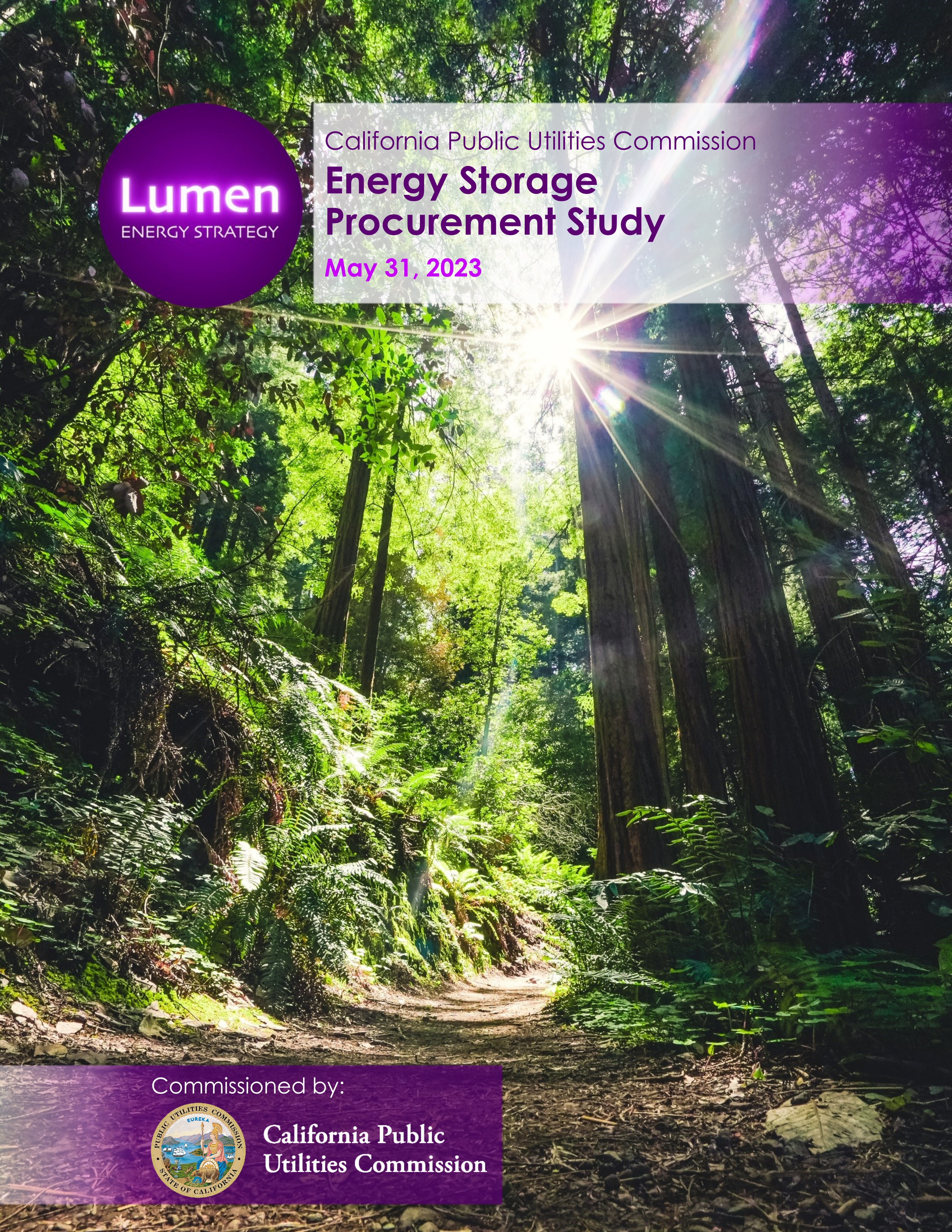

Lumen
ENERGY STRATEGY

California Public Utilities Commission

Energy Storage Procurement Study

May 31, 2023

Commissioned by:

California Public Utilities Commission

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Please cite as: Aydin, Mariko Geronimo, and Cevat Onur Aydin. 2023. *California Public Utilities Commission Energy Storage Procurement Study*. Lumen Energy Strategy, LLC. Prepared for the California Public Utilities Commission. May 31, 2023. www.lumenenergystrategy.com/energystorage.

This work has been developed and published by Lumen Energy Strategy, LLC in Oakland, California under commission by the California Public Utilities Commission. All errors and omissions are the authors' own.

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ABBREVIATIONS AND TERMS

CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DER	distributed energy resource
DOE	U.S. Department of Energy
ELCC	effective load-carrying capability
ESP	electric service provider
GHG	greenhouse gas
GW	gigawatt(s)
GWh	gigawatt-hour(s)
IOU	investor-owned utility (informally, utility)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LBNL	Lawrence Berkeley National Laboratory
LSE	load-serving entity (includes IOU, CCA, ESP)
MW	megawatt(s)
MWh	megawatt-hour(s)
NEM	net energy metering
NQC	net qualifying capacity
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric Company
PNNL	Pacific Northwest National Laboratory
RA	resource adequacy
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SOC	state of charge

$/kW-month	Dollars per kW (capacity) per month. Many benefits and costs in this report are expressed as this metric due to its prevalence in resource adequacy planning and markets. The metric normalizes benefits and costs so resources of different sizes and in operation for varying lengths of time are more comparable. For example, a 2 MW resource operating for 6 months that yields $192,000 in benefits is twice as beneficial per kW and per month ($192,000÷2,000 kW÷6 months = $16/kW-month) as a 100 MW resource operating for 12 months that yields $9.6 million in total benefits ($9.6 million÷100,000 kW÷12 months = $8/kW-month). For more information about our calculations please see **Attachment A**.
2021 Preferred System Plan	An outcome of the CPUC's 2019–2020 Integrated Resource Plan cycle and the adopted portfolio that meets a statewide 38 million metric tons (MMT) greenhouse gas target for the electric sector in 2030 and 35 MMT for 2032. Includes 13,571 MW of new battery storage plus 1,000 MW new pumped (long-duration) storage installed in 2022–2032. See the CPUC's February 10, 2022 Decision 22-02-004, Table 5.

ancillary services	Ancillary services provide grid operational flexibility and stabilization for the purposes of reliable electricity delivery. CAISO ancillary services markets include non-spinning and spinning contingency reserves, and regulation up and down. We use the term more broadly to include additional services like blackstart and voltage support (reactive power).
capacity credit/contribution	A generic term referring to a resource's ability to provide resource adequacy capacity service relative to its full capacity. Not to be confused with the formal definition of RA capacity in the CPUC's RA program and RA procurements.
capacity value	A generic term referring to the monetization of capacity credit or capacity contribution.
duration	The number of consecutive hours an energy storage resource can discharge at its power capacity, starting from a full charge. Duration reflects physical configuration and technical limits, not the full range of operational capability. For example, a 10 MW 4-hour battery can also discharge 5 MW over 8 hours.
effective load-carrying capability	A probabilistically-derived metric that summarizes a resource's or group of resources' ability to serve electricity demand across all time periods—as opposed to more traditional metrics that reflect available capacity during a single peak load hour. ELCC has become an increasingly important planning and performance metric as California achieves increasingly high renewables and energy storage penetration.
energy capacity	The maximum technical limit of total MWh an energy storage resource can provide without recharging or replenishing stored energy.
energy storage	Mechanical, chemical, and thermal technologies as defined in California Assembly Bill 2514 (Skinner, 2010) and clarified in CPUC Decision 16-01-032.
energy time shift	Refers to the service provided by energy storage to move large volumes of renewable generation from one time period to another.
grid domain	Refers to the general electrical location. Energy storage can be connected at the bulk grid level on the transmission network (transmission domain), on the distribution network and in front of the utility's customer meter (distribution domain), or behind the utility's customer meter (customer domain).
life or lifetime	Refers to the period during which storage can be in service economically. For batteries, life or lifetime is typically expressed as the number of full charge/discharge cycles and/or calendar time once energized. For more discussion please see **Attachment G**.
marginal resource	The last and most expensive resource cleared in a competitive market. In this report, we may refer to the marginal resource in a wholesale electricity marketplace for energy, ancillary services, or RA capacity.
marginal value	Derived from an actual or counterfactual market-clearing price for a service in a competitive market. In this report, we convert market revenues or avoided costs into a standardized $/kW-month metric for ease of comparison of marginal value among supplier costs and many types of supplier services.

net grid benefits	May be a ratepayer or societal net benefit metric, depending on contract terms or ownership structure of the resource producing the benefits. We use this term when the procurement details of future resources are undetermined.
power capacity	The maximum technical limit of instantaneous MW an energy storage resource can provide.
ratepayer (net) benefit	A version of California's Program Administrator Cost (PAC) test that represents the (net) benefits to all ratepayers, including program participants and non-participants but excluding out-of-pocket participant costs. Not to be confused with the state's Ratepayer Impact Measure (RIM) test which is a metric for program non-participants.
real option	An economically valuable right (but not an obligation) to make a business decision or investment in the future. In this report we discuss the ability of energy storage to create real options through its physical and operational modularity. Real options are achievable via design and procurement of an energy storage project with the flexibility to increase duration later if/when needed, and through the flexibility to provide alternative services if the primary use case doesn't work as planned.
roundtrip efficiency	The ratio of useful energy discharged to energy consumed for charge.
SB 100 Core scenario	An indicative resource portfolio developed by California state agencies to achieve 100 percent of electricity retail sales and state loads from renewable and zero-carbon resources in California by 2045. Includes 48,600 MW new battery storage installed in 2020–2045. See the March 15, 2021 publication "SB 100 Joint Agency Report: Charting a Path to 100% Clean Energy Future," under CEC Docket 19-SB-100 (TN# 237167).
short-/long- duration	While there is no standard industry definition, we use "short-duration" as resources configured to discharge at full MW capacity for up to 10 hours, and long-duration as those configured to discharge at full MW capacity for more than 10 hours.
state of charge	The share of energy capacity held in a battery at a given time. For example, a 10 MWh battery at 50% state of charge is capable of discharging 5 MWh without recharging. State of charge factors into operating performance, operating capabilities, and battery degradation.
use case	A technical, operational, and/or financial model for developing and operating an energy storage resource to provide a specific set of services (e.g., microgrid use case). Use cases are varied and may or may not "stack" services within a grid domain (e.g. customer outage mitigation plus bill savings) and/or across grid domains (e.g., community outage mitigation plus energy services to the bulk grid).

PREFACE

In 2010, California Assembly Bill 2514 (Skinner) directed the California Public Utilities Commission (CPUC) to determine appropriate targets for the procurement of energy storage systems by electricity load-serving entities under its jurisdiction. The bill enabled several policy innovations to explore and accelerate the scalability of then-emerging stationary energy storage technologies.

In 2013, the CPUC issued Decision 13-10-040 and directed California's three large investor-owned utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric—to procure 1,325 megawatts of energy storage by 2020 with installation by the end of 2024. The decision also directed other load-serving entities to procure energy storage, adopted a framework to guide the procurement program, and directed the CPUC's Energy Division to conduct periodic comprehensive evaluations of the procurement program. This report is the first of the Energy Division's comprehensive evaluations.

With its 2013 decision the CPUC recognized new energy storage technology as a potential game-changer to provide crucial services to the electricity grid and to customers as the state moves towards an increasingly clean and sustainable energy future. The CPUC and its stakeholders also acknowledged many unknowns and risks in terms of costs, operating capabilities, ability to participate in wholesale markets, and long-term cost-effectiveness. Comprehensive evaluations were to provide a pathway to study and resolve those unknowns over time and to adapt procurement policies accordingly.

Specifically, the purpose of this evaluation is to determine to what degree CPUC-directed energy storage procurements meet Assembly Bill 2514 stated goals of **grid optimization**, **renewables integration**, and **greenhouse gas emissions reductions**. At the heart of this evaluation is an analysis of actual energy storage operations, benefits, and costs in the 5-year study period 2017–2021. The evaluation also broadly assesses the stationary energy storage market in California to determine progress towards market maturity and its potential to benefit Californians at a large scale.

The historical evaluation in our report is not intended to be—nor would it be correctly interpreted as—a prudency review of any individual energy storage resource procurement. California's journey with energy storage development included substantial investment in the innovation process. This necessitates learning from pilots, demonstration projects, and first-of-its-kind procurements to facilitate future potential benefits of a larger fleet. The resource-level rankings presented are intended to illuminate key themes in successes and challenges to guide development of effective policies as we move forward, rather than to identify "good" or "bad" energy storage installations.

Stakeholders had a significant role in shaping the scope of this CPUC Energy Storage Procurement Study. The CPUC issued a Request for Information in early 2020 to determine desired study scope, timeline, and contractor requirements, then engaged with stakeholders over a period of six months to make necessary refinements. Assessment of safety-related best practices is included in the core study scope. This evaluation also includes several "special studies" to inform future policy developments, including: review of other energy storage procurement policies in practice, models for stacking multiple services and value at once, analysis of cost-effectiveness of future procurements and natural gas peaker replacements, and documentation of end-of-life options. Safety best practices and these special studies are considered in the overall assessment and recommendations, with further detail in attachments to this report.

The authors would like to thank Gabe Petlin and Michael Castelhano of the CPUC Energy Division for their valuable feedback and guidance. The authors are grateful to the many stakeholders who contributed by providing data and feedback to this study, with a special thanks to the CPUC, California Energy Commission, California ISO, Public Advocates Office, Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, San Diego County Water Authority, and California Energy Storage Alliance.

EXECUTIVE SUMMARY

Under the direction of California Public Utilities Commission (CPUC) Decision 13-10-040, the CPUC Energy Storage Procurement Study learns from historical stationary energy storage procurements and operations to assess the evolution of California's energy storage industry both historically and looking forward. The study's key observations and guiding recommendations are meant to highlight policy levers that will support development of a cost-effective energy storage portfolio that effectively contributes to meeting the state's goals of electricity grid optimization, renewables integration, and greenhouse gas (GHG) emissions reductions.

Over the past decade, the California state agencies, utilities, and many other stakeholders explored many uncharted pathways to accelerate development of a variety of stationary energy storage technologies and use cases—and successfully launched a vibrant energy storage market in the state. During our 2017–2021 study period California ratepayers invested an average of $75 million per year in exploratory projects and incentive programs to drive market transformation. The more recent market-mature projects reveal the first fruits of this investment: they were on track to yield net benefits at a rate of $22 million per year by the end of 2021. The cost of earlier exploratory projects and incentive programs will continue at $89 million per year on average over their full amortization period. However, as grid-scale battery installations expand to 13.6 gigawatts to meet the state's 2021 Preferred System Plan we expect going-forward net benefits to grow to a potential of $835 million to $1.34 billion of annual net grid benefits by 2032. With future policy adjustments to address existing barriers to grid benefits and anticipated future challenges, we believe California can secure these benefits and unlock the full potential of its energy storage portfolio: a more diversified and effective portfolio and a total net grid benefit of $1–$1.6 billion per year by 2032.

This study closely examines the operations and net benefits of resources counted towards the Decision 13-10-040 requirement for utilities to install 1,325 MW of energy storage by 2024, plus resources more recently procured to satisfy system-wide resource adequacy needs under CPUC jurisdiction. This group of resources includes energy storage procured under energy storage-specific, general rate case, local reliability, system reliability, distribution planning, and bilateral procurement tracks. The group also includes installations incentivized by programs like the Self-Generation Incentive Program (SGIP), utility Permanent Load Shift and Thermal Energy Storage programs, and the Electric Program Investment Charge (EPIC) program. Most of these resources utilize lithium-ion battery technology but the group includes thermal energy storage, pumped storage hydroelectric, and alternative battery chemistries. Installation sizes range from 25 kilowatts to 300 megawatts in terms of instantaneous capacity and these resources are considered "short duration." Most resources analyzed are capable of discharging up to four hours at full megawatt capacity, but range from 0.25 to 7 hours. This resource set represents a variety of use cases and services provided to customers directly, to the distribution system, and to the transmission system.

Our net benefit calculations are grounded in California's existing practices and methodologies, namely those reflected in the state's Standard Practice Manual for cost-effectiveness tests, the state's Avoided Cost Calculator for distributed energy resources, and the utilities' various Least-Cost Best-Fit calculations for bid evaluations in resource procurements. We expand upon these methodologies in four dimensions: (1) we evaluate and learn from historical resource-specific storage operations rather than exclusively generic resources in the future, (2) we evaluate at a finer granularity to capture meaningful temporal and spatial patterns in benefits, (3) we evaluate storage installed at any location (customer, distribution system, transmission system) with a single consistent approach, and (4) we attempt to quantify the full spectrum of benefit types identified by stakeholders. By doing so we observe trends and patterns in both benefits and challenges as the short-duration stationary energy storage market exits its infancy and enters a massive growth phase of thousands of MW installed per year over the next decade.

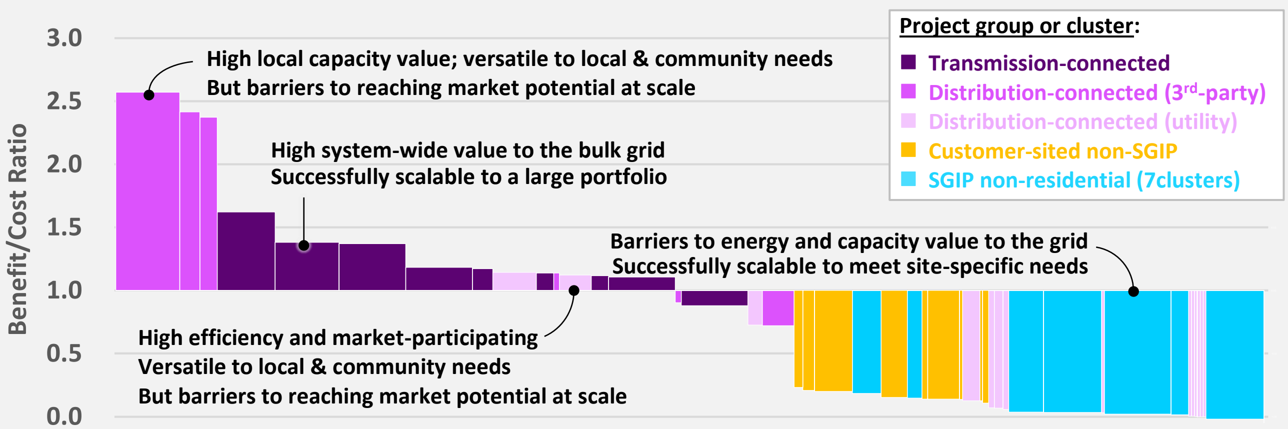


Figure 1: Summary of ratepayer benefit/cost ratio results.

Figure 1 summarizes our ratepayer net benefit results for the 2017–2021 operating period, expressed as benefit/cost ratios. Most bars represent an individual resource with the width of the bar showing relative MW capacity. Small customer-sited installations are aggregated into utility contracts or clusters. A benefit/cost ratio of one indicates benefits equal to costs; a ratio of two indicates $2 in benefits for every $1 in cost; and a negative ratio indicates negative benefits or a net cost. These results may reflect a snapshot of the total operating lives of an individual resource as well as market and operating conditions specific to the 2017–2021 timeframe. As such, the benefit/cost results do not necessarily reflect the lifetime net benefits of any resource and can only be appropriately interpreted along with the context of our more detailed analysis of net benefit trends and patterns.

The primary purpose and value in California's energy storage portfolio is its ability to move large volumes of renewable generation from one time period to another in a controllable fashion—so-called "energy time shift." This enables efficient integration and use of renewable capacity and generation. We observe that resources with the lowest benefit/cost ratios operate under use cases that did not provide significant energy time shift services to the grid. This will be one of the greatest policy challenges going forward. Although energy storage has the potential for many other benefit types (Figure 2), as long as large portions of the total storage portfolio do not mostly charge when renewable generation is in excess and do not mostly discharge when renewable generation is in scarcity, then we will observe significant barriers to realizing the benefits of energy storage. When these barriers are present, they are most evident both in the energy value and in the capacity value of energy storage as these two values are closely intertwined.

		Grid Domains		
	Services to Grid and Customers	Transmission	Distribution	Customer
Energy & AS Markets and Products	Energy	✓	✓	✓
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Blackstart	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	✓	✓
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		✓	✓
	Microgrid/Islanding		✓	✓
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			✓

Figure 2: Scope of possible services for transmission-, distribution-, and customer-sited resources.

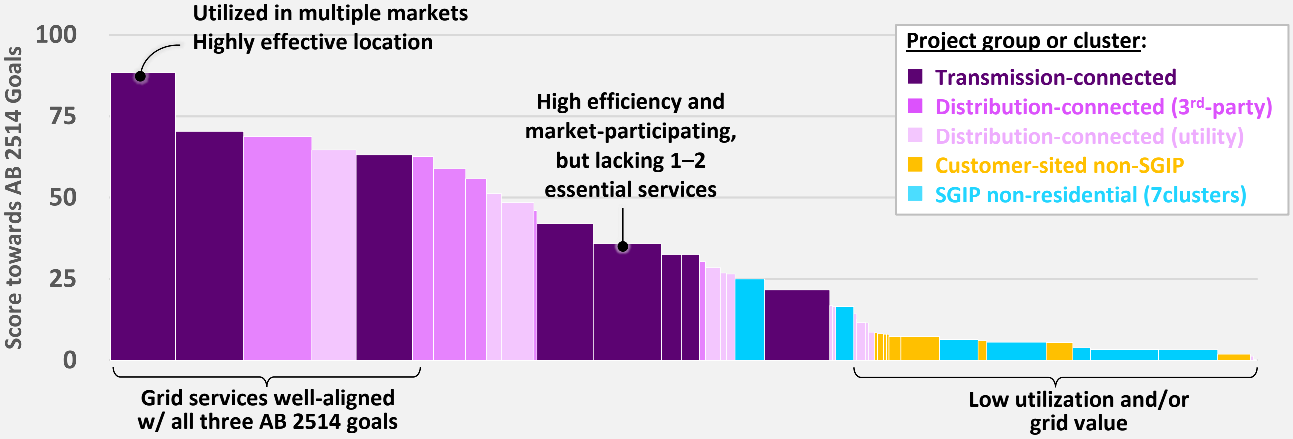


Figure 3: Summary of utilization towards Assembly Bill 2514 goals.

Figure 3 summarizes our assessment of the contribution of each resource or cluster towards the Assembly Bill 2514 stated goals of grid optimization, renewables integration, and GHG emissions reductions the 2017–2021 operating period. Scores reflect actual utilization of capacity towards a variety of services regardless of value or cost. Each bar is a simple average of three 0–100 scores: one for contribution to each goal. The grid optimization portion of the score considers the full spectrum of grid services shown previously in Figure 2 and share of capacity used to provide those services. The renewables integration portion of the score includes the subset of grid services that help specifically with renewables integration—such as the portion of energy time shift that reduces renewable curtailments. The GHG emissions reductions portion of the score reflects the volume of net reductions (or net increases) per MWh capacity. For each of the three goals, resource or cluster-specific contributions are calculated and normalized on a 0–100 point scale. Then, a simple average is taken and shown in the chart.

Observations on actual benefits and challenges during the 2017–2021 period

The market for stationary energy storage in California grew and matured significantly, from a pilot phase into commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations.

Customer-sited installations under SGIP grew from 60 MW/120 MWh to 470 MW/1,070 MWh. Grid-scale installations grew from 130 MW/510 MWh or 11% of all installations in the country to 2,400 MW/9,100 MWh or 44% of all installed capacity in the country.

Significant cost reductions were achieved for installations across all grid domains in California.

Third-party contract prices landed in the ranges of \$5–\$8/kW-month for capacity and \$9–\$14/kW-month for all attributes by the end of 2021. The capital cost of utility-owned projects dropped from \$6,000–\$11,500/kW for pre-2015 pilot and demonstration projects, to \$1,200–\$1,600/kW by the end of 2021.

Frequency regulation value for a subset of transmission- and distribution-connected storage resources was relatively high, but at the expense of GHG emissions increases.

This highlights the drawback of the operating losses of energy storage. Energy storage is a net consumer of electricity due conversion losses in its operating cycle (for lithium-ion, typically 15–20%). To provide frequency regulation, a storage resource charges more MWh within the same hour it discharges. If fossil-fired generation is on the margin, then storage is using more fossil-fired generation than it is displacing. This leads to higher GHG emissions.

A major shift away from the frequency regulation use case and towards the more broadly beneficial and scalable energy time shift use case occurred in the CAISO marketplace in 2021.

During the initial phase of deployment, primary use case and value centered around ancillary services for CAISO-participating resources. In 2020 and 2021, as installed storage capacity grew significantly and ancillary services markets saturate, we observe an increase in energy value and corresponding GHG emissions reduction value for most resources participating in the CAISO marketplace.

The resource adequacy use case reached scalability and grew substantially to meet grid needs.

By the end of 2021 about 2,200 MW/8,900 MWh of mostly grid-scale online installations provided resource adequacy services. An additional more than 5,000 MW/20,000 MWh was procured for system reliability in 2022–2023. In early 2022 the CPUC adopted its 2021 Preferred System Plan with an incremental 13,571 MW battery storage plus 1,000 MW pumped (long-duration) storage by 2032, suggesting an average build of 1,325 MW storage per year for resource adequacy purposes until 2032.

Non-residential customer-sited installations under SGIP provided a low level of service towards meeting the grid's energy and capacity needs and most of them increased GHG emissions.

Installations at commercial and retail sites performed among the worst and had operating patterns in competition with solar generation and indicative of demand charge bill management. Clusters of these resources provided negative energy value as low as -40¢/kW-month on average and they increased GHG emissions. This finding is consistent with the state's prior SGIP evaluation reports. Corrective program requirements were effective in April 2020 for non-residential installations to respond to a marginal GHG emissions rate signal. These new performance requirements are not apparent during our evaluation period, likely due to the length of project development timelines and legacy exemptions.

Schools, colleges, and residential customer-sited installations fared better with high solar PV attachment rates but still performed well below their potential.

Top-performing non-residential clusters had 99% solar PV attachment (i.e., 99% of those with storage installed also had solar installed) and represented a high share of schools and colleges. These resources provided up to 60¢/kW-month in energy value and corresponding GHG emissions reductions but were underutilized overall and fell short of their \$3–\$4/kW-month energy value potential.

Residential installations also have a high solar PV attachment rate of 97%. Although we did not analyze residential installations directly, the state's SGIP evaluation studies indicate a similar result of relatively high performance compared to other customer-sited installations but low absolute value compared to our \$3–\$4/kW-month benchmark.

Other customer aggregations provided low energy and capacity value—even when participating in the wholesale marketplace.

An additional 76 MW/318 MWh customer aggregations outside of SGIP also produced well below their energy value potential. These resources had low responsiveness to system emergencies even when receiving capacity payments and when participating directly in the wholesale energy marketplace. Those not participating in CAISO energy markets provided negative energy value and increased GHG emissions with operating patterns indicative of demand charge bill management. Those that did participate in CAISO energy markets provided only about \$1/kW-month in energy value, no GHG emissions reductions, and did not respond consistently to system emergencies due to restrictions in contract arrangements.

Utility-owned distribution-connected resources developed for microgrid and other distribution-related services provided very little value to the bulk grid and contributed to net GHG emissions increases.

This highlights the drawback of standby losses when transmission-level grid services are not integrated into the energy storage use case. A 10 MW/24 MWh subset of resources were significantly underutilized and/or on extended periods of standby while continuously drawing from the grid at a net cost and during hours when fossil-fired generation was on the margin.

Customer outage mitigation needs, awareness, and value increased significantly after 2019 PSPS events, but lack of customer impact data makes it difficult to quantify resilience benefits of storage.

Wildfire risks accelerated and shifted rapidly in 2017–2021 along with utility use of extended planned outages of sections of the distribution system (Public Safety Power Shutoffs) as a mitigation tool. Most of the 205 MW/425 MWh of SGIP-funded non-residential installations that we analyzed were not configured or not in the locations to provide multi-day outage mitigation services. Since the inception of the Equity Resiliency budget under SGIP in 2020, however, we observe a trend of residential installations paired with solar PV and concentrated in high wildfire threat areas.

No California-specific and statistically significant estimate of the cost of multi-hour and multi-day outages to customers is available in the industry. Our estimates of outage mitigation value are likely conservative and likely do not reflect the full range of benefits across circumstances, locations, or the diversity of specific customer needs.

Storage served at scale as generators providing capacity within local transmission-constrained areas of the grid, but no resource operated specifically as a transmission asset.

909 MW/3,579 MWh in storage capacity was procured by utilities to meet various resource adequacy needs in local transmission-constrained parts of the grid. These resources addressed local grid constraints by acting as generation assets and we calculated their benefits accordingly as the avoided cost of a generator. However, these types of local grid constraints may alternatively be fully or partially addressed by new transmission solutions. As such, storage operating in these transmission-constrained areas may alternatively be thought of as a generation substitute for transmission (also known as "non-wires alternative").

No resource operated specifically as a transmission asset operated by CAISO. This specific use case is still in a very early pilot and demonstration phase. One resource was procured under the storage as a transmission asset (SATA) use case in 2019 but has yet to be developed. A major challenge appears to be a disconnect between planning uncertainties in the size of a transmission need and inflexibilities in the storage procurement and development process to adjust to new information.

Storage developed to defer specific distribution investments faced major challenges as the size and timing of identified needs changed over time.

One resource analyzed was originally procured to defer a distribution system investment. However, the deferral need disappeared just prior to start of operations. At least nine projects earmarked for distribution investment deferral were canceled—including almost all third-party-owned projects procured under this use case. We observe that not only is this benefit difficult to capture but it is in need of pairing with other synergistic grid-level services, like energy and resource adequacy capacity, to hedge against shifting needs on the distribution system.

Developers utilize the modularity of battery storage systems in their construction and market participation strategies.

Some projects were built in phases ahead of their resource adequacy contracts, starting with target MW capacity at shorter durations offered into energy and ancillary services markets and progressively adding more duration to meet their contract obligations. Under the distribution deferral use case, one project demonstrates the advantages of energy storage's use case flexibility. That project successfully reached commercial operations and provided benefits by participating in the CAISO marketplace—despite evaporation of the original distribution deferral needs when the utility's demand forecast decreased.

Severely lagged, limited, and/or complex access to the most basic resource-specific operating data created unprecedented challenges against understanding actual benefits and costs compared to other types of grid assets.

With the exception of requirements for non-residential storage under SGIP, no investor-owned utility or program administrator systematically and comprehensively collected, retained, quality-controlled, or reported the most basic operating data on energy storage resources in their portfolio. This highlights a challenge to scaling a new technology group that crosses grid domains and traditional boundaries in planning and operations.

Other than a September 2022 event at the Moss Landing site, no major safety event at a stationary battery energy storage system in California has yet occurred, and the state is at the beginning stages of comprehensively integrating the industry's safety best practices.

Recent safety events in the state highlight increasing risks as the number of installations increase. In April 2019 a catastrophic safety failure at the McMicken Battery Energy Storage System in Surprise, Arizona raised national awareness on the safety risks of lithium-ion battery systems. Although codes and standards advanced rapidly in subsequent years, lessons learned from events in the U.S. and around the world point to a need for state and local action to ensure best practices are actually in place and met, to ensure installations are appropriately designed for local environmental conditions, and to ensure installations are also designed to minimize the size and extent of storage capacity on outage in the event of a safety failure.

Indications of future trajectories and challenges

Ancillary services is a niche market with abundant supply and not a primary vehicle for GHG emissions reductions or renewables integration.

Despite GHG emissions increases, the ancillary services use case for energy storage supports renewables integration and it is an important part of a total energy storage portfolio. But the niche market for these services is small and supply is plentiful with gigawatts of storage on the system. The market is already showing signs of saturation and we do not see this use case as scalable to levels materially beyond what it is today. Also, it is not a primary vehicle for GHG emissions reductions or renewables integration.

Increased energy storage penetration, as planned, will tighten energy price differentials and rapidly reduce the marginal energy value of resources providing intra-day energy time shift (e.g., short duration storage).

We expect total energy value potential to grow with increased renewables buildout but this will be offset by saturation effects at high storage penetration. Over time, as more energy storage is built on the system we project a flattening of energy prices and decreasing marginal energy value that drops below \$4/kW-month with 45 gigawatt-hours of energy storage capacity on the system (slightly less than the 2021 Preferred System Plan for 2032), and below \$1/kW-month with 73 gigawatt-hours on the system (about 1/3 of battery storage in 2045 under the SB 100 Core scenario).

Capacity market revenues will become increasingly important to ensure revenue sufficiency for the storage fleet and to incentivize new builds of the right type and at the right time.

As such, energy storage resources will become increasingly dependent on RA capacity payments. We expect capacity market participation and capacity prices to increase to ensure revenue sufficiency for new projects.

The CPUC is in the process of significant revisions to its planning processes and procurement mechanisms to adapt to a system with high penetration of renewables and energy-limited storage. The CPUC's migration to an effective load carrying capability-based approach (ELCC) for mid- to long-term planning better represents system needs and the ability of energy storage to meet those needs. However, many parameters to the ELCC approach are yet to be tested. If implemented without sufficient stakeholder vetting and transparency, it could undermine the efficiency of future energy storage procurements and create disconnects between RA capacity payments and performance for many years to come.

We expect the cost-effectiveness crossover points from 4-hour energy storage to longer duration configurations (6- to 10-hour) to be highly uncertain and sensitive to ELCC modeling assumptions. We observe that the incremental ELCC schedule developed for mid-term reliability procurement shows little difference in ELCC levels across alternative durations and may not appropriately signal for longer-duration storage when needed.

Additionally, the impacts of climate change and extreme system events are recognized but are yet to be explored in the ELCC calculations.

The CPUC has a limited and narrowing window to translate energy market price signals into economic incentives for customer-sited storage installations and use cases that are in sync with grid conditions and state goals.

We observe significant untapped energy time shift (both energy and RA capacity value) and GHG emissions reduction potential which will grow as customer-sited installations are expected to grow tenfold or more over the next ten years. Policy solutions that can be implemented within the next couple of years will be needed to get ahead of that activity and unlock its potential to benefit ratepayers and help meet state goals. Distributed storage that is more responsive to grid conditions can avoid potentially thousands of MW in new storage builds at the bulk grid level. Future energy market saturation also creates urgency to bringing grid signals to customers. As marginal energy prices flatten, efforts to develop a scalable framework to synchronize customers with energy markets and grid needs will become increasingly difficult.

Community and customer outage mitigation use cases need further support in order to scale up to address a growing resilience problem.

Resilience needs are rising due climate change-induced extreme weather events, which are not yet fully captured in the state's grid planning models nor in our model of future cost-effectiveness. SGIP will continue to be instrumental in unlocking outage mitigation benefits for the most vulnerable customers, communities, and critical facilities. Most installations under the SGIP Equity Resiliency budgets are for residential sites. It is unclear if the program design works as intended to support outage mitigation at key non-residential sites such as community centers and critical facilities. We observe that schools and colleges operate storage under use cases that provide energy time shift value to the grid and might be good candidates to provide community-level outage mitigation services.

Advancements in data collection and management are urgently needed.

Current data management practices present a significant barrier to understanding and managing the state’s energy storage portfolio and adapting planning assumptions and policies quickly to market changes. Under the status quo, the data management problem will become much worse due to explosive growth in the energy storage market across all grid domains, types of installations, and use cases. Without advancements in this area policymakers do not have the tools to track benefit and cost trends, to gauge resource or portfolio performance, or to identify opportunities to expand use cases to incorporate additional services.

Safety events will happen, but risks are manageable as long as state and local agencies act soon to proactively implement safety best practices and to address linkages among energy storage safety, permitting processes, and system reliability.

Based on historical events in the U.S., it is reasonable to expect at least a handful of safety events across the storage fleet over the next ten years. When events do happen, they tend to occur within 1–2 years of a resource being online. The industry has developed national and international safety best practices that require certain state and local actions towards risk assessment, risk management, and emergency preparedness. The degree of state and local engagement on this issue will likely impact safety event outcomes, the speed and quality of the permitting and development process for storage, and whether or not safety events result in extended outages of storage resources and any co-located generation or critical facilities.

Recommendations on policy efforts going forward

Evolve Signals for Resource Adequacy Capacity Investments

The most urgent effort is to ensure that adjustments to the CPUC’s planning and resource adequacy capacity market mechanisms provide transparent, unambiguous, accurate, and consistent signals for the grid’s instantaneous (MW) and energy (MWh) capacity needs.

With the understanding that the CPUC is in the process of advancing its planning and procurement practices our recommendations for the CPUC are to:

- **Continue development of ELCC methods for assessing system capacity needs for reliability and various resource type’s ability to meet those needs**, including use of the CPUC’s ELCC surface analysis which considers the dynamic interactions of resources within a portfolio.
- **Further validate ELCC signals for longer duration storage investments**, with more transparency and stakeholder discussion of underlying ELCC modeling assumptions and results to identify and explain drivers of ELCC differences (or lack thereof) across storage durations.
- **Incorporate real options for longer-duration energy storage installations into IOU solicitations and CPUC contract approvals** to support a timely and cost-effective transition for a portfolio with longer duration storage, utilizing the modularity of battery storage capacity. Utility and other LSE’s system designs and contracts with third parties, for example, could include options to expand duration at the existing site in an expedited manner.
- **Incorporate impacts of climate change and weather-driven extreme grid events in resource planning and ELCC models** to assess future resource needs and system vulnerabilities.

Bring Stronger Grid Signals to Customers

Improved grid signals to customer-sited installations can unlock energy value and GHG emissions reductions, and can potentially save ratepayers significant investment dollars by avoiding new builds—but opportunities to do so will likely expire within the next 5–10 years as storage saturates the energy market.

With acknowledgement that integration of customers with grid needs is a particularly difficult challenge, our recommendations to the CPUC are to:

- **Bring stronger grid signals to customers overall** on the time-varying value to the grid of storage operations. Longer-term solutions require significant changes to the retail rate design and wholesale market participation paradigm, such as the retail rate design framework described in CPUC Staff's June 2022 California Flexible Unified Signal for Energy (CalFUSE) white paper. Regardless of the CPUC's long-run policy pathway to this aim two critical activities are:
  - Continued work on basic alignment of rate structures with grid needs. Actual or potential misalignments that we observe in our analysis and that can significantly reduce the net benefits of energy storage include:
    - Retail non-coincident demand charges versus grid energy and RA capacity avoided costs
    - Net energy metering incentives for standalone solar PV versus solar plus storage
    - Peak period definitions that exclude 8–9 p.m., weekends, and holidays despite grid emergencies during those times
    - Off-peak period definitions that do not differentiate the grid cost of mid-day versus nighttime charging
  - Interim solutions that can bring stronger grid signals to customers within the next couple of years. Examples of interim solutions include building upon the SGIP and ELRP mechanisms already in place.

To better focus ratepayer investments to beneficial configurations, use cases, and customer behaviors:

- **Elevate assessment of effectiveness of GHG signals in SGIP:** Expedite evaluation of the effectiveness of GHG reduction requirements in SGIP, and broaden scope of that evaluation to consider (a) the importance of energy and RA capacity value among all benefit categories and (b) the degree of actual versus potential contributions towards state goals. The evaluation should apply the April 1, 2020 cutoff for new projects based on application submission dates, as stipulated in the CPUC Decision 19-08-001.

- **Strengthen grid signals in SGIP:** Consider a course-correction to align SGIP program goals and performance requirements to produce significantly more energy and RA capacity value.
  - Review findings of the above-mentioned study on effectiveness of the GHG reduction rule in SGIP and determine if adjustments are needed to strengthen and leverage requirements to follow the GHG signal in order to improve GHG reductions and energy value.
  - Address conflicting signals to non-residential participants of demand charges versus the GHG signal.
  - Introduce and create linkages to additional incentives for voluntary performance during grid reliability events for all SGIP participants—such as auto-enrollment in ELRP, other pilots providing a similar signal, and/or incentives for performance during Flex Alerts.
  - Set a framework to link and provide information on bulk grid alerts/emergencies (e.g., ELRP, Flex Alerts), local alerts/emergencies (e.g., PSPS), and historical outage risk during those alerts/emergencies so customers can program their systems to dynamically offer more capacity to the grid (rather than hold reserves) when they determine it is safe to do so.

- **Incorporate more flexibility in IOU contracts for customer aggregations:** Improve contract structures for customer aggregations that can be quickly realigned with changing grid needs, including (a) performance requirements to address system needs shifted to late evenings and extended to weekends and holidays, and (b) measures against conflicting retail rate signals and use cases such as non-coincident demand charge management.

Remove Barriers to Distribution-Connected Installations

To produce net benefits to ratepayers and additional options for scalability and resource solutions, further market transformation is needed to support third-party-owned distribution-connected resources, and both existing and new resources must be positioned for multiple use applications.

Considering ways to maximize value of ratepayer-funded resources, open the door to innovative and opportunistic low-cost solutions to solve a variety of local grid problems as the state moves towards its 2045 goals, and clear the path to scaling up installations across all domains, our recommendations to the CPUC are to:

- **Remove barriers to accelerated market transformation** including improvements to third-party project development success rates relative to IOU-owned developments with a focus on:
  - Speeding up and addressing other major developer risks in the IOUs' execution of WDAT interconnection processes;
  - Require that utility procurements include some flexibility to adjust the size and/or use case of a project if the original procurement need (e.g., distribution deferral) shifts.
  - More generally, incorporation of more value streams into individual IOU solicitations, including both system-wide and local area services.
- **Enable multiple use applications** by requiring distribution-connected resources to offer transmission grid-level services when idle and minimize extended periods of standby, following MUA guidelines. As a starting point and to build more real-world case studies with clearly-defined multiple services, require all utility-owned installations and contracted third-party distribution deferral projects to (a) with distribution deferral as the priority service, define specific time periods and/or portions of resource capacity that could be available to serve the transmission grid, (b) if significant capacity is available, seek participation in the CAISO marketplace, and (c) if CAISO participation is not feasible, articulate specific operational and/or financial reasons why.

Improve the Analytical Foundation for Resilience-Related Investments

Customer outage mitigation is crucial component of resilient electricity service to meet essential loads and to protect vulnerable customers, communities, and critical facilities. An improved analytical foundation for resilience-related investments is needed to identify and address the state's outage mitigation and growing resilience needs.

Considering the many challenges in identifying and addressing outage mitigation and resilience needs our recommendations to the CPUC are to:

- **Continue focus on equity and resilience in SGIP** to support customers with high outage risks but inability to pay for a cost-effective storage solution.
- For the purpose of improving CA's analytical framework for resilience planning overall, estimating the extent of the resilience problem for disadvantaged and low-income customers, and estimating the market depth for customer-sited energy storage for resilience:
  - **Pursue initiatives to significantly improve the state's understanding of the cost of outages** (value of lost load) on a diversity of customers, communities, businesses, schools, and critical sites. The estimates of value of lost load should be California-specific and include:
    - Distinctions in outage duration, like impacts of multi-hour (representing rolling blackouts) versus multi-day (representing PSPS) outages;
    - Distinctions in the geographic extent of outages, like impacts of outages on a distribution segment versus on multiple contiguous communities;
    - Distinctions in the environmental and weather context of the outages, like impacts during a normal weather day versus during a heat wave with surrounding wildfires and smoke;
    - Distinctions in financial drivers to the customers' ability to withstand an outage;

- For each customer type analyzed, estimates of what share or quantity of electricity demand is essential (high impact if lost) versus discretionary (low impact if lost);
- The cost of outage warnings (e.g., CAISO alerts and warnings, PSPS warnings) even if outages are not implemented.
- Track and report total installation costs of customer-sited energy storage, using data collected through SGIP, for use in benefit/cost evaluations that consider the full spectrum of services provided by distributed energy storage.

– **Expand and periodically update estimates of customer resilience-related vulnerabilities**, going beyond wildfire risks and PSPS, grounded in up-to-date and spatially granular long-term forecasts of environmental and weather risks. This would be in collaboration with the CEC Energy Research and Development and Energy Assessments divisions and for use in the CPUC's resilience planning including resilience-related program eligibility requirements.

