC	2020	1	2	554,800
			4	1,109,600
			6	1,664,400
			8	2,219,200

Technology	Year	Power Capacity (MW)	Energy Duration (hr)	Annual Energy Discharge (kWh/year)
			10	2,774,000
		10	2	5,548,000
			4	11,096,000
			6	16,644,000
			8	22,192,000
			10	27,740,000
		100	2	55,480,000
			4	110,960,000
			6	166,440,000
			8	221,920,000
			10	277,400,000
	2030	1	2	554,800
			4	1,109,600
			6	1,664,400
			8	2,219,200
			10	2,774,000
		10	2	5,548,000
			4	11,096,000
			6	16,644,000
			8	22,192,000
			10	27,740,000
		100	2	55,480,000
			4	110,960,000
			6	166,440,000
			8	221,920,000
			10	277,400,000
Lead acid	2020	1	2	402,230
			4	930,677
			6	1,520,846
			8	2,263,584
			10	2,992,453
		10	2	4,022,300
			4	9,306,770
			6	15,208,455
			8	22,635,840
			10	29,924,525
		100	2	40,223,000
			4	93,067,700
			6	152,084,550
			8	226,358,400

Technology	Year	Power Capacity (MW)	Energy Duration (hr)	Annual Energy Discharge (kWh/year)
			10	299,245,250
	2030	1	2	402,230
			4	930,677
			6	1,520,846
			8	2,263,584
			10	2,992,453
		10	2	4,022,300
			4	9,306,770
			6	15,208,455
			8	22,635,840
			10	29,924,525
		100	2	40,223,000
			4	93,067,700
			6	152,084,550
			8	226,358,400
			10	299,245,250
RFB	2020	1	2	624,150
			4	1,248,300
			6	1,872,450
			8	2,496,600
			10	3,120,750
		10	2	6,241,500
			4	12,483,000
			6	18,724,500
			8	24,966,000
			10	31,207,500
		100	2	62,415,000
			4	124,830,000
			6	187,245,000
			8	249,660,000
			10	312,075,000
	2030	1	2	624,150
			4	1,248,300
			6	1,872,450
			8	2,496,600
			10	3,120,750
		10	2	6,241,500
			4	12,483,000
			6	18,724,500
			8	24,966,000

Technology	Year	Power Capacity (MW)	Energy Duration (hr)	Annual Energy Discharge (kWh/year)
			10	31,207,500
		100	2	62,415,000
			4	124,830,000
			6	187,245,000
			8	249,660,000
			10	312,075,000
CAES	2020	100	4	110,960,000
			10	277,400,000
		1000	4	1,109,600,000
			10	2,774,000,000
		10000	4	11,096,000,000
			10	27,740,000,000
	2030	100	4	110,960,000
			10	277,400,000
		1000	4	1,109,600,000
			10	2,774,000,000
		10000	4	11,096,000,000
			10	27,740,000,000
PSH	2020	100	4	110,960,000
			10	277,400,000
		1000	4	1,109,600,000
			10	2,774,000,000
	2030	100	4	110,960,000
			10	277,400,000
		1000	4	1,109,600,000
			10	2,774,000,000
HESS	2020	100	10	277,400,000
	2030		10	277,400,000

The ESGC is a crosscutting effort managed by DOE's Research Technology Investment Committee (RTIC). The Energy Storage Subcommittee of the RTIC is co-chaired by the Office of Energy Efficiency and Renewable Energy and Office of Electricity and includes the Office of Science, Office of Fossil Energy, Office of Nuclear Energy, Office of Technology Transitions, ARPA-E, Office of Strategic Planning and Policy, the Loan Programs Office, and the Office of the Chief Financial Officer.

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