– **Further investigate barriers to non-residential enrollment under SGIP Equity Resiliency budgets**, including consideration of additional eligibility criteria for sites with high-value and synergistic use cases such as schools and colleges with solar PV to offer community-level resilience.

– Given new findings on resilience needs and value from the efforts above**, further analyze the market potential and tradeoffs of developing distributed versus grid-scale storage to improve resilience**. This would be in collaboration with the state's resource planning community and used to assess the implications of IRP procurement plans and other CPUC efforts (e.g., SGIP, ELRP, retail rate design) on future resilience.

Enhance Safety

Expanded safety-related initiatives can help mitigate harm to people and improve emergency response to a safety event. They also have the potential to facilitate fast and high-quality local permitting review and to minimize outages of storage resources and any co-located generation or critical facilities.

With recognition that safety is a multi-agency issue and the CPUC, CEC, and local agencies will need to work closely together, our recommendations to the CPUC are to:

- **Form a storage safety collaborative:** The CPUC Energy Division and Safety and Enforcement Division to build upon their coordination with the CEC to form a safety collaborative with the purposes to (a) define roles and responsibilities in the context of a multi-agency risk management plan, (b) promote two-way knowledge exchange with local authorities and emergency responders on installation characteristics, possible risk factors including vulnerabilities to local environmental conditions, and the effectiveness of mitigations, (c) facilitate rapid absorption and integration of safety best practices into local laws, building and fire codes, site-specific emergency plans, inspection checklists, permitting processes overall and (d) identify and implement measures to minimize storage and any co-located resource outages and recovery periods following a safety event. Importantly, all safety collaborative meetings and materials should be transparent and available to the public.
- **Explore the safety-reliability link:** The CPUC and utilities to consider development of a safety and reliability score in the utilities' least-cost best-fit resource evaluations, based on guidance from the safety collaborative and/or developer guarantees or remedies for a safety-related event.
- **Develop guidance materials for local agencies to build from:** The CPUC and the CEC to consider development of training webinars and guidebooks for local governments such as model (boilerplate) law for storage system requirements, a model permit application, a model inspection checklist, and information on how battery system safety is incorporated into state fire and building codes.

Improve Data Practices

Lack of comprehensive and quality-controlled actual project characteristics and operational data across all resources and grid domains will continue to obscure the imperative to stack benefits in customer-sited and distribution-connected storage use cases. Lack of these data will also make it difficult for the CPUC and utilities to diagnose key shifts in operating performance in response to policy and market levers such as ELCC.

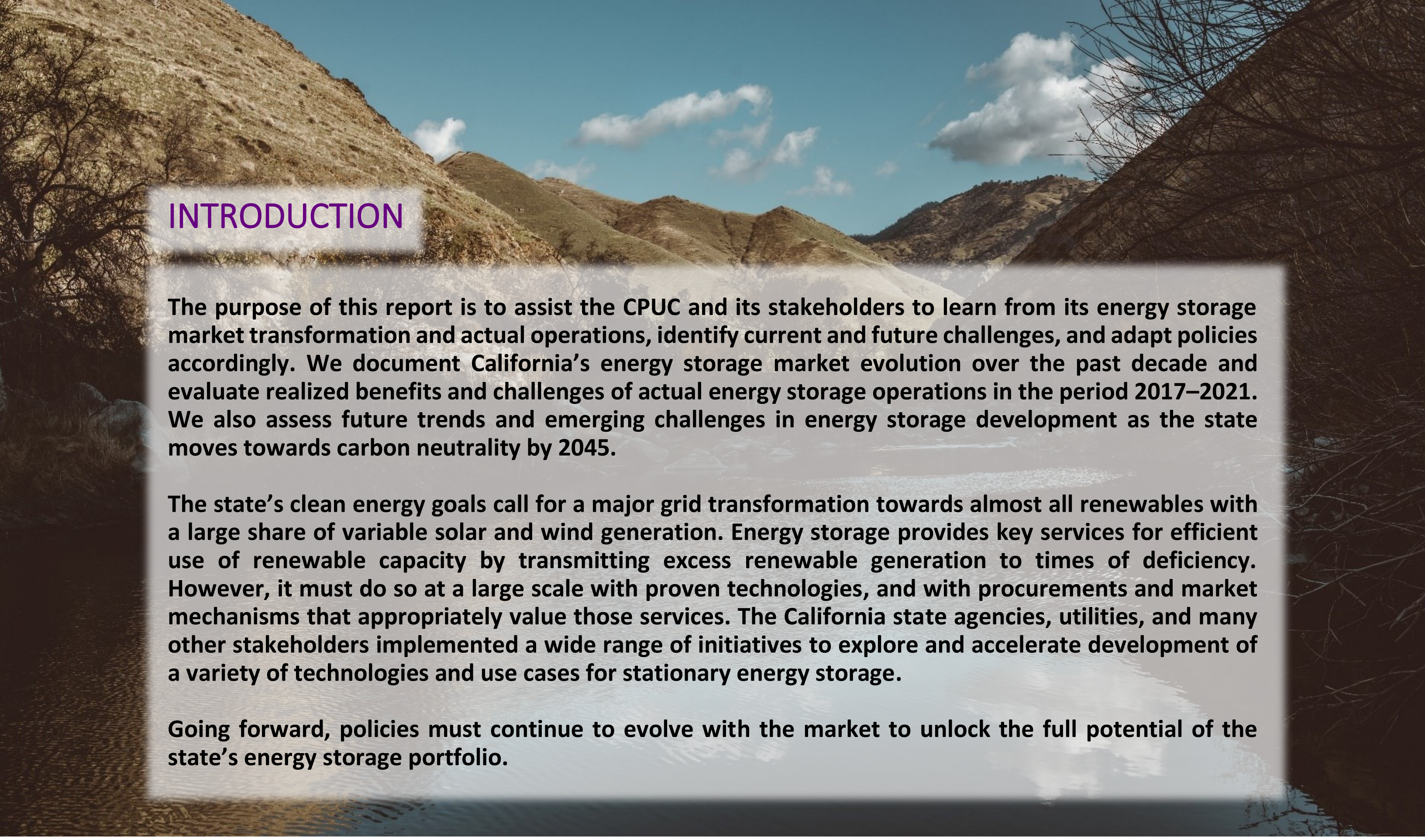
With the objective to clear the path for CPUC to access the minimum data it needs to assess the performance of energy storage resources and effectiveness of policies our recommendations to the CPUC are to:

- Using CEC's EPIC and PIER final report templates as a guide, **require that all pilot and demonstration projects funded by ratepayers through other channels (e.g., General Rate Case) yield a research report accessible to stakeholders in a timely manner**.
- **Develop universal and standardized data collection, retention, quality control, and reporting of interval-level operations for all ratepayer-funded energy storage resources**, modeled after the SGIP requirements for Performance Based Incentives and expanded to include information on state of charge, standby losses, and operations during upstream grid outages.
- Expand upon recent data collection efforts to **develop a relational energy storage database** that includes data compiled in this study and across multiple CPUC groups, linkages to energy storage data being collected by the CEC, and linkages to data collected by the multi-agency safety collaborative described above. The database should be broadly accessible and useful among all CPUC groups and updated monthly. To the extent confidentiality restrictions allow, data should be routinely posted and shared with stakeholders.
- Routinely **collect project-specific cost data** across all ratepayer-funded energy storage procurements, including total installed cost and a standardized breakdown of cost components (e.g., hardware, engineering & construction, permitting & siting, and interconnection) with the purpose to track cost trends in a timely manner and develop policies to facilitate cost reductions (e.g., soft costs).

Concluding Remarks

Overall, the energy storage market in California matured significantly during our study period, in terms of technologies and use cases. For short duration energy storage, California surpassed its pilot phase and achieved commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations. More recently installed projects indicate significant net benefits will be realized with a future storage portfolio although we see evidence of some untapped potential in distributed resources.

In this study we expand upon the state's planning and analytical practices to learn from historical resource-specific storage operations, at a fine temporal and spatial granularity, across all grid domains, and across all potential services offered by energy storage resources. In its next energy storage procurement study the CPUC will have even more historical data to work with—likely with more complex market interactions as storage penetration increases. In future studies we recommend continuing to build upon the framework we developed here, incorporation of other technologies and longer durations as they develop in the marketplace, consideration of market price impacts in the benefits, and incorporation of future state agency and stakeholder data and analytical innovations to refine our future outlook.



INTRODUCTION

The purpose of this report is to assist the CPUC and its stakeholders to learn from its energy storage market transformation and actual operations, identify current and future challenges, and adapt policies accordingly. We document California's energy storage market evolution over the past decade and evaluate realized benefits and challenges of actual energy storage operations in the period 2017–2021. We also assess future trends and emerging challenges in energy storage development as the state moves towards carbon neutrality by 2045.

The state's clean energy goals call for a major grid transformation towards almost all renewables with a large share of variable solar and wind generation. Energy storage provides key services for efficient use of renewable capacity by transmitting excess renewable generation to times of deficiency. However, it must do so at a large scale with proven technologies, and with procurements and market mechanisms that appropriately value those services. The California state agencies, utilities, and many other stakeholders implemented a wide range of initiatives to explore and accelerate development of a variety of technologies and use cases for stationary energy storage.

Going forward, policies must continue to evolve with the market to unlock the full potential of the state's energy storage portfolio.

California is a world leader in innovative energy policies to transform markets to address the true costs of environmental damage and climate change to people and their quality of life. As part of its path towards clean energy goals the state dramatically transformed its stationary energy storage market. Ten years ago the CPUC and its stakeholders faced many unknowns and risks in terms of energy storage costs, operating capabilities, ability to participate in wholesale markets, and long-term cost-effectiveness. While we now have much more information to understand those unknowns and risks, we also face new questions about how to scale and diversify the energy storage portfolio to yield as much benefit to Californians as possible.

The purpose of this report is to assist the CPUC and its stakeholders to learn from its energy storage market transformation and actual operations, identify current and future challenges, and adapt policies accordingly. This report is organized in three chapters:

- **Chapter 1 (Market Evolution)** provides historical policy and planning context to the evolution of California's market for stationary energy storage from about 2010 when California Assembly Bill 2514 directed the CPUC to develop an energy storage procurement framework.
- **Chapter 2 (Realized Benefits and Challenges)** captures the procurement, energy market, and storage operations outcomes of the CPUC's energy storage procurement framework. We analyze actual energy storage operations in the period 2017–2021 and calculate realized net benefits at the resource level, across all grid domains, and across all services provided. We also assess each resource's contribution to Assembly Bill 2514 stated goals of grid optimization, renewables integration, and greenhouse gas emissions reductions.
- **Chapter 3 (Moving Forward)** discusses the going-forward implications of current policies, grid needs, market trends, and observed challenges to energy storage development. We provide recommendations on policy adjustments and next steps to unlock the full potential of the state's energy storage portfolio.

This report also includes several attachments providing more detail on analytical approach, calculations, and research-related findings to support our key observations and recommendations.

California's Energy Policy Challenges and the Role of Energy Storage

California's clean energy goals include 33% renewable energy by 2020, rising to 60% by 2030, and carbon neutrality by 2045 (Figure 4). In order to achieve those goals, the state is in the process of a major grid transformation towards an electricity supply portfolio of mostly solar photovoltaic (PV) generation, plus generation from hydroelectric, wind, biomass, geothermal, and natural gas resources. Stationary energy storage plays an essential role in the total resource portfolio, and its key benefit is to support the efficiency, cost-effectiveness, and reliability of a system with high levels of renewable generation.

Energy storage has the potential for a wide range of services (Figure 5). Electrically, the closer an installation is to the customer, the more services it can theoretically provide. Storage resources interconnected directly to transmission system can provide wholesale market, resource adequacy and transmission services. Distribution-connected storage resources can provide the same set of services to the transmission system, in addition to distribution system services. Customer-sited resources can provide all of the above, plus a suite of customer-specific services, like bill management. Some services shown in the figure are not fully additive or additive at all. However, the primary purpose and value in California's energy storage portfolio is its ability to move large volumes of renewable generation from one timeframe to another in a controllable fashion—so-called "energy time shift." This enables efficient use of renewables. Energy time shift is most evident both in the energy value and in the resource adequacy capacity value of energy storage as these two services can be closely intertwined.

MW or MWh?

An energy storage resource's capacity to discharge electricity has two key dimensions: its maximum instantaneous output (expressed as MW capacity) and its total energy output with full charge (expressed as MWh capacity).

If only one metric must be expressed then MWh capacity is generally the more informative choice. However, many electricity resource planning and market constructs express resource capacity, costs, and market value in terms of MW.

In this study we often reference MW capacity to facilitate a better understanding of how energy storage fits into these planning and market constructs and how it may compare to other more traditional resources on the grid.

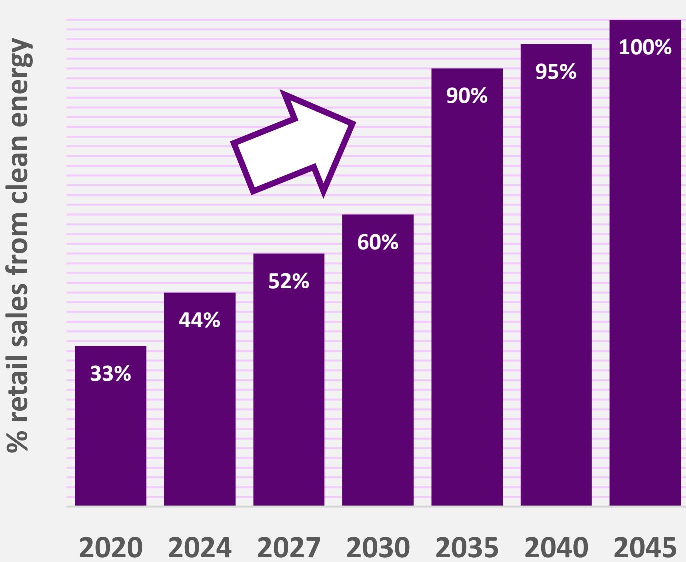


Figure 4: California's clean energy goals.

Energy & AS Markets and Products	Energy
	Frequency Regulation
	Spin/Non-Spin Reserve
	Flexible Ramping
	Voltage Support
	Blackstart
Resource Adequacy	System RA Capacity
	Local RA Capacity
	Flexible RA Capacity
T & D Related	Transmission Investment Deferral
	Distribution Investment Deferral
	Microgrid/Islanding
Site-Specific & Local Services	TOU Bill Management
	Demand Charge Management
	Increased Use of Self-Generation
	Backup Power

Figure 5: Scope of possible energy storage services.

Policies for Accelerated Market Development

Over a decade ago Assembly Bill 2514 formally identified energy storage as a potential game-changer to address a variety of renewables integration and infrastructure development challenges. But some type of energy storage technology would need to become more cost-effective and more quickly scalable to large quantities beyond what is feasible with traditional alternatives (e.g., pumped storage hydroelectric, multi-state transmission). The policy challenge was thus to initiate a market for novel energy storage technologies and, within ten years, achieve commercial scaling and cost-competitiveness with alternative resource solutions. Key questions for energy storage market development included:

- <u>Is the technology proven</u> to be capable of providing the services needed for grid optimization, renewables integration, and GHG emissions reductions?
- <u>Can viable value propositions be achieved</u> for developers, investors, and owners for services to utilities and electricity customers?
    - <u>Can costs be reduced</u> and by how much?
    - <u>Can revenue streams be developed</u> that are technology-neutral to services provided?
- <u>Can California build enough of an energy storage development ecosystem</u> to increase innovation and momentum towards commercial scaling?

Figure 6 shows a summary of the progression of energy storage procurements since 2010. In response to Assembly Bill 2514, CPUC's Decision 13-10-040 created an umbrella procurement framework and common goal for the utilities to procure 1,325 MW energy storage by 2020, with operations by 2024. The market for stationary energy storage in California grew and matured significantly, from initial use cases including pilots and local RA capacity (2014), to Assembly Bill 2868 opening the door to more development (2016–17), to distribution investment deferral procurements (2018–19), to expanded procurements for resource adequacy and system reliability (2020–21). The development pathway required investment in a diversity of technologies—and testing of a variety of use cases and business models. At the heart of this effort was a spectrum of CPUC procurement orders and programs (including SGIP) that could count towards meeting Decision 13-10-040 requirements, the CEC's technology innovation and advancement programs, the CAISO's initiatives to integrate energy storage into markets, and the utilities' pilot and incentive programs. **Chapter 1 (Market Evolution)** discusses this policy journey in more detail.

Figure 6: Timeline of California's key energy storage mandates and procurements.

As evidence of its commercial success, energy storage presence in the CAISO marketplace and in California's capacity markets has grown significantly. By the end of 2021 about 2,400 MW/9,100 MWh of grid-scale resources were installed, with several thousand MWs under active development. About 2,200 MW/8,900 MWh of that provided resource adequacy services. An additional more than 5,000 MW/20,000 MWh was procured for 2022–2023 system reliability. Resource adequacy-driven procurements for energy storage continued to grow rapidly through early 2022 at the time of this report development.

Even with maturation of the energy storage market important policy questions about the existing storage fleet remain. At the heart of this report is an analysis of actual energy storage operations, benefits, and costs in the 5-year study period 2017–2021. From this analysis we can better understand to what degree the CPUC energy storage procurement framework helps to meet state goals. We can also assess:

- Are ratepayers seeing net benefits from its storage investments?
- What types of installations and use cases have seen significant growth in value?
- Are we leaving any sources of ratepayer value untapped?
- Are some types of installations not scaling up and what are the challenges?

Chapter 2 (Realized Benefits and Challenges) investigates these questions.

Policies that Evolve with the Market

Policies must continue to evolve as the energy storage penetration increases and as the grid transforms to meet the state's goals. In early 2022 the CPUC adopted its 2021 Preferred System Plan at the conclusion of its 2019–2020 Integrated Resource Plan cycle, including an incremental 13,571 MW battery storage plus 1,000 MW pumped (long-duration) storage by 2032. The plan suggests an average build of 1,325 MW new storage per year for resource adequacy needs over the next decade.

Further into the future, even more storage will be needed. Figure 7 shows an indicative resource portfolio California needs to achieve carbon neutrality by 2045.

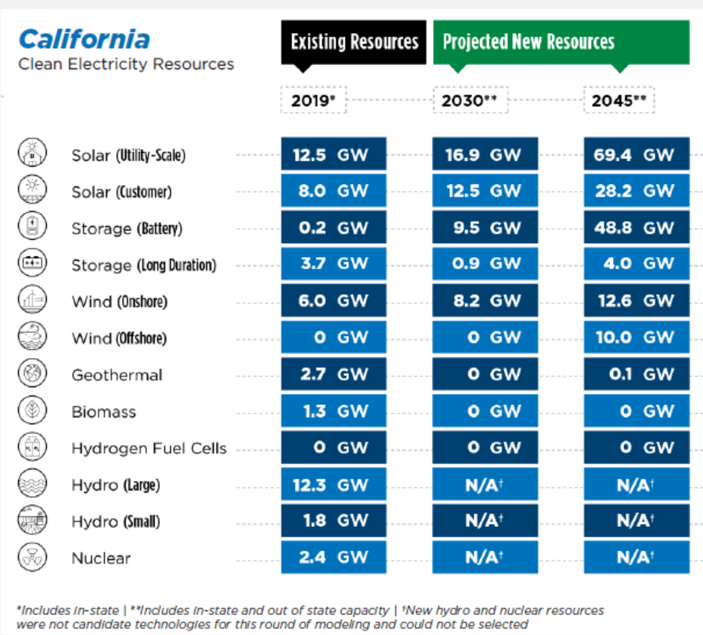


Figure 7: California's indicative resource portfolio to meet state clean energy goals.

(SB100 Joint Agency 2021)

Although likely overestimated due to modeling limitations, the scenario indicates development of 48,600 MW new battery storage between 2020 and 2045, which corresponds to an average buildout of nearly 2,000 MW of new storage per year. Not only is this an unprecedented volume of energy storage on the grid, but based on planning models and actual development trends we can expect a significant share of new solar and battery storage installations to be at customer sites.

The state's electric system needs and market dynamics will change dramatically over time. **Chapter 3 (Moving Forward)** discusses the energy storage-related policy challenges to this grid transformation.

CHAPTER 1: MARKET EVOLUTION

Over the past decade the California state agencies, utilities, and many other stakeholders continuously broke new ground to explore and accelerate development of a variety of technologies and use cases for stationary energy storage and successfully vitalized a vibrant energy storage market in the state.

The market for stationary energy storage in California grew and matured significantly, from a pilot phase into commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations. Significant cost reductions were achieved for installations across all grid domains. Transmission- and distribution-connected energy storage participated in energy, ancillary services, and capacity markets, and demonstrated capability to provide a wide variety of other services. By the end of 2021 grid-scale installations grew to 2,400 MW/9,100 MWh or 44% of all installed capacity in the country. In mid-2022, California's planned grid-scale energy storage represented 45% of all planned installations in the country. In parallel, customer installations under SGIP grew to 470 MW/ 1,070 MWh with about 30,000 installations and hundreds of developers and installers available to customers in the marketplace.

The market for stationary energy storage in California grew significantly over the past decade. As a part of the rapidly-changing industry environment and market acceleration process, California implemented several policies to drive and support market development across three dimensions:

1. Development towards <u>technological maturity</u>, with an aim to identify, test, and demonstrate the capability of various technologies to provide the services needed—even if not yet economical;
2. Development of <u>viable value propositions</u>, with an aim to increase the economic or financial viability of different use cases for energy storage; and
3. Development of an <u>ecosystem for project deployment</u>, with an aim to strengthen the presence of developers, installers, owners, operators, subject matter experts, and other energy storage deployment stakeholders.

These three market dimensions are interrelated. Steps towards viable value propositions, for example, require technological advancements like improvements in battery management systems needed to participate in the CAISO marketplace. As another example, development of an ecosystem for project development helps to reduce installation costs and refine revenue streams towards viable value propositions.

In this chapter we assess the progress of energy storage market evolution towards readiness to serve the grid and customers at a large scale, given the timing and extent of grid transformation needed to meet the state's clean energy goals.

Technological Maturity

The path to technological maturity includes research and development to innovate, pilot projects to test and experiment with technologies, and small-scale demonstration projects. A key threshold question for a technology's maturity is: with public sector support, can the technology demonstrably provide the grid services needed without major drawbacks, and at a scale needed to play a major role in California's electricity resource portfolio?

In 2011 the CEC through its Public Interest Energy Research (PIER) program published a strategic analysis of energy storage in California, including a development status review. The report cited a 2009 technical maturity assessment study (Figure 8) which identified several electrochemical battery technologies, including lithium-ion, as close to mature.

The CEC supported many battery-based research and development, pilot, and demonstration projects through its PIER and Electric Program Investment Charge (EPIC) programs and the utilities implemented similar efforts through various pilot and demonstration programs. Figure 9 shows a summary of a 32 MW/113 MWh group of earlier grid-scale energy storage projects that were (a) funded by ratepayers through technology development programs, and (b) counted towards the Assembly Bill 2514 goals and Decision 13-10-040 procurement requirements. These battery-based resources were funded through PIER and EPIC, cost shares with the U.S. Department of Energy, utility pilot programs included in general rate cases, and utility bilateral contracts. They were installed and began operations in the 2011–2018 period. Unless retired prior to 2017 these resources are included in our historical benefit-cost analysis presented in **Chapter 2 (Realized Benefits and Challenges)**.

Experience with actual operating and market environments in California was an important step to bring battery technologies to maturity. The CEC's 2011 strategic analysis highlighted challenges including "life cycle and performance uncertainties, lack of demonstration and performance data" and "a need for superior control system and power electronics for seamless interoperability between storage devices and the grid" (Abele et al. 2011). In 2012, technology-related barriers identified by the CPUC and stakeholders included "lack of commercial operating experience" and "lack of well-defined interconnection process" (CPUC 2012).

Pilots and demonstrations to overcome these barriers would at the same time help to define specific use cases and carve the path to viable value propositions

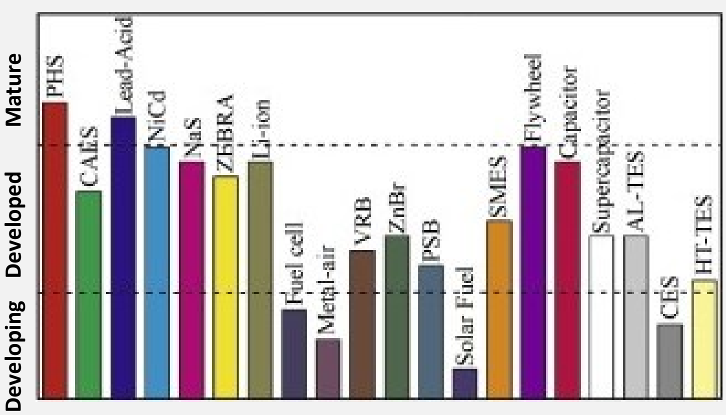


Figure 8: A 2009 assessment of storage technical maturity.

(Chen et al. 2009)

	# Installations	MW	MWh
Lithium-Based Batteries			
Lithium-Nickel-Manganese-Cobalt Oxide (NMC)	8	20	50
Lithium Polymer Battery (LiPo)	8	2	4
Lithium Nickel Cobalt Aluminum Battery (NCA)	1	1	3
Lithium Manganese Oxide Battery (LMO)	2	2	3
Lithium Ion-Doped Nickel Oxide	1	1	3
Non-Lithium Batteries			
Sodium Sulfur Battery (NaS)	3	7	49
Nickel Metal Hydride Battery (NiMH)	1	0	1
TOTAL	**24**	**32**	**113**

Figure 9: California's early-adopted battery storage chemistries (installed 2011–2018).

	Vaca-Dixon	Yerba Buena	Browns Valley	Tehachapi	DESI 1	DESI 2	Mercury 4	Borrego Springs Unit 1, CES, SES	GRC Program Units 1–4, 6–9
Year Operational	2012/2014*	2013/2015*	2016	2014/2016*	2015	2018	2018	2012–2014	2012, 2014
Utility	PG&E	PG&E	PG&E	SCE	SCE	SCE	SCE	SDG&E	SDG&E
Grid Domain	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution
MW Capacity	2	4	0.5	8	2.4	1.4	2.8	1.6	4.6
MWh Capacity	14	28	2	32	3.9	3.7	5.6	4.7	10.0
Notable Funding**	EPIC	EPIC	EPIC	DOE	GRC	GRC	GRC	EPIC/PIER/DOE	GRC
Battery Chemistry	Sodium Sulfur	Sodium Sulfur	Lithium-Ion NMC	Lithium-Ion NMC	Lithium-Ion NMC	Lithium-Ion NMC	Lithium-Ion NMC	Various lithium-based	Various lithium-based
Primary Purpose	Gain experience with CAISO energy & regulation market participation (NGR model)		Gain experience with peak shaving for distribution deferral	Evaluate ability to support wind integration, reactive power, line overload	Manage load on a distribution line	Manage load on a distribution line	Manage high solar PV impacts on a distribution line	Learn from multi-asset microgrid in real operating environment	Various services to distribution system
Key Accomplishments	Refined market participation model and logistics with CAISO		Demo'd automated mgmt. of peak overload on substation	Installation & operating experience for manufacturer, utility	*unkown; no public report on pilot results available*	*unkown; no public report on pilot results available*	*unkown; no public report on pilot results available*	Demo'd and learned from microgrid functions	*unkown; no public report on pilot results available*

Figure 10: Examples of California's early pilot and demonstration projects.

Notes: *Year of physical installation/market-ready **GRC=General Rate Case

Figure 10 summarizes a subset of California's early pilots and demonstration projects. These projects helped build experience in grid applications and wholesale market participation models with CAISO (Vaca-Dixon, Yerba Buena, and Tehachapi) and a better understanding of operations to manage distribution line and substation loadings (Browns Valley, DESI 1 & 2), local renewables integration (Tehachapi, Mercury 4), and microgrid operations (Borrego Springs).

Ultimately, lithium-nickel-manganese-cobalt oxide (NMC) battery was the only emerging technology to scale up significantly and develop alongside the already-mature hydroelectric pumped storage and thermal energy storage technologies. Lithium-ion batteries undoubtedly gained an advantage in the global marketplace due to its development and success in the transportation and small electronics sectors. Figure 11 shows a summary of the remaining 744 MW/3,001 MWh energy storage procured by the utilities that were (a) operational prior to mid-2021 (b) outside of SGIP, and (c) counted towards the Assembly Bill 2514 goals and Decision 13-10-040 procurement requirements.

	# Installations	MW	MWh
Lithium-Ion (NMC) Battery	914	694	2,702
Customer-Sited	*900*	*70*	*280*
Grid-Scale	*14*	*624*	*2,422*
Thermal (Ice/Air/Chilled Water)	804	10	60
Hydroelectric Pumped Storage	1	40	240
TOTAL	**1,719**	**744**	**3,001**

Figure 11: Technologies in the IOUs' post-pilot and demonstration energy storage installations to meet AB 2514.

By the time lithium-ion NMC batteries surfaced as the dominant scalable technology, California's industry had already learned a great deal about how to integrate stationary battery systems into markets and grid operations through the CEC and utilities' earlier pilots and demonstrations. It should be noted, however, that ratepayer-funded pilots and demonstrations that do not conclude with a widely-available public report on challenges and lessons learned (e.g., DESI 1 & 2, Mercury, GRC Program units) are not as helpful to the state's industry towards building market-readiness for new technologies.

Longer-duration energy storage technologies such as compressed air, fuel cell, and hydrogen are currently in their pilot and demonstration phase with the CEC and utilities.

Figure 12 below summarizes the progression of California's energy storage procurement over time, under various CPUC-directed procurement tracks. The market for stationary energy storage in California grew and matured significantly, from a pilot phase into commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations.

Customer-sited storage capacity grew from 70 MW at the start of 2017 to 540 MW by the end of 2021 (possibly not counting some of the privately-funded storage installations), largely driven by 470 MW of SGIP-funded installations. Distribution-connected storage capacity increased from 70 MW in 2017 to 300 MW by 2021. Storage projects connected to the transmission system remained under 100 MW until mid-2020 but grew to more than 1,800 MW by the end of 2021. This rapid growth is a result of various procurements for local capacity and more recently the procurements needed for system reliability. Under current procurements installed storage capacity is expected to reach 10 GW by 2024, as the state continues to build storage to meet future reliability needs while also decarbonizing its grid.

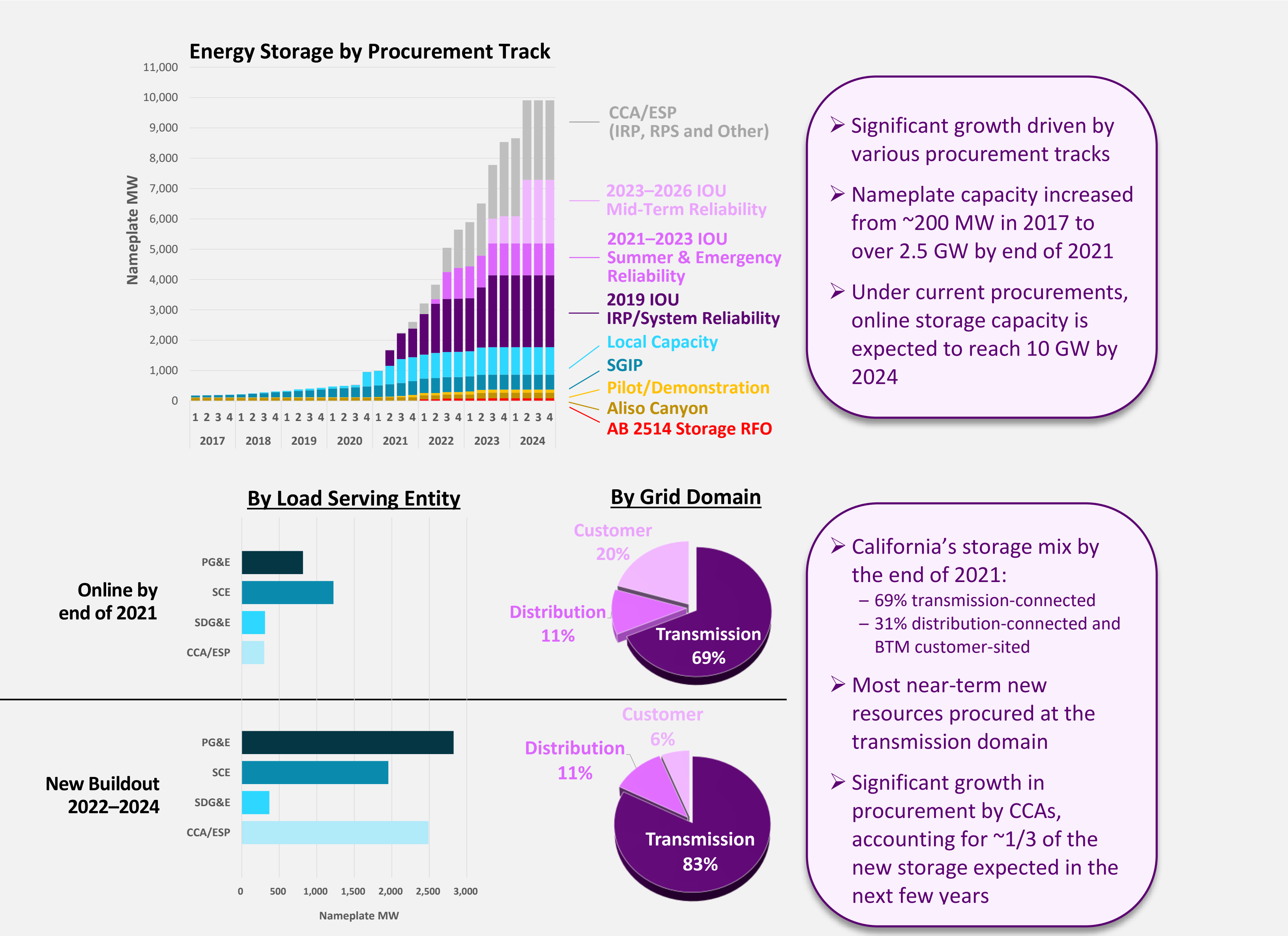


Figure 12: Summary of energy storage procurement in California as of mid-2022.

Other states in the U.S. also have taken action to accelerate energy storage development, although not at the same scale as California. Figure 13 shows existing and planned grid-scale energy storage installations in the U.S. based on data compiled by the U.S. Energy Information Administration, excluding pumped storage hydroelectric storage (EIA 2022). As of mid-2022, total installed capacity was just over 7,000 MW and on track to grow to at least 24,000 MW by 2025. California held 48% of the nation's installed capacity and 45% of planned capacity.

Significant shares of the operational and planned grid-scale energy storage capacity are in Texas, Nevada, New York, Arizona, Florida, Hawaiʻi, and Massachusetts. Like California, many of these states have high renewables penetration and/or relatively ambitious clean energy goals, which creates a growing need for flexible technologies to support a reliable grid. Storage development in Texas is largely driven by wholesale electricity market design that incentivizes independent power producers to develop short-duration standalone merchant projects. These states demonstrate a diversity of policy approaches and energy storage development challenges, but all point to the significance of energy storage as a beneficial technology.

See **Attachment D** for a summary of policy and market drivers for energy storage development in other selected states.

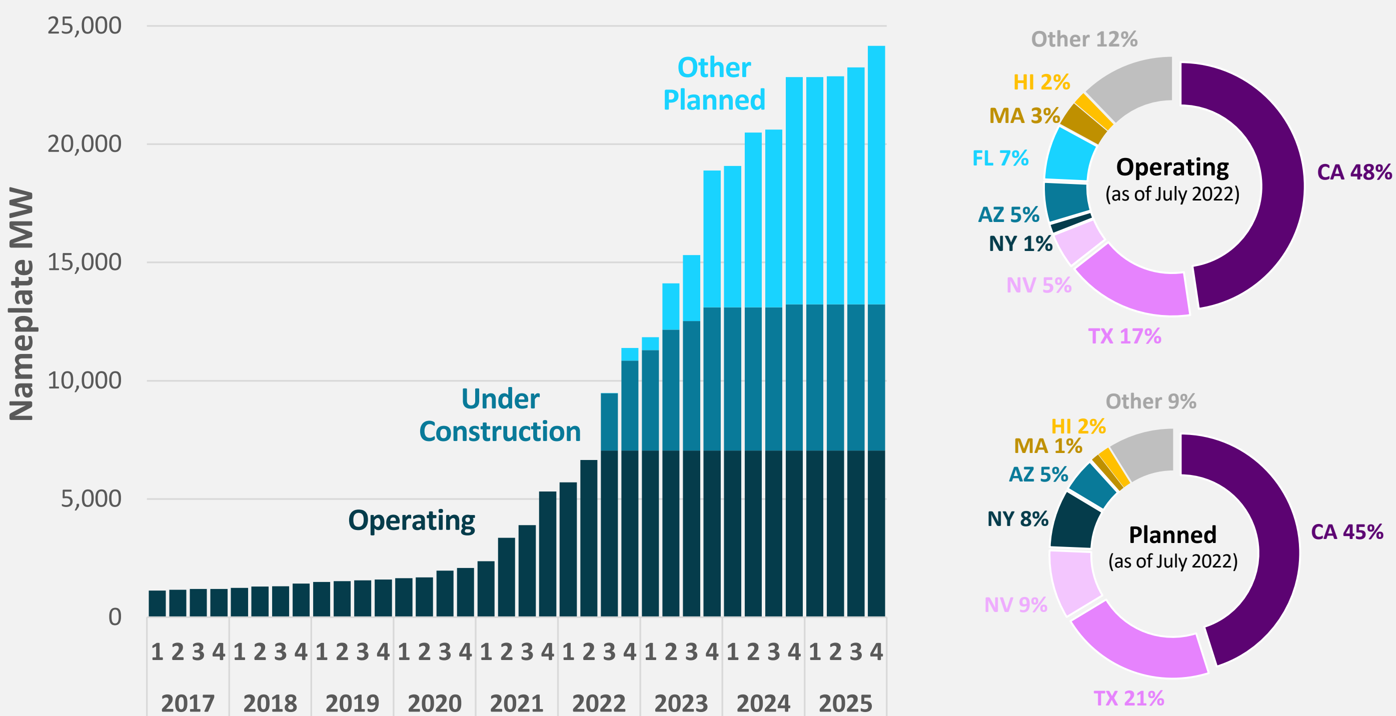


Figure 13: Existing and planned U.S. grid-scale energy storage installations.

*As of July 2022; excludes PS hydro.

Cost Trends

The recent growth in California's stationary storage applications is driven in part by the rapid decline in cost of lithium-ion batteries, fueled by the EV industry's quest to become cost competitive. As the state transitions from smaller proof-of-concept projects to large-scale commercial deployment, lithium-ion batteries currently dominate both customer-sited and grid-scale storage installations and the latest storage procurements suggest this trend will likely continue over the next several years.

The capital cost of battery projects has four components:

1. **Battery pack** including cells, modules, and battery management system;
2. **Balance-of-system (BOS)** including other hardware, such as inverters, power controls, electric wiring, and safety systems;
3. **Engineering procurement and construction (EPC)** including engineering cost, procurement of construction equipment, labor for installation, commissioning, and testing;
4. **Soft costs** including project development, permitting, grid interconnection, and taxes.

The average price of lithium-ion battery packs declined from over $1,200/kWh in 2010 to $132/kWh in 2021, with a 6% drop from the 2020 level, according to BloombergNEF's annual battery price survey (BloombergNEF 2021). These prices are averages across multiple use cases in the global battery industry. The survey shows the lowest prices were in China at $111/kWh and cost of battery packs in the U.S. were 40% higher, which translates to an average of around $155/kWh. Prices also vary by end use. Battery packs in stationary storage systems cost $20/kWh above the average (Frith 2021). Assuming similar cost premium in the U.S. market brings up the average 2021 price of battery packs used for the U.S. stationary storage systems to roughly $175/kWh.

This is consistent with the NREL report on cost of stationary battery storage systems installed in early 2021, which is summarized in Figure 14 (Ramasamy et al. 2021). In 2022 dollars, battery pack costs were about $190/kWh for grid-scale and commercial installations, and $240/kWh for small standalone residential systems.

When all costs are included, stationary storage projects total to around $320/kWh for grid-scale systems, $400/kWh for commercial systems, and over $1,400/kWh for residential systems. The difference is largely driven by the soft costs, such as permitting and grid interconnection, sales & marketing, developer overhead and profit margin that are much higher for small residential projects than for grid-scale or commercial projects.

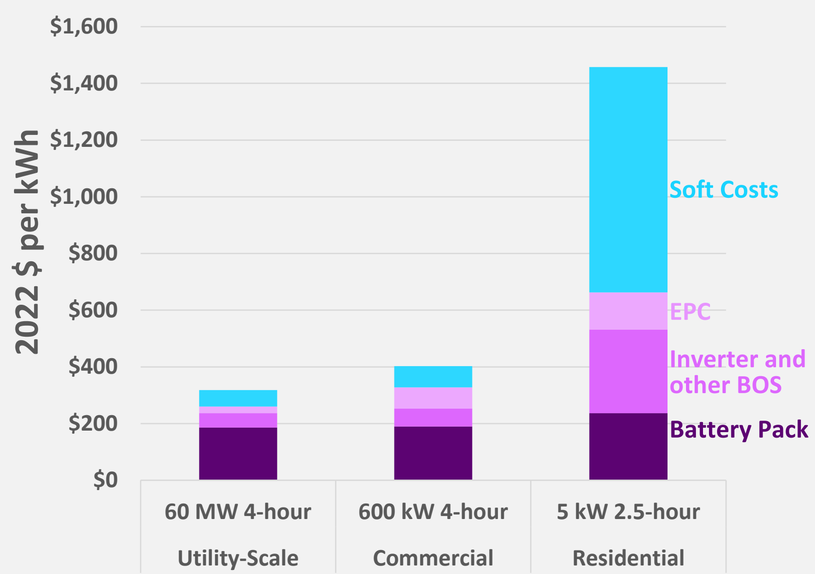


Figure 14: Installed cost of storage systems in 2021 (2022 $).

Figure 15 below shows the installed cost of storage projects owned by California IOUs, in dollars per kW. Bubble sizes are roughly proportional to project sizes ranging from 25 kW to 30 MW. Cost data presented here is compiled based on research of utility applications and CPUC decisions on various storage procurement tracks, supplemented with information provided by the IOUs.

Earlier small pilot and demonstration projects are at the top of the curve, with most of them at \$6,000–\$11,500/kW. Under declining battery prices, new utility-owned storage projects that are recently installed or under development are expected to cost \$1,300–\$1,700/kW, except for a few very small projects above that range. With 4-hour duration, this translates to \$325–\$425 per kWh for larger systems, which is in line with the cost estimates summarized in Figure 14. The cost data for new projects due for installation in 2021–2022 is shown in aggregate to preserve confidentiality. The values are based on estimates as of early 2022 and actual costs may vary.

Note that estimated costs of recent utility-owned storage procurements to meet summer 2022–2023 emergency reliability needs are not shown due to confidentiality. But public information disclosed under the utility applications suggest that the cost of these projects will likely be higher than the 2021–2022 installations due to expedited timeline of these projects, combined with the current supply chain challenges and rising raw material costs.

More recent industry reports show battery costs went up in 2022 for the first time after a decade of decline. For example, a recent NREL report found that installed cost of stationary battery storage in the U.S. was 10–13% higher in 2022 compared to prior year (Ramasamy et al. 2022). BloombergNEF's battery price survey estimated global average price of lithium-ion battery packs increased by 7% in 2022, from a year ago, despite increased adoption of lower cost chemistries (BloombergNEF 2022). The survey predicted prices to start declining again with average pack price falling below \$100/kWh in 2026, two year later than previously estimated.

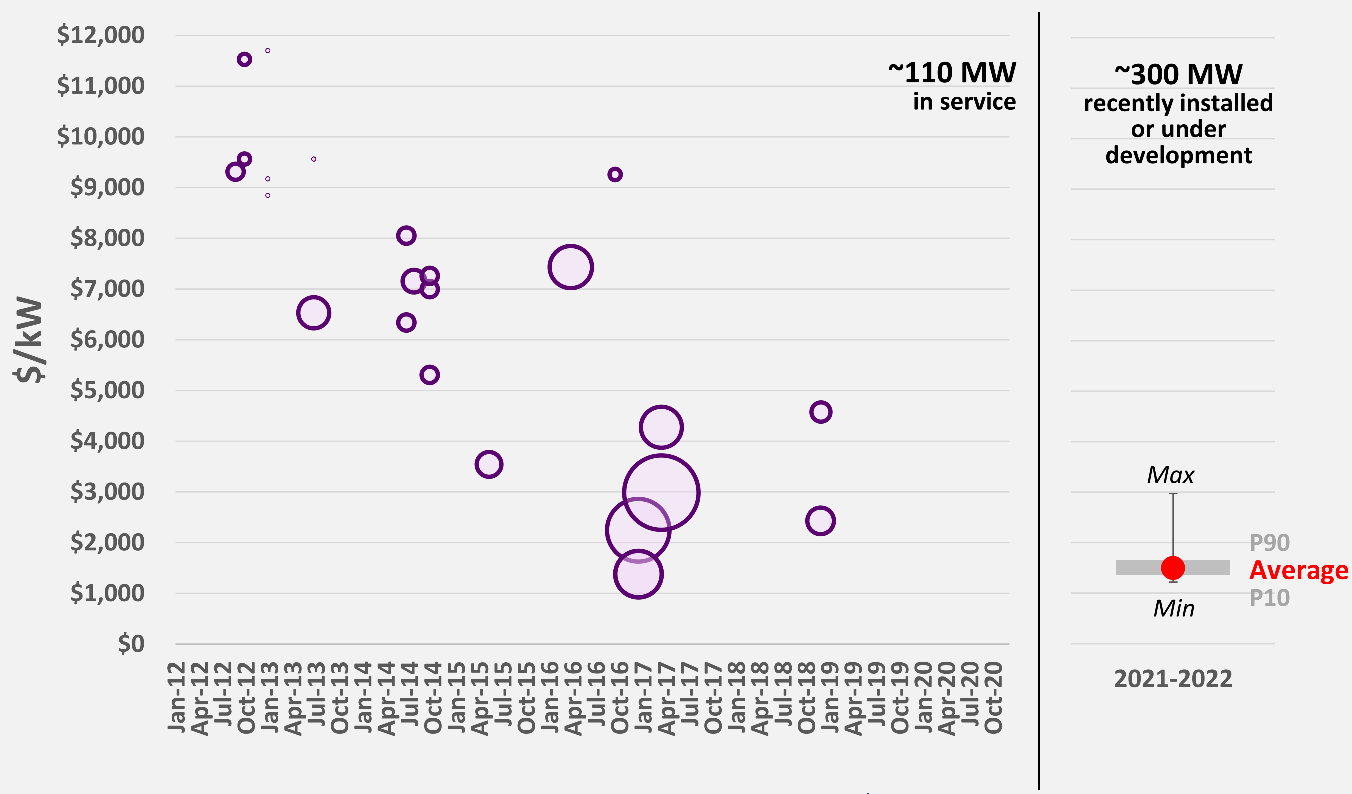


Figure 15: Installed cost of utility-owned storage projects in California (2022 \$).

While many of the initial pilot projects were utility-owned, a large share of more recent storage projects is procured under third-party contracts where the utility or load serving entity pays a contract price in exchange for the rights to the project's certain attributes. Most of the energy storage contracts executed by the California utilities have either a fixed flat price that remains constant over time or a price schedule escalating annually at a set rate.

Figure 16 below summarizes the IOUs' energy storage contract prices over time, with data aggregated by grid domain and type of contracts. Overall, we see a wide range of prices depending on vintage, grid domain, procurement track, and project size. Earlier energy storage contracts were significantly more expensive across all grid domains. Recent contracts are predominantly for much larger transmission-connected energy storage projects, and they generally reflect the cost reductions seen in the global storage industry.

For projects approved in 2020–2021, most contract prices are in the range of \$5–\$8/kW-month for resource adequacy (RA)-only contracts and \$9–\$14/kW-month for all-in contracts through which the utility retains all of project attributes for the contracted period.

Under an RA-only contract, the utility buys RA capacity and the third-party owner retains all other resource attributes. For example, resource owners can participate in the CAISO energy and ancillary services markets and keep associated revenues. This allows the owner of the project to offer the resource's capacity at a lower price point relative to an all-in contract. The data show the historical price differential between recent RA-only and all-in storage contracts approved in 2020–2021 was around \$5/kW-month on average.

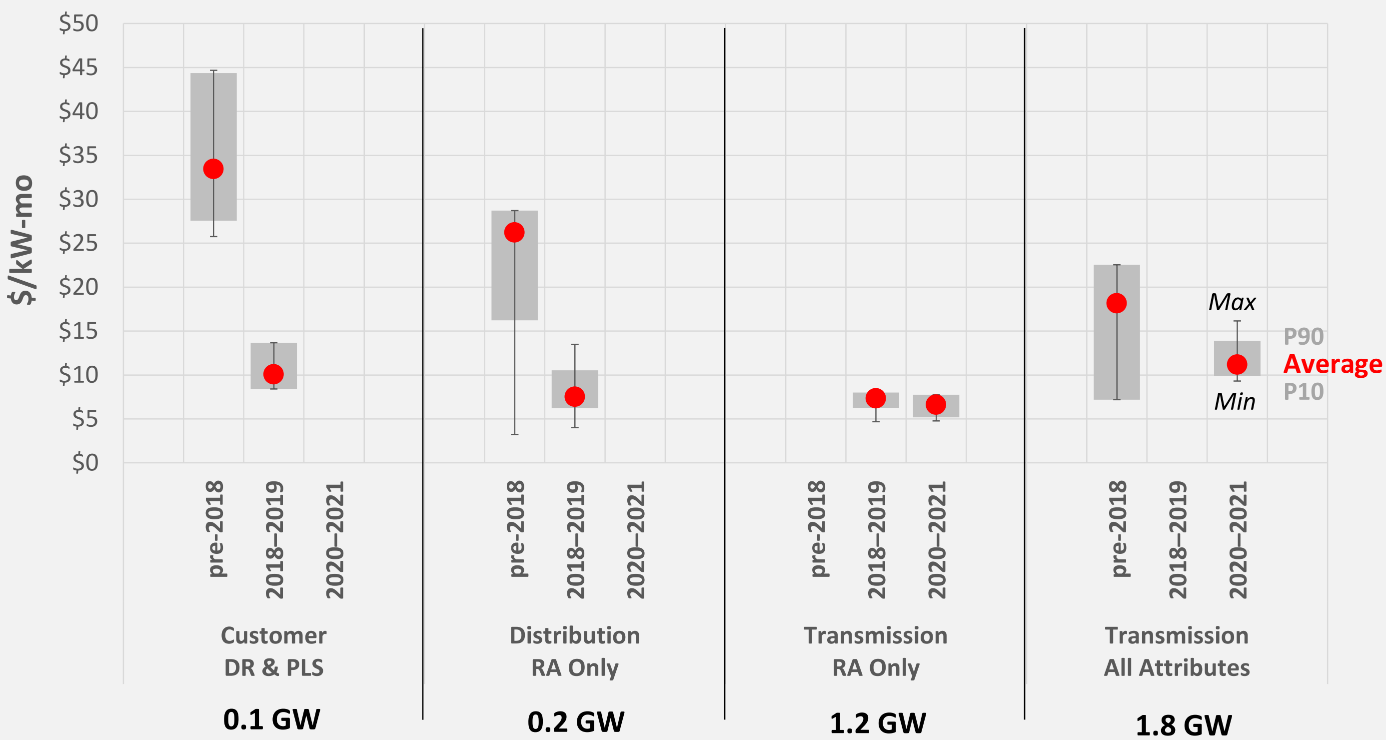
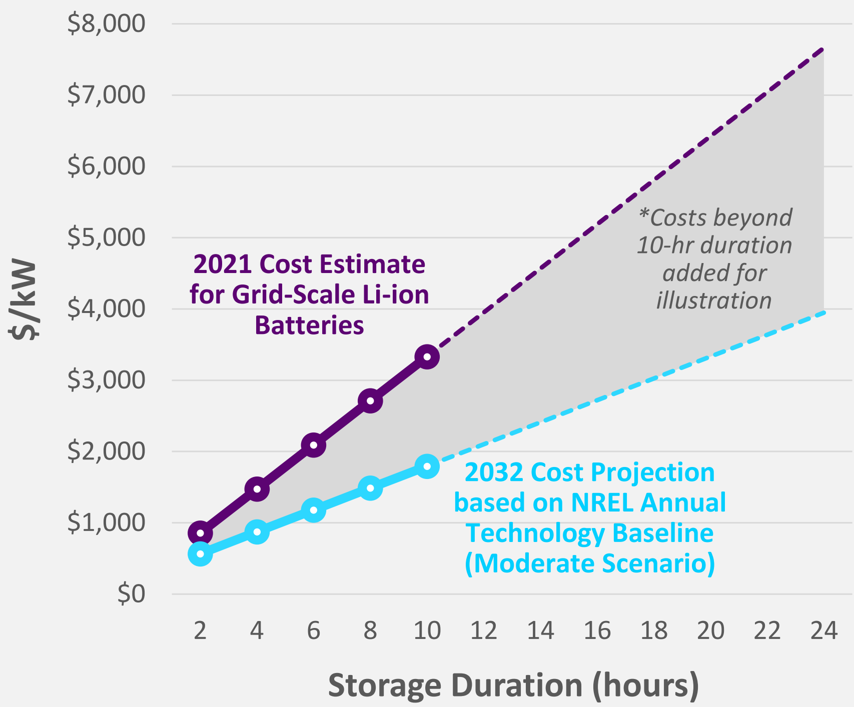


Figure 16: IOUs' third-party storage contract prices by grid domain and CPUC approval year (2022 \$).

Most grid-scale battery energy storage systems historically procured in California are configured for 4-hour duration, which means they can continuously discharge up to 4 hours at full capacity. This is a result of the high initial value of 4-hour storage in addressing current system reliability needs. Lithium-ion batteries currently dominate the market due to their favorable economics for providing short-duration capacity.

Going forward, as California continues to decarbonize its electric system by deploying more clean energy resources, system flexibility needs and the role of storage will evolve and longer duration storage systems will be needed. Batteries are highly modular and there are no technical barriers to configuring them with longer durations above 4 hours. But a very large share of batteries' installed cost is from energy-related costs (e.g., battery pack), which increases with duration. For example, a 4-hour transmission-connected battery currently costs around \$1,500/kW (Figure 17). A battery with 8-hour duration is estimated to cost around \$2,700/kW, which is 1.8 times the cost of a 4-hour battery with the same nameplate MW.

The cost-effectiveness of long-duration energy storage depends partly on how fast the future storage needs and value will evolve over time (see **Attachment B**) and partly on cost trajectory of lithium-ion batteries and emerging long-duration storage technologies. For the near-term, when system needs can still be met by intraday energy time shift (up to 10 hours), lithium-ion batteries will likely stay cost competitive and set the price to beat. For example, in early 2022, two separate long-duration storage procurement efforts by a group of California CCAs both resulted in contracts with 8-hour lithium-ion battery projects. When multiday, multiweek, or seasonal storage is needed in the future as the state approaches to 100% clean energy goal, storage technologies with high power-related costs and low energy-related costs such as compressed air or hydrogen storage can become more competitive as they can scale up their durations with little incremental cost.



- Batteries are highly modular; there are no technical barriers to configuring them with longer durations
- But lithium-ion batteries have relatively high energy-related capex, which increases linearly with duration
- This cost structure makes it difficult to deploy lithium-ion batteries cost effectively at longer durations above a certain level

Figure 17: Impact of adding duration on installed cost of grid-scale battery projects.

Value Propositions

Potential Grid and Customer Services by Storage

Energy storage can offer a wide range of services and values depending on where it is interconnected on the grid, as shown in Figure 18. Electrically, when a resource gets closer to the end use customer, it can *potentially* provide more services and value. Storage resources interconnected directly to transmission system can provide wholesale market, resource adequacy and transmission services. Distribution-connected resources can provide the same set of services, plus distribution system services. Customer-sited resources could provide all of the above, plus a suite of customer-specific services, like bill management. This is consistent with the CPUC decision D.18-01-003 which adopted several rules to govern multiple-use storage applications.

		Grid Domains		
	Services to Grid and Cust.	**Tran.**	**Dist.**	**Cust.**
Energy & AS Markets and Products	Energy	✓	✓	✓
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Blackstart	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	✓	✓
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		✓	✓
	Microgrid/Islanding		✓	✓
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			✓

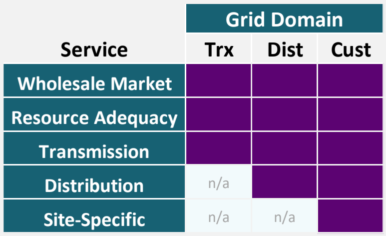
Figure 18: Scope of possible services for transmission-, distribution-, and customer-sited resources.

Potential storage services and associated value streams in California include:

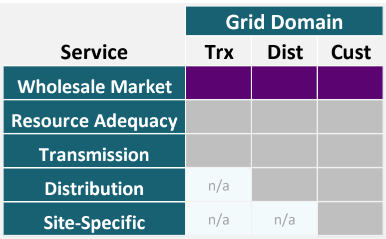
- **Energy, or energy arbitrage:** Storage can move energy from one time to another by charging in off-peak periods when prices are low and discharging during peak periods when high.
- **Ancillary services:** Storage can provide various ancillary services in the CAISO market, including frequency regulation by automatically responding to CAISO's control signals to address small random variations in supply and demand, and contingency reserves (spin and non-spin) to quickly respond in case of an unexpected loss of supply on the system. Storage resources can also provide voltage support to help dynamically maintain stable voltage levels in distribution or transmission systems, and blackstart to self-start without an external power supply and help the grid recover from a local or system-level blackout.
- **Flexible ramping:** Storage resources provide upward and downward ramping capability to help CAISO manage rapid changes in the system due to demand and renewable forecasting errors.
- **Resource adequacy (RA):** Storage resources can be available to discharge during peak periods to help with meeting system RA, local RA, and flexible RA requirements to ensure system reliability.
- **Transmission investment deferral:** Storage can defer the need for new transmission investments by charging during periods with low transmission use and discharging when local transmission system is constrained.
- **Distribution investment deferral:** If interconnected to the distribution system, storage can defer the need for new distribution investments by reducing local peak loading on the distribution grid.
- **Microgrid/islanding:** Distributed storage resources can improve resilience by supporting islanding and microgrid capabilities for sections of the distribution grid and thus help to mitigate the risk of power interruptions at the community level.
- **Site-specific customer services:** Storage resources that are interconnected behind the utility meter can help customers reduce their electric bills through time-of-use (TOU) bill management by charging when their retail rates are lowest and discharging when retail rates are highest, and demand charge management by reducing customer's net peak usage. Customer-sited resources can also provide backup power to mitigate impacts of power outages. If paired with solar PV, storage can increase use of self-generation by storing excess PV output during the day to use after the sunset.

Key Activities and Initiatives to Unlock Storage Value

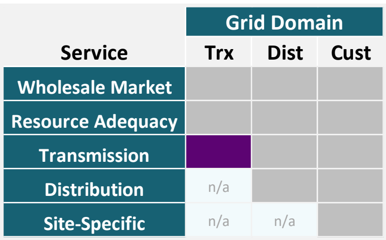
There has been a significant push in the industry over the past decade to achieve full economic potential of energy storage resources by unlocking access to a variety of value streams. Key activities in California are summarized below. The purple color on the charts highlights types of services and value streams explored for energy storage at various grid domains.



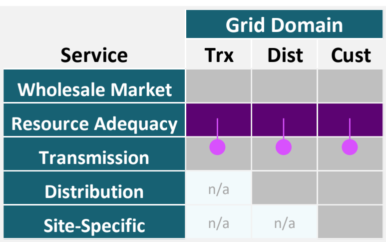
In 2018, CPUC approved D.18-01-003 which marked an important step towards enabling "value stacking" of energy storage systems that can provide multiple services to the grid. The decision adopted a joint staff proposal of the CPUC and CAISO to develop 11 stacking rules to govern multi-use-application (MUA) for grid-scale and distributed energy storage.



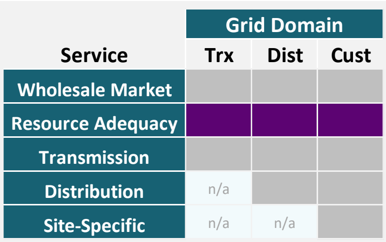
CAISO's energy storage and distributed energy resource (ESDER) initiative over the 2015–2021 period focused on various ways to improve ability of transmission-connected and distributed energy resources to participate in the wholesale markets. Separately, CAISO's ongoing energy storage enhancements initiative aims to improve optimization, dispatch, and settlement of energy storage resources through bid enhancements.



CAISO's storage as transmission asset (SATA) initiative kicked off in 2018 to explore how to enable storage provide transmission services while also participating in the wholesale markets, but the initiative is temporarily suspended until storage market participation model is further refined. CAISO transmission planning process (TPP) considers energy storage alternatives to transmission buildout and approved two projects in its 2017/18 TPP cycle.



Several storage procurements driven by local RA needs, including 2013-2016 LCR solicitations due to OTC and SONGS plant retirements in LA Basin and San Diego, 2016-2018 ACES solicitations to address reliability needs due to Aliso Canyon gas leak, 2018 LCR solicitations to meet local needs in Moorpark and Moss Landing. Local needs are determined based on CAISO LCR studies, which can be addressed local RA resources or transmission upgrades.



CPUC's Integrated Resource Planning (IRP) efforts led to two procurement orders to address system reliability needs: D.19-11-016 and D.21-06-035 requiring a combined 14,800 MW of net qualifying capacity (NQC) by 2026. Under the IRP procurement track, most of the resource need so far is met by standalone energy storage and storage paired with solar.

	Grid Domain		
Service	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

In 2016, CPUC adopted the Competitive Solicitation Framework under the Integrated Distribution Resources (IDER) proceedings and approved IDER incentive pilot to test distribution deferral. In 2018, CPUC established the Distribution Investment Deferral Framework (DIDF) to create an annual process to identify, review, and select opportunities for distributed energy resources to defer or avoid distribution investments.

	Grid Domain		
Service	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

Several utility pilots and demonstration projects were installed at the distribution system to test various services and storage use cases, including CAISO wholesale market participation, resource adequacy, distribution deferral, microgrid/islanding (see Figure 10). Oakland Clean Energy Initiative (OCEI) under utility-CCA partnership selected distribution-connected projects to facilitate gas peaker retirement, which would otherwise require transmission upgrade.

	Grid Domain		
Service	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

Self-Generation Incentive Program (SGIP) was established in 2001 to provide financial incentives for distributed generation. Program is transformed in 2017 and allocated 75% of funds to storage. In 2019, CPUC adopted use of a GHG signal that reflects real-time emission intensity in wholesale markets to align performance with GHG goals. Same year, CPUC established Equity Resiliency budget for storage installations by vulnerable customers in high wildfire threat areas.

	Grid Domain		
Service	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

In 2021, CPUC created the Emergency Load Reduction Program (ELRP) as a new Demand Response pilot to compensate electricity customers for voluntarily reducing their demand or increasing supply during periods of grid emergencies. This is a 5-year pilot program, started with commercial customers and extended in December 2021 to include residential customers.

At the federal level, there were two key FERC orders affecting wholesale market integration of storage:

- In 2018, FERC's Order 841 required the regional transmission organizations (RTOs) and independent system operators (ISOs) to enable participation of energy storage resources in wholesale energy, ancillary services, and capacity markets.
- Later in 2020, under a similar but broader scope, FERC's Order 2222 required RTOs and ISOs to open up wholesale markets to distributed energy resource (DER) aggregations, which includes distribution-connected and customer-sited energy storage, among other technologies.

Energy Storage Installations by Procurement Track

Figure 19 shows the 2017-2021 energy storage installations by procurement track.

During the initial phase through mid-2020, a significant share of California's installed energy storage capacity came from two sets of projects: (1) customer-sited energy storage projects funded by the SGIP and (2) energy storage projects procured to address reliability concerns associated with the Aliso Canyon gas leak discovered in 2015, which created fuel supply disruptions in southern California and led to a state of emergency.

The SGIP is originally established in 2001 to provide financial incentives for distributed generation. The program went through a major transformation in 2016 and re-allocated 75% of funding to energy storage resources, which accelerated deployment of customer-sited storage in California. Early SGIP installations were mostly standalone batteries installed by nonresidential customers to manage their demand charges for bill savings. Recent growth, however, is driven by the SGIP installations by residential customers who "pair" them with rooftop solar PV. As documented in our study and also in several SGIP evaluation reports, most SGIP-funded projects provided bill savings for the customers who installed them, but they provided little/no value to the grid. In 2019, CPUC adopted the use of a GHG signal that reflects real-time marginal GHG emission intensity in wholesale electricity markets to align resource performance with the program's emission reduction goals. Later in that year, CPUC established the Equity Resiliency budget for energy storage installations by lower-income, medically vulnerable customers who are in high fire-threat areas and at risk of outages due to utility Public Safety Power Shutoffs (PSPS). The funds are also made available to critical facilities and infrastructure supporting community resilience in the event of a PSPS or wildfire. As discussed in **Chapter 2 (Realized Benefits and Challenges)**, storage projects funded under Equity Resiliency budget will create resilience value at these locations by mitigating extended customer outages.

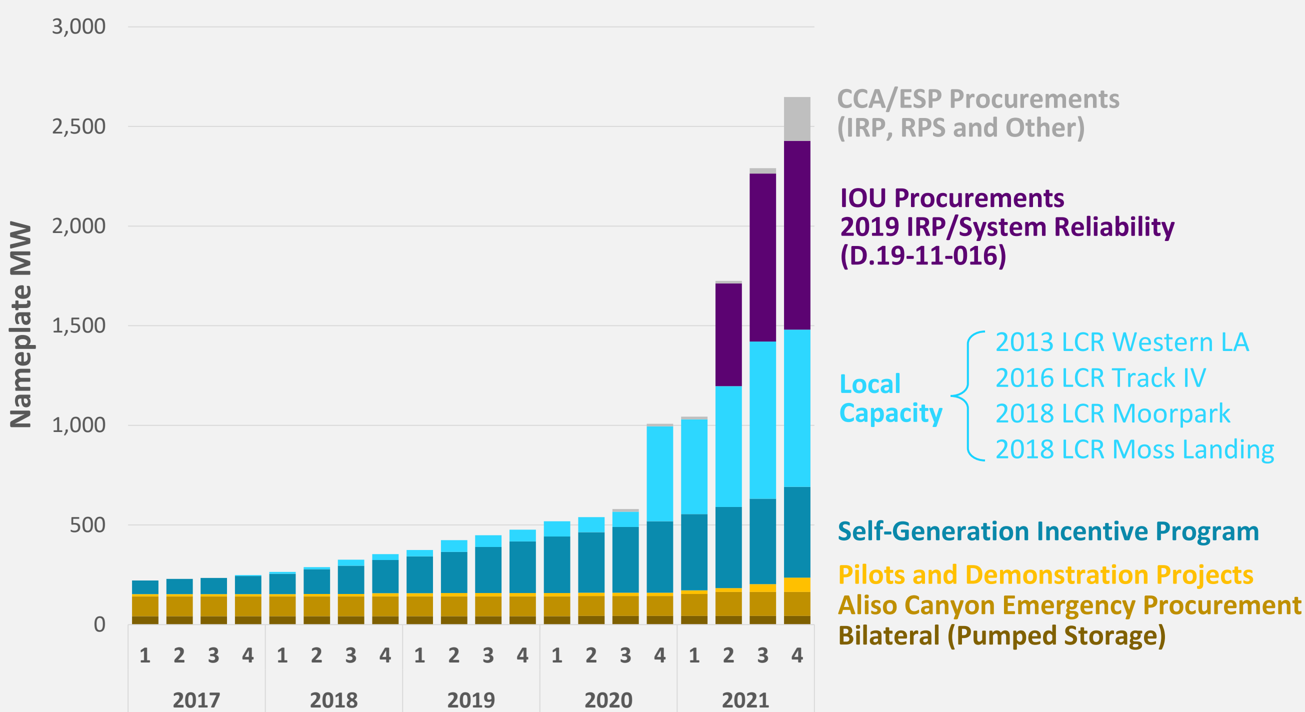


Figure 19: Actual energy storage installations in California by procurement track (2017–2021).

Energy Storage Needed for Local Capacity

Nearly 100 MW of energy storage operating in 2017 (almost half of installed storage MW at the time) was procured to address local reliability issues caused by prolonged natural gas leak at Aliso Canyon. The gas leak was first discovered in October 2015 and the governor proclaimed a state of emergency in January 2016, requesting state agencies take all necessary actions to ensure reliability. In response, CPUC required both SCE and SDG&E to conduct an expedited competitive procurements of energy storage resources to help alleviate grid outage risk driven by Aliso Canyon. The entire process was completed in record time: solicitations, development, permitting, construction, and interconnection of 7 storage projects took about 9 months from start to finish. Two of the projects were paired with existing gas plants at the transmission grid and the remaining 5 projects were connected to the distribution system. All projects participated in the CAISO market and provided system and local RA capacity, energy, and ancillary services benefits since they were in service by early 2017.

The significant growth of installations in 2020 through mid-2021 is driven by various storage procurements to address *local capacity needs* near load pockets, with a relatively high RA capacity value:

SCE's 2013 LCR Western LA RFO selected 264 MW of energy storage, of which 176 MW was online by 2021. This was an all-source RFO to procure up to 2,500 MW of capacity in Western LA local area to address the need created by retirement of once-through-cooling (OTC) power plants. The RFO had a carve-out of minimum 50 MW of energy storage plus 550 MW of preferred resources, such as demand response, energy efficiency, and renewables. Storage was cost-competitive with other preferred resources and accounted for more than half of preferred resource capacity procured at the end.

SDG&E's 2016 LCR Track IV RFO selected 83.5 MW of energy storage, of which 30 MW was online by 2021. This was a preferred resources RFO, open to energy storage, as well as demand response, energy efficiency, renewables, distributed generation, and combined heat and power (CHP) applications. A total of 88 MW is procured to meet part of the need created by the early retirement of SONGS nuclear plant. Storage accounted for 95% of the preferred resource capacity procured.

SCE's 2018 LCR Moorpark RFO selected a 100 MW storage project, which started operations in early 2021. Moorpark LCR deficiency was initially identified in 2013, driven by OTC retirements. Through the 2013 RFO, SCE contracted a 262 MW gas peaker, but CEC rejected permitting of the plant due to environmental concerns. SCE's 2018 solicitation was an all-source RFO to meet the remaining LCR need in Moorpark area after the peaker project was rejected.

PG&E's 2018 LCR Moss Landing RFO selected 567.5 MW of energy storage, of which 482.5 MW was online by 2021. PG&E's solicitation was open to energy storage resources only and intended to eliminate or reduce the need for reliability-must-run (RMR) contracts in the Moss Landing local capacity area. While PG&E was conducting the LCR RFO, CAISO identified and approved transmission upgrades to address the local need, but storage was needed to reduce risk of future deficiencies.

Energy Storage in IRP and System Reliability Procurements

Energy storage installations in second half of 2021 and expected development over the next several years are primarily a result of the procurement orders to address emerging ***system reliability needs*** identified in CPUC's Integrated Resource Planning (IRP) studies.

The IRP Procurement Track was initiated in 2019, as ordered in CPUC decision D.19-04-040, to explore options for facilitating procurements of new resources necessary for system reliability and/or renewables integration. In late 2019, the CPUC issued decision D.19-11-016 and ordered load serving entities (LSEs) to procure 3,300 MW of net qualifying capacity (NQC) across multiple tranches, with at least 50% of this capacity to be online by August 2021, at least 75% by August 2022, and the full 100% by August 2023. CPUC's tracking as of February 1, 2022 shows nearly 4,000 MW is procured for compliance, exceeding the 3,300 MW order, and vast majority of the procurement (over 80% of total NQC) is from standalone batteries or batteries paired with solar PV.

In response to the mid-August 2020 system emergency events and rotating power outages in California, the state agencies CAISO, CPUC, and CEC prepared a Final Root Cause Analysis investigating factors contributing to the outage events. They developed recommendations for improved resource planning, procurement, and market practices. The final report confirmed that one of top contributing factors was the climate change-induced extreme heat wave across the western U.S. and recommended an updated, broader range of climate scenarios to be considered in future planning studies, along with increased coordination among the agencies to prepare for contingencies. The report also highlighted that resource planning targets have not kept pace with the impact of significant renewable penetration on grid needs beyond the period of gross peak demand. In light of the events, the CPUC opened Emergency Reliability Rulemaking (R.20-11-003) to procure near-term capacity on an expedited basis to maintain system reliability. Under this rulemaking, the CPUC issued multiple decisions (D.21-02-028, D.21-03-056, and D.21-12-015) requiring the IOUs to take actions for summer reliability in 2021–2023, which led to procurement of over 1,700 MW of energy storage.

In June 2021, the CPUC issued its mid-term reliability decision D.21-06-035 ordering LSEs to procure an additional 11,500 MW of NQC between 2023 and 2026 from preferred resources including energy storage, renewables, demand response, energy efficiency, and zero-emitting resources. Of the total requirement, at least 2,500 MW is ordered specifically to replace generation from Diablo Canyon retiring in 2025, and it needs to come from zero-emitting generation, renewables paired with storage, or demand response resources, that are available everyday 5 p.m. to 10 p.m. Also, a minimum 1,000 MW of long-duration storage and 1,000 MW of firm zero-emitting or RPS-eligible generation is required by 2026. Based on the approved procurements so far, a large share of the total 11,500 MW requirement will be met by standalone or hybrid storage resources.

Altogether, recent grid events, system needs assessments, procurement orders, and solicitation outcomes suggest energy storage is positioned to play an essential role to help with system reliability in California and provide significant system RA capacity value, while facilitating the state's transition needed to achieve ambitious clean energy targets.

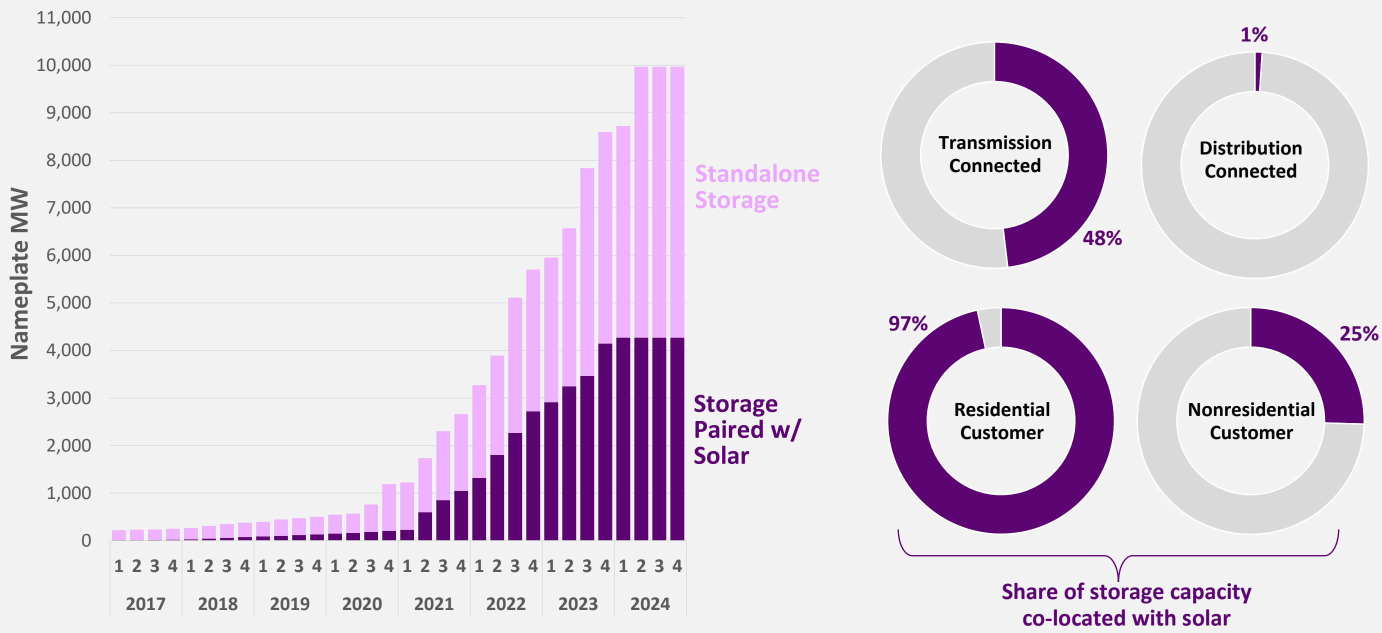


Figure 20: Standalone and co-located storage procurement in California as of summer 2022.

Storage Paired with Renewables

There has been a growing interest in developing energy storage resources paired with renewables, especially solar. This is a trend we see in most regions, but especially in California and the rest of the West. Even though most of California's operational storage capacity as of early 2021 were from standalone projects, solar + storage accounts for approximately half of new energy storage capacity currently under development in California.

Relative to standalone development, co-located or hybrid projects can provide cost synergies and get additional tax incentives. A key benefit is the shared equipment and infrastructure that can help reduce equipment, interconnection, and permitting costs. A recent NREL report shows installed cost of grid-scale co-located/hybrid systems can be 6–7% lower than cost of solar and storage sited separately. Until recently, only energy storage co-located with solar would get federal investment tax credit (ITC) that could offset 26–30% of costs. The Inflation Reduction Act of 2022 extended the ITC to also standalone storage for up to 30% of their installed cost. If DC-coupled, co-locating solar and storage can also capture the solar energy that would otherwise be clipped and reduce the overall roundtrip energy losses. An important consideration is the interconnection process. Adding storage to an existing facility can reduce the cost and timeline for interconnection with the grid.

On the other hand, taking advantage of these co-location benefits creates more restrictive operational constraints, such as grid charging and interconnection limits, and it may not allow storage resources to be placed at highest-value locations of the grid. A recent LBNL study demonstrates that the corresponding missed value opportunity (called "coupling penalty" in the study) relative to independently-sited systems can offset most of the co-location benefits described above.

Customer-sited energy storage installations driven by SGIP incentives are growing rapidly. While the initial deployment was mostly by larger nonresidential customers, this has changed in recent years and small residential customers now account for nearly 80% of the storage MW added in California based on data for the 2020-2021 program years.

Storage installations by nonresidential customers are primarily standalone systems used to maximize bill savings through demand charge reductions. Storage installations by small residential customers, on the other hand, are almost exclusively paired with rooftop PV and they are often charged by solar during the day and discharged after sunset to maximize bill savings under time-of-use (TOU) rates.

Even though most customers who installed storage have it paired with solar, the opposite is not true: share of storage attached to customer-sited solar systems are relatively low in California. According to public data from California DG Stats, energy storage attachment rate was around 5% by the end of 2021. Only 60,000 out of 1.2 million residential customers with rooftop solar PV also installed energy storage, and fewer than 1,500 out of 30,000 nonresidential customers with solar also installed storage.

A recent LBNL study on BTM solar + storage market data and trends highlights the significant difference between much higher storage attachment rates in Hawai'i and other states, including California. The study attributes the significant difference to net metering reforms implemented in Hawai'i, which started to incentivize self-consumption of on-site solar generation (see below).

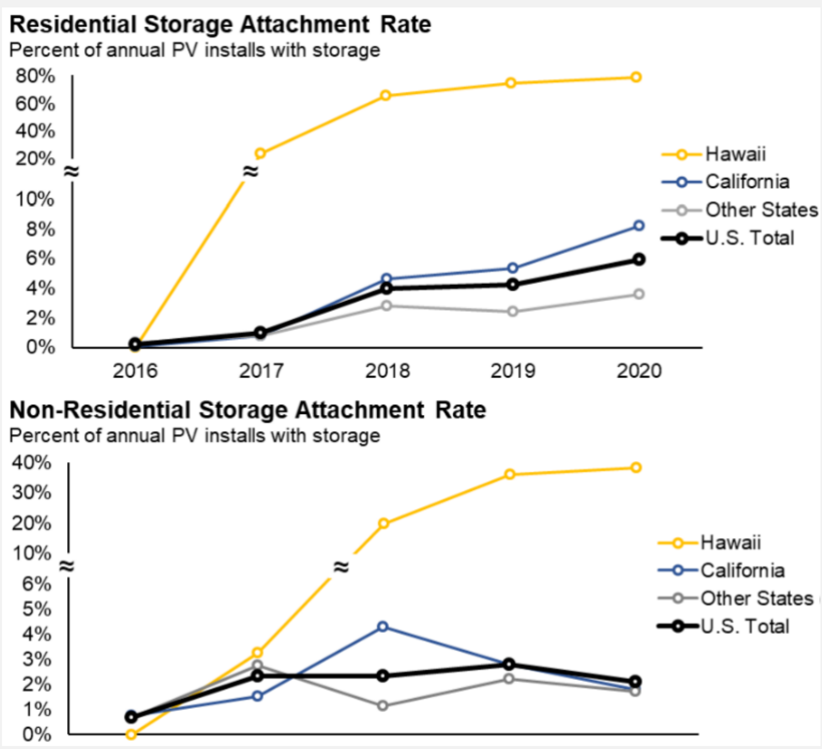


Figure 21: Hawai'i's customer-sited storage attachment rate to solar PV installations over time.

(Barbose et al. 2021)

According to the LBNL study, Hawai'i has, by far, the highest storage attachment rate of any state, with 80% of residential customers and 40% of nonresidential customers who installed solar PV in 2020 included storage. The study attributes this difference to net metering reforms in Hawai'i that incentivize self-consumption.

Over the past 5 years, Hawai'i has transitioned away from net energy metering (NEM) to alternative tariff structures, including net billing tariffs that reduced compensation for exports to align with actual grid costs, and tariffs that limit grid exports. These changes made solar + storage more attractive relative to standalone solar PV.

Energy and Ancillary Services Value

CAISO developed several distinct models for energy storage technologies to participate in the wholesale energy and ancillary services markets:

- **Pumped-Storage Hydro** model reflects characteristics of pumped storage hydroelectric units acting as load when using grid energy to pump water to higher elevations and acting as generators when releasing water to produce energy.
- **Non-Generator Resource (NGR)** model is the primary model designed for today's common storage technologies like lithium-ion batteries, which allows them to operate as either load or generators, dispatched at any level within their full operating range, subject to charge, discharge, and state-of-charge (SOC) limits.
- **Proxy Demand Resource (PDR)** model allows resources to participate as demand response and submit bids for load curtailment.
- **Proxy Demand Resource - Load Shift Resource (PDR-LSR)** model is like the PDR model, but allows for *bi-directional* dispatch based on bids for load curtailment and load increase.
- **Reliability Demand Response Resource (RDRR)** model is like the PDR model, but load curtailment is triggered only under emergency conditions.
- A new model, called *energy storage resource (ESR)* model, is proposed as an alternative to the NGR model to allow resources submit bids based on SOC values rather than dispatch power levels.

Between 2015 and 2021, CAISO led Energy Storage and Distributed Energy Resource (ESDER) initiative to improve the ability of both transmission-connected and distributed energy resources to participate in wholesale markets (Figure 22). Separately, CAISO's ongoing energy storage enhancements initiative aims to improve optimization, dispatch, and settlement of energy storage resources through bid enhancements and to ensure storage resources have sufficient SOC in critical hours. CAISO launched the initiative in May 2021 and began exploring several potential enhancements to better model and compensate storage resources in the marketplace.

ESDER Phase 1 (2015–2016)	Implemented enhancements to NGR model and PDR/RDRR performance measures Clarified rules for multiple-use applications
ESDER Phase 2 (2016–2018)	Implemented new types of demand response performance evaluation methods Clarified station power treatment for storage resources
ESDER Phase 3 (2017–2020)	Removed single LSE requirements for DR aggregations Created PDR-LSR model to allow for bi-directional dispatch of BTM storage Refined participation model for electric vehicle supply equipment
ESDER Phase 4 (2019–2021)	Streamlined market participation agreements for non-generator resources Created storage default energy bids for market power mitigation Created end-of-hour SOC bid parameter to help manage usage of storage in real-time Created parameters to better reflect operational characteristics of DR resources

Figure 22: Phases of the CAISO's ESDER initiative.

Ecosystem for Project Deployment

Since the time of Assembly Bill 2514 and through 2021 California built a rich ecosystem for energy storage research and development, commercialization, and project deployment. The CPUC's Energy Storage Procurement Framework provides crucial motivation to the development of both demand and supply in this marketplace.

In this section we describe evidence of workforce development with a focus on the energy storage supplier activity. We find that the Self-Generation Incentive Program fosters an environment for local installers and developers to enter the energy storage market and gain depth of experience specific to California. Further upstream on the distribution system, third-party interconnections face ongoing hurdles to reach project completion and to access wholesale markets. State and federal policies have made some headway to clear the path for distribution-connected installations but challenges remain. On the transmission system, the CAISO interconnection queue shows more storage development activity than all other centralized wholesale market areas in the U.S. Relatedly, utility competitive solicitations have attracted dozens of national and international energy storage developers to the state.

Members of the Energy Storage Market Ecosystem

A wide range of energy storage specialists contribute to the growth and evolution of California's energy storage market.

Supply development for energy storage involves a complex and highly skilled workforce who have faced and addressed many unknowns in energy storage project deployment over the last decade.

Researchers, academia, inventors, and startups are at the heart of the innovation and proof of technology processes. Pilots and demonstrations—supported by the CEC, utilities, the CPUC—help developers to poise for commercialization in a specific market and policy context. These activities disseminate valuable information broadly to the industry and build a knowledge pool for workforce development. Commercial project deployment requires technical and financial experts who build viable business cases to attract investors, skilled developers and installers, and project review by local representatives and utilities for community and grid integration. Operations and maintenance also requires knowledgeable and highly trained experts. Many other parties are involved who carry crucial roles, such as trade organizations, software development experts, and data service providers.

Demand for energy storage has grown as value propositions improve and as energy storage yields services more accessible and more useful to more customers.

As described in the Introduction to this report, California's statutory and policy goals are at the foundation of the demand for energy storage deployment. Legislation such as Assembly Bill 2514 plus the CPUC's resource planning process, RA Program, and various rulemakings and procurement orders translate the future promise of clean energy into utility and ratepayer demand for energy storage solutions. Over time, we see this demand accelerate into new avenues of service to customers, including energy storage procurements by Community Choice Aggregators (CCAs) and corporate contracts. With the help of SGIP and the electric vehicle market the concept of stationary energy storage became broadly accessible to customers seeking bill management and resilience for their homes and businesses.

Evolution of Energy Storage Suppliers in California

California is a national hub for energy storage installer and developer activity. Suppliers are exploring opportunities in all grid domains to bring a variety of viable use cases to scale.

Installers of customer-sited storage. Development activity under SGIP shows significant growth in the number of energy storage installers and their depth of experience over time. Energy storage installations with the program year 2009 and with relatively little activity in the first two program years. Under the 2011 program year, only 3 installers were present—with Tesla being one of them. Options for installers continued to be limited to a few companies for the next 5 program years. Then, under the 2017 program year the installer market concentration dispersed considerably from a dozen or two installers to 165 (Figure 23). The number of installers continued to grow to almost 300 in 2020, then back down to 220 in 2021 likely at least partly due to economic impacts of a global pandemic. In terms of the Herfindahl-Hirschman Index (HHI), a standard indicator for structural market concentration and competition, the market for installed kW was highly concentrated until 2016 then fell into the unconcentrated zone starting in 2017.

Researchers at the Lawrence Berkeley National Lab (LBNL) have studied the characteristics and trends of co-located solar PV plus storage installations extensively and note that (a) market concentration is much lower for standalone solar , and (b) certain installers like Tesla, SunRun, and Semper Solaris leverage their experience to yield relatively high storage attachments to solar PV installations (or solar PV attachments to storage) (Barbose et al, 2021). Clearly the supplier market for customer-sited installations in California has gained much momentum over the past decade.

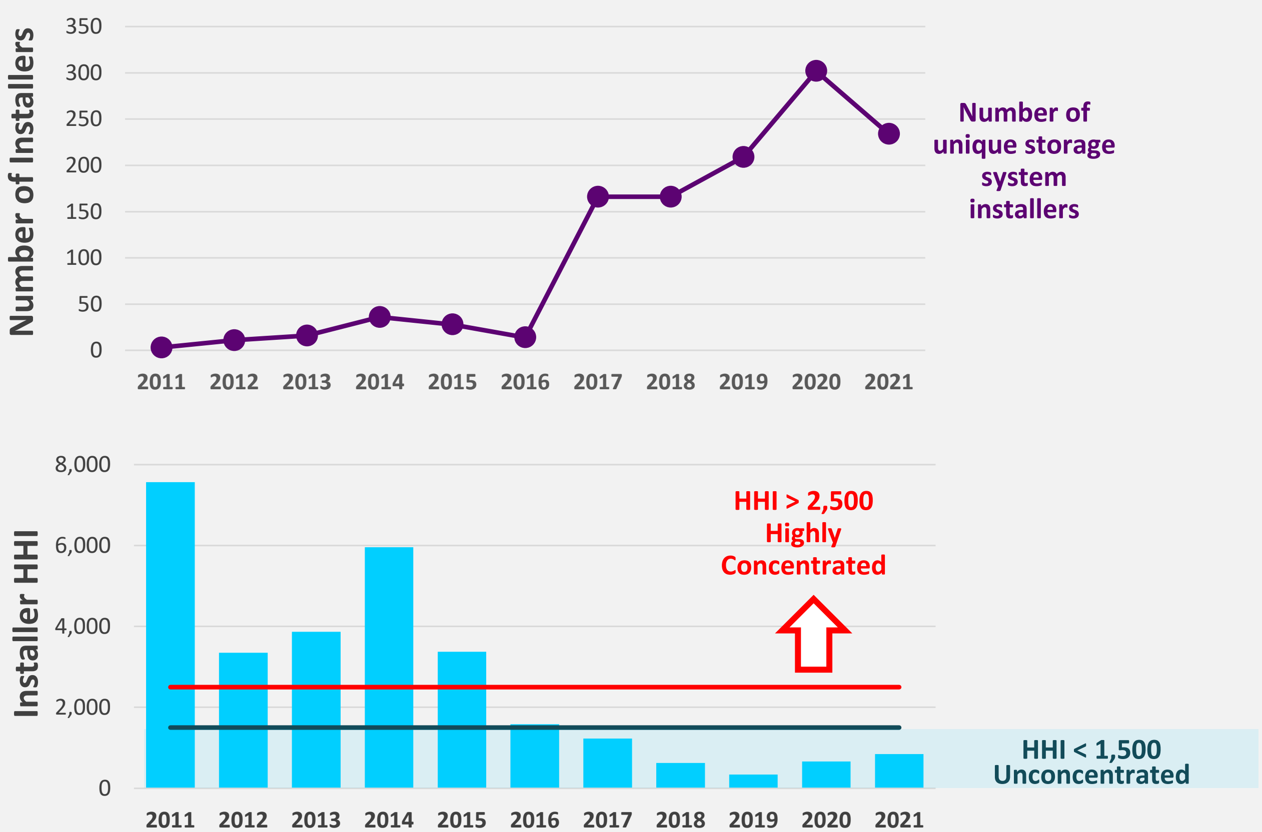


Figure 23: SGIP energy storage installers and market concentration over time.

Challenges with distribution-connected project deployments. Distribution-connected projects face challenges with the interconnection process also seen historically in projects with transmission-level interconnections. For some storage installations, finalization of project designs is inherently circular with the utility's (or system operator's) analysis of impacts to the surrounding grid. Grid impacts unavoidably not gradual with each project installed—impacts are triggered at certain thresholds, raising many questions on how to study individual projects and the fairness of who pays for major grid upgrades. Furthermore, when feasibility, impact, and grid upgrade analyses are needed they can be intense and require the engagement of highly trained and specialized personnel. Some developers enter the interconnection process with highly conceptual designs or even multiple versions of the same design. Staffing and resource constraints are well-known problems here, and it is not uncommon to find that all parties involved want a simpler and more streamlined process.

Distribution-connected energy storage projects must have an interconnection agreement with the utility. All projects that would operate like a generator (as opposed to a wire) must interconnect under Wholesale Distribution Access Tariff (WDAT), which is regulated by the Federal Energy Regulatory Commission (FERC). Stakeholders have expressed financial and logistical challenges with the utility interconnection process severe enough to threaten project viability and completion. Those challenges are evident in project developments under the utilities' energy storage procurements. Half of all third-party-owned storage projects connected to the distribution system and procured for start of operations by the end of 2021 were canceled (Figure 25).

Suppliers entering the CAISO interconnection queue. Research by LBNL shows energy storage capacity in the CAISO interconnection queue exceeded that of all other centralized wholesale market areas in the U.S. (blue areas in Figure 24) (Rand et al. 2022). From 2019 to 2021, storage capacity entering the CAISO queue grew exponentially, and in 2021, it represented nearly half of all interconnection requests in the country.

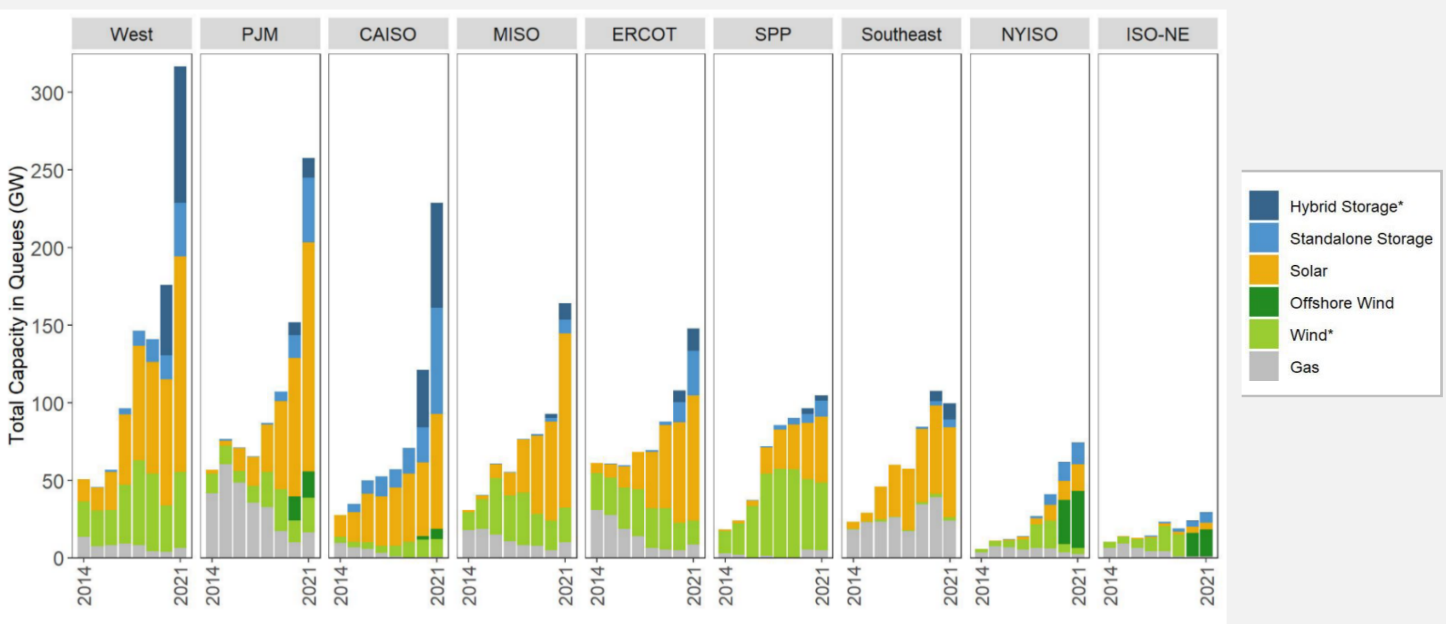


Figure 24: Grid-scale energy storage capacity in interconnection queues over time (2014–2021).
(Rand et al. 2022)

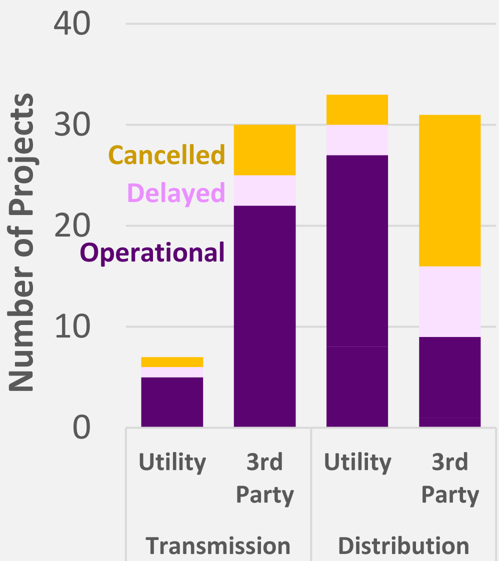


Figure 25: Status of IOU energy storage procurements for start of operations by the end of 2021.

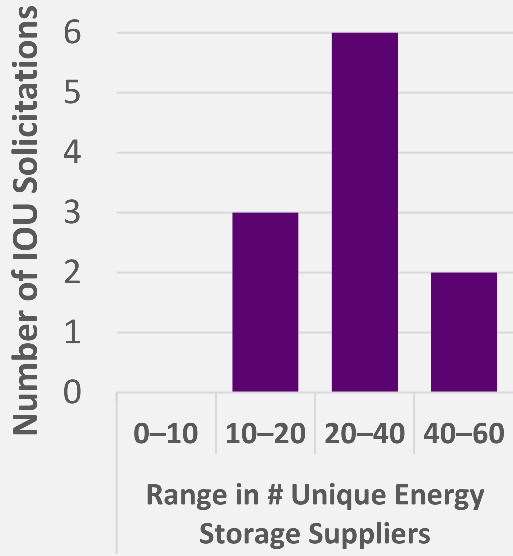


Figure 26: Distribution of IOU solicitations based on the number of unique energy storage suppliers.

Supplier participation in IOU resource solicitations.

In **Chapter 1 (Market Evolution)** the Value Propositions section (page 25) describes the large IOUs' various resource procurement tracks since about 2013. These competitive solicitations attracted dozens of national and international energy storage developers to California's energy storage market.

We reviewed the results for 11 specific competitive solicitations conducted by PG&E, SCE, and SDG&E over the timeframe 2013–2020. Six of these solicitations attracted 20–40 unique energy storage suppliers (Figure 26). Three solicitations attracted less (10–20) and two attracted more (40–60).

Suppliers submitted anywhere from 1 to 26 offers (4–7 on average) typically yielding hundreds of individual offers in each procurement. Offers spanned third-party-owned and utility-owned projects, projects across all grid domains, and standalone and co-located projects—although with a higher concentration in standalone transmission-connected installations.

Key Observations for Chapter 1 (Market Evolution)

Ratepayer-funded pilots and demonstrations that do not conclude with a widely-available report on challenges and lessons learned are not as helpful to the state's industry towards building market-readiness for new technologies.

The market for stationary energy storage in California grew and matured significantly, from a pilot phase into commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations.

Significant cost reductions were achieved for energy storage installations and contracts across all grid domains in California.

Climate change-induced extreme weather events in California and across the western U.S. created a need for updated, broad range of climate scenarios to be considered in future planning studies and requires increased coordination among the state agencies to prepare for contingencies.

System reliability and RA capacity needs are rapidly growing, which is planned to be addressed primarily by deployment of grid-scale energy storage resources.

There is a growing interest in developing energy storage resources paired with solar, driven by cost synergies and tax incentives, but co-location benefits can be offset by more restrictive operational and siting constraints reducing grid value (relative to standalone development).

Customer-sited energy storage is increasingly paired with solar, but storage attachment rate among all solar installations in California is still very low compared to its potential.

CAISO's wholesale markets facilitated stacking of energy and ancillary services value for grid-scale energy storage resources.

Distribution-connected energy storage installations faced challenges with grid interconnection and with achieving commercial operations.

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CHAPTER 2: REALIZED BENEFITS AND CHALLENGES

We analyzed the actual 2017–2021 operations of 1,374 MW energy storage in California, including 927 MW (of 976 MW) counted towards utility procurements required under CPUC Decision 13-10-040, plus 42 MW of customer-sited storage above the procurement target and 405 MW procured for system RA capacity that recently became online. We calculated realized net benefits to ratepayers at the resource level and evaluated each resource for utilization towards meeting the Assembly Bill 2514 stated goals of grid optimization, renewables integration, and greenhouse gas emissions reductions.

Cost decreases and growth in key market value streams indicate a major shift from earlier pilot and demonstration projects into mature commercial scalability during our study period. In the 5-year timeframe California ratepayers incurred $75 million net cost per year on average for exploratory projects and programs. More recent market-mature projects reveal the first fruits of this investment: they were on track to yield net benefits at a rate of $22 million per year by the end of 2021.

However, major challenges are also evident. In particular, some distribution-connected and all customer-sited installations operate well below their full potential.

At the heart of this evaluation is an analysis of actual energy storage operations, benefits, and costs within the 5-year study period 2017–2021. From this analysis, we seek to better understand to what degree the CPUC energy storage procurement framework helps to meet state policy goals. We also assess:

- Are ratepayers realizing net benefits from energy storage investments?
- What types of installations and use cases demonstrate meaningful growth in value?
- Are any sources of ratepayer value left untapped?
- Are some types of installations and use cases not scaling up and what are the challenges?

In this chapter we define the scope and context of the historical analysis, present the results of net benefits realized, and discuss key observations on successes and challenges.

Scope of Historical Analysis

Scope of resources. A list of energy storage resources included in our historical analysis is shown in Figure 27. These are resources procured by load-serving entities under CPUC jurisdiction. Most of these projects:

- Are counted towards utilities' requirements under CPUC Decision 13-10-040;
- Operated within the 5-year study period 2017–2021; and
- Reached commercial operations by April 2021 (for sufficient operational data to analyze).

To make full use of available data we also analyzed the operations of three resources procured for system RA capacity (Gateway, Vista, Blythe) and not counted towards utilities' requirements under CPUC Decision 13-10-040. The historical operations of some resources shown could not be analyzed due to data limitations as indicated in the figure. Overall, the resource set represents 1,571 MW/5,176 MWh of total nameplate capacity, with 976 MW counted by the IOUs towards their CPUC Decision 13-10-040 requirements and 1,374 MW included in our analysis of historical operations.

		Nameplate							Procurement	MW IOU	MW
	Count	MW	MWh	LSE	Online	Technology	Owner	CAISO?	Track	AB 2514	Analyzed
Transmission-Sited	**8**	**865**	**3,053**							**460**	**865**
3rd-Party	**6**	**845**	**3,044**							**440**	**845**
Vista Energy Storage	1	40	44	SDG&E	Jun-18	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	40
Gateway Energy Storage	1	250	700	Various	Sep-20	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	250
Lake Hodges Pumped Hydro	1	40	240	SDG&E	Aug-12	Pumped Storage	Third Party	Y	Bilateral	40	40
Vistra Moss Landing	1	300	1,200	PG&E	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	300	300
AES Alamitos ES	1	100	400	SCE	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Blythe Energy Storage II	1	115	460	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	115
Utility-Owned	**2**	**20**	**8.6**							**20**	**20**
SCE EGT - Center	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
SCE EGT - Grapeland	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
Distribution-Sited	**33**	**236**	**925**							**236**	**227**
3rd-Party	**7**	**146**	**583**							**146**	**145**
W Power - Stanton - 1	1	1.3	5.2	SCE	May-20	Lithium-Ion (NMC)	Third Party	Y	Energy Storage RFO	1.3	no data
ACORN I ENERGY STORAGE LLC	1	2	6	SCE	Mar-21	Lithium-Ion (NMC)	Third Party	Y	IDER Pilot	1.5	2
AltaGas Pomona	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	20	20
Powin Energy - Milligan ESS 1	1	2	8	SCE	Jan-17	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	2	2
Orni 34 LLC	1	10	40	SCE	Feb-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	10	10
Silverstrand Grid, LLC	1	11	44	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	11	11
Ventura Energy Storage (formerly Strata Saticoy)	1	100	400	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Utility-Owned	**26**	**90**	**342**							**90**	**82**
Vaca-Dixon	1	2	14	PG&E	Jul-14	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	2	2
Yerba Buena	1	4	28	PG&E	Jun-13	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	4	4
Browns Valley	1	0.5	2	PG&E	Sep-16	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Tehachapi Storage Project (TSP)	1	8	32	SCE	Apr-16	Lithium-Based	Utility	Y	EPIC / PIER / DOE	8	8
Escondido	1	30	120	SDG&E	Mar-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	30	30
El Cajon	1	7.5	30	SDG&E	Feb-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	7.5	7.5
Tesla - Mira Loma	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	20	20
Smart Grid Stabilization System (SGSS) Unit 1	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Smart Grid Stabilization System (SGSS) Unit 2	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Mercury 4	1	2.8	5.6	SCE	Dec-18	Lithium-Ion (NMC)	Utility	N	General Rate Case	2.8	2.8
Distribution Energy Storage Integration (DESI) 1	1	2.4	3.9	SCE	May-15	Lithium-Based	Utility	N	General Rate Case	2.4	no data
Distribution Energy Storage Integration (DESI) 2	1	1.4	3.7	SCE	Dec-18	Lithium-Based	Utility	N	General Rate Case	1.4	1.4
Borrego Springs Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Borrego Springs Unit 2	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 3	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 4	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
GRC Energy Storage Program Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Based	Utility	N	General Rate Case	0.5	0.5
GRC Energy Storage Program Unit 2	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 3	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 4	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 5	1	1	3	SDG&E	Jun-14	Lithium-Ion (NMC)	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 6	1	1	1.5	SDG&E	Jun-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 7	1	1	2.3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	no data
GRC Energy Storage Program Unit 8	1	1	1.5	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 9	1	1	3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
Catalina Island Battery Storage	1	1	7.2	SCE	Aug-12	Sodium-Sulfur	Utility	N	General Rate Case	1	1
SGIP Customer-Sited	**22,660**	**390**	**858**							**200**	**205**
SGIP Nonresidential (as of Apr'21)	**1,160**	**244**	**504**							**177**	**205**
SGIP Nonresidential PG&E	330	63	126	PG&E	Various	BTM Battery	Customer	N	SGIP	62	48
SGIP Nonresidential SCE	580	142	293	SCE	Various	BTM Battery	Customer	N	SGIP	85	126
SGIP Nonresidential SDG&E	250	39	84	SDG&E	Various	BTM Battery	Customer	N	SGIP	30	31
SGIP Residential (as of Apr'21)	**21,500**	**147**	**355**							**23**	0
SGIP Residential PG&E	9,900	71	173	PG&E	Various	BTM Battery	Customer	N	SGIP	23	no data
SGIP Residential SCE	7,000	45	108	SCE	Various	BTM Battery	Customer	N	SGIP	0	no data
SGIP Residential SDG&E	4,600	31	73	SDG&E	Various	BTM Battery	Customer	N	SGIP	0	no data
Non-SGIP Customer-Sited	**1,705**	**80**	**340**							**80**	**76**
BTM Battery CAISO PDR	**900**	**70**	**280**							**70**	**70**
HEBT Irvine1 DRES	10	5	20	SCE	Nov-17	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT Irvine2 DRES	10	5	20	SCE	Feb-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT WLA1 DRES	50	25	100	SCE	Apr-19	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	25	25
HEBT WLA2 DRES	30	15	60	SCE	Mar-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	15	15
Stem Energy DRES - 402040	800	20	80	SCE	Aug-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	20	20
BTM Battery non-CAISO	**1**	**0.1**	**0.5**							**0.1**	0
Discovery Science Center	1	0.1	0.5	SCE	Jun-14	Metal Hydride	Customer	N	Other	0.1	no data
PLS/TES	**804**	**10**	**60**							**10**	**6**
Ice Bear PLS - 431058	250	1.92	11.52	SCE	Jan-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431061	250	1.92	11.52	SCE	Apr-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431151	150	1.28	7.68	SCE	Mar-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
Ice Bear PLS - 431154	150	1.28	7.68	SCE	Dec-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
PLS/TES - Chaffey College	1	0.8	4.8	SCE	Jul-16	Thermal	Customer	N	PLS	0.8	no data
PLS/TES - Cypress College	1	0.7	4.2	SCE	Jun-18	Thermal	Customer	N	PLS	0.7	no data
PLS/TES - Mt San Antonio College	1	1.5	9	SCE	Mar-17	Thermal	Customer	N	PLS	1.5	no data
PLS/TES - Santa Ana College Central	1	0.53	3.18	SCE	Jun-19	Thermal	Customer	N	PLS	0.53	no data
Total Storage Across All Domains >>		**1,571**	**5,176**							**976**	**1,374**

Figure 27: List of energy storage resources included in the 2017–2021 historical analysis.

Resource procurement tracks. The historical analysis includes energy storage procured under energy storage-specific, general rate case, local reliability, system reliability, distribution deferral, and bilateral procurement tracks. The group also includes installations incentivized by programs like the Self-Generation Incentive Program (SGIP), utility Permanent Load Shift and Thermal Energy Storage programs, and the Electric Program Investment Charge (EPIC) program (Figure 28).

7% of the MW capacity analyzed is utility-owned, 78% third-party-owned, and 15% customer-owned.

Resource characteristics. Most of these resources utilize lithium-ion battery technology but the group includes thermal energy storage, pumped storage hydroelectric, and alternative battery chemistries. Installation sizes range from 30 kilowatts to 300 megawatts in terms of instantaneous capacity and these resources are considered "short duration." Most resources analyzed are capable of discharging up to four hours at full megawatt capacity, but range from 0.25 to 7 hours. This resource set represents a variety of use cases and services provided to customers directly, to the distribution system, and to the transmission system.

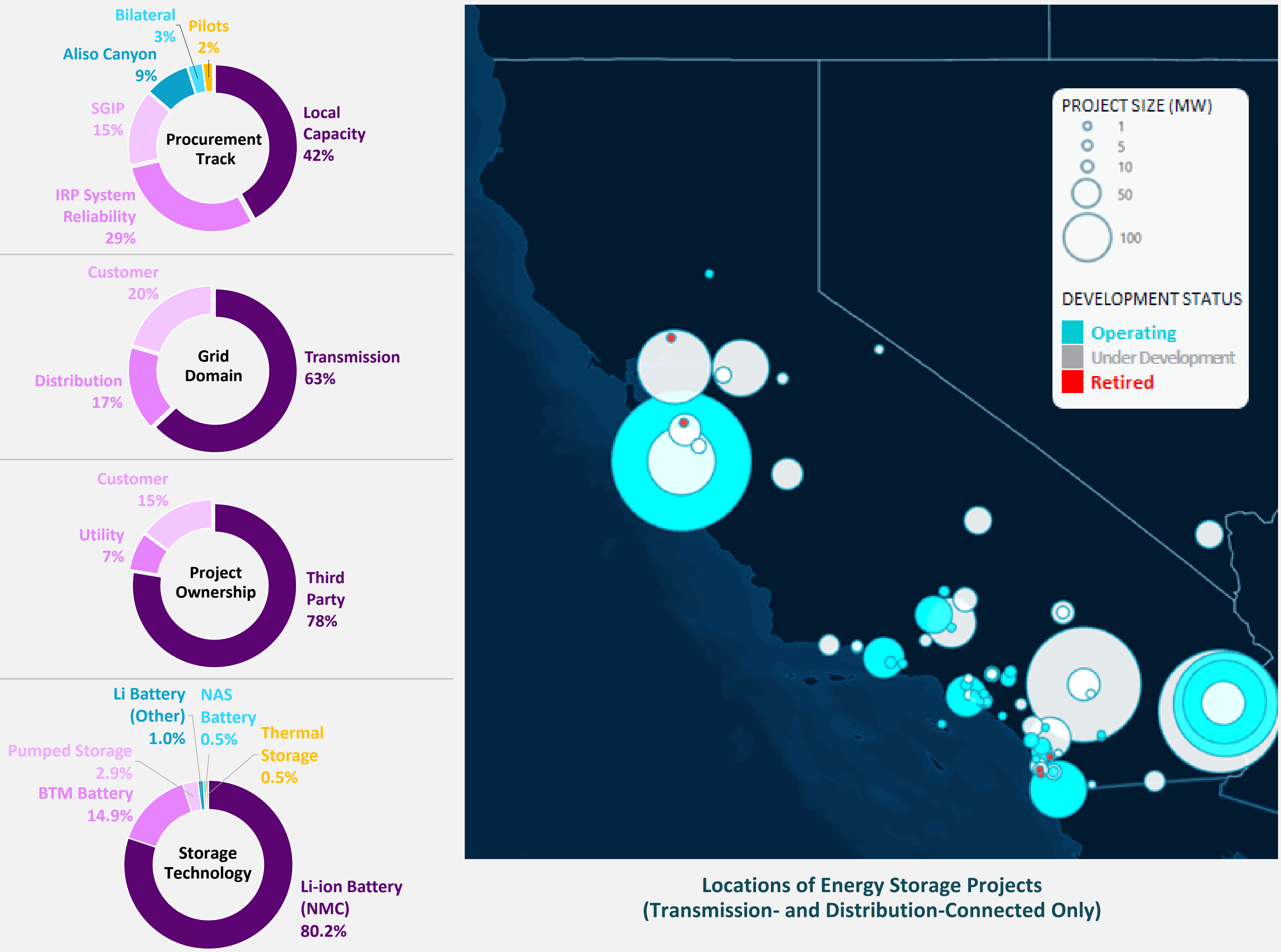


Figure 28: Characteristics of energy storage capacity (1,374 MW) included in the 2017–2021 historical analysis.

Consistency with state practices. Our net benefit calculations are grounded in California's existing practices and methodologies, namely those reflected in the state's Standard Practice Manual for cost-effectiveness tests, the state's Avoided Cost Calculator for distributed energy resources, and the utilities' various Least-Cost Best-Fit calculations for bid evaluations in resource procurements.

Consistent with state practices, benefits reflect the avoided cost of market alternatives to the energy storage resource analyzed.

Benefits and costs focus mostly on ratepayer impacts but also consider societal impacts (e.g., GHG emissions reductions) and benefits that flow directly to customers with energy storage installed (e.g., customer outage mitigation).

Many benefit types are monetized in our net benefit calculations, but some, like "renewables integration" are not standardized products traded in markets and require some expert judgment to quantify. Thus for each resource we evaluate (1) monetized net benefits in the form of a benefit/cost ratio alongside (2) contributions towards meeting the state's policy goals in the form of a 0–100 score. This two-pronged approach is utilized throughout the state's historical evaluation methodologies.

Contributions to advancements of the state's evaluation frameworks. The CPUC, utilities, and stakeholders have put forth significant effort across many planning and procurement proceedings to identify, quantify, and monetize the multiple cost and benefit streams of energy storage. Over time, evaluation methods evolved and informed each other to include a broader range of resources and additional difficult-to-quantify costs and benefits. In 2020 CPUC Staff recommended development of a common resource valuation methodology (CRVM) under the IRP procurement framework (Rulemaking 20-05-003) that would take one more step towards a universal evaluation framework. Our analysis provides some avenues for further advancements of the state's evaluation frameworks (Figure 29). We expand upon the current suite of evaluation methodologies in four dimensions:

(1) Historical data—we evaluate and learn from historical resource-specific storage operations which can serve as a benchmark for forward-looking models;
(2) Temporal and spatial granularity—subject to data availability, we evaluate operations at a 5- or 15-minute granularity and market value at nodal or locational pricing points;
(3) All grid domains—we evaluate stationary storage installed at any location (customer, distribution system, transmission system) with a single consistent approach;
(4) All benefit types—we attempt to quantify the full spectrum of benefit types identified by stakeholders.

	Consistent Evaluation Protocol (CEP)	Competitive Solicitation Framework	Avoided Cost Calculator (ACC)	Utility Least-Cost Best-Fit (LCBF)	SGIP Energy Storage Impact Evaluations	This Study's Historical Analysis
Vintage	2014	2016	Ongoing	Ongoing	Ongoing	2022
Reference	D.14-10-045	D.16-12-036	D.20-04-010	D.13-10-040	D.16-06-055	D.13-10-040
Perspective	Forward-Looking	Forward-Looking	Forward-Looking	Forward-Looking	Retrospective	Retrospective
Resource Type	Proposed Future	Proposed Future	Proposed Future	Proposed Future	Actual Installed	Actual Installed
Storage Dispatch	Not Specified	Not Specified	Sample Days	Fwd. Curve	Actual	Actual
Market Price Intervals	Not Specified	Not Specified	Hourly	Fwd. Curve	Hourly	5- & 15-minute
Market Price Points	Zonal	Not Specified	Zonal	Zonal	Zonal	Nodal
Resource Grid Domain(s)	All	Distribution, Customer	Customer	All	Customer	All
Benefits Scope *A/S=Ancillary Services*	Energy, A/S, some Capacity, Customer	Energy, some A/S, Capacity	Energy, some A/S, Capacity	Energy, some A/S, Capacity	Energy, some A/S, Capacity, Customer	All

Figure 29: Key evaluation frameworks used in California resource planning and procurements.

Data sources. Energy storage operational data was provided by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), the CAISO, and the CPUC. The CAISO provided detailed historical market data, including resource-specific settlements, market prices, and other system data. PG&E, SCE, and SDG&E provided detailed information on most of their energy storage procurements including bid evaluation results, contract information, actual ratepayer costs, resource characteristics, and a variety of other supporting information.

Caveats to interpretation of evaluation results. Our evaluation metrics are designed to show relative performance of individual energy storage resources or groups of resources with the purpose to identify successes and challenges in use cases and their potential to support the state's energy goals.

While this historical analysis offers a reality check on conceptual pro-storage rhetoric and generally accepted resource planning assumptions, it also has a few drawbacks. Most importantly, historical market value reflects market and grid conditions that are at times volatile and cyclical, and thus not directly comparable to prospective planning study outcomes under normalized and smoothed future conditions (Figure 30).

Specifically, our historical analysis:

✓ Can show how resources and groups of resources compare in terms of realized cost-effectiveness and contributions towards meeting state goals

✓ Can identify areas of market growth towards meeting state policy goals at a large scale

✓ Can reveal patterns of untapped benefit potential and associated challenges

✓ Can highlight major discrepancies between actual operations and market performance, and forward-looking evaluation methodologies used in resource planning and procurements

× Cannot revisit prudency of past procurements; investment in the innovation process and market acceleration is important context

× Cannot extrapolate resource-level results to the full life of an installation; especially for projects at the beginning of their economic lives

× Cannot readily apply high-level historical results to support forward-looking studies without further consideration of how the grid and markets will evolve; see **Chapter 3 (Moving Forward)** for further discussion

Attachment A contains additional details on our approach and assumptions to the historical analysis.

	Prospective Planning Studies or Procurement Evaluations	**This Study's Historical Analysis**
Timeframe	10–20 years forward	2017–2021 actual historical
Storage Installation	Generic or proposed future	Actual installed
Operating Period	Entire project life	Limited window (partial life)
Weather Conditions	Normalized	Actual, volatile
Electricity Consumption	50/50 or 90/10 weather, smoothed economic and population projections	Actual, cyclical
Grid Conditions	(some) Conceptual infrastructure with limited/no unexpected outages and muted real-time volatility	Actual infrastructure with unexpected outage events, with real-time uncertainty and volatility
Market Prices	Smoothed, optimized with a long-run foresight of benefit streams	Actual/volatile; partial view of potentially back-loaded benefits
Energy Storage Project Costs	Full view; investments optimized with market price outcomes	Partial view of potentially front-loaded costs

Figure 30: Key differences in prospective versus historical evaluations.

Net Benefits Realized in 2017–2021

Theoretical versus realized benefit categories. California explored a wide range of services and use cases in its early pilots and demonstration projects but much work still remains. Many benefit categories, or types of services, are not developed to scale due to immature markets for those services and/or limited demand. Furthermore, although energy storage resources have the ability to provide multiple services at once many use cases at the distribution and customer level do not fully take advantage of multi-use applications.

Figure 31 shows a cross-reference between theoretical and realized benefit categories. Each column represents an individual resource or group of resources included in our historical analysis. The 3 large boxes, one for each grid domain, define the set of services theoretically possible. Dark purple indicates a service that is clearly provided and monetized. White space shows the gaps where potential services are not provided.

While it is not reasonable to expect all resources to provide every possible service, significant gaps across rows (services) and columns (resources) indicate barriers to realizing benefits. Prevalent gaps in two core services—energy and RA capacity—indicate major roadblocks to contributions towards meeting state policy goals. In comparing theoretical versus realized benefit categories, we observe that:

- A large share of distribution-connected resources provides only 1–3 services of limited value, faces significant barriers in energy service, and does not provide RA capacity services;
- Customer-sited resources across the board face significant barriers in energy service;
- Access for several types of services are either not established or extremely limited during this historical period (voltage support, blackstart, transmission and distribution investment deferral, self-generation, and backup power).

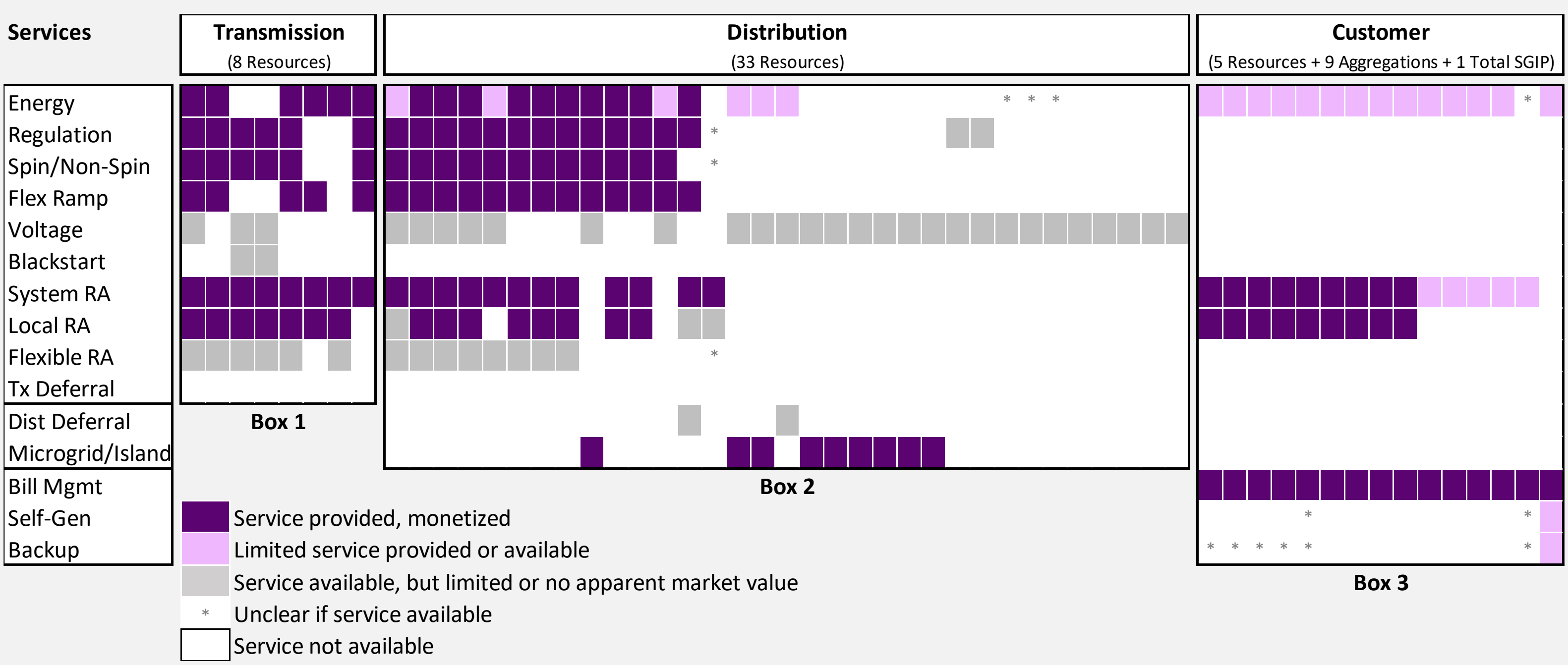


Figure 31: Theoretical versus actual benefit categories (row) by resource or resource group (column).

Ratepayer net benefits. Figure 32 summarizes our ratepayer net benefit results for the 2017–2021 operating period, expressed as benefit/cost (B/C) ratios. The chart highlights the differences relative to a B/C ratio of 1.0, which indicates estimated benefits are equal to costs. About half of the analyzed storage capacity yielded more benefits than costs to ratepayers (B/C ratio above 1.0).

Most bars on the chart represent an individual energy storage resource with the width of the bar showing relative MW capacity. Small customer-sited installations are aggregated into utility contracts or clusters with similar operational patterns. The bottom chart shows the underlying benefit and cost components. For storage under RA only contracts, energy and ancillary services values are not included as they are not ratepayer benefits. As explained earlier, there were no projects with T&D deferral benefits and the GHG reduction value is already reflected in energy value (no GHG adder). Avoided RPS costs were relatively small compared to core benefits from energy, ancillary services, and RA capacity.

Among all projects analyzed, the top 3 of the third-party-owned distribution-connected resources performed particularly well compared to others. These resources provide high-value local resource adequacy (RA) capacity and they participate in the CAISO marketplace. Transmission-connected resources and two utility-owned distribution-connected resources also performed relatively well, due to RA capacity service, participation in the CAISO marketplace for energy and ancillary services, and high efficiency achieved from daily operations. Customer-sited and some utility-owned distribution-connected resources performed the worst due to lack of service to the transmission grid and/or relatively high procurement costs. These results are explained in more detail throughout this chapter.

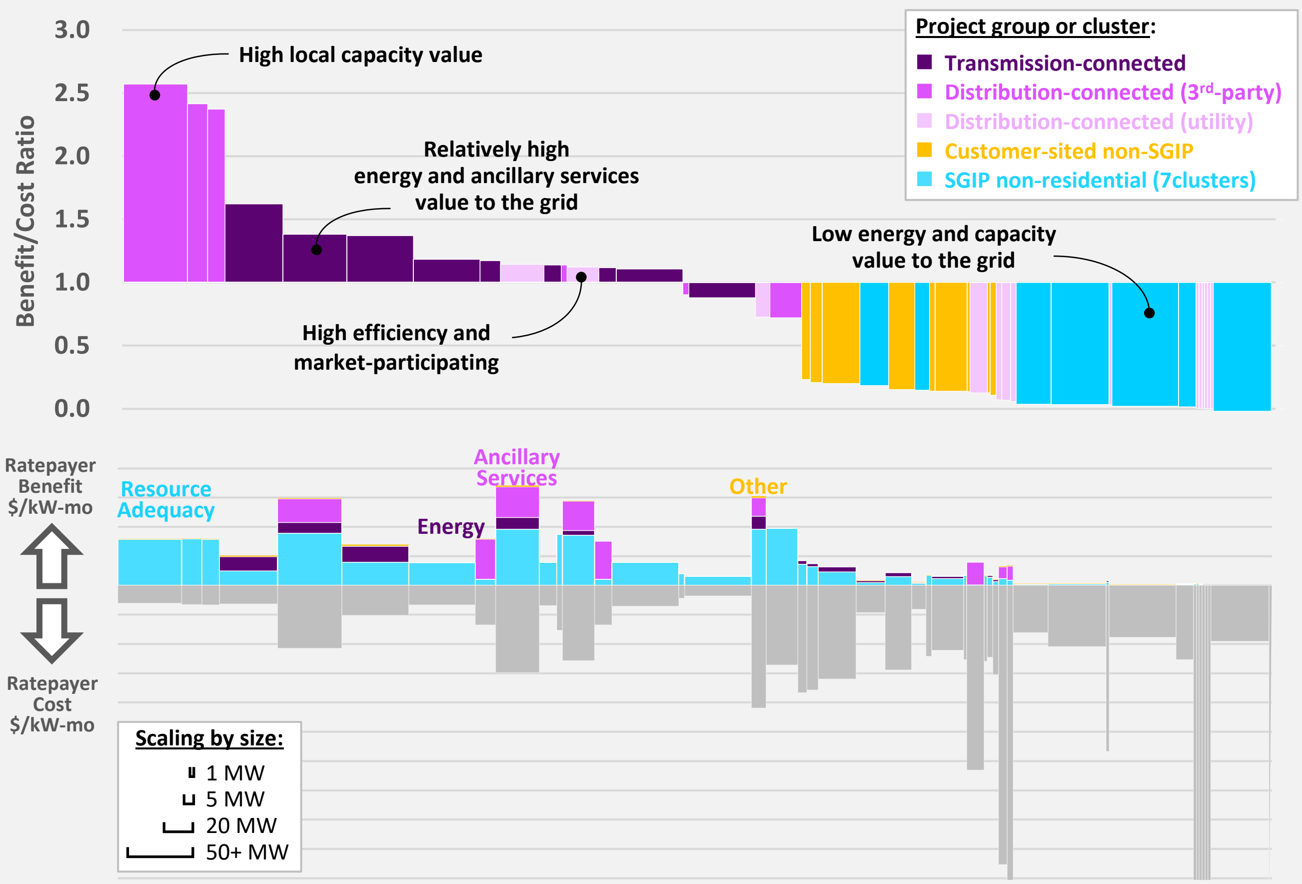


Figure 32: Summary of ratepayer benefit/cost ratio results (top) and underlying components (bottom).

Total dollar impacts. In terms of absolute dollars, the benefit/cost ratios represent a portfolio-wide average of $72 million per year in net ratepayer cost over the 5-year study period. Exploratory pilots and incentive programs—including storage resources developed under pilots, demonstrations, SGIP, and/or first-in-kind procurement tracks—cost ratepayers an average $75 million per year. This is offset by $3 million per year net benefit from energy storage resources developed under mature use cases and procurement tracks. The $3 million per year is a diluted metric, which is derived from a total $16 million of benefits mostly incurred in 2021, but averaged over the entire 5-year study period.

The time profile of ratepayer impacts reveals three striking trends over time (Figure 33):

1. **Steady ongoing amortized net investment cost of early utility-owned pilot and demonstration programs** (grey line) at almost $30 million/year;
2. **Steady buildup of net ratepayer cost of customer-sited installations** (yellow and turquoise lines) as the number of installations grow—due to lack of storage operations beneficial to the grid coupled with relatively high costs—reaching a rate of approximately $80 million per year by the end of 2021; and
3. **Recent growth in net ratepayer benefit of distribution- and transmission-connected installations** (magenta and purple lines) as the volume of capacity participating in the CAISO marketplace and providing local and system resource adequacy grows, landing at an annualized rate of $30 million per year by the end of 2021, which includes $22 million per year in net benefits produced by market-mature resources, plus $8 million from earlier market entrants.

These trends have key implications for future energy storage procurement and policy direction which we discuss in **Chapter 3 (Moving Forward)** of our report.

The performance of more recent and market mature energy storage projects indicate an acceleration towards future growth in benefits. However, the net cost of earlier exploratory projects and incentive programs will continue at $89 million per year on average over their full amortization period.

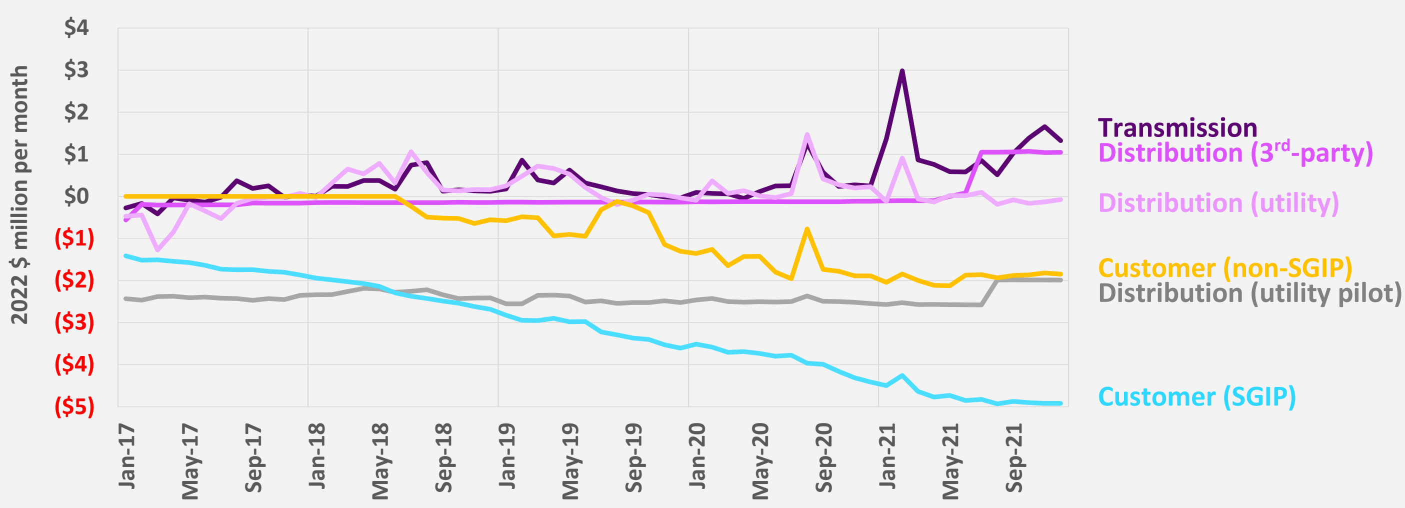


Figure 33: Net ratepayer benefits (costs) over time.

*Lump-sum capital costs or incentive payments are levelized over economic life of the projects.

Scoring towards state goals. Figure 34 summarizes project scores on contributions towards meeting state goals of grid optimization, renewables integration, and GHG emissions reductions during the 2017–2021 study period. Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited installations are aggregated into utility contracts or clusters. As with the B/C ratios previously shown, relative ranking across resources and resource groups is as important as the absolute scores.

Final score (height of bar) is an average of 3 individual scores for grid optimization, renewables integration, and GHG emission reduction normalized between 0 (worst performance) and 100 (best performance) in each category. (See **Attachment A** for additional details on methodology.)

As with our benefit/cost analysis results, third-party-owned distribution- and transmission-connected resources performed relatively well while customer-sited resources performed at the bottom.

Three key findings highlight the importance of taking this more societal perspective and considering contributions to meeting state goals beyond what can be monetized in benefit/cost metrics:

- Many distribution-connected storage resources demonstrate relatively high utilization across multiple grid services and significant reductions in local renewable curtailments—despite not capturing the highest market values as reflected in their B/C ratios;
- Transmission-connected resources that rank lower here than in benefit/cost ratios provide fewer types of services compared to their peers (e.g., narrow ancillary services focus, low RA capacity) or have extended outages limiting their overall performance.
- Resources that provide negligible GHG emissions reductions or increase GHG emissions are given a score of zero in that category. Several storage resources did not contribute towards the state's GHG emissions reductions goals. Likewise, several storage resources did not contribute meaningfully to renewables integration.

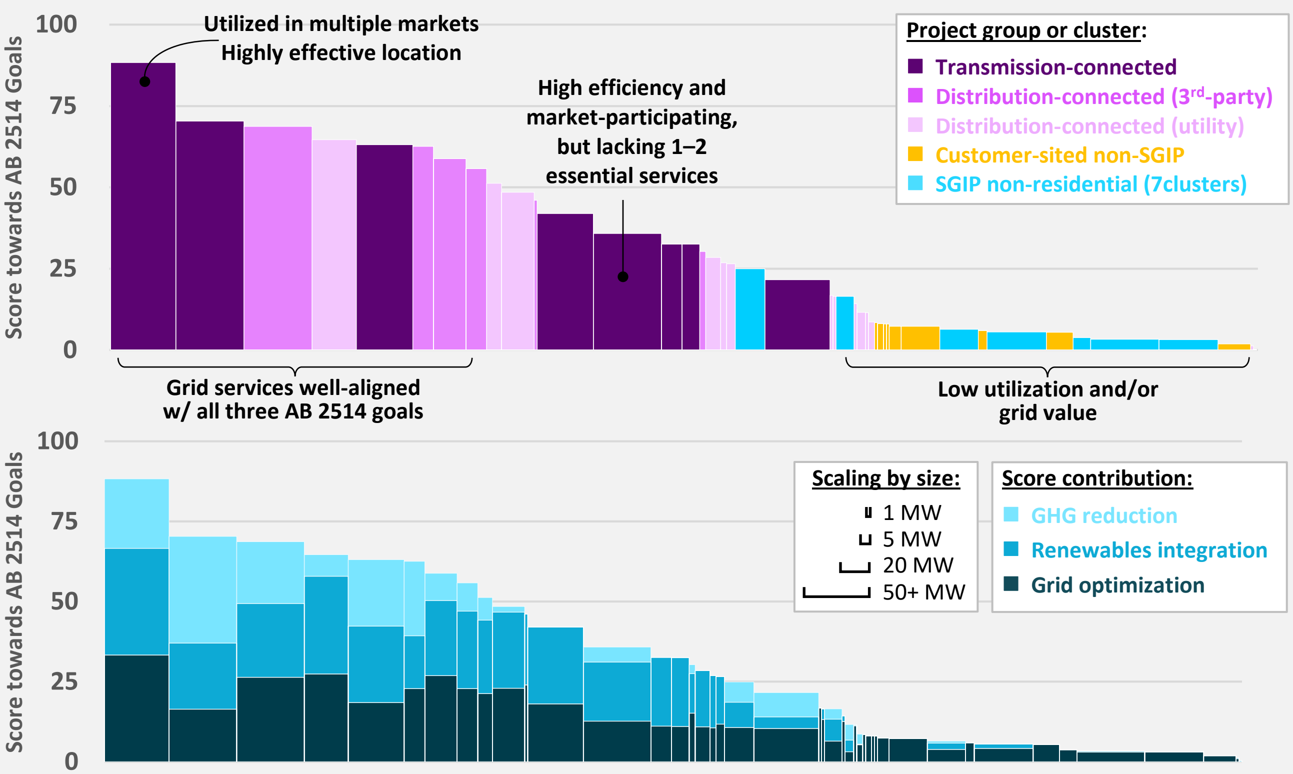


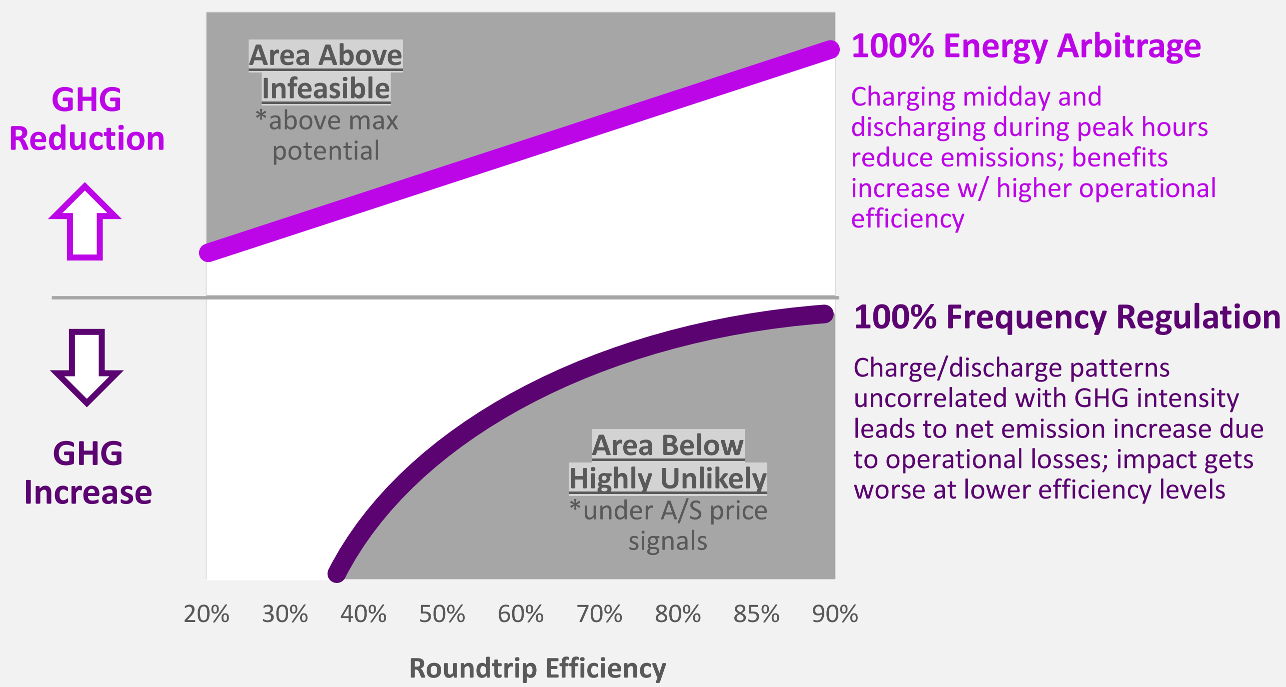
Figure 34: Summary of scoring towards state goals (top) and underlying components (bottom).

Box 1: Necessary Conditions for GHG Reduction Benefits from Energy Storage

For energy storage resources to provide GHG reduction benefits, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG intensity to periods with high GHG intensity.

Energy storage is a net consumer of energy: it can retrieve less energy than the energy initially used for charging, due to operational losses. While most storage projects in California have relatively high efficiency in the range of 80–90% when they operate regularly, their average efficiency drops significantly when they remain on standby for extended periods of time. To provide GHG benefits, it is essential for storage resources to have highly efficient operations.

Being efficient is necessary, but not sufficient for reducing GHG emissions. The storage use case must also allow for shifting bulk energy from periods with low marginal emissions (e.g., midday) towards periods with high marginal emissions (e.g., evening peak). Today's energy storage technologies are very flexible and can provide significant value by helping with grid's needs for frequency regulation. However, the signals for frequency regulation are typically not correlated with GHG intensity of the system, so this use case can result in net GHG increase after losses are factored in.



Successes and Challenges

The historical analysis of net benefits and contributions towards state policy goals is based on a detailed review of:

- The policy and market context for each project's procurement and its development process;
- Stated services at the time of procurement versus actual services provided;
- Each project's historical charge/discharge patterns and how those patterns relate to its use case, market prices, and grid conditions;
- Participation in CAISO markets and historical CAISO settlements;
- Utility contracts with third parties, services provided under contract, and other contractual requirements;
- Actual contract payments to third parties and installation costs of utility-owned projects;
- Each project's location, size, configuration, and how all of that relates to market prices, marginal GHG emissions, local and system renewable curtailments, distribution-level PSPS and high wildfire threat areas;

Through this process, we learned a great deal about the realized benefits and untapped potential for each individual resource and groups of resources. Looking across different energy storage technology and system designs, grid domains, and use cases, some are clearly on track to help meet the state's needs at a larger scale, some have hit natural limits to the services that can be provided, and some are entangled in market or policy obstacles that prevent realization of full potential of benefits.

The following subsections of the report discuss several notable successes and challenges observed during the 2017–2021 period:

- Drawbacks of the Frequency Regulation Use Case
- Shift in Wholesale Market Value Proposition
- Growth in Resource Adequacy (RA) Use Case
- Challenges with Customer-Level Integration
- Growth and Challenges in Customer Outage Mitigation Use Case
- Drawbacks of Use Cases with Storage Mostly on Standby
- Growth and Challenges with Transmission Investment Deferral
- Challenges with Distribution Investment Deferral
- Challenges with Data Collection and Management
- Industry-Wide Growth in Safety Best Practices

Drawbacks of Frequency Regulation Use Case

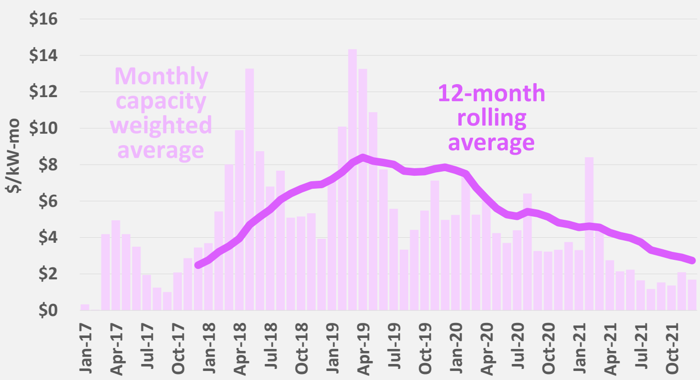
The market for frequency regulation (regulation) service is managed and administered by the CAISO. Regulation provides operating flexibility to fine-tune the grid's frequency through rapid injections to and withdrawals from the grid. Energy storage is unique in its ability to provide up to 2 MW of regulation for every 1 MW of capacity depending on state of charge and operating status in the moment (i.e., charging or discharging and at what rate).

We analyzed the operations and market settlements of 18 CAISO-participating resources that provided regulation during 2017–2021 with a total capacity of 742 MW/2,495 MWh. These resources earned significant revenues in the regulation market, particularly in 2018–2020 period (Figure 35, top left), and attracted developers and investors to the marketplace.

However, the regulation use case does not offer scalable benefits to customers or towards the state's clean energy goals for three reasons: (1) it is limited by its total market size of 400–700 MW, (2) it does not move renewable energy in bulk from one time period to another or reduce GHG emissions, and (3) as long as fossil-fired generation is on the system it will <u>increase</u> GHG emissions.

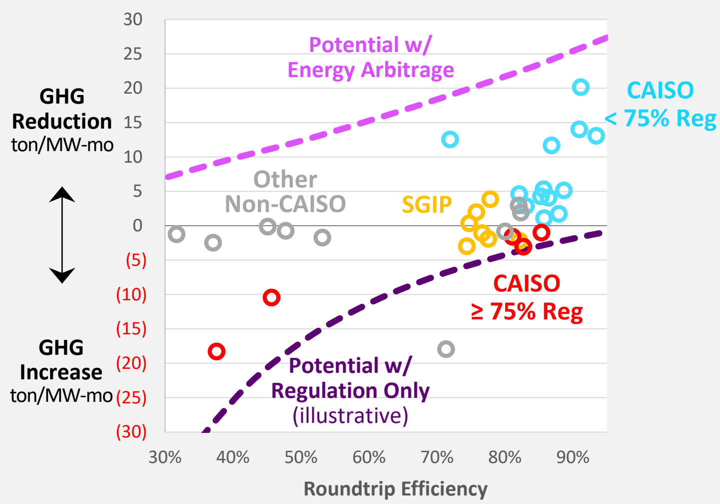
Dispatch for regulation requires automatic response to a 4-second regulation signal from the system operator to increase (regulation up) or decrease (regulation down) net injections to the grid. Although regulation capacity needs are somewhat correlated with high and low energy needs on the grid, the regulation signals are mostly rapid random signals throughout the day (Figure 35, bottom left). In order to provide regulation, storage resources must charge in the same market intervals they discharge, and they must do so even when fossil-fired generation is on the margin. Since storage is a net consumer of energy due to operating losses (typically about 15% losses for lithium-ion) it creates a need for <u>more</u> fossil-fired generation than it displaces when responding to a regulation signal—and thus <u>increases</u> GHG emissions (Figure 35, right).

This use case as a standalone service is not consistent with the energy time shift use case to move renewable generation from times of excess to times of deficiency.



Average CAISO regulation market revenues across storage fleet

Regulation signal to Vaca-Dixon on October 23, 2014 *(PG&E, 2016)*



Actual GHG emissions impact of regulation service provided by energy storage

* <u>CAISO resources split into 2 groups based on share of wholesale market revenues from regulation service</u>

Figure 35: Observed characteristics of frequency regulation service provided by energy storage.

Shift in Wholesale Market Value Proposition

The prior Figure 35 shows average regulation market revenues decreasing steadily in 2020, down to less than $4/kW-month by the end of 2021. This downward trend coincides with a tenfold increase in CAISO-interconnected battery storage capacity from about 200 MW at the beginning of 2020 to about 2,500 MW by the end of 2021, including both grid-scale installations and customer-sited aggregations. It also coincides with an upward trend in energy market revenues in the same period (Figure 36).

With significantly more battery storage on the CAISO system, starting in 2021, we observe saturation of the relatively small ancillary services market and expansion of the energy time shift use case. In 2021, a clear pattern of bulk charging during the day and discharging during the grid's evening ramp emerged (Figure 37). For the storage portfolio as a whole and in a high solar PV penetration context, this operating pattern is an indication of grid optimization, renewables integration, and GHG emissions reductions towards the state's clean energy goals.

Furthermore, developers anticipate shifts in use cases and utilize the modularity of battery storage systems in their construction and market participation strategies. Several of the recent and large-scale projects were constructed in phases ahead of their resource adequacy contracts, starting with target MW capacity at shorter durations offered into energy and ancillary services markets and progressively adding more duration to meet their contract obligations.

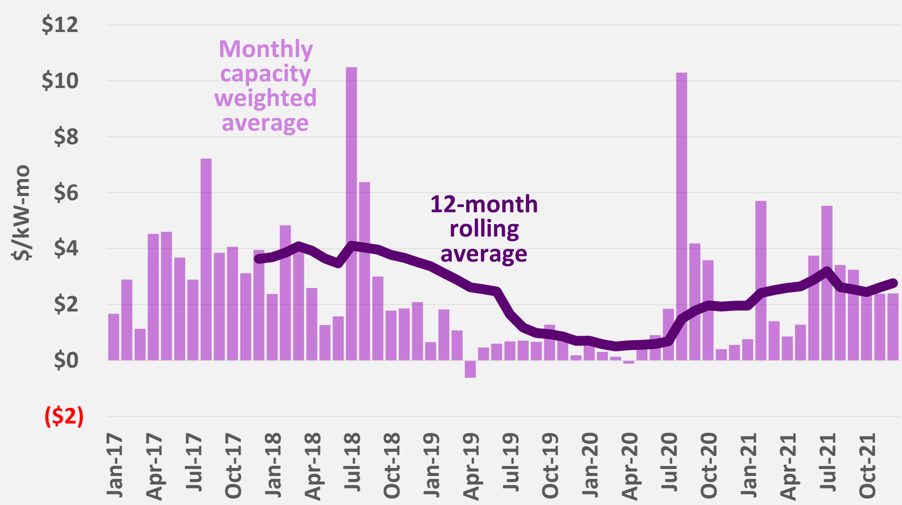


Figure 36: Average CAISO energy market revenues across the storage fleet.

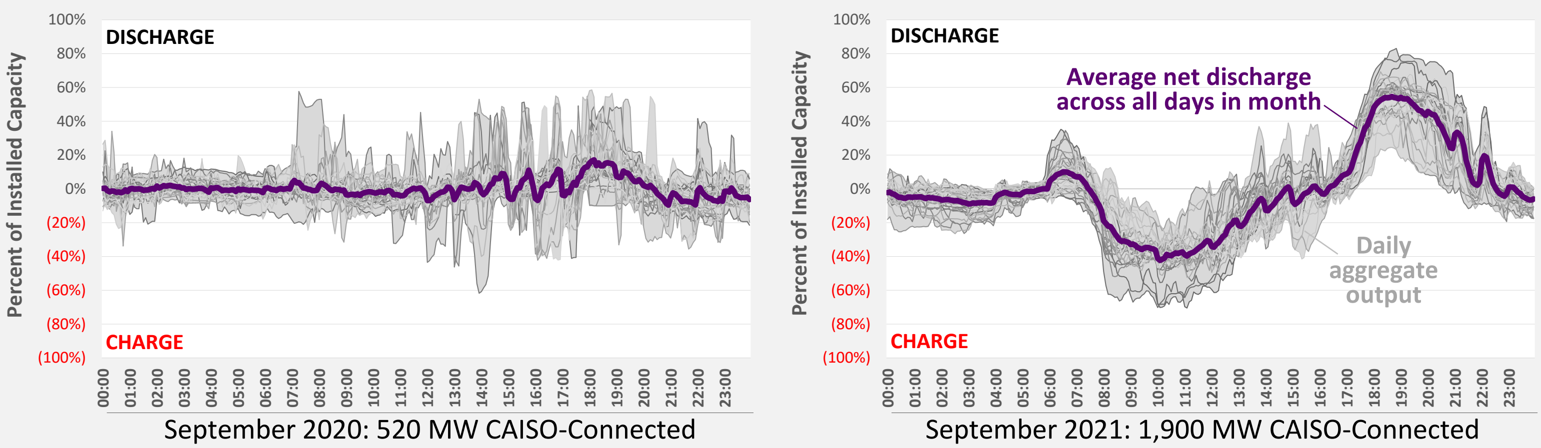


Figure 37: CAISO aggregate battery output in September 2020 versus September 2021.

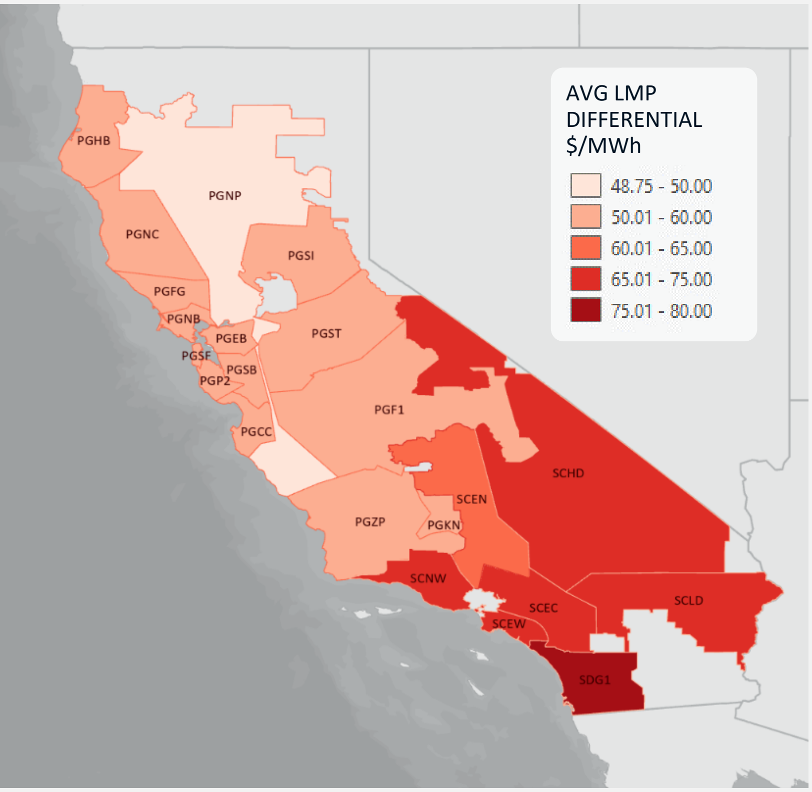


Figure 38: Average differential between real-time LMPs in top 4 and bottom 4 hours during 2018–2021

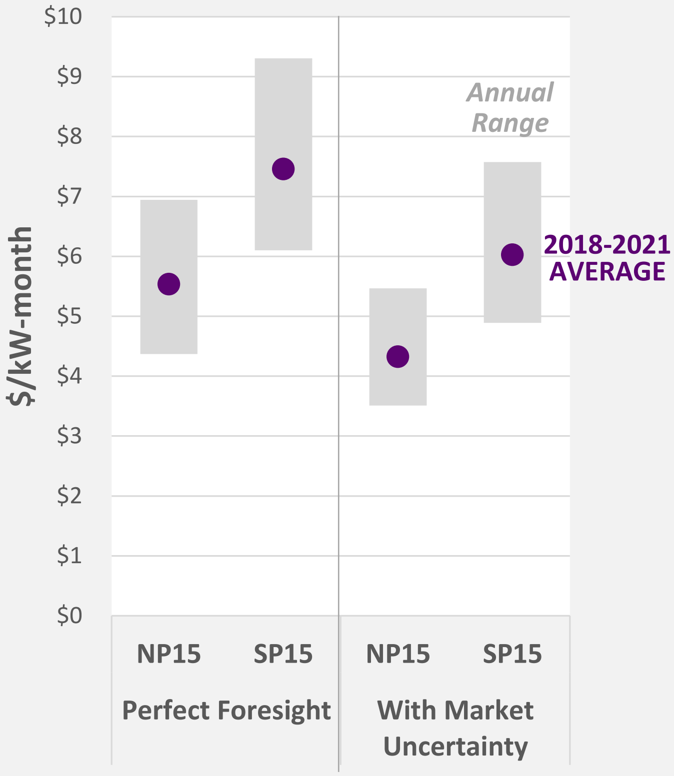


Figure 39: Estimated energy value potential for 4-hour storage in California under historical LMPs

As the bulk energy time shift use case becomes more prominent for energy storage resources participating in the CAISO market, a large share of their wholesale market value will come from the arbitrage opportunities tied to intraday energy price differentials. Figure 38 shows the historical LMP difference between top 4 and bottom 4 hours averaging at $50–$80 per MWh based on CAISO real-time subarea (by sub-load aggregation point, or subLAP as shown in the figure) prices in 2018–2021. For a 4-hour storage resource cycling daily with 85% roundtrip efficiency, the price differential of $50–$80/MWh would translate to a range of $5–$8/kW-month in energy value net of charging costs, if real-time prices were known ahead of time with perfect foresight.

To account for market uncertainty, we first determined the next day's hourly schedule using day-ahead LMPs, then evaluated economic dispatch deviations for each interval using real-time LMPs assuming only prices up to the current interval are known, before moving to the next interval. Using this approach more realistically captures the effects of market uncertainty, while it also recognizes the ability of storage resources to quickly respond to volatile real-time market needs and signals.

Figure 39 above shows the results of this analysis using historical NP15 and SP15 prices in 2018–2021. For 4-hour storage with 85% roundtrip efficiency, our estimated net energy value under real-time prices with perfect foresight averages at $5.5–$7.5 /kW-month depending on price hub. Accounting for market uncertainty, the estimated net energy value of 4-hour storage drops to $4.3/kW-month under NP15 prices and $6.0/kW-month under SP15 prices.

Growth in Resource Adequacy (RA) Use Case

By the end of 2021 about 2,200 MW/8,900 MWh of online storage capacity provided resource adequacy services, including:

- 76 MW/318 MWh of customer aggregations procured for local capacity in the LA Basin under demand response and permanent load shift contracts;
- 200 MW/802 MWh of distribution-connected resources procured to meet local capacity needs in the Big Creek/Ventura, LA Basin, and San Diego areas;
- 633 MW/2,459 MWh of transmission-connected resources procured to meet local capacity needs in the Bay, LA Basin, and San Diego areas;
- 1,299 MW/5,336 MWh transmission-connected resources procured to meet system-level capacity needs.

In the period of 2019–2021, demand for future RA capacity, via CPUC procurement orders, increased by more than 15,000 MW. In 2019 the CPUC ordered at least 3,300 MW of incremental capacity online between 2021 and 2023, with flexibility to exceed the requirement (Decision 19-11-016). In 2021 the CPUC required an additional 11,500 MW of net qualifying capacity procurement for mid-term reliability in 2023-2026 (Decision 21-06-035). Then, in 2021 the CPUC also issued a series of decisions which accelerated RA capacity procurements for summer 2021 reliability, created a path for emergency procurement of energy storage resources to prepare for extreme weather in 2022–2023, and increased the planning reserve margins (PRM) for 2021 and 2022 from 15% to 17.5% (Decisions 21-02-028, 21-12-015, 21-03-056). The 2021 decisions advanced development of capacity to meet the earlier decisions and provided temporary solutions for emerging near-term needs.

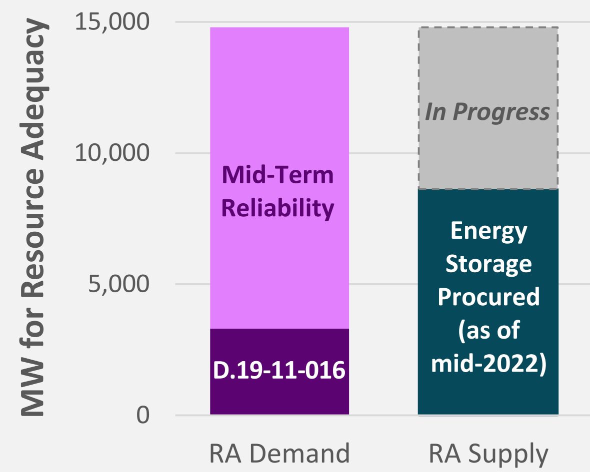


Figure 40: Demand and supply for 2021–2026 resource adequacy procurements.

LSE procurements so far indicate that energy storage will meet a significant share of those requirements (Figure 40). Most online capacity and procurements for resource adequacy utilize lithium-ion (NMC) battery technology. About half of the batteries procured are paired with co-located solar.

Going forward, the state may need to continue building nearly 2,000 MW storage per year on average to meet 2045 clean energy goals as discussed in this report's Introduction. During 2017–2021 in order for energy storage to receive full capacity designation and payments it was required to configure to produce its maximum MW capacity over at least four hours ("4-hour rule"). As procurements accelerate, so does the need to address questions of whether, when, and how should the CPUC procurement orders and load-serving entity (LSE) procurements signal the need for discharge over longer durations in a technology-neutral fashion. We discuss these issues further in **Chapter 3 (Moving Forward)**.

Challenges with Customer-Level Integration

IOU-procured customer-sited storage installations that were operational during 2017–2021 include:

- 70 MW/280 MWh of customer aggregations procured for local capacity in the LA Basin under five demand response contracts and participating in the CAISO marketplace;
- 6 MW/38 MWh of customer aggregations procured for local capacity in the LA Basin under four demand response contracts and <u>not</u> participating in the CAISO marketplace;
- 4 MW/22 MWh consisting of mostly four college campus thermal energy storage installations for which we could not obtain any operational data (and so are not included in our analysis);
- 244 MW/504 MWh of 1,160 non-residential installations under SGIP, nearly all enrolled under program years prior to 2020; and
- 147 MW/355 MWh of over 20,000 residential installations under SGIP, for which we could not access sufficient data to analyze.

We evaluated customer aggregations at the utility contract level (9 contracts total). For non-residential storage under SGIP, we conducted an analysis to group 654 resources into 7 clusters based on each installation's interval-level operating behavior during the historical period.

<u>Non-residential use cases (clusters)</u>: Average daily operations by cluster provides significant intuition on the benefit-cost outcomes for non-residential installations under SGIP (Figure 41, left). Clusters 1, 2, and 3 demonstrate operating patterns synergistic with wholesale energy markets: they charge during the day and discharge during the grid's morning and evening ramps into and out of solar generation periods. These resources are mostly schools and colleges (Figure 41, top right) and they have a high solar attachment rate (Figure 41, bottom right). Cluster 6 operates similarly but with significant night charging when renewable supply is not abundant.

Clusters 4 and 5 demonstrate a traditional demand charge management pattern that operates in discord with wholesale energy markets: storage is discharged steadily throughout the day, mostly unresponsive during morning and evening ramps, then charged at night. Cluster 7 is a catch-all category for installations that operate with no clear use case consistent with how other non-residential installations operate.

These resources appear underutilized overall. No cluster on average uses more than 20% of its total nameplate MW capacity on a daily basis. This suggests fewer than once-daily cycles and/or significant capacity on constant reserve (e.g., for back-up power or to preserve battery life).

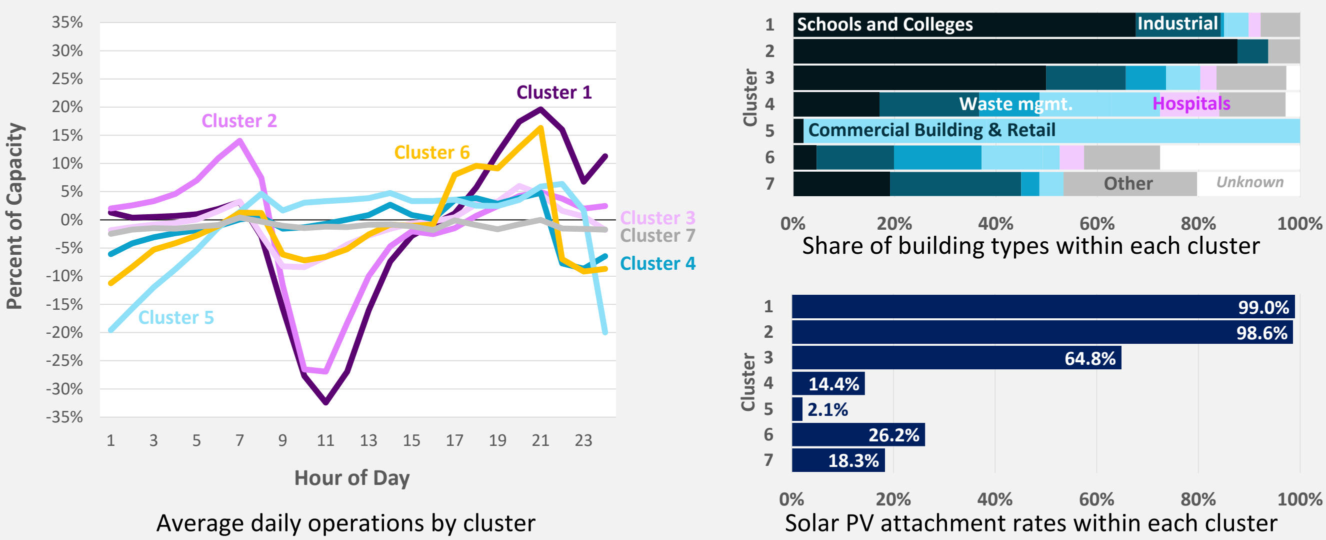


Figure 41: Observed characteristics of non-residential installations under SGIP (654 installations in 7 clusters).

Energy value: Among all non-residential projects, we observe Clusters 1, 2, and 3 yield relatively high energy value (Figure 42) and associated GHG reduction value. Cluster 6 performs slightly worse due to its practice of night charging. Clusters 4, 5, and 7 produce negative energy value as low as -40¢/kW-month on average and they increase overall GHG emissions, indicating operations at a net cost to ratepayers. Due to underused capacity, no cluster produces more than 60¢/kW-month in energy value, well below a potential of $3–$4/kW-month we estimated for 2-hour storage during 2017–2021. For more information on specific GHG emissions impacts please see **Attachment A**.

SGIP evaluation studies found that residential installations produce at least twice energy value of non-residential installations (Verdant 2022). These customers have a very high solar PV attachment rate, with 97% of customers with storage installed paired it with solar. Although we could not access sufficient operational data to directly analyze these resources, we expect their behavior to be similar to the non-residential Clusters 1–2 with equally high solar PV attachment rates. Given this, we expect that residential energy storage installations—although producing some energy value to the grid—are still performing well below their potential.

Storage working in concert with solar generation is clearly a use case that is beneficial to the grid and to customers overall. California by far is the national leader is small-scale solar PV installations: about 1.2 million homes had solar PV installed by the end of 2021. However, only about 60,000 homes had both solar PV and storage installed: a 5% storage attachment rate. Storage installed at the customer along with solar PV operates in synergy with a high renewables grid environment. It also reduces the need for distribution upgrades and provides outage mitigation services to the customer. The low storage attachment rate indicates a large undeveloped potential for scaling up the customer-level solar plus storage use case.

Customer aggregations procured under utility demand response contracts operate similarly to our SGIP non-residential Clusters 4 and 5. They discharge steadily throughout the day, are mostly unresponsive during morning and evening ramps, then charge at night. They do not participate in the CAISO marketplace. These resources also produce negative energy value on average.

The CAISO-participating customer aggregations perform better than non-CAISO resources, but still below their operating potential. These resources produce $1/kW-month of energy value on average.

Avoided resource adequacy cost: Results follow patterns of energy value. Customer installations provided a low level of service to the grid during system emergencies. SGIP Clusters 1–2 performed among the best but provided only 13.2% and 11.5% of nameplate capacity, respectively. Average avoided resource adequacy cost ranges from zero to $1/kW-month.

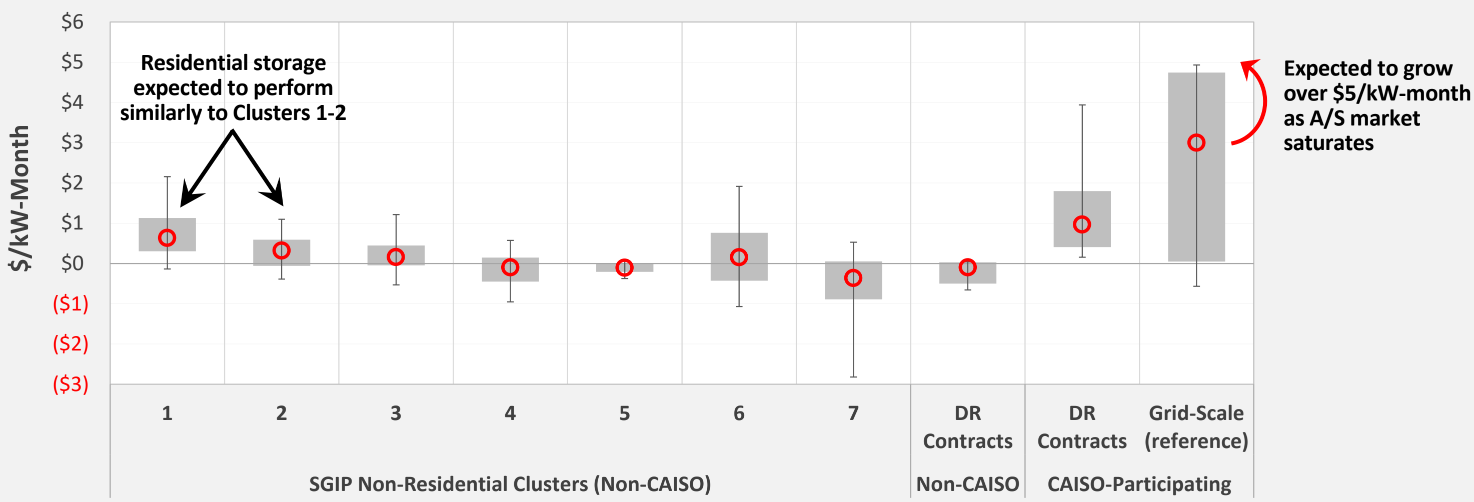


Figure 42: Average energy value produced by customer-sited energy storage.

Growth and Challenges in Customer Outage Mitigation Use Case

Reliability and power quality are vital attributes of electricity service. On average around the country, sustained service interruptions to customers last about 1.5 hours at a time. Although this can vary widely across customers and circumstances, a typical customer can reasonably expect an hour or two of total outage time per year, possibly spread over multiple events.

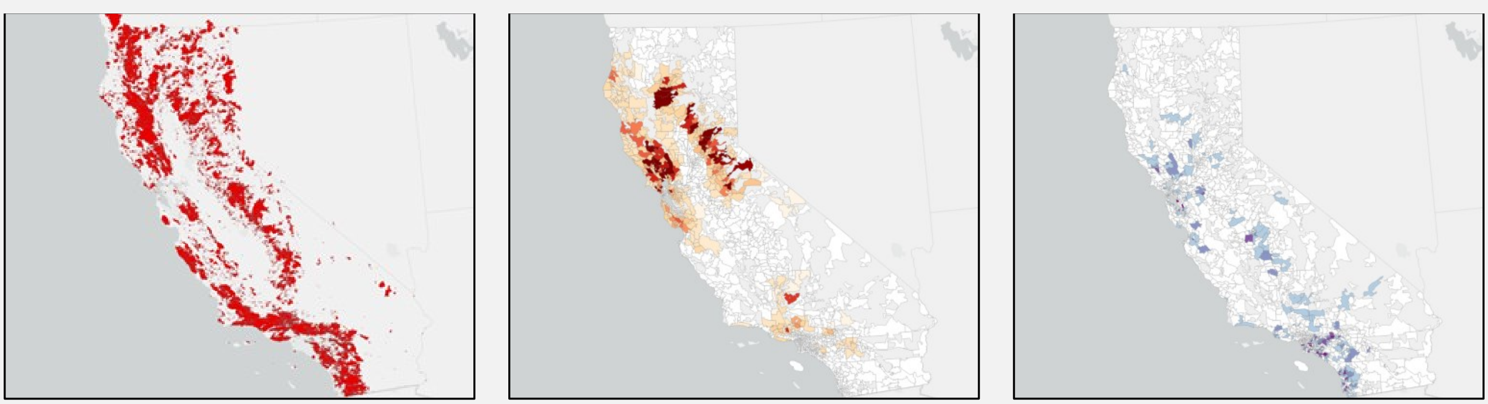
Unfortunately, wildfire risks in the West have accelerated rapidly, revealing a complex relationship to electricity service and a strong dynamic of wildfire risks both to and from the grid. The IOUs have relied upon sustained day-long or multi-day outages to reduce ignition risks in the areas and times of the year with high risk of cascade into disastrous megafires. These Public Safety Power Shutoffs (PSPS) affect millions of people living or doing business in California, who can now reasonably expect multiple outages per year with each lasting several days at a time.

Our outage mitigation value estimates focus on these extended PSPS outages and impacts to customers. Energy storage (a) connected to either radial sections of the distribution grid or directly at customer sites, (b) co-located with a generation source such as solar PV, and (c) configured to operate during a grid outage hold the potential to mitigate the impact of extended outages lasting several hours or days.

During a PSPS event a customer with this type of energy storage installation can avoid the direct and indirect cost of service interruptions to their essential circuits. However, many customers were unaware of PSPS and their wildfire risk until events of late 2019.

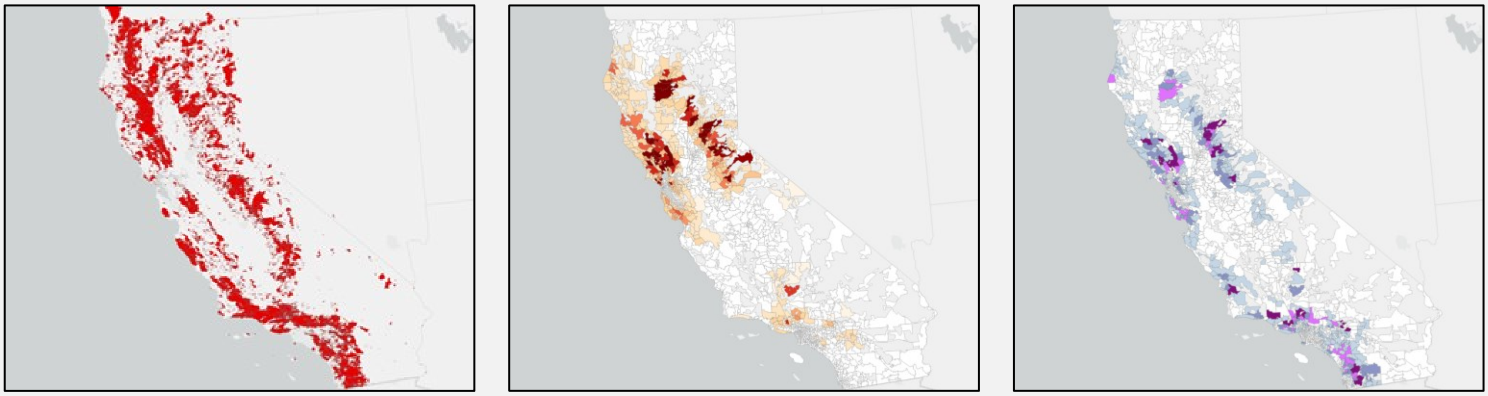
In 2017–2021 outage mitigation value for non-residential SGIP installations was largely an untapped potential. Historical wildfire perimeters and PSPS areas compared to the distribution of non-residential storage shows low spatial correlation (Figure 43). Only 11% of non-residential storage installations were located in PSPS outage areas and installed with solar PV that could provide generation during a multi-day outage. We estimate an average value of $16/kW-month for this subset of installations, which varies widely by customer level depending on the extent of outages in the area.

Additionally, we found monetization of this value to be particularly difficult as there is no California-specific and statistically significant estimate of the cost of multi-hour and multi-day outages to customers available in the industry. Our estimates of outage mitigation value are likely conservative and likely do not reflect the full range of benefits across circumstances, locations, or the diversity of specific customer needs.



Historical fire perimeters | Relative PSPS severity in total customer-hours | Distribution of SGIP non-residential installations in kWh capacity

Figure 43: Comparison of SGIP non-residential installations to wildfire threat areas.



Historical fire perimeters | Relative PSPS severity in total customer-hours | Distribution of storage plus solar installations under the SGIP Equity Resiliency budget

Figure 44: Comparison of SGIP Equity Resiliency budget installations to wildfire threat areas.

SGIP Equity Resiliency budget: Since inception of the SGIP Equity Resiliency budget in 2020 we observe growth in installations paired with solar PV and concentrated in high wildfire threat areas (Figure 44). Most of these are residential installations, with very few at non-residential sites.

It is unclear if the Equity Resiliency budget works as intended to support outage mitigation at key non-residential sites such as community centers and critical facilities. As discussed earlier, schools and colleges operate storage under use cases that provide energy time shift value to the grid and might be good candidates for outage relief to communities. Currently, they are not eligible for these funds unless specifically designated by the utility to provide assistance during PSPS events or by the state as a cooling center.

Drawbacks of Use Cases with Storage Mostly on Standby

IOU-owned distribution-connected resources developed for microgrid and other distribution-related services provided very little value to the bulk grid and contributed to GHG emissions increases. This highlights the drawback of standby losses when transmission-level grid services are not integrated into the energy storage use case.

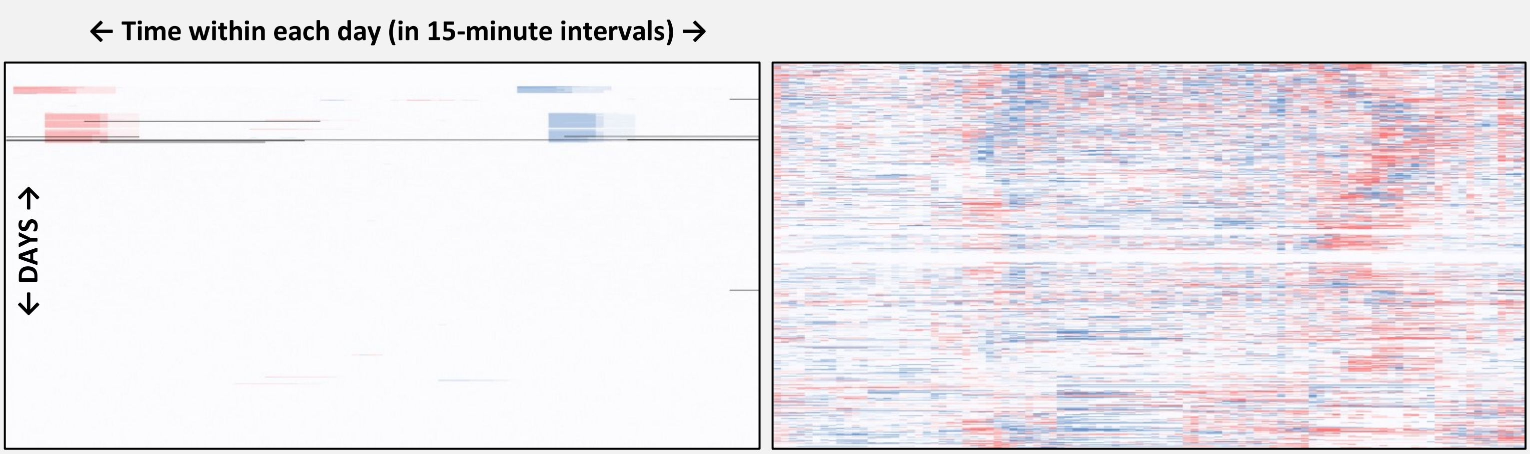
A 10 MW/24 MWh subset of early pilot and demonstration projects were significantly underutilized and/or on extended periods of standby while continuously drawing from the grid at a net cost and during hours when fossil-fired generation was on the margin. These resources were developed by the IOUs under the stated use cases of distribution-level microgrid, power quality, and renewables integration and do not participate in the CAISO marketplace.

While the pilot/demonstration phase is clearly a valuable part of the learning process towards market development, actual operations show the major drawbacks of these use cases that do not provide upstream services to the grid while idle.

Figure 45 shows a heatplot comparison of the actual 15-minute operations of IOU-owned distribution-connected resources at two ends of potential operating activity over a two-year period (for the entire calendar years 2019 and 2020). One is focused solely on distribution-level services that leave the storage mostly on standby (left), and the other is highly active in the CAISO marketplace throughout the year (right).

Red indicates discharge and blue indicates charge or energy use while idle. More color saturation shows the resource operating closer to its full capacity. Persistent very light colors, as in the left figure, indicate significant underutilization. All of the white space in the left figure indicates the resource offline, operating well below its capacity, or on standby with slight draw from the system (standby losses). Standby losses accumulate significantly over long periods (days, weeks, months), and they reduce roundtrip efficiency to extremely low levels.

Resources operating as shown in Figure 45 (a) do not help to decrease GHG emissions. Instead, they <u>increase</u> GHG emissions through their constant draw from the grid while idle. They are among the lowest performing resources with almost no value beyond their initial research and development value for every ratepayer dollar spent.



(a) Use case with storage mostly inactive (b) CAISO-participating

Figure 45: Heatplot of 2 years of distribution-connected energy storage charge (blue) and discharge (red).

Notes: Data reflect 2019–2020 operations; black lines in both heatplots indicate missing data.

Growth and Challenges with Transmission Investment Deferral

The national discussion of transmission investment deferral indicates that energy storage can help to defer investments in the transmission system through two use cases. In the first use case, energy storage acts as an energy resource, alters the load and generation balance in an area to relieve transmission bottlenecks (and/or provide ancillary services), and thus replaces transmission solutions that could do the same. A variety of generation and load resources could theoretically serve the same function. In the second use case, storage is used by the system operator like a controllable transmission asset. The resource could be operated, for example, to redirect power flow and prevent overloads on specific circuits. Since these use cases are deployed on either side of the legal and functional separation of generation and transmission (respectively), they are distinguished by who operates the energy storage resource, to what objective, and how the resource is paid for.

In California, energy storage has achieved scalability to help relieve transmission bottlenecks under the first use case. A total of 909 MW/3,579 MWh of energy storage resources operating in the 2017–2021 period was procured to meet local capacity needs driven by major generation retirements (i.e., once-through cooling, San Onofre nuclear generators, Moss Landing generators) and issues related to Aliso Canyon. Since these energy storage resources were procured under generation RA capacity procurement, where the resource alternative is a generation or load resource, we allocate these services and benefits towards local RA capacity. However, as part of the CAISO's Transmission Planning Process, generating resources, including energy storage, are considered directly as alternatives to transmission investments. In its 2017-2018 TPP, the CAISO approved a 10 MW/40 MWh PG&E-owned energy storage project as part of a combined transmission/generation solution to prevent overloads in the Oakland area after the planned retirement of a gas peaker. Development of that project has apparently been hampered by changes in scope identified in subsequent TPPs and it is not clear if or when the project will be developed.

Additionally under this first use case we find that the energy storage fleet increasingly helped to avoid renewable curtailments that would otherwise be solvable with investments in transmission capacity to export excess renewable generation to other states. Again, since these energy storage resources were not procured to avoid specific upgrades to the CAISO's (or California's) transmission export capacity, we allocate benefits towards avoided generation capacity rather than transmission investment deferral.

The second transmission investment deferral use case—storage operated as a controllable transmission asset—is still in a pilot and demonstration phase nationally with California as a leader. In its 2017–2018 Transmission Planning Process (TPP) the CAISO approved a 7 MW/28 MWh energy storage projects as a cost-effective solution to manage a transmission contingency that would interrupt service to the town of Dinuba. PG&E conducted a competitive solicitation in 2019 and selected a winning bidder. However, when the transmission need increased to 12 MW in a later TPP, PG&E cited challenges with procurement and contracting. Assessment of transmission needs is a dynamic process and apparently in need of (a) a clearer understanding of how a specific need could fluctuate over time, and (b) procurement and contracting practices that better take advantage of the modularity of energy storage system and site designs.

A third use case—"dual-use" energy storage—presents major legal and policy challenges in that it envisions the operations of a single energy resource being split between generation and transmission functions. This use case is still in early development phase under initiatives led by the CAISO and the Midcontinent ISO (MISO).

Challenges with Distribution Investment Deferral

Energy storage developed to defer distribution investments faced similar planning and procurement challenges to transmission investment deferral. However, the use cases are not as clearly distinct as with transmission due to a different legal and regulatory environment for distribution. California's distribution investment deferral use cases are still in an exploratory phase with the main challenge being a policy framework that enables third parties to come forward with develop distribution wires alternatives and contract with the utilities for the distribution deferral service.

Storage developed to act as a distributed energy resource and relieve constraints on the distribution system was explored through an incentive pilot, the CPUC's Integrated Distributed Energy Resources (IDER) proceedings. The pilot resulted in 6 contracts, four of which were canceled, and two were online in 2021. Of these two, one of projects became online in early 2021 and included in our study. The other one became online in late 2021 and it was not included in the study due to not having sufficient operational history.

Storage developed to directly defer or avoid distribution investments is procured through an annual process under the CPUC's Distribution Investment Deferral Framework (DIDF). That process has not yet yielded an operational project. Many of the utility DIDF solicitations either resulted in no selected offers or were not held at all. Three out of only four DIDF offers ever selected were canceled and the fourth resource is due online in 2023. CPUC Staff identified several challenges with DIDF, including "changing distribution system needs; a risk of over and under procurement; infeasibility of near-term deferrals; forecast uncertainty; interconnection queues and delays; and technology neutrality limitations." Based on the rate and circumstances of contract cancellations, a DIDF contract is clearly risky to third-party developers and cannot be relied upon as a standalone use case to secure financing or other project development commitments.

Notably, the one distribution deferral resource that did achieve commercial operations within the timeframe considered in our study (procured under IDER) participates in the CAISO marketplace and is among the better-performing resources in our historical analysis. The distribution need driving the procurement of this resource disappeared due to a reduction in the utility's demand forecast. By participating in the CAISO marketplace this resource is able to provide benefits to the grid despite fluctuating needs on the distribution system. The modularity of storage to provide a wide range of services, and to do so flexibly, may be beneficial to the distribution investment deferral use cases.

Challenges with Data Collection and Management

We mentioned in **Chapter 1 (Market Evolution)** that a crucial ingredient to the learning process from technology and use case pilots and demonstrations is documentation and data that is widely available to stakeholders. Similarly, the CPUC explores many innovative and novel policies (such as CPUC's IDER pilot) and it needs timely information in order to evaluate those policies and adjust them quickly. Furthermore, it is standard in the resource planning process to validate the projected output of both dispatchable and non-dispatchable resources against actual and historical data of some kind. Planning model validation and calibration is essential to confidence and consensus on model results, and planning models are at the heart of the CPUC's policy decisions to accelerate the energy storage market and to procure resources.

A core motivation for this study is a need to collect and learn from energy storage data in order to adjust and adapt the CPUC's storage procurement framework to a rapidly-changing energy storage market and resource planning context. Through our data collection process for this study we find that severely lagged, limited, and/or complex access to the most basic resource-specific operating data created unprecedented challenges in understanding actual benefits and costs compared to other types of grid assets. This presents a major data problem that hampers the CPUC's ability to quickly and nimbly identify needs for policy adjustments and implement those changes.

Despite being a directly-metered resource, and with the exception of requirements for non-residential storage under SGIP, no investor-owned utility or program administrator systematically and comprehensively collected, retained, quality-controlled, or reported the most basic operating data on energy storage resources in their portfolio. This is a largely unprecedented situation in the electricity industry with the exception perhaps of behind-the-meter generators. Output and capacity factors of traditional generating resources can be, at a minimum, checked against publicly-available data repositories such as the Environmental Protection Agency's generation and emissions database under the Continuous Emission Monitoring System. Reasonable estimates of aggregate historical wind and solar renewable generation can be derived from weather data and basic resource characteristics, even with significant quantities installed at the customer level. Since energy storage is a controllable resource with many types of services and multi-service use cases possible, output cannot be derived from environmental data or even wholesale market data in some cases. Operating data of resources across the entire portfolio is needed to understand the actual benefits and costs of energy storage funded by ratepayers.

Overall, we find that energy storage presents a unique set of data-related challenges:

- It is a controllable resource with many types of services and multi-service use cases possible, and thus output cannot be derived from environmental data or even wholesale market data.
- It crosses all grid domains and traditional boundaries in industry expertise. Evaluation of an energy storage resource portfolio requires information sharing among many experts in transmission grid planning, wholesale markets, distribution planning, and customer-level incentives and programs—to name a few.
- It is scalable down to 8 kWh for residential installations so presents a sheer data volume issue.

Industry-Wide Growth in Safety Best Practices

In 2019, a tragic event at the McMicken energy storage facility in Surprise, Arizona elevated battery energy storage system safety to the national stage. Significant improvements in national and international codes and standards rapidly ensued. From the codes and standards perspective, the industry consensus is that safety risks are knowable and manageable, but that good risk management goes well beyond the technicalities of mitigations in manufacturing and system components. It requires robust communication and knowledge-sharing among the manufacturers, developers and installers, utilities, system operators, site manager, and other parties involved with energy storage development and operations. State agencies are uniquely positioned to add value in this area.

McMicken and other safety events around the country revealed significant confusion among battery storage system operators, the emergency response community, regulators, and the public (and even in some cases, technical experts) on how to effectively manage the safety risks of an energy storage system. This confusion is rooted in (a) that lithium-ion battery-based systems can produce both fire and thermal runaway propagation—two meaningfully distinct chemical processes—and (b) the common mistake to consider thermal runaway as a type of fire. The misunderstanding runs deep in the industry and perpetuates a false sense of security with certain design features (like fire protection systems), downplays the need to proactively engage with local authorities and the fire response community (who are well-trained to fight all types of fires but may have never seen thermal runaway), and leads to inefficient and dangerous emergency response situations despite the best efforts and bravery of responders. Much of the communication and knowledge-sharing needed in this space is to sufficiently disseminate the true risk profile of battery storage and what mitigations are most effective.

In addition to the communication and knowledge-sharing problem, historical safety events and industry lessons learned point to two gaps in risk management which are best addressed by state energy regulators. The first is to address the linkage between safety practices and system reliability. The second is to support the speed, consistency, and quality of the local permitting process in a way that can both reinforce the quality of site and system designs while reducing developer soft costs. We discuss these issues with a going-forward perspective in **Chapter 3 (Moving Forward)**.

Other than a September 2022 event at the Elkhorn Battery Energy Storage Facility (on the Moss Landing site)—which required a half-day local shelter-in-place advisory and road closures—no major safety events at a stationary battery energy storage system in California has yet occurred. Three other relatively minor safety events in the state highlight increasing risks as the number of installations increase. California's state and local authorities is at the beginning stages of comprehensively integrating the industry's safety best practices. Progress to date includes a new section of the California Fire Code, effective July 1, 2021, on electrical energy storage systems (Section 1206). The section outlines safety measures and practices for battery systems, flow batteries, capacitors, and other electrochemical storage technologies and sets the stage for a more comprehensive and coordinated safety risk management approach in the state.

With few exceptions, safety review and permitting of battery storage projects (grid-scale and customer-sited) primarily fall under the jurisdiction of local government agencies. The California Energy Commission has an important role in working with local authorities to facilitate the permitting process, but its direct jurisdiction is limited to batteries built on a CEC-licensed natural gas sites and blackstart battery energy storage. All other projects are cleared through the local permitting process. As of mid-2022 the CEC licensed three battery projects, including one co-located with an existing natural gas-fired turbine and two blackstart battery systems.

More detail on historical safety events across the country and the industry's lessons learned and best practices can be found in **Attachment F**.

Key Observations for Chapter 2 (Realized Benefits and Challenges)

Frequency regulation value for a subset of transmission- and distribution-connected resources was relatively high, but at the expense of GHG emissions increases.

A major shift away from the frequency regulation use case and towards the more broadly beneficial and scalable energy time shift use case occurred in the CAISO marketplace in 2021.

The resource adequacy use case reached scalability and grew substantially to meet grid needs.

Non-residential customer-sited installations under SGIP provided a low level of service towards meeting the grid's energy and capacity needs and most of them increased GHG emissions.

Schools, colleges, and residential customer-sited installations fared better with high solar PV attachment rates but still performed well below their potential.

Other customer aggregations provided low energy and capacity value—even when participating in the wholesale marketplace.

Utility-owned distribution-connected resources developed for microgrid and other distribution-related services provided very little value to the bulk grid and contributed to net GHG emissions increases.

Customer outage mitigation needs, awareness, and value increased significantly after 2019 PSPS events, but lack of customer impact data makes it difficult to quantify resilience benefits of storage.

Storage served at scale as generators within local transmission-constrained parts of the grid, but no resource operated specifically as a transmission asset.

Storage developed to defer specific distribution investments faced major challenges as the size and timing of identified needs changed over time.

Developers utilize the modularity of battery storage systems in their construction and market participation strategies.

Severely lagged, limited, and/or complex access to the most basic resource-specific operating data created unprecedented challenges in understanding actual benefits and costs compared to other types of grid assets.

Other than a September 2022 event at the Moss Landing site no major safety event at a stationary battery energy storage system in California has yet occurred, and the state is at the beginning stages of comprehensively integrating the industry's safety best practices.

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CHAPTER 3: MOVING FORWARD

A massive grid transformation is underway in California in order to meet the state's clean energy goals and achieve carbon neutrality by 2045.

Looking towards the horizon of the CPUC's 2021 Preferred System Plan, the energy storage fleet has the potential to yield $835 million to $1.34 billion of annual net grid benefits by 2032, compared to a grid without energy storage. A large share of that potential is likely to be realized under current policies and planning practices as transmission-connected energy storage scales up to 10 GW or more.

With future policy adjustments to address (a) existing barriers to grid benefits and (b) anticipated future challenges, we believe California can secure these benefits and unlock the full potential of its energy storage portfolio: a more diversified and effective portfolio with a total net grid benefit of $1–$1.6 billion per year by 2032. The right signals for shorter verses longer duration storage, stronger grid signals to customers, enhanced growth in distribution-connected storage resources, refined resilience planning, and advancements in safety risk management and data practices are key issues to address.

With key observations on historical energy storage market evolution in **Chapter 1 (Market Evolution)** and historical operations in **Chapter 2 (Realized Benefits and Challenges)** as a foundation, in this third chapter we look forward towards the state's clean energy goals. We assess how grid needs and market dynamics might change with significantly more variable renewable generation, significantly more distributed resources, and a dramatically different resource portfolio overall. We identify and explore pressing policy challenges to continued energy storage market growth that supports state goals, including:

- When will the system need energy time shift over longer timeframes (e.g., longer duration)?
- What is the cost-effectiveness of natural gas-fired peaker replacement with energy storage?
- How can we improve policy signals for the most beneficial configurations and operations?
- How can we improve procurements to better address adaptation and resilience needs in a changing climate?

This chapter concludes with additional key observations and policy recommendations that will help to unlock the full potential of the energy storage fleet. These observations and policy recommendations are grouped into six themes:

1. Evolve signals for resource adequacy capacity investments;
2. Bring stronger grid signals to customers;
3. Remove barriers to distribution-connected installations;
4. Improve the analytical foundation for resilience-related investments;
5. Enhance safety; and
6. Improve data practices.

Evolve Signals for Resource Adequacy Capacity Investments

Chapter 1 (Market Evolution) shows that early pilot and demonstration projects and CAISO initiatives opened the door for energy storage to provide an array of services in the CAISO wholesale marketplace. At the same time, the CPUC's procurement orders carved a path for energy storage to help meet the state's rapidly-growing system reliability and resource adequacy capacity needs.

Based on analysis of actual operations, **Chapter 2 (Realized Benefits and Challenges)** shows the resulting energy, ancillary, and RA capacity services provided by energy storage during the 2017–2021 timeframe. Although the ancillary services use case did not reduce GHG emissions or bolster renewable generation, it attracted developers to the market and served as a stepping stone towards future benefits. By the end of 2021, we see realized growth in two important value streams: (1) in energy services in the CAISO marketplace, and (2) in system RA capacity services procured by the utilities and other LSEs.

These findings demonstrate that **<u>energy storage is now well-positioned to support state goals at a large scale through the energy time shift and RA capacity use cases</u>**.

Based on a 2032 system and resource buildout consistent with the 2021 Preferred System Plan, we estimate a 4-hour energy storage fleet of 13.6 GW to potentially yield $835 million to $1.34 billion per year in net grid benefits (Figure 46). Up to about 10 GW of energy storage would help to avoid renewable curtailments and replacement renewable energy credits (RPS savings), move energy to high-value times and displace inefficient natural gas-fired generation, reduce GHG emissions, and provide RA capacity when needed (energy and RA capacity value). The energy value of energy storage grows as more variable renewable generation is added to the system. By 2045, we expect the potential energy value to grow far beyond the 2032 levels and for more of the energy storage portfolio to contribute to that set of services. This analysis accounts for future growth in benefits as more renewables are added to the system and offsetting impacts of storage market penetration. Costs are assumed within a recent historical range since most of this future capacity is already contracted (see **Attachment B** for full detail).

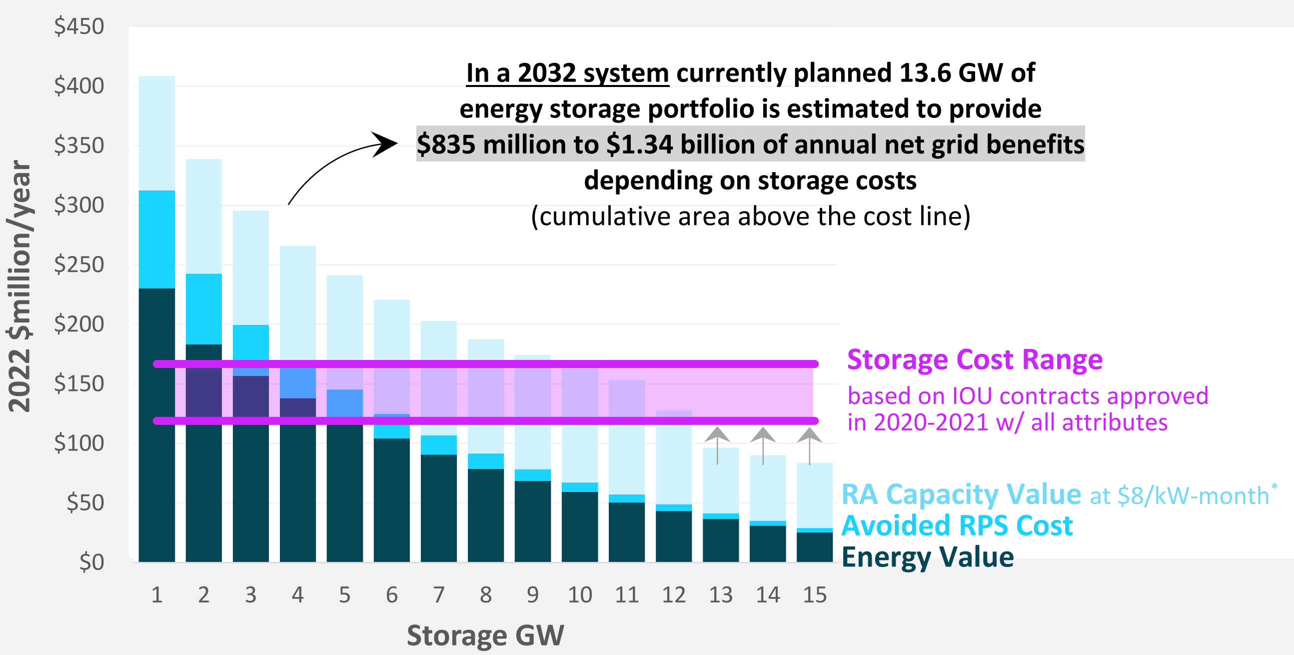


Figure 46: Incremental energy, renewables integration, RA capacity value of 4-hour storage in 2032 (2022 $).

* Marginal RA value is shown at $8 per NQC kW-month in line with the top 10% of system RA contract prices for 2021 delivery. At high penetrations, RA price would likely be higher to incentivize storage or other clean investments needed for reliability.

Additional energy storage beyond 10 GW in a 2032 system would provide more RA capacity-focused services to support system reliability with relatively low marginal value from energy and RPS savings. For those resources, the figure does not show the RA capacity value beyond what is needed to incentivize the storage investment (net CONE). The vast majority of the recent system reliability procurements are for energy storage resources. Without storage, other more costly alternatives would be needed to meet the reliability targets. The related RA capacity cost savings are likely significant, but not shown because they are highly dependent on the "counterfactual case" which is sensitive to the assumptions and outputs of the state's IRP optimization models—in particular, the shape and characteristics of the supply curve for new clean capacity.

Furthermore, additional potential benefits and grid resilience can be realized through the expansion of community and customer outage mitigation services provided by distributed energy storage resources.

The future role of the ancillary services use case will be naturally limited by market size. Ancillary services are essential to grid operations and battery storage has the advantage of being able to provide 2 MW of frequency regulation for every 1 MW of capacity. However, energy storage providing frequency regulation has the disadvantage of conversion losses that will increase net energy consumption and GHG emissions as long as there is fossil-fired generation on the system.

The entire market size is currently around 400 MW for regulation up and 700 MW for regulation down (Figure 47). Supply for this service can be met by a fraction of the energy storage fleet operating today and is not scalable to beyond that level.

Going forward, the ancillary services use case, by itself, is not a high-yield pathway for energy storage to deliver grid optimization, renewables integration, or GHG emissions reductions. With tens of GW of energy storage on the system it will likely be a niche revenue stream for a small subset of resources. Furthermore, as long as fossil-fired generation is on the system it may be more beneficial for other types of resources, such as hydroelectric generation, to meet the system's frequency regulation needs.

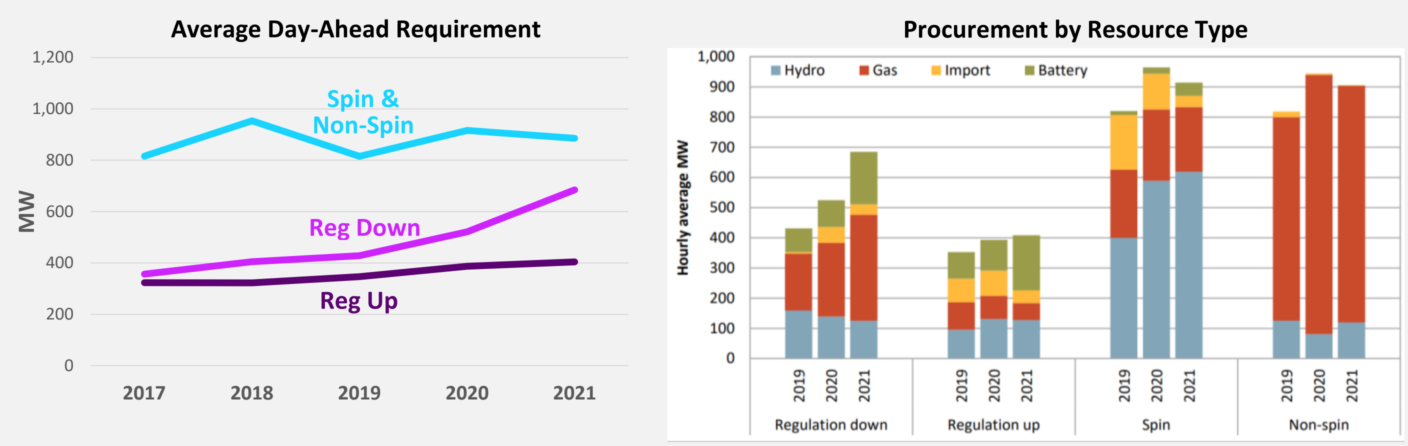


Figure 47: CAISO ancillary services markets size and supply.
(CAISO OASIS n.d.; CAISO DMM 2022)

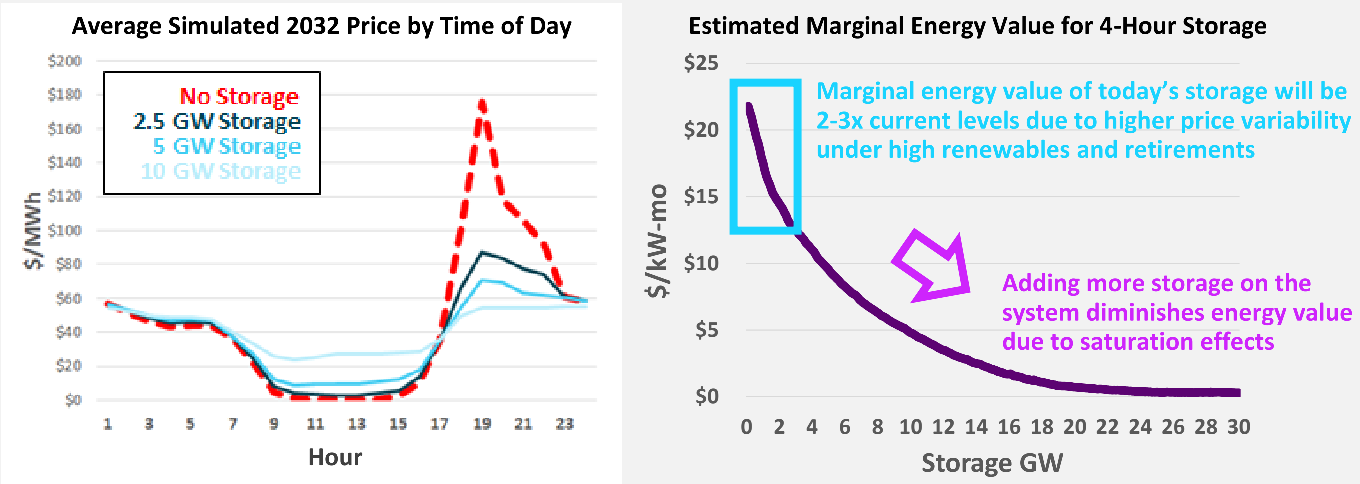


Figure 48: Simulated 2032 energy prices and storage energy value (2022 $).

Energy value and avoided renewable curtailments will decrease as energy storage grows and saturates markets. The transition to energy time shift in the CAISO marketplace is an important signpost for the wholesale market maturity of energy storage. Without energy storage, high renewables penetration creates time periods of low-cost supply during which energy prices drop, and time periods of undersupply during which expensive and relatively inefficient fossil-fired peakers operate to help meet demand. These price differentials are the basis for the energy value brought by energy storage and the differentials widen as more renewables are developed with all else being equal. In 2017–2021 intraday price differentials yielded energy value potential of $4–6/kW-month for 4-hour storage participating in the CAISO energy market (without ancillary services focus). We estimate that value would be 2–3 times higher in a 2032 electric system and renewable buildout consistent with the 2021 Preferred System Plan.

However, increasing levels of energy storage are expected to diminish market value on a marginal basis due to price effects. Our simulation of hourly energy prices with different quantities of energy storage installed shows how intra-day energy price differentials narrow at higher levels of energy storage penetration (Figure 48, left) and energy margins decrease rapidly (Figure 48, right). The storage portfolio provides significant value as a whole, but flattening of marginal energy prices increasingly signal market saturation and no more need for new entry for energy. The 2021 Preferred System Plan calls for 13.6 GW of battery storage by 2032 and at that level estimated marginal energy value drops below $3/kW-month.

A portion of the energy time shift directly reduces renewable curtailments by mitigating oversupply conditions that would otherwise worsen as California continues to decarbonize its electric system. Avoided renewable curtailments reduces the need (and cost) to procure offsetting additional renewables to meet RPS targets. As with energy value overall, when energy storage penetration increases the marginal value of RPS benefits decreases. In a 2032 system, we estimate RPS value to be high for initial storage deployment at today's levels, but marginal value drops below $0.50/kW-month when installed storage is 13.6 GW.

Developers will increasingly rely on RA capacity market signals and revenues to attract and retain the size of the energy storage portfolio needed over the next 10 years. Given the (a) natural limits to revenues from ancillary services, (b) declining energy and RPS value, and (c) increasing presence in the RA capacity market, <u>we expect RA capacity payments to become increasingly important to incentivize new energy storage development.</u>

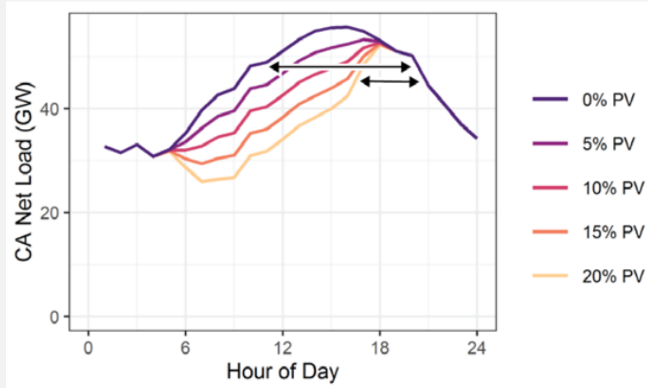


Figure 49: Effect of solar on net peak duration
(Blair et al. 2022)

As the California's grid transformation continues, **<u>new challenges are emerging to create fair and efficient RA capacity market signals to properly capture the contribution of energy storage towards meeting future resource adequacy needs within a rapidly changing mix of resources in the system</u>**.

These challenges include how to characterize the inevitable (but highly uncertain) decline in storage capacity credits due to saturation effects and how to differentiate signals for resources with longer duration.

New and existing energy storage face decreasing and uncertain marginal capacity credits. In 2014, the CPUC established RA program eligibility requirements for energy storage and supply-side demand response (D. 14-06-050). The requirements include "the ability to operate for at least four consecutive hours at maximum power output (PmaxRA), and to do so over three consecutive days," also known as the "4-hour rule." As such, most of the grid-scale battery storage operating on the system is 4-hour duration storage. Customer installations tend to be shorter duration: about 2 hours on average, mainly because most of the initial SGIP funds declined after the first 2 hours of duration.

While this simple approach can be considered sufficiently close in capturing the capacity value of the first wave of energy storage resources towards system reliability, longstanding concerns about expected decline in capacity contributions of energy-limited resources at high penetration rates and portfolio interactions among load, renewables, and storage led to implementation of stochastic approaches to estimate effective load carrying capability (ELCC) of resources. There are two complex interactions that needs to be considered: (1) increased solar buildout shifts net peak to evening periods and compresses the need to fewer hours, and (2) increased storage penetration flattens net load extending the need to longer durations.

Recognizing these complex dynamic interactions in the system, CPUC's IRP studies are currently updated with a multivariable "ELCC surface" developed based on ELCC studies to characterize portfolio ELCC levels as a function of solar PV and battery storage (see IRP's Modeling Advisory Group webinar in April 2022). Utilizing a similar ELCC study, in October 2021, CPUC published incremental ELCC values to be used for compliance with the Mid-Term Reliability Procurement order, which required LSEs to procure 11,500 MW of net qualifying capacity by 2026. ELCCs for the first 8,000 MW of this requirement by 2023–2024 are finalized. ELCC values for the remaining 3,500 MW in 2025–2026 are also finalized for contracts executed by November 30, 2022. Contracts executed after then will use updated ELCCs for 2025–2026.

To adapt to the rapidly changing energy landscape in California, CPUC's Resource Adequacy (RA) program, which focuses on near-term needs, is also refining its RA accounting and compliance framework. After an extended stakeholder process and several proposals, the CPUC selected a stakeholder proposal (called "slice-of-day") to refine the current RA framework. The proposed approach divides the days into 24 hourly slices and creates RA requirements varying by month. This is intended to account for the fact that California's system reliability needs are no longer confined to "gross peak" while also attempting to balance complexity, administrative burden, and transactability. Counting for storage resources will consider daily resource capabilities and efficiency losses, and LSEs will need to show capacity to meet storage charging needs. Many implementation details still need to be figured out and final implementation is expected in 2025 under the schedule adopted in CPUC's decision D. 22-06-050 issued in June 2022.

Figure 50 below illustrates the "tipping point" for 4-hour energy storage at high penetration levels, estimated based on a simulation of 2032 system conditions. Under a massive solar buildout consistent with the 2021 Preferred System Plan, marginal capacity contribution of storage remains high until around 12 GW of cumulative storage capacity is installed and then drops significantly. This sudden drop is driven by the shape of net load in California. At high solar penetrations, net load is peakier with a relatively short window of capacity need in the evening. But when storage installations reach a certain level and flatten the evening net peak demand, getting the next MW of capacity requires a much longer duration, which reduces the capacity value of storage.

We benchmarked these results against other studies analyzing capacity credit of energy storage in California, including the results from Astrapé/E3 study (2021) used to determine incremental ELCC values for Mid-Term Reliability Procurement and NREL study (2018) evaluating the potential of storage to provide peaking capacity in California under increased solar PV penetration. While final metrics are not directly comparable, they show similar patterns on tipping point for 4-hour storage at around 12 GW of capacity. Although these results are indicative of future trends, it is important to note that the exact tipping point is highly uncertain as it depends on how much solar is on the system, which keeps growing to support state's decarbonization goals.

Net CONE is the amount of capacity revenue that a resource would need to support its initial investment costs that are not covered by other types of benefits. In Figure 51 below, we show the calculations of net CONE of energy storage based on levelized capital and O&M costs *minus* non-capacity benefits (energy and RPS), normalized for the ELCC or capacity credit of the resource. The example illustrates how declining marginal capacity credit and other value streams can put upward pressure on net CONE for energy storage, even with anticipated cost reductions.

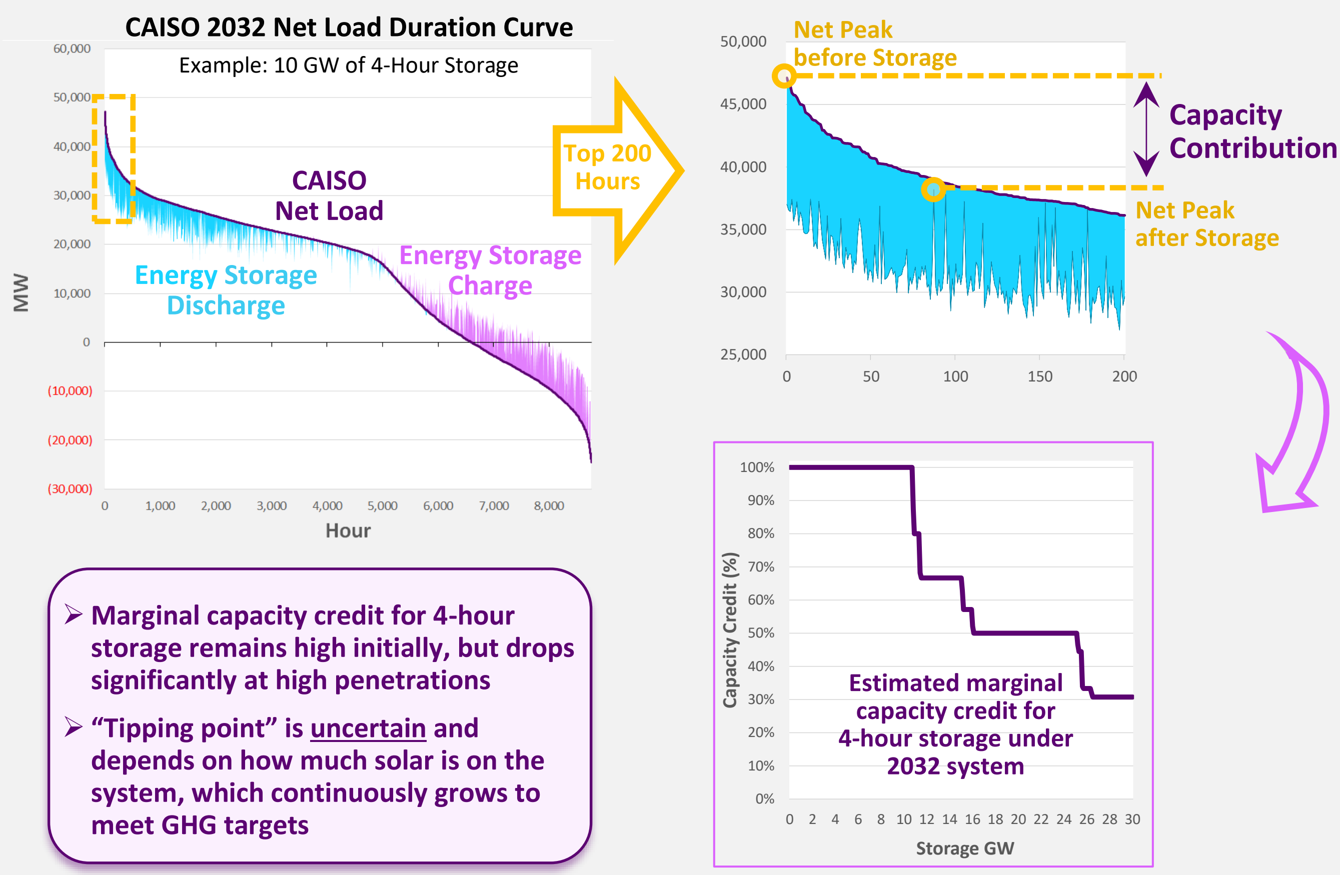
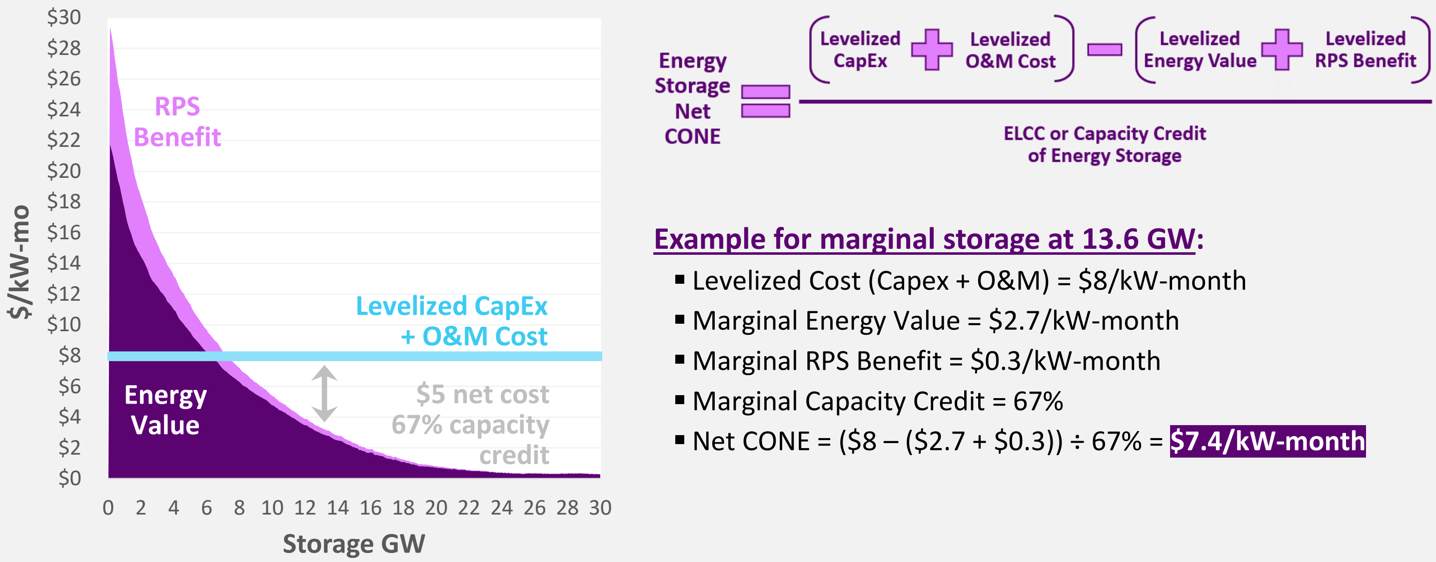


Figure 50: Illustration of declining marginal capacity credit for 4-hour storage at high penetration levels.



Example for marginal storage at 13.6 GW:

- Levelized Cost (Capex + O&M) = $8/kW-month
- Marginal Energy Value = $2.7/kW-month
- Marginal RPS Benefit = $0.3/kW-month
- Marginal Capacity Credit = 67%
- Net CONE = ($8 – ($2.7 + $0.3)) ÷ 67% = **$7.4/kW-month**

Figure 51: Calculation of marginal net cost of new entry (net CONE) for energy storage.

Needs for long(er) duration energy storage are uncertain and sensitive to the characteristics of the grid's resource portfolio. When will the California system need energy time shift over longer durations? The question of when the state will need energy storage to charge and discharge over longer timeframes is an important one because: (a) the transition will likely happen very soon, and (b) under-procurement of longer duration storage can have system reliability implications, or it may inadvertently require over-procurement of shorter duration storage at higher cost.

For clarification, in this section, we discuss longer timeframes that still fall within the "short duration" category: up to 10-hour duration energy storage used primarily for intraday energy time shift. Long durations with multi-day, weekly, monthly, or even seasonal energy storage will inevitably be needed when the state approaches its 100% clean energy goal by 2045.

As the recent IRP procurements show, energy storage in California will play an increasingly important role to help the state maintain reliability while transitioning to a clean energy future. However, meeting the state's goals with 4-hour storage alone is not economically plausible as declining marginal capacity credits and other value streams will raise capacity payments needed to support further development. At a certain point, storage systems with longer duration will likely offer lower cost solutions to address incremental RA capacity. Exact timing of this transition is uncertain and highly sensitive to relative ELCC or marginal capacity credit curves for storage at different duration levels.

Figure 52 shows our estimated net CONE of storage resources in a 2032 system with high renewables. We assumed 4-hour energy storage development drives overall storage penetration and calculated net CONE based on marginal resources added with durations ranging from 4 hours to 10 hours.

Net CONE is zero for the initial deployment because energy and RPS value in 2032 would have been sufficient to recover costs if penetration remained low.

Overall, 4-hour storage is more cost effective initially (as expected) but the gap with longer duration storage configurations closes as more storage is installed. We see crossover points after capacity credit of 4-hour storage drops significantly at around 12 GW. But the difference remains relatively low until storage penetration levels reach 25 GW or more.

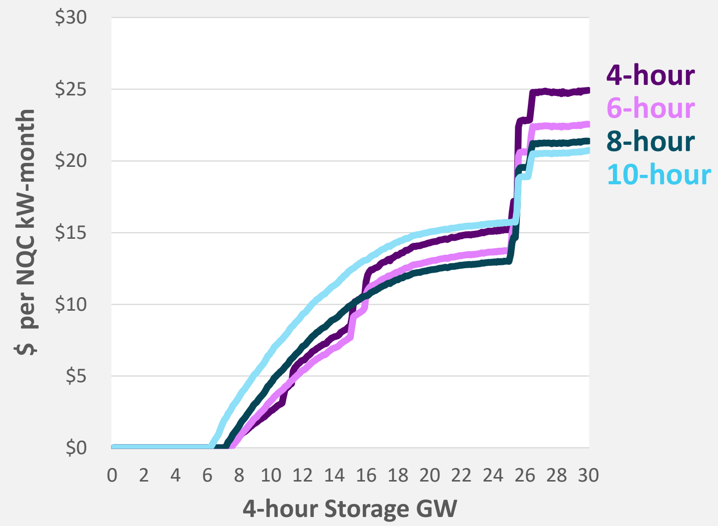


Figure 52: Estimated 2032 net CONE of storage by duration (in 2022 $)

*Net CONE values estimated for marginal additions with different durations in a system where bulk of the storage portfolio has 4-hour duration.

These results suggest the path for cost-effective longer-duration storage (up to 8–10 hours) is in sight, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC or capacity credit modeling assumptions. As described earlier, the IRP and RA program is going through several reforms to adapt to the rapidly changing energy landscape in California. But implementation is not yet fully tested, and more stakeholder input and transparency are needed to understand key differences in modeling assumptions and results across durations to make sure they signal the need for long-duration storage when the need arises.

The differences were less important in the beginning as 4+ hour storage got high ELCC regardless, but this will change quickly as we approach the tipping point discussed previously. Both absolute and relative ELCC levels matter:

- Overestimating marginal ELCC leads to under-procurement, with increased exposure to reliability events
- Underestimating marginal ELCC leads to over-procurement, with cost implications
- Not sufficiently capturing delta across duration levels may fail to signal need for long duration

Incremental ELCC values for the CPUC's mid-term reliability procurement show little difference between the ELCC estimates of 4- and 8-hour batteries: 74.2% vs. 82.2% in 2025 and 69.0% vs. 78.2% in 2026. Future updates to ELCC values deserve extra attention and stakeholder input before getting finalized. If the difference is indeed small, it needs to be sufficiently explained and illustrated why that is. **With less than 10% delta in ELCC values, it is highly unlikely any 8-hour storage will be developed economically, beyond the 1,000 MW carve-out.**

This is important because if capacity contribution of long-duration storage is inadvertently understated in ELCC estimates, it may lead to higher costs for ratepayers. For example, Figure 52 above shows longer duration storage can enter the market at \$3–\$5 per kW-month below the price point for 4-hour storage at higher penetration if ELCC of 4-hour storage drops rapidly but ELCC of longer duration storage remains high. In that scenario, procurement of each 1,000 MW of NQC from 4-hour storage costs \$36–\$60 million per year more, relative to procuring the same NQC from storage with higher duration. Understating ELCC of long-duration storage also results in over-procurement of resources to meet the 1,000 MW carve-out. Figure 52 above shows estimated net CONE of 8-hour storage at around \$\$10/kW-month if its ELCC stays high (above 95%) when installed storage approaches 15 GW in the system. An ELCC of 80% instead of 95% would require approximately 200 MW more storage capacity at an incremental cost of over \$20 million per year.

Energy storage modularity can provide real option value for adding duration when needed.

There are inherent uncertainties with future RA capacity needs and resource contributions, even with "perfect" analysis. Procurement efforts may have to pivot quickly and adjust target portfolios based on unexpected changes and new information. Battery storage systems and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost. In our review of the actual grid-scale installations, we see that some of the developers are already taking advantage of this modularity in their market participation and development strategies by building the MW capacity first and increasing duration later when the need arises.

Creating a "real option" to add more duration to battery projects at the initial design and procurement phase could support a timely and cost-effective transition for longer duration. There is an extrinsic value associated with such an option because when to economically transition from current 4-hour systems to longer configurations is highly uncertain. If utility and other LSE's energy storage system designs or contracts with third parties, for example, included options to expand duration in an expedited manner, it would give them the right, but not the obligation, to deploy longer-duration storage capabilities quickly and hedge against potential price surges and/or lead-time constraints.

Reflection of future climate trends and extremes in the state's resource planning and ELCC models is becoming essential.

As previously described in **Chapter 1 (Market Evolution)**, CAISO, CPUC, and CEC's joint investigation of the mid-August 2020 system emergency events and power outages in California confirmed that one of top contributing factors was the climate change-induced extreme heat wave across the western U.S. and recommended an updated, broader range of climate scenarios to be considered in future planning studies, along with increased coordination among the agencies to prepare for contingencies.

Understanding and incorporating the effects of climate change on frequency and magnitude of extreme events, and electric supply and demand is an area of active research and development. For example, even though the state agencies' Final Root Cause Analysis showed that mid-August 2020 events were driven by a 1-in-30 year weather event, based on 35 years of historical data, it is not clear how frequently the system will experience similar events going forward. Demand forecasts and supply availability assumptions used in resource planning rely on historical weather variants and do not yet fully consider that the normal levels and variability of weather events have been changing historically and will continue to change in the future, potentially at a faster pace.

Through the EPIC program, the CEC has launched several studies designed to break down institutional barriers and accelerate innovations and uptake of new climate projection data and weather extremes throughout the state's resource planning activities. One effort in particular, awarded under the solicitation GFO-21-302 and launched in 2022, aims to build a resilience planning framework and re-parameterize the state's planning model inputs and assumptions in order to capture key climate-related uncertainties and risks to future electricity supply and delivery.

Recommendations. With the understanding that the CPUC is in the process of advancing its planning and procurement practices our recommendations for the CPUC are to:

- **Continue development of ELCC methods for assessing system capacity needs for reliability and various resource type's ability to meet those needs**, including use of the CPUC's ELCC surface analysis which considers the dynamic interactions of resources within a portfolio.
- **Further validate ELCC signals for longer duration storage investments**, with more transparency and stakeholder discussion of underlying ELCC modeling assumptions and results to identify and explain drivers of ELCC differences (or lack thereof) across storage durations.
- **Incorporate real options for longer-duration energy storage installations into IOU solicitations and CPUC contract approvals** to support a timely and cost-effective transition for a portfolio with longer duration storage, utilizing the modularity of battery storage capacity. Utility and other LSE's system designs and contracts with third parties, for example, could include options to expand duration at the existing site in an expedited manner.
- **Incorporate impacts of climate change and weather-driven extreme grid events in resource planning and ELCC models** to assess future resource needs and system vulnerabilities.

Bring Stronger Grid Signals to Customers

As discussed in **Chapter 1 (Market Evolution)**, customer-sited stationary energy storage capacity grew from around 70 MW at the start of 2017 to at least 540 MW by the end of 2021 (possibly not counting some of the privately-funded storage installations), largely driven by 470 MW of SGIP-funded installations (Figure 53).

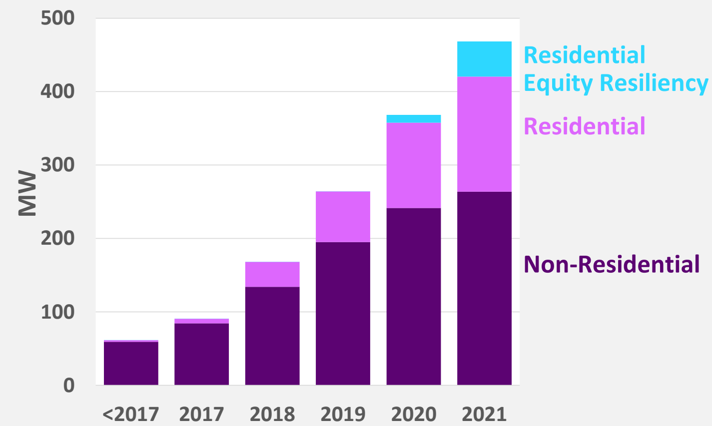


Figure 53: SGIP-funded installed storage capacity over time.

In 2016, the CPUC set 3 primary goals for the SGIP: GHG emissions reductions, provision of grid services, and market transformation. Towards the latter, growth in installations and the installer workforce indicate that meaningful market transformation has been achieved. Going forward, more specific market transformation objectives such as soft cost reduction targets would provide clearer program direction (see further discussion in our recommendation to improve data practices later in this chapter).

Under **Chapter 2 (Realized Benefits and Challenges)** we document a challenge consistent with the program's impact evaluation reports: many SGIP-funded storage projects provided bill savings for the customers who installed them, but provided little or no value to the grid. This is especially striking when we compare performance to the operating profiles and net benefits of grid-scale storage. Clusters of SGIP non-residential projects with high solar attachment rates—mostly representing schools and colleges—ranked highest among the installations. Their benefit/cost ratio was still low at around 20% and their GHG emission reduction on average was a small fraction of their potential. Clusters with low solar attachment rates—largely representing commercial and retail buildings—followed an operating pattern of demand charge management that involves discharging throughout the day and night charging. These installations ranked much lower with benefit/cost ratios, below 5%, and average net GHG emission *increases*. For these customers it is unclear to us whether retail rates appropriately reflect the tradeoffs of reducing demand charge-related costs (such as distribution line loadings) versus reducing the costs of local or system-wide solar oversupply and curtailments. We also observe only 5% of customers with solar PV installed also install storage, despite storage's ability to (a) mitigate local and/or system congestion and curtailment costs from solar exports during the day and (b) provide high value exports when the grid is most constrained.

In **Chapter 2 (Realized Benefits and Challenges)** we also find that customer aggregations procured under RA and demand response contracts yielded little value to the grid. For resources outside of the CAISO marketplace, operating patterns did not align with grid needs, resulting in negative energy value and increased GHG emissions. CAISO market-participating customer aggregations fared slightly better but still well below their potential. These resources responded to grid signals when offered into the CAISO marketplace, but contractual requirements were too narrow and inflexible to keep up with grid needs as those needs shifted during our study period.

<u>Overall, we find that customer-sited installations reached maturity in terms of volume of installations and MW built, but not in terms of grid benefits yielded, leaving significant untapped potential</u>.

The institutional practices, market structures, and policy forces behind this result have a long and complex history we only partially discuss in this report. Going forward, development of significantly stronger grid signals to customers will be needed to enable energy storage use cases and operations that are beneficial to both customers and to the grid. The sections below highlight the most important elements of stronger grid signals needed to achieve this aim.

Customers face significant gaps in grid signals for both energy value and RA capacity value. Our analysis shows specifically that energy and RA capacity are the two key going-forward benefit streams energy storage can provide at a large scale towards meeting the state's goals of grid optimization, renewables integration, and GHG emissions reductions. To tap into these benefits, customers with energy storage must be connected to grid signals that enable customers to provide energy and RA capacity services to the grid. Every type of customer-sited resource we studied, however, faces an insufficient or incomplete grid signal to fully capture one or both of these value streams.

Under SGIP, customers with energy storage can produce both GHG emissions reductions and grid energy market-related benefits by following the existing SGIP GHG signal. It is not necessary for customers to respond to separate GHG and energy price signals. This is because the SGIP GHG signal is derived from 5-minute real-time CAISO marginal energy prices. In many ways it mimics a time-granular energy price signal, albeit with the distribution of prices truncated to exclude very low and very high prices (very low prices all translate to a marginal GHG emissions rate of zero, and very high prices all translate to a marginal GHG emissions rate threshold of natural gas-fired generation at 0.67 kg CO_2/kWh).

SGIP does not currently pass a grid signal for the value of RA capacity to customers. Among the resources and procurements we analyzed, customer-provided local RA capacity service was piloted in 2013 through utility contracts with aggregators and with mixed results. We also observe several contracts and programs over the years designed generally to shift demand from peak periods to off-peak periods.

Neither SGIP's GHG signal nor time-of-use (TOU) retail rates provide sufficiently time-granular signals during peak periods for RA capacity value. Under TOU retail rates, incentives to charge energy storage during the day and discharge in the evening are directionally aligned with grid conditions, but the value to delay charge or discharge within each TOU window when grid conditions might be more extreme is not conveyed. For example, if TOU peak pricing is 4–9 p.m. a customer with 2-hour storage may automatically discharge from 4–6 p.m. even if the grid has the greatest need after 6 p.m. This is a reality we saw in 2020 and 2022, when CAISO had a Stage 3 Emergency on August 14, 2020 from 6–9 p.m., a Stage 3 Emergency on August 15, 2020 from 6–7 p.m., and an Energy Emergency Alert 3 on September 6, 2022 from 5–8 p.m.

Grid signals for RA capacity value are particularly difficult to bring to customers especially due to its insurance product qualities. Part of RA capacity service is to provide available generating capacity (in the case of energy storage, the ability to discharge) when the grid is most in need of it. Sometimes energy storage supplying RA capacity will need to discharge when the grid is strained, and sometimes it will need to just be ready with a full state of charge even if the grid does not call upon that energy. It is not sufficient to simply exist as installed capacity or to occasionally discharge during a grid emergency to provide RA capacity to the grid. Consequently, this service comes with some performance-related challenges. And these challenges are particularly difficult when the resource is installed behind the customer meter.

A complicating factor is RA capacity needs on the grid are shifting rapidly as the state progresses towards its clean energy goals. For customer-sited energy storage this means a grid signal for RA capacity, and storage operations, will need to be correspondingly dynamic. This is a departure from the mostly static peak and off-peak periods of the past and it requires more dynamic operations.

Furthermore, customers will optimize bill savings and their own outage mitigation needs along with services to the grid. It is not yet clear how much RA capacity customer-sited energy storage can provide—even with the perfect grid signal.

At the time of this report, pilots are underway to explore that issue and lay the groundwork to connect customers with a grid signal for RA capacity. In 2021 the CPUC launched its 5-year Emergency Load Reduction Program (ELRP) pilot through which customers can voluntarily reduce their demand during a grid emergency. Presumably, rates of actual responsiveness to grid emergencies may be observed from this pilot to help inform the appropriate capacity credits for distributed energy resources. For energy storage specifically, in 2022 PG&E and Tesla launched a pilot to enroll customers with installed Powerwalls into the state's ELRP. Participants keep a pre-defined portion of the energy storage capacity on reserve for backup, then provide residual battery capacity to the grid during system emergencies and assuming no distribution-level outages. This pilot may help to inform how customers stack bill savings and their own outage mitigation against services to the grid.

<u>Important groundwork for customer-facing grid signals for energy value and RA capacity value in retail programs has been achieved, but these signals are still in an initial pilot phase with impacts that are not yet fully understood.</u>

Stakeholders point to structural barriers in wholesale markets preventing full use of storage capabilities. Energy storage industry representatives highlight barriers to participation in the CAISO marketplace and the RA capacity program, namely, exclusion of customer-sited energy storage exports to the grid under certain market participation models. This is a complex issue, aimed towards capture of RA capacity payments, and the subject of much ongoing industry discussion and debate. The CAISO offers market participation models (NGR and DERP) that allow for exports but are tied to the WDAT interconnection process and continuous ("24/7") CAISO market participation rules that are apparently a challenge for energy storage aggregators.

In contrast, demand response market participation models (PDR, RDRR, PDR-LSR) do not require WDAT interconnection and they allow for more day-to-day tailored market participation. These rules are consistent with <u>traditional</u> demand response resources' (e.g., load adjustments) unique energy constraints, inability to export, and tendency to have attributes suited for a reliability-only use case. These market participation models are apparently more attractive to storage aggregators who seek to mimic the market presence of a reliability-only use case despite customer-sited energy storage's ability to provide energy services on a daily basis.

While we recognize that the technical capabilities of energy storage resources to export to the grid are distinct from traditional demand response and should be recognized in wholesale markets, we also find that energy storage is distinct from traditional demand response in that it is not best used as a pure capacity product. We find that energy time shift, including energy and capacity services, is a key value stream for achieving grid optimization, renewables integration, and GHG emissions reductions at a large scale. Also, the need to demonstrate deliverability of energy storage exports to the transmission grid, as is studied through the WDAT interconnection process, is a key distinction from traditional demand response.

The CPUC and stakeholders are exploring these issues in the CPUC's RA program rulemaking (CPUC 2021). Based on our study of energy storage market evolution and historical operations, we offer the following observations to contribute to that dialogue:

- The ability of energy storage to provide energy time shift, including energy and capacity services, is a key value stream for achieving grid optimization, renewables integration, and GHG emissions reductions at a large scale. Energy storage that functions as a capacity-only product, with poor wholesale energy value, is not cost-effective from a ratepayer perspective and it significantly underutilizes the proven capabilities of the technology.
- Further investigation into challenges storage aggregators face in the WDAT interconnection process is warranted, as it also may be a factor in the poor project success rates for distribution-connected installations (see next set of recommendations starting on page 85).
- For customers and aggregators with clearly-defined cross-domain multiple use cases and <u>additive</u> value streams (such as customer outage mitigation plus grid reliability services), further investigation into a 24/7 wholesale market participation requirement and to what extent it presents operational or financial conflicts that prevent cross-domain value-stacking is warranted.

<u>Similarly, important groundwork to open the door for energy storage aggregations to enter wholesale markets has been achieved, but market participation is still in an initial pilot phase with challenges in establishing deliverability to the transmission grid and in implementation of cross-domain multiple use applications.</u>

Interim policy solutions that can be implemented to better align customers with grid needs in the next few years will be crucial. Design and implementation of mechanisms to connect customers with grid signals has been one of the greatest market and policy challenges throughout the industry for many years. Undoubtedly, the CPUC will need to continue to break new ground to move forward on this front.

Ultimately, advanced retail rate design AND some form of wholesale market integration are needed to reveal the dynamic cost and value of grid services to customers and enable them to operate their energy resources in synergy.

Two policy routes will achieve this aim. Both involve difficult tradeoffs and disruptions to institutional practices that promise a lengthy and arduous policy journey.

One route is to focus on major reconstruction of retail rates to mimic grid conditions while following the other objectives of regulated rate design. How to fully integrate customer behaviors into wholesale grid operations and planning may become clearer as people, markets, and technologies adjust.

The other route is to instead focus on wholesale market integration. To support efforts along this route a baseline alignment of retail rates with the grid must be in place, but then efforts would shift to development of customer aggregation models to participate in CAISO and RA capacity markets at-par with grid-scale resources.

California has implemented pilots and other more serious efforts along both routes. More recent retail rate reform efforts include a 2022 CPUC decision to make adjustments to the net energy metering tariff that, among other impacts, would better incentivize energy storage attachments to solar PV installations (CPUC 2022c). Separately, in 2021 and 2022 the CPUC held a series of workshops with stakeholders to explore strategies to improve demand flexibility. As part of that effort CPUC Staff released a white paper in June 2022 proposing an advanced retail rate design framework called the California Flexible Unified Signal for Energy, or CalFUSE (Madduri et al. 2022). Concurrently, in July 2022 CPUC launched a rulemaking to advance demand flexibility through electric rates (CPUC 2022b).

Towards wholesale market integration, the CAISO has a broad set of initiatives to better integrate energy storage and distributed energy resources into its marketplace (see Figure 22 for more detail). In 2013 IOUs piloted contracts to bring customer aggregations into energy and RA capacity markets. But misaligned retail rates are clearly a barrier to the effectiveness of these wholesale market integration efforts, as we can see evidence of in our historical analysis. Furthermore, issues under discussion in the CPUC's RA program rulemaking demonstrate major challenges in wholesale market integration of a highly flexible resource that crosses grid domains.

Practical solutions are urgently needed to improve grid signals to customers. These solutions may not achieve widespread advanced rate design and/or wholesale market integration but they should take important steps along the way. Over the next 10 years, we anticipate the rapid growth in customer-sited installations will continue. The CEC's 2021 IEPR forecast (mid-mid scenario), for example, shows about 25% per year future growth in customer-sited energy storage which implies several thousand MW of installed capacity by 2032. Under status quo, if current operations and use cases remain unchanged, thousands of MW built at customer sites would focus on bill management to avoid grid charges without providing commensurate grid value, which would shift costs to other ratepayers.

In the greater context SGIP and ELRP may be viewed as temporary and/or incomplete mechanisms to bring grid signals to customers. But these programs are essential as they can be implemented relatively quickly to get ahead of customer installations, compared to the more comprehensive policy solutions ultimately needed.

Optimal comprehensive solutions of advanced rate design and wholesale market integration involve major policy challenges that may not be overcome within the timeframe of customer-sited energy storage reaching GW scale. Interim policy solutions that can be implemented sooner will have a crucial role to synergize customer investments and behaviors with grid-scale investments and grid operations.

In our recommendations we do not attempt to address the long history and many challenges of retail rate design or wholesale market integration. We instead focus on the more immediate policy actions needed to enable customer-sited energy storage to contribute towards meeting state goals at a large scale. Customers with, or considering, energy storage are in need of (a) clear signals for energy and RA capacity value, (b) improved retail rate alignment with those signals, and (c) policy solutions that can be implemented within the next couple of years.

SGIP can be honed to continue to serve state goals and bring stronger grid signals to customers.

SGIP has been instrumental to market transformation for customer-sited installations. It has also become instrumental for improving equity and resilience in customer-sited investments. This is a program already in place that can be adapted to continue to serve state goals going-forward and bring stronger grid signals to customers. However, along with its successes, the market and policy challenges to effective design of an incentive program of this size are clear. In particular, challenges with the program's purpose and performance requirements will need to be overcome.

The SGIP 2014–2015 Impacts Evaluation Report, published in late 2016, found that non-residential energy storage projects increased GHG emissions. In response and after almost three years of study with stakeholders, in 2019 the CPUC adopted GHG emission reduction requirements and the use of a GHG signal to better align resource performance with the program's goals. Under the rules, new commercial projects after April 2020 are required to reduce GHG emissions by 5 kg/kWh annually. The requirement is an outcome of the CPUC's stakeholder process. It is well below the 25 kg/kWh annual target CPUC Staff originally proposed and it is only a fraction of at least 60 kg/kWh annual GHG reduction potential we estimated for a 2-hour storage with access to grid signals. We find the 5 kg/kWh-year GHG reduction requirement to be directional at best and we expect it will not produce meaningful GHG emissions reductions compared to program costs or compared to benefits accessible through grid-scale installations. With limited grid benefits, the current incentive of large-scale storage at $0.25/Wh to reduce 5 kg/kWh per year over a 5-year period translates to an implied GHG abatement cost of $10,000/ton. As is, this GHG target will likely enable prioritization of individual customers' non-coincident peak demand smoothing throughout the day above meaningful GHG emissions reductions and other grid services that are more aligned with the state's policy goals.

Actual impacts of the 5 kg/kWh GHG emissions reduction requirements on non-residential installations funded by SGIP will take some time to observe. CPUC Decision 19-08-001, which adopts the GHG reduction rule, requires an evaluation to determine if further changes to the GHG rules are necessary. However, because only projects submitting applications after April 1, 2020 are required to reduce GHG emissions, only a few of the projects analyzed in the 2020 SGIP impact evaluation were subject to the 5 kg/kWh target. The 2020 SGIP impact evaluation report shows 84 new non-legacy projects based on a cutoff using incentive received dates, but most of these projects do not need to comply with the GHG reduction rule as they submitted their applications before April 2020. In operational data we analyzed through September 2021, we observe no effects of the GHG reduction rule due to lags driven by exemptions for legacy projects, and program enrollment and data collection timelines. We believe even the 2021 SGIP impact evaluation may not have sufficient data to assess impacts of the GHG signal and the GHG reduction rule. If impacts can be observed in 2022 operational data, then they would be reported in the annual SGIP impact evaluation study published in late 2023. Following the status quo, if the SGIP impact evaluation study published in 2023 finds a need to increase the GHG reduction requirement, and if a more stringent requirement is implemented by the CPUC, then it would be reasonable to expect corresponding energy storage performance improvements after 2030. This timeline and process would make it impossible for the CPUC to leverage SGIP to unlock the full potential of customer-sited energy storage to align with the state's goals of grid optimization, renewables integration, and GHG emissions reductions.

We see an urgent need for the CPUC to (a) more fully orient the program goals of SGIP, corresponding grid signals, and performance requirements towards the value streams that can provide ratepayer benefits in bulk and (b) expedite all or parts of the program evaluation and refinement process in order to do so quickly.

The scale of untapped potential for grid benefits is significant. Instead of the status quo, if 4 GW of customer-sited energy storage resources can be *partially* incentivized to capture 30–50% of the energy value provided by grid-scale energy storage and also provide 1–2 GW of capacity contribution (in the form of net peak reduction) it can potentially avoid 1–2 GW of grid-scale storage investment that would otherwise be needed and could save $143–$334 million per year in net grid costs.

The CPUC has a limited and narrowing window to translate energy market price signals into economic incentives for customer-sited installations and use cases that are in sync with grid conditions and state goals. As California develops significantly more short-duration (4-hour) storage over the next 5–10 years, its marginal value will eventually decline due to flattened net load and prices. At that point, the ability for new customer-sited storage to help with the grid needs would be far more limited than today, because the system will need longer duration storage. Investments in short-duration grid-scale storage that could have been avoided will already be made and intra-day energy time shift value opportunities will be greatly reduced.

We recognize that this is a topic with a long history of policy efforts and of great stakeholder debate. While it is up to the CPUC and its stakeholders to explore specific solutions to the problem of integrating individual customer needs with grid needs, we highlight a few innovative strategies from other U.S. states and jurisdictions relevant to California's policy context and challenges in **Attachment D**.

Recommendations. With acknowledgement that integration of customers with grid needs is a particularly difficult challenge, our recommendations to the CPUC are to:

- **Bring stronger grid signals to customers overall** on the time-varying value to the grid of storage operations. Longer-term solutions require significant changes to the retail rate design and wholesale market participation paradigm, such as the retail rate design framework described in CPUC Staff's June 2022 California Flexible Unified Signal for Energy (CalFUSE) white paper. Regardless of the CPUC's long-run policy pathway to this aim two critical activities are:
    - Continued work on basic alignment of rate structures with grid needs. Actual or potential misalignments that we observe in our analysis and that can significantly reduce the net benefits of energy storage include:
        - Retail non-coincident demand charges versus grid energy and RA capacity avoided costs
        - Net energy metering incentives for standalone solar PV versus solar plus storage
        - Peak period definitions that exclude 8–9 p.m., weekends, and holidays despite grid emergencies during those times
        - Off-peak period definitions that do not differentiate the grid cost of mid-day versus nighttime charging
    - Interim solutions that can bring stronger grid signals to customers within the next couple of years. Examples of interim solutions include building upon the SGIP and ELRP mechanisms already in place.

To better focus ratepayer investments to beneficial configurations, use cases, and customer behaviors:

- **Elevate assessment of effectiveness of GHG signals in SGIP**, including expedited evaluation of the effectiveness of GHG reduction requirements in SGIP, and a broadened scope of that evaluation to consider (a) the importance of energy and RA capacity value among all benefit categories and (b) the degree of actual versus potential contributions towards state goals. The evaluation should apply the April 1, 2020 cutoff for new projects based on application submission dates, as stipulated in the CPUC Decision 19-08-001.

- **Strengthen grid signals in SGIP** through a course-correction to align program goals and performance requirements to produce significantly more energy and RA capacity value.
    - Review findings of the above-mentioned study on effectiveness of the GHG reduction rule in SGIP and determine if adjustments are needed to strengthen and leverage requirements to follow the GHG signal in order to improve GHG reductions and energy value.
    - Address conflicting signals to non-residential participants of demand charges vs. GHG signal.
    - Introduce and create linkages to additional incentives for voluntary performance during grid reliability events for all SGIP participants—such as auto-enrollment in ELRP, other pilots providing a similar signal, and/or incentives for performance during Flex Alerts.
    - Set a framework to link and provide information on bulk grid alerts/emergencies (e.g., ELRP, Flex Alerts), local alerts/emergencies (e.g., PSPS), and historical outage risk during those alerts/emergencies so customers can program their systems to dynamically offer more capacity to the grid (rather than hold reserves) when they determine it is safe to do so.

- **Incorporate more flexibility in IOU contracts for customer aggregations** through improved contract structures for customer aggregations that can be quickly realigned with changing grid needs, such as (a) performance requirements to address system needs shifted to late evenings and extended to weekends and holidays, and (b) measures against conflicting retail rate signals and use cases such as non-coincident demand charge management.

Remove Barriers to Distribution-Connected Installations

Chapter 1 (Market Evolution) presents evidence that third-party developers of distribution-connected installations faced challenges with grid interconnection and with achieving commercial operations. Among other potential contributing factors, barriers in the Wholesale Distribution Access Tariff (WDAT) interconnection process with the IOUs—which all distribution-connected resources are required to go through—are well-known and documented by stakeholders. Distribution-connected resources remain dominated by IOU installations and market transformation is yet to be achieved.

We also observe in **Chapter 2 (Realized Benefits and Challenges)** that the third-party-owned distribution deferral use case is still in an early pilot and demonstration phase. Distribution deferral needs in terms of MW size and timing are inherently difficult to pinpoint exactly. The needs shift and can disappear, and development plans and utility-contracted use cases do not appear to be flexible enough to adjust. Under this use case, we see several procurements that were not able to reach project completion. We noticed a similar issue in the transmission deferral use case: development of a resource procured by PG&E in 2019 to avoid a transmission investment stalled after the procurement need grew from 7 MW to 12 MW. These types of projects may need more flexibility in the procurement process to take advantage of the modularity energy storage can offer to adjust sizing and use case.

In **Chapter 2 (Realized Benefits and Challenges)**, we see that the successfully installed distribution-connected resources fall into two groups:

- One group of resources is among the most beneficial in the entire fleet, with resources providing a wide array of multiple services, including local RA capacity and local renewables integration. Within this group, three third-party-owned resources procured for local RA capacity service yield a 2.5 ratepayer benefit/cost ratio compared to a 1.6 benefit/cost ratio for the next-best transmission-connected resources. Two utility-owned distribution-connected resources yield positive ratepayer benefit/cost ratios due to multiple services offered to the grid. A few other resources with low ratepayer benefit/cost ratios fare better from a societal perspective, due to relatively high utilization and/or multiple grid services offered.
- The second group of resources includes installations operating mostly on standby. These standby use cases include microgrid and local distribution system support services and do not include services to the transmission grid. These resources are severely underutilized and operate well below their potential to help meet state goals, both from a ratepayer and a societal perspective.

<u>Overall, we find that distribution-connected installations have the potential to yield high net benefits to ratepayers, but (a) third-party developers face barriers to project completion and (b) the practice of standby use cases rather than value-stacking yields some of the worst-performing resources in the overall storage portfolio.</u>

In addition to challenges with WDAT, stakeholder feedback reflected agreement that multiple use applications (MUA) that stack distribution transmission services are possible but (a) generally not well developed and (b) dependent on resource-specific circumstances. Questions on how to approach the diversity of possible use cases and fit them into generalized MUA models have many parallels to challenges with wholesale market integration of customer-sited energy storage under discussion in the CPUC's RA program rulemaking discussed above (CPUC 2021).

CPUC's 2018 MUA decision (CPUC 2018) laid important groundwork, but this is still an area of active study that would benefit from additional real-world case studies to pinpoint challenges and opportunities. Some microgrid resources under development, approved by the CPUC under the condition they "maximize ratepayer benefits and net revenue under least-cost dispatch during normal conditions" (CPUC 2022a) may provide additional insight to identify scalable MUA models.

Distribution-connected resources are needed for local services. Going forward, we anticipate a continued need for distribution-level solutions to local grid problems as the system transitions to carbon neutrality and more distributed solar PV. Accelerating weather and environmental risks also point to higher future resilience needs at the community and customer levels that cannot be met by transmission-connected resources. Resilience is discussed further in the next subsection.

The challenge of peaker replacements calls for creative solutions across all grid domains. The state must face the challenge of replacing part or all of its local fossil-fired generation and capacity in order to meet clean energy goals. The CPUC's local RA capacity procurements demonstrate how energy storage can help address local constraints due to generator retirements such as the once-through cooling-driven retirements and retirement of the San Onofre Nuclear Generating Station.

The path towards cost-effectively replacing additional existing local generating resources depends on the utilities' and developers' ability to find innovative low-cost alternatives. We screened the cost-effectiveness of around 100 individual natural gas peaker units' replacement with energy storage under the challenging system conditions observed in 2020. We find that replacing peakers' output with standalone storage would require either significantly overbuilding storage MW or installing long-duration storage at relatively high cost.

Under today's grid-scale energy storage costs, replacement of the local peakers in California will likely require significant investments: very few peakers can be replaced with standalone storage at $10/kW-month and most peakers would require well above $15/kW-month, which is several times higher than the current RA price levels. If the site or local area has sufficient land that can be used to install solar capacity, developing storage paired with solar can reduce the need for overbuilding MW and/or duration, and lower net costs. With current cost levels, about 4,000 MW (40%) of the peakers in California can be replaced with solar + storage at $10/kW-month. If the current supply chain issues are addressed, and battery and solar PV costs decline as previously projected, up to 9,000 MW (90%) of the peaker capacity can be replaced at a net cost of $5/kW-month (Figure 54).

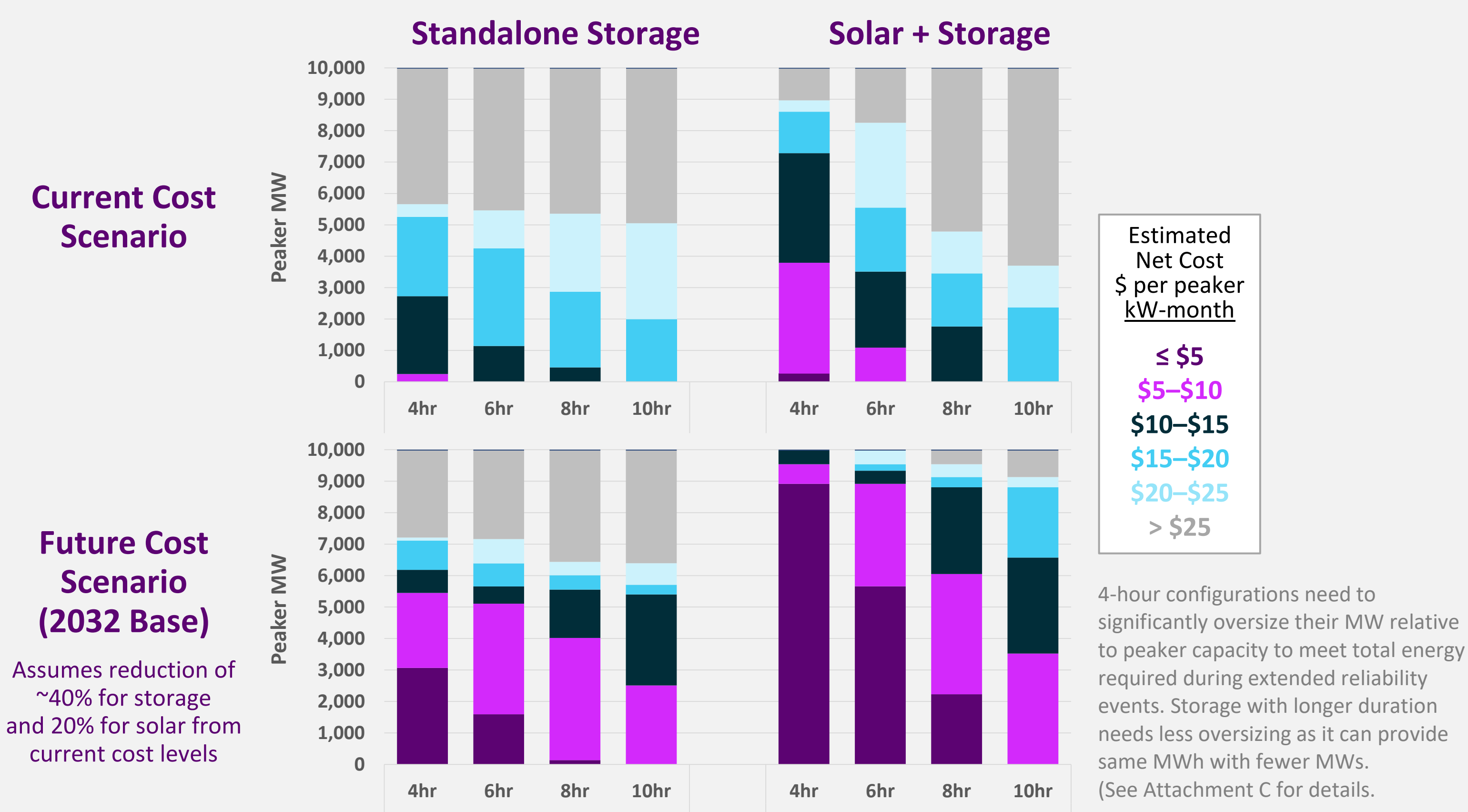


Figure 54: Distribution of peaker replacement net costs with no limitations on grid interconnection (2022 $).

Exactly how much peaker capacity can be replaced, however, will depend upon site-specific considerations, including: (a) the peaker's relative to-go costs to stay online, (b) whether or not the energy storage replacement can obtain interconnection rights to oversize its MW capacity relative to peaker's capacity, (c) charging and other operating constraints identified by the CAISO Local Capacity Technical studies (CAISO 2022), and (d) whether or not solar PV can be developed at a reasonable cost within the local capacity-constrained area.

Third-party developers of distribution-connected resources may be able to offer creative and low-cost solutions that bypass land, interconnection, and other constraints by distributing interconnections across the local grid, while also offering downstream benefits of outage mitigation and distribution system support.

More generally, <u>a more robust competitive market for distribution-connected installations may be able to offer creative and low-cost solutions to a range of difficult local grid problems, including peaker replacements.</u>

Stakeholders commented on disconnects between (a) the CPUC's long-term resource planning and procurements framework and (b) its recognition of local area needs, such as local RA capacity and other grid services that would be needed for peaker replacements. Based on our analysis of market evolution, we emphasize local area needs also span community-level outage mitigation and distribution system support.

Although we did not analyze procurement mechanisms for peaker replacements, we recognize importance of integration of local area needs in long-term resource planning and procurements. Improvements here would provide a key platform for resources to stack transmission and distribution service and thus produce a more diverse and cost-effective storage portfolio. An example of this type of integration is through improvements in resilience planning discussed in the next section below (page 88).

Recommendations. Considering ways to maximize value of ratepayer-funded resources, open the door to innovative and opportunistic low-cost solutions to solve a variety of local grid problems as the state moves towards its 2045 goals, and clear the path to scaling up installations across all domains, our recommendations to the CPUC are to:

- **<u>Remove barriers to accelerated market transformation</u>** including improvements to third-party project development success rates relative to IOU-owned developments with a focus on:
    - Speeding up and addressing other major developer risks in the IOUs' execution of WDAT interconnection processes;
    - Require that utility procurements include some flexibility to adjust the size and/or use case of a project if the original procurement need (e.g., distribution deferral) shifts.
    - More generally, incorporation of more value streams into individual IOU solicitations, including both system-wide and local area services.
- **<u>Enable multiple use applications</u>** by requiring distribution-connected resources to offer transmission grid-level services when idle and minimize extended periods of standby, following MUA guidelines. As a starting point and to build more real-world case studies with clearly-defined multiple services, require all utility-owned installations and contracted third-party distribution deferral projects to (a) with distribution deferral as the priority service, define specific time periods and/or portions of resource capacity that could be available to serve the transmission grid, (b) if significant capacity is available, seek participation in the CAISO marketplace, and (c) if CAISO participation is not feasible, articulate specific operational and/or financial reasons why.

Improve the Analytical Foundation for Resilience-Related Investments

Chapter 1 (Market Evolution) shows how the IOUs and stakeholders tested the distribution-connected microgrid and islanding use cases through several early pilots and demonstrations. Projects such as SDG&E's Borrego Springs microgrid helped to bring these use cases to technological maturity. In 2022, the distribution-level outage mitigation use cases are not yet commercially viable due to no clear monetization of this service as a community-level insurance product. At the customer level, however, growth in SGIP has produced a mature market for installations and, with it, more access to outage mitigation services through a stacked or primary use case.

We observe a rapidly increasing awareness of, and need for, the outage mitigation use case. In response to 2019 PSPS events, the Equity Resiliency budget was created under SGIP to support vulnerable customers in high wildfire threat areas. Then, rolling blackouts in 2020 highlighted major challenges in resource planning and grid operations in the context of climate change and extreme weather. This further elevated the need for resilience planning.

Chapter 2 (Realized Benefits and Challenges) further describes how customer outage mitigation needs, awareness, and value increased significantly after the 2019 PSPS events. At the customer level, residential customer adoption of energy storage for resilience in 2020–2021 under the SGIP Equity Resiliency budget was strong while non-residential customer adoption shows evidence of barriers to adoption. We find that estimates of the value of outage mitigation are indicative at best due to lack of California-specific and statistically significant estimates of customer impacts. This presents challenges to understanding the size of the outage risk problem, how outage mitigation value weighs against other services energy storage can provide, and how grid-scale versus distributed investments compare from a societal perspective.

<u>Outage mitigation needs at the customer and community level are growing, but the size of the problem (avoidable outage cost or value of lost load) is not yet well measured and thus cannot be fully integrated into a benefit/cost evaluation framework.</u>

We used a conservative value based on industry research but likely do not capture the severity and diversity of impacts on customers.

Resilience planning and solutions at the customer and community level are needed. Going forward, the ability of energy storage to provide outage mitigation to customers and communities is an important piece of the puzzle for reliable and resilient electricity service. Customer outage mitigation use cases create electricity supply for customers that is more resilient to all upstream grid failures, whether the failure is due to PSPS, rolling blackouts, impending wildfire, or another catastrophic event. In terms of impacts on customers the 2020 blackouts resulted in only a few hours of outage, compared to more severe and frequent outages driven by PSPS. Customers living or doing business in California's high wildfire threat areas, which cover a huge portion of the state, can reasonably expect multiple multi-day PSPS outages every year during wildfire season. Distributed energy storage (distribution-connected and customer-sited) is uniquely positioned to mitigate negative consequences of PSPS outages and all other upstream grid failures. This points to a need for resilience planning and solutions at the customer and community level that include distributed storage. This also leads to foundational questions on what exactly resilience is and how to plan for it.

Planning efforts are not guided by a common definition of resilience. The state agencies and key stakeholders currently discuss resilience with no common definition or specific resilience evaluation metrics to support the resource planning decision-making process. Without this definition, it is not clear how to size the resilience problem or best identify solutions across grid domains and resource types. SGIP has been a key mechanism for addressing that need and directing funds to the most vulnerable customers. But how SGIP funds perform at the customer level versus community level, or compared to other types of procurement approaches, is unknown.

<u>California is in need of a specific definition of resilience and resilience objectives in order to build more coordinated and data-driven resilience planning and investments across the state.</u>

A definition of "resilience" is yet another area in which California will need to break new ground as the term is not well defined in the electricity industry as a whole. In this report we refer to resilience as:

The ability of the grid to serve critical sites and customers' essential electricity needs under a variety of knowable extreme grid stressors and in the event of a system failure.

By "grid" we mean the entire grid from the bulk power system all the way to customer-sited resources. And by "essential electricity needs" we mean the basic level of electricity service each customer needs, such as an essential level of lighting, temperature control, and communications, especially during an emergency.

Alternative definitions on the national stage are highly conceptual. They are not sufficiently focused on the impacts to customers of system failures to be translatable into a resource planning framework across all grid domains. Agencies under the Department of Energy have built upon the Presidential Policy Directive (PPD) 21 on Critical Infrastructure Security and Resilience. The National Renewable Energy Laboratory (NREL), for example, defines resilience as "The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions through adaptable and holistic planning and technical solutions." FERC and the RTOs under its jurisdiction focus on "resilience of the bulk power system" and have built upon a definition proposed in 2009 by the National Infrastructure Advisory Council: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events."

Elsewhere in the industry's resilience planning efforts we observe varying degrees of focus on mitigation and adaptation (e.g., reducing risk) versus emergency preparedness and recovery (e.g., managing the unavoidable residual risk), depending on the agency or entity's role. Energy storage has an important role in both dimensions. It can support nimble and robust power supply at the bulk grid level *and* it can serve customers and aid in system recovery in the event of a transmission or distribution system outage. Within California's resilience planning framework it is important to capture both of these dimensions.

The Resiliency & Microgrids Working Group, under the CPUC's microgrids proceeding (CPUC 2019), have made significant advancements in exploring the meaning of resilience and in developing a foundational "4 Pillar Methodology" for approaching resilience evaluation and valuation. Development of a more tangible definition of resilience that (a) is useful across a wide range of resource planning activities and (b) can be used to develop specific resilience evaluation metrics are among the important next steps in application of the 4 Pillar Methodology in the state's resource planning activities.

A stronger resilience investment framework is needed to weigh the full potential ratepayer and societal benefits of customer-sited installations. Our analytics in **Chapter 2 (Realized Benefits and Challenges)** focus specifically on the risk and occurrence of PSPS as a major driver of resilience value during the 2017–2021 timeframe. This outage mitigation value is a private benefit that goes to the customer who installs storage—it is not a ratepayer benefit. However, <u>the depth of potential benefits to ratepayers of customer-sited energy storage depends crucially on the value proposition to individual customers</u>.

	[1] Ratepayer B/C Ratio < 1.0	[2] Ratepayer B/C Ratio > 1.0
[A] Individual Customer B/C Ratio < 1.0	**[1A]** **NON-MONETIZED BENEFIT** *Example investments:* Most earlier SGIP projects *Example policy drivers:* Innovation, market transformation	**[2A]** **RATEPAYER BENEFIT** *Example investments:* Grid-scale storage *Example policy drivers:* Ratepayer + societal benefits
[B] Individual Customer B/C Ratio > 1.0	**[1B]** **CUSTOMER BENEFIT** *Example investments:* *Projects funded by* SGIP Equity Resiliency budget *Example policy drivers:* Equity, overcome financing hurdles	**[2B]** **ALL BENEFIT** *Example investments:* Subset of customer-sited storage projects with synergistic use case *Example policy drivers:* Ratepayer + societal benefits

Figure 55: Investment and policy drivers and implications to support customer-sited installations based on ratepayer and/or private customer benefits.

Figure 55 shows a summary of investment and policy implications for customer-sited installations that yield net ratepayer benefits (column [2]) and/or net private benefits to individual customers (row [B]). Starting with top-left quadrant [1A], installations that yield no ratepayer benefits or private benefits would not be funded without policy intervention. Early pilots and programs fall into this category for the purposes of longer-term policy objectives like innovation and market transformation.

Projects that fall under bottom-left quadrant [1B] of Figure 55 yield no net ratepayer benefits, but they do yield net benefits to the individual customer. Based on our research and indicative analysis we expect outage mitigation value to be a major driver of these investments. Customers with high outage risks will understand their own private resilience benefits the most (i.e., how much an outage costs them), and they can best decide if it is more economical to install storage than to endure outages. Customers who can pay when it is economical to do so will install. Policies do not need to intervene with this decision unless customers cannot install even when it is economical to do so (e.g., due to a financing hurdle).

Another reason for policy intervention in [1B] is to shift the economics of a project from quadrant [1B] to quadrant [2B] to produce net benefits to both ratepayers and the individual customer. Our recommendations to Bring Stronger Grid Signals to Customers suggest a route to achieving this movement but it is still unclear what the full potential of [2B] is.

Improved data on the costs and benefits customers face are needed to better gauge the depth of the market for customer-sited energy storage installations (i.e., how many potential customers are there in row [B]?). This would indicate how much storage capacity individual customers might be willing to co-fund that could produce both private benefits and some grid benefits to ratepayers in quadrant [2B]. If customers can co-fund at levels that make ratepayer-funded portion of the costs more comparable to transmission-connected installations, then a mutually-beneficial multi-use application can be achieved. These would be the customer-sited installations that have the potential to avoid investments on the bulk grid and to support downstream societal benefits that grid-scale energy storage cannot provide. But without a better analytical foundation—including improvements to estimates of value of lost load, future resilience risk profiles (discussed next), customer installation cost data, and a resilience planning framework—the market depth for this use case is unclear. Our future potential benefit estimates assume that the equivalent of 1–2 GW out of about 4 GW in customer-sited installations fall into this multi-use application (quadrant [2B]) within the next decade. While the limited data indicate this is a conservative estimate, a stronger analytical foundation for assessing the full benefit potential for customer-sited installations can provide much-needed insights.

Going back to quadrant [1B], better information on the depth of the market for customer-sited energy storage installations is also needed to guide future funding for resilience equity purposes. As of 2022 SGIP's total Equity Resiliency budget is $660 million with most participation by residential customers. With today's data limitations it is not clear how much more funding will be needed in the future. It may unrealistic to expect SGIP funds can install storage at every individual home that qualifies under Equity Resiliency. Investing in Equity Resiliency at the community level may be more cost-effective but we observe very little adoption in SGIP so far and it is unclear why. The energy storage use cases of schools and colleges, in particular, demonstrate relatively high value to the grid compared to other non-residential SGIP participants and they are logical community hubs for people to access essential electricity service during an emergency. Improved information on the extent of the resilience problem for customers who cannot pay can help inform (a) what level of Equity Resiliency funding is needed in the future, and (b) how much of the resilience investment should be at the individual customer level versus the community level.

Opportunities are emerging to better understand the rapidly changing and future climate resilience risk profile. Eligibility requirements under SGIP are based on a historical geospatial risk profile that has changed and likely will continue to change meaningfully at the property level. Customers qualify if they previously experienced two or more PSPS events or if they are within a Tier 1 or Tier 2 High Wildfire Threat District (HWTD) area. The HWTD maps were approved by the CPUC in 2018 (via disposition letter in response to Advice Letters 5211-E and 3172-E) but developed in the 2016–2017 timeframe. Significant advancements have been made in wildfire risk characterization over the past five years, and new information on long-term risks from the Intergovernmental Panel on Climate Change Sixth Assessment Report (IPCC 2022) is in the process of being incorporated into wildfire risk assessments. Multiple research groups deployed by the CEC and grid planners across the state are studying the IPCC climate projections closely to better understand future extreme conditions and human vulnerabilities. As mentioned earlier in this chapter, a recent coordinated effort, initiated by the CEC's solicitation GFO-21-302 and launched in 2022, aims to build a resilience planning framework and re-parameterize the state's planning model inputs and assumptions to capture key climate-related uncertainties and risks to future electricity supply and delivery to customers and communities in California. SGIP and other initiatives related to resilience planning will need to be updated periodically with new information on wildfire risk and other emerging climate-related grid vulnerabilities.

Recommendations. Considering the many challenges in identifying and addressing outage mitigation and resilience needs our recommendations to the CPUC are to:

- **Continue focus on equity and resilience in SGIP** to support customers with high outage risks but inability to pay for a cost-effective storage solution.
- For the purpose of improving CA's analytical framework for resilience planning overall, estimating the extent of the resilience problem for disadvantaged and low-income customers, and estimating the market depth for customer-sited energy storage for resilience:
  - **Pursue initiatives to significantly improve the state's understanding of the cost of outages** (value of lost load) on a diversity of customers, communities, businesses, schools, and critical sites. The estimates of value of lost load should be California-specific and include:
    - Distinctions in outage duration, like impacts of multi-hour (representing rolling blackouts) versus multi-day (representing PSPS) outages;
    - Distinctions in the geographic extent of outages, like impacts of outages on a distribution segment versus on multiple contiguous communities;
    - Distinctions in the environmental and weather context of the outages, like impacts during a normal weather day versus during a heat wave with surrounding wildfires and smoke;
    - Distinctions in financial drivers to the customers' ability to withstand an outage;
    - For each customer type analyzed, estimates of what share or quantity of electricity demand is essential (high impact if lost) versus discretionary (low impact if lost);
    - The cost of outage warnings (e.g., CAISO alerts and warnings, PSPS warnings) even if outages are not implemented.
    - Track and report total installation costs of customer-sited energy storage, using data collected through SGIP, for use in benefit/cost evaluations that consider the full spectrum of services provided by distributed energy storage.
  - **Expand and periodically update estimates of customer resilience-related vulnerabilities**, going beyond wildfire risks and PSPS, grounded in up-to-date and spatially granular long-term forecasts of environmental and weather risks. This would be in collaboration with the CEC Energy Research and Development and Energy Assessments divisions and for use in the CPUC's resilience planning including resilience-related program eligibility requirements.
  - **Further investigate barriers to non-residential enrollment under SGIP Equity Resiliency budgets**, including consideration of additional eligibility criteria for sites with high-value and synergistic use cases such as schools and colleges with solar PV to offer community-level resilience.
  - Given new findings on resilience needs and value from the efforts above**, further analyze the market potential and tradeoffs of developing distributed versus grid-scale storage to improve resilience**. This would be in collaboration with the state's resource planning community and used to assess the implications of IRP procurement plans and other CPUC efforts (e.g., SGIP, ELRP, retail rate design) on future resilience.

Enhance Safety

Chapter 1 (Market Evolution) shows how California has become the national leader in energy storage development. By the end of 2021 California's grid-scale installations represented 44% of all installed capacity in the country. In mid-2022 the state's planned installations represented 45% of all planned installations in the country. In parallel, customer installations under SGIP grew significantly with over 20,000 installations and hundreds of developers and installers available to customers in the marketplace.

Chapter 2 (Realized Benefits and Challenges) shows how the state's leadership in energy storage development is likely to continue and accelerate as utility procurements ramp up to meet system RA capacity needs. We also discuss in Chapter 2 how the national and international industry responded quickly to the disaster at the McMicken facility in Arizona and to other safety failures at battery energy storage sites around the country and the world. Events repeatedly demonstrate that good safety management requires much more than developer and operator adherence to the technicalities of risk mitigations in manufacturing and system components.

<u>The industry's lessons learned and best practices identify a need for California's state and local agencies to look beyond the scope of codes and standards.</u>

Codes and standards are critical but they are a subset of best practices. Three safety management gaps stand out that require the engagement of state and local agencies: the need for robust and proactive communication among all parties involved to disseminate information about safety risks and effective mitigations, the linkage between safety and system reliability, and the need for consistency of speed and quality in the permitting process across all local jurisdictions.

Going forward, the state may need to continue building nearly 2,000 MW storage per year on average to meet 2045 clean energy goals. Based on the rate of events around the country, California can expect at least a handful of safety events across the storage fleet over the next ten years. When events do happen, they tend to occur within 1–2 years of a resource being online. We know from efforts at the federal level and in other states that it can take years to address safety management gaps due to the number of parties involved who have different information and perspectives on safety.

<u>California therefore faces an unprecedented situation to address these safety gaps quickly and for a current and future battery storage fleet that is larger than anywhere else in the country.</u>

It is particularly important for the state to act now so it can influence system and site designs for quickly-approaching planned new installations. How these gaps are addressed not only has implications for the severity of events and impacts to people and communities, but for electricity system reliability, and for the speed and quality of local review.

Safety directly impacts system reliability.

The implications of safety events on system reliability could be extensive across a large fleet of energy storage with overreliance on national and international codes and standards. This is especially concerning in the California context of local environmental conditions, climate change, and co-location with large volumes of solar PV. Lithium-ion battery performance, safety failure modes, and safety event outcomes are sensitive to environmental conditions. This is an area that warrants further study from a combined safety and system reliability perspective unique to the state agencies. During the Victorian Big Battery (VBB) event in July 2021, for example, thermal runaway in one isolated container propagated to a second container despite prior system evaluation under the industry's gold standard UL 9540A test method (Figure 56). Investigation revealed a disconnect between the maximum wind speed in the UL 9540A testing environment (12 miles per hour) versus actual conditions on the day of the event (36 miles per hour) and the need to consider local conditions in site design. The regulator involved expressed this event as a "near miss" which could have been much worse in another time of the year when wind speeds are significantly higher. This situation has obvious parallels to California's (growing) wildfire season and wind speeds on high wildfire threat days.

VBB's system and site design utilized the modularity of battery energy storage in a way that contributed to efficient recovery from the event. Two hundred out of 212 containers (total of 300 MW/450 MWh) were brought back online within a few months. This is in contrast to a relatively minor safety event at the Moss Landing facility in California (Figure 57) that shut down the entire 300 MW/1,200 MWh facility for almost a year. The event occurred in September 2021 and the facility came back online in late June 2022. A long duration outage spanning multiple seasons has many potential grid impacts, including during the summer when RA capacity needs are highest and spring when solar integration challenges are more pronounced. Unfortunately, an almost year-long recovery from a safety event is not uncommon. In 2012, an incident with a lead acid energy storage system at the Kahuku Wind Farm in Kahuku, Hawaiʻi destroyed the entire battery system and resulted in a year-long outage of the wind facility. The 2019 event at McMicken halted Arizona Public Service's energy storage development activities for two years. And, in South Korea, rampant safety issues required a moratorium on new installations for a year while the government investigated.

Pressure is on the local permitting process. The speed at which California is developing energy storage puts pressure on local authorities' review and permitting process. Many challenges are becoming apparent to achieving consistent and timely permitting without sacrificing the quality of safety reviews and system and site designs. In July 2021 Governor Newsom signed an Emergency Proclamation which granted the CEC special authority to license certain types of battery storage at certain sites through October 2022. This temporarily provided a relief valve but local authorities still shoulder much of the burden. The CEC is well positioned to support local authorities with training, knowledge-share forums, data, and boilerplate materials to guide the review and permitting process. In New York, for example, the New York State Energy Research and Development Authority (NYSERDA) developed training webinars and a guidebook for local governments including model (boilerplate) law for storage system requirements, a model permit application, a model inspection checklist, and information on how battery system safety is incorporated into state fire and building codes.

Figure 56: Victorian Big Battery Project event (July 2021).

(Image credit: Fire Rescue Victoria)

Figure 57: Moss 300/Dallas Energy Storage installation.

(Image credit: Vistra Corp.)

Recommendations. With recognition that safety is a multi-agency issue and the CPUC, CEC, and local agencies will need to work closely together, our recommendations to the CPUC are to:

- **Form a storage safety collaborative**: The CPUC Energy Division and Safety and Enforcement Division to build upon their coordination with the CEC to form a safety collaborative with the purposes to (a) define roles and responsibilities in the context of a multi-agency risk management plan, (b) promote two-way knowledge exchange with local authorities and emergency responders on installation characteristics, possible risk factors including vulnerabilities to local environmental conditions, and the effectiveness of mitigations, (c) facilitate rapid absorption and integration of safety best practices into local laws, building and fire codes, site-specific emergency plans, inspection checklists, permitting processes overall and (d) identify and implement measures to minimize storage and any co-located resource outages and recovery periods following a safety event. Importantly, all safety collaborative meetings and materials should be transparent and available to the public.
- **Explore the safety-reliability link:** The CPUC and utilities to consider development of a safety and reliability score in the utilities' least-cost best-fit resource evaluations, based on guidance from the safety collaborative and/or developer guarantees or remedies for a safety-related event.
- **Develop guidance materials for local agencies to build from**: The CPUC and the CEC to consider development of training webinars and guidebooks for local governments such as model (boilerplate) law for storage system requirements, a model permit application, a model inspection checklist, and information on how battery system safety is incorporated into state fire and building codes.

Improve Data Practices

Chapter 1 (Market Evolution) points out two data gaps that hamper the energy storage market acceleration process. One gap is inconsistent documentation of lessons learned from pilot and demonstration projects that are funded through channels outside of the CEC's EPIC and PIER grant programs. Much information is lost if a pilot or demonstration project does not yield documentation on lessons learned that is widely available to the industry. Another data gap is apparent in energy storage installed cost information. For this study we collected data on utility RA capacity contract payments to third parties and on the installed costs of utility-owned projects. In these data we observe trends in cost reductions, but it is not clear (a) how installed costs of third parties versus utilities compare, or (b) whether cost reductions were due to cost components driven by global markets or cost components driven by state and local factors (e.g., soft costs).

Chapter 2 (Realized Benefits and Challenges) describes data collection and management challenges that would not have occurred with any other type of controllable and metered resource on the grid. The challenges stem partly from insufficient and inconsistent data collection, retention, management, and reporting practices among different types of energy storage resources. The challenges also stem from institutional barriers to analysis of a resource fleet that crosses grid domains, many types of services to the grid, many different areas of resource planning, and many traditionally separate areas of expertise. In our data collection process we often encountered information barriers among experts in different areas of planning, procurement, and operations.

We collected as much information as we could in order to assess historical operations accurately and in the right market and policy context. Through that process it is clear that more needs to be done to ensure the CPUC has complete and reliable access to energy storage data across the ratepayer-funded fleet needed to monitor and assess the performance of resources and policies.

Going forward, the data collection process we implemented in this study is not sustainable. The state is at the beginning of explosive growth in the energy storage market across all grid domains, types of installations, and use cases. Left unchecked, today's inconsistencies in data collection and validation, completeness, reporting and retention, data formats will worsen considerably. Furthermore, the rate of development combined with the modularity of battery energy storage to develop sites and contract in a variety of ways makes it increasingly difficult to track what resources are on the system. These data challenges threaten the ability of the CPUC to access timely, complete, and reliable information it needs to implement effective and nimble policies.

Several existing practices and templates may help improve access to the most essential energy storage data. For example:

- The CEC's EPIC and PIER grant programs provide an effective template for documentation of **pilots and demonstrations** for projects funded through the General Rate Case.
- The Self-Generation Incentive Program—through its data reporting requirements for non-residential installations, website tools, and evaluation studies—implements California's most comprehensive and consistent approach to energy storage **operating data** management and is a model to expand upon and to follow for the rest of the energy storage fleet.
- The Federal Energy Regulatory Commission (FERC) recently switched to a relational database structure for collecting and managing information needed for its market-based rate (MBR) program. FERC describes the following benefits: "The relational database construct modernizes the Commission's data collection processes, eliminates duplications, and renders information collected through its market-based rate program usable and accessible for the Commission" (FERC 2019). FERC's MBR database is, in some respects, larger and more complex than what is needed for tracking energy storage development. However, its relational structure provides a template for efficiently capturing **resource characteristics** and the modularity of energy storage's MW capacity, MWh capacity, and contracting arrangements over time in one centralized database.

- In 2018 the New York Public Service Commission (NY PSC) issued an Energy Storage Order which identified high soft costs as a major barrier for energy storage deployment in the state. The NY PSC approved several initiatives to achieve soft cost reductions in the state and directed New York Department of Public Service staff to prepare an annual report to keep track of **installed cost** of energy storage systems and document progress towards reducing soft costs in that year. To that end, the state increased emphasis in collecting detailed cost data from storage projects supported by various state initiatives in New York. For example, NYSERDA requires all applicants to submit data on total installed costs and a breakdown of cost components for hardware, engineering & construction, permitting & siting, and interconnection before they can receive any payments under New York's market acceleration program (the Bridge Incentive program).

Recommendations. With the objective to clear the path for the CPUC to access the minimum data it needs to assess the performance of energy storage resources and effectiveness of policies our recommendations to the CPUC are to:

- Using CEC's EPIC and PIER final report templates as a guide, **require that all pilot and demonstration projects funded by ratepayers through other channels (e.g., General Rate Case) yield a research report accessible to stakeholders in a timely manner**.
- **Develop universal and standardized data collection, retention, quality control, and reporting of interval-level operations for all ratepayer-funded energy storage resources**, modeled after the SGIP requirements for Performance Based Incentives and expanded to include information on state of charge, standby losses, and operations during upstream grid outages.
- Expand upon recent data collection efforts to **develop a relational energy storage database** that includes data compiled in this study and across multiple CPUC groups, linkages to energy storage data being collected by the CEC, and linkages to data collected by the multi-agency safety collaborative described above. The database should be broadly accessible and useful among all CPUC groups and updated monthly. To the extent confidentiality restrictions allow, data should be routinely posted and shared with stakeholders.
- Routinely **collect project-specific cost data** across all ratepayer-funded energy storage procurements, including total installed cost and a standardized breakdown of cost components (e.g., hardware, engineering & construction, permitting & siting, and interconnection) with the purpose to track cost trends in a timely manner and develop policies to facilitate cost reductions (e.g., soft costs).

Our work products to the CPUC include suggested templates for these data collection categories.

Concluding Remarks

Overall, the energy storage market in California matured significantly during our study period, in terms of technologies and use cases. For short duration energy storage, California surpassed its pilot phase and achieved commercial scaling of lithium-ion battery technology in both customer-sited and transmission-connected installations. More recently-installed projects indicate significant net benefits will be realized with a future storage portfolio although we see evidence of untapped potential in distributed resources.

We estimate that the planned 13.6 GW transmission-connected energy storage portfolio has the potential to yield $835 million to $1.34 billion of annual net grid benefits by 2032, relative to a grid without energy storage. Recent planning projections suggest customer-sited energy storage installations will reach roughly 4 GW by 2032. If these resources can be partially incentivized to capture 30–50% of the energy value provided by grid-scale energy storage and also provide 1–2 GW of capacity contribution (in the form of net peak reduction) it can potentially avoid 1–2 GW of grid-scale storage investment, that would otherwise be needed and provide an additional $143–$334 million per year in net grid benefits. This would bring the total storage portfolio-wide 2032 net grid benefits to a range of $1–$1.6 billion per year in 2022 dollars, as summarized in Figure 58 below.

In this study we expand upon the state's planning and analytical practices to learn from historical resource-specific storage operations, at a fine temporal and spatial granularity, across all grid domains, and across all potential services offered by energy storage resources. In its next energy storage procurement study the CPUC will have even more historical data to work with—likely with more complex market interactions as storage penetration increases. In future studies we recommend continuing to build upon the framework we developed here, incorporation of other technologies and longer durations as they develop in the marketplace, consideration of market price impacts in the benefits counterfactual, and incorporation of future state agency and stakeholder data and analytical innovations to refine our future outlook.

		High Storage Cost Scenario	*Low Storage Cost Scenario*
Estimated 2032 Net Grid Benefits of 13.6 GW Planned Transmission-Connected Energy Storage Portfolio	[1]	**$835 million**	**$1.34 billion**
Additional Net Grid Benefits from Better Utilization of Future Customer-Sited Storage			
30% replacement	[2a]	$200 million	$143 million
50% replacement	[2b]	$334 million	$238 million
Total Estimated 2032 Net Grid Benefit of Storage			
30% replacement	[1]+[2a]	$1.04 billion	$1.49 billion
50% replacement	[1]+[2b]	$1.17 billion	$1.58 billion

Total 2032 Net Storage Benefit Range $1–$1.6 billion/year
(in 2022 dollars)

Figure 58: Estimated 2032 net grid benefit potential of the planned energy storage portfolio (2022 $).

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ATTACHMENTS

A: Benefit/Cost and Project Scoring of Historical Operations

B: Cost-Effectiveness of Future Procurement

C: Cost-Effectiveness of Peaker Replacement

D: Procurement Policy Case Studies

E: End Uses and Multiple-Use Application Case Studies

F: Safety Best Practices

G: End of Life Options

H: Stakeholder Engagement

Access the main report and attachments at www.lumenenergystrategy.com/energystorage.

ATTACHMENT A: HISTORICAL BENEFIT-COST ANALYSIS AND SCORING OF ENERGY STORAGE PROJECTS IN CALIFORNIA[1]

This attachment provides details on our analysis of actual energy storage operations, benefits, and costs within the 5-year study period 2017–2021. From this analysis, we seek to better understand to what degree the CPUC energy storage procurement framework helps to meet state policy goals. We also assess:

- Are ratepayers realizing net benefits from its energy storage investments?
- What types of installations and use cases demonstrate meaningful growth in value?
- Are any sources of ratepayer value left untapped?
- Are some types of installations and use cases not scaling up and what are the challenges?

In this attachment, we define the scope of the historical analysis, describe key assumptions and metrics, and present the results of the cost-benefit analysis and scoring towards AB 2514 goals.

CONTENTS

[1] This is an attachment to the CPUC Energy Storage Procurement Study Access the main report and other attachments at www.lumenenergystrategy.com/energystorage.

Evaluation Framework

The study follows a two-pronged approach considering both monetized and non-monetized evaluation metrics calculated at the project or cluster level:

1. Cost-effectiveness test reflects monetized benefits and costs, unadjusted for statutory and solicitation-specific preferences, and
2. Effectiveness at meeting AB 2514 goals is quantified via scores that reflect the alignment of project's use cases with the state goals.

	Evaluation scope	Evaluation metrics
Monetized	Cost-effectiveness	Benefit-cost ratios
Quantified	Effectiveness at meeting AB 2514 goals	Scorecards

Figure 1: Two-pronged study scope and approach.

The overall approach utilized in the study is grounded in California's existing practices and methodologies, namely those reflected in the state's Standard Practice Manual for cost-effectiveness tests, the state's Avoided Cost Calculator for distributed energy resources, and the utilities' various Least-Cost Best-Fit calculations for bid evaluations in resource procurements. For an apples-to-apples comparison among projects, we applied a single framework across all types of energy storage projects across all grid domains considered. Consistent with the state practices, estimated benefits reflect the avoided cost of market alternatives to the energy storage resource analyzed. Benefit-cost analysis focuses mostly on total ratepayer impacts but also consider societal impacts such as GHG emissions reductions, and benefits that flow directly to customers with energy storage installed such as resilience value associated with customer outage mitigation.

Data Sources

Energy storage operational data was provided by California IOUs, CAISO, and CPUC. CAISO also provided detailed historical market data, including resource-specific settlements, market prices, and other system data. PG&E, SCE, and SDG&E provided detailed information on most of their energy storage procurements including bid evaluation results, contract information, actual ratepayer costs, resource characteristics, and a variety of other supporting information.

Interpretation of Evaluation Results

Our evaluation metrics are designed to show relative performance of individual energy storage resources or groups of resources with the purpose to identify successes and challenges in use cases and their potential to support the state's energy goals.

While this historical analysis offers a reality check on conceptual pro-storage rhetoric and generally accepted resource planning assumptions, it also has a few drawbacks. Most importantly, historical market value reflects market and grid conditions that are at times volatile and cyclical, and thus not directly comparable to prospective planning study outcomes under normalized and smoothed future conditions. See Chapter 2 of the main report for more discussion.

Storage Resources Analyzed

Energy storage in our historical analysis includes resources procured by load-serving entities under CPUC jurisdiction. Most of these projects:

- Are counted towards utilities' requirements under CPUC Decision 13-10-040;
- Operated within the 5-year study period 2017–2021; and
- Reached commercial operations by April 2021 (for sufficient operational data to analyze).

To make full use of available data, we also analyzed the operations of three resources procured for system reliability and resource adequacy (Gateway, Vista, Blythe) and not counted towards utilities' requirements under the CPUC Decision 13-10-040.

Overall, the resource set represents 1,571 MW/5,176 MWh of total nameplate capacity, with 976 MW counted by the IOUs towards their CPUC Decision 13-10-040 requirements and 1,374 MW included in our analysis of historical operations. Figure 2 summarizes basic characteristics of these resources, including where they connected to grid, who owns the project, underlying technology, and procurement track. Figure 3 provides a full list of the resources considered in the study, including some of the resources that could not be analyzed due to data limitations.

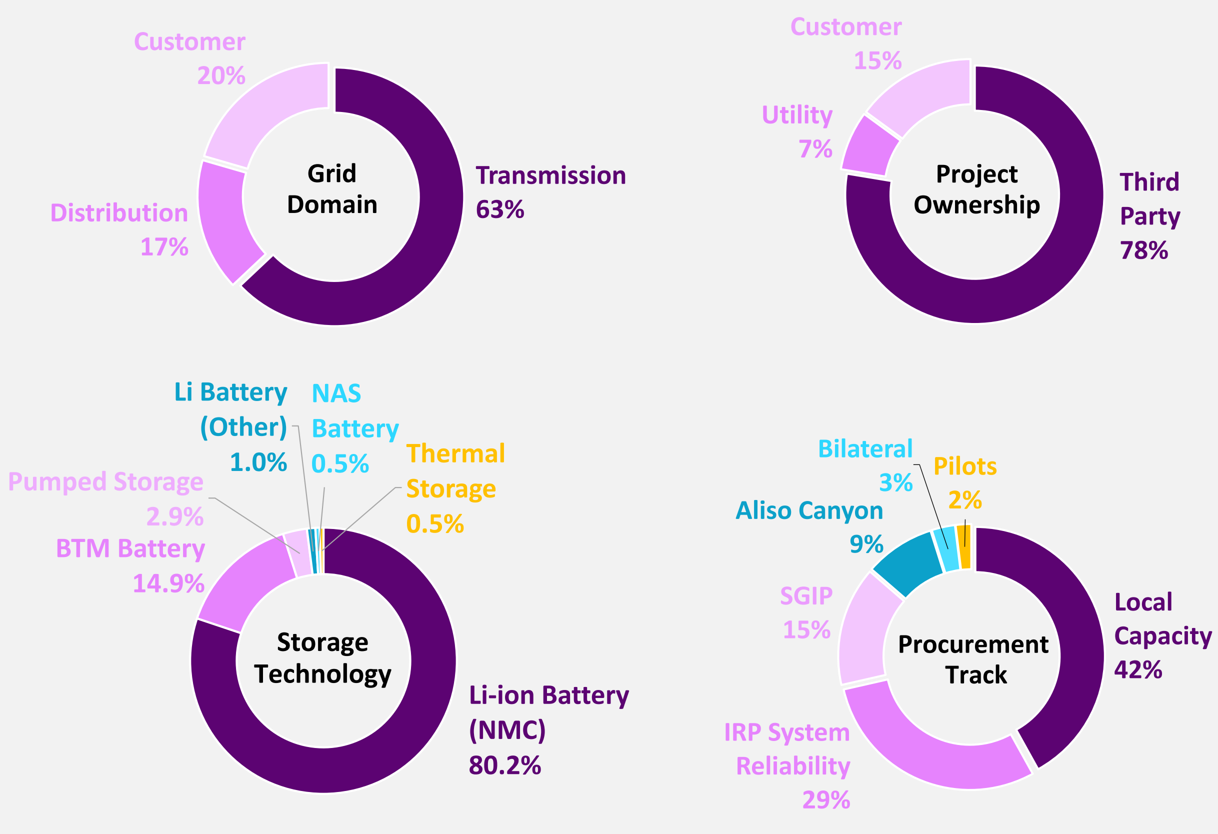
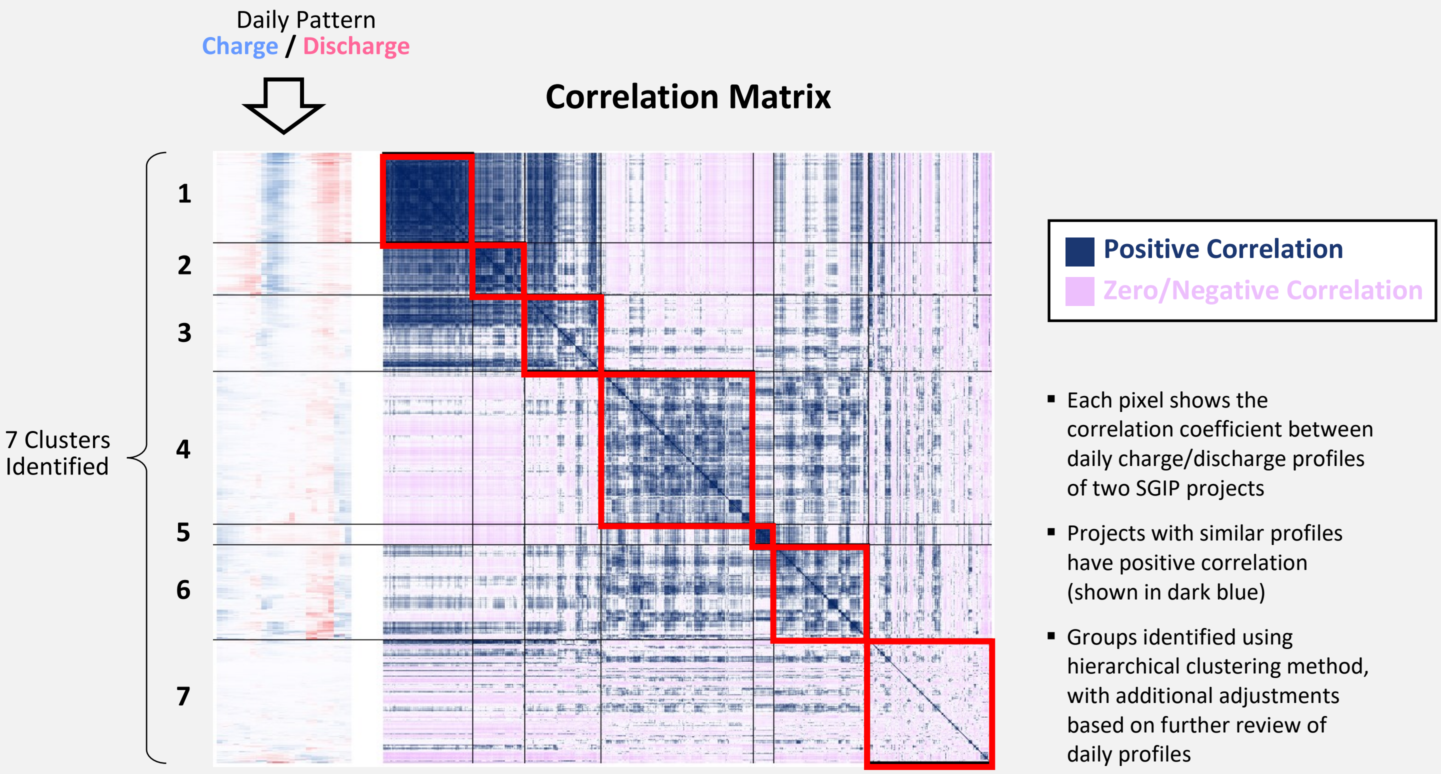


Figure 2: Characteristics of energy storage resources included in the 2017–2021 historical analysis.

		Nameplate							Procurement	MW IOU	MW
	Count	MW	MWh	LSE	Online	Technology	Owner	CAISO?	Track	AB 2514	Analyzed
Transmission-Sited	**8**	**865**	**3,053**							**460**	**865**
3rd-Party	**6**	**845**	**3,044**							**440**	**845**
Vista Energy Storage	1	40	44	SDG&E	Jun-18	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	40
Gateway Energy Storage	1	250	700	Various	Sep-20	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	250
Lake Hodges Pumped Hydro	1	40	240	SDG&E	Aug-12	Pumped Storage	Third Party	Y	Bilateral	40	40
Vistra Moss Landing	1	300	1,200	PG&E	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	300	300
AES Alamitos ES	1	100	400	SCE	Dec-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Blythe Energy Storage II	1	115	460	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	IRP System Reliability	0	115
Utility-Owned	**2**	**20**	**8.6**							**20**	**20**
SCE EGT - Center	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
SCE EGT - Grapeland	1	10	4.3	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	10	10
Distribution-Sited	**33**	**236**	**925**							**236**	**227**
3rd-Party	**7**	**146**	**583**							**146**	**145**
W Power - Stanton - 1	1	1.3	5.2	SCE	May-20	Lithium-Ion (NMC)	Third Party	Y	Energy Storage RFO	1.3	no data
ACORN I ENERGY STORAGE LLC	1	2	6	SCE	Mar-21	Lithium-Ion (NMC)	Third Party	Y	IDER Pilot	1.5	2
AltaGas Pomona	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	20	20
Powin Energy - Milligan ESS 1	1	2	8	SCE	Jan-17	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	2	2
Orni 34 LLC	1	10	40	SCE	Feb-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	10	10
Silverstrand Grid, LLC	1	11	44	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Aliso Canyon	11	11
Ventura Energy Storage (formerly Strata Saticoy)	1	100	400	SCE	Apr-21	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	100	100
Utility-Owned	**26**	**90**	**342**							**90**	**82**
Vaca-Dixon	1	2	14	PG&E	Jul-14	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	2	2
Yerba Buena	1	4	28	PG&E	Jun-13	Sodium-Sulfur	Utility	Y	EPIC / PIER / DOE	4	4
Browns Valley	1	0.5	2	PG&E	Sep-16	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Tehachapi Storage Project (TSP)	1	8	32	SCE	Apr-16	Lithium-Based	Utility	Y	EPIC / PIER / DOE	8	8
Escondido	1	30	120	SDG&E	Mar-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	30	30
El Cajon	1	7.5	30	SDG&E	Feb-17	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	7.5	7.5
Tesla - Mira Loma	1	20	80	SCE	Dec-16	Lithium-Ion (NMC)	Utility	Y	Aliso Canyon	20	20
Smart Grid Stabilization System (SGSS) Unit 1	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Smart Grid Stabilization System (SGSS) Unit 2	1	2	0.5	SCE	Jun-11	Lithium-Ion (NMC)	Utility	N	General Rate Case	2	no data
Mercury 4	1	2.8	5.6	SCE	Dec-18	Lithium-Ion (NMC)	Utility	N	General Rate Case	2.8	2.8
Distribution Energy Storage Integration (DESI) 1	1	2.4	3.9	SCE	May-15	Lithium-Based	Utility	N	General Rate Case	2.4	no data
Distribution Energy Storage Integration (DESI) 2	1	1.4	3.7	SCE	Dec-18	Lithium-Based	Utility	N	General Rate Case	1.4	1.4
Borrego Springs Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Ion (NMC)	Utility	N	EPIC / PIER / DOE	0.5	0.5
Borrego Springs Unit 2	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 3	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
Borrego Springs Unit 4	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	EPIC / PIER / DOE	0.025	0.025
GRC Energy Storage Program Unit 1	1	0.5	1.5	SDG&E	Sep-12	Lithium-Based	Utility	N	General Rate Case	0.5	0.5
GRC Energy Storage Program Unit 2	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 3	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 4	1	0.025	0.072	SDG&E	Dec-12	Lithium-Based	Utility	N	General Rate Case	0.025	no data
GRC Energy Storage Program Unit 5	1	1	3	SDG&E	Jun-14	Lithium-Ion (NMC)	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 6	1	1	1.5	SDG&E	Jun-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 7	1	1	2.3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	no data
GRC Energy Storage Program Unit 8	1	1	1.5	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
GRC Energy Storage Program Unit 9	1	1	3	SDG&E	Sep-14	Lithium-Based	Utility	N	General Rate Case	1	1
Catalina Island Battery Storage	1	1	7.2	SCE	Aug-12	Sodium-Sulfur	Utility	N	General Rate Case	1	1
SGIP Customer-Sited	**22,660**	**390**	**858**							**200**	**205**
SGIP Nonresidential (as of Apr'21)	**1,160**	**244**	**504**							**177**	**205**
SGIP Nonresidential PG&E	330	63	126	PG&E	Various	BTM Battery	Customer	N	SGIP	62	48
SGIP Nonresidential SCE	580	142	293	SCE	Various	BTM Battery	Customer	N	SGIP	85	126
SGIP Nonresidential SDG&E	250	39	84	SDG&E	Various	BTM Battery	Customer	N	SGIP	30	31
SGIP Residential (as of Apr'21)	**21,500**	**147**	**355**							**23**	0
SGIP Residential PG&E	9,900	71	173	PG&E	Various	BTM Battery	Customer	N	SGIP	23	no data
SGIP Residential SCE	7,000	45	108	SCE	Various	BTM Battery	Customer	N	SGIP	0	no data
SGIP Residential SDG&E	4,600	31	73	SDG&E	Various	BTM Battery	Customer	N	SGIP	0	no data
Non-SGIP Customer-Sited	**1,705**	**80**	**340**							**80**	**76**
BTM Battery CAISO PDR	**900**	**70**	**280**							**70**	**70**
HEBT Irvine1 DRES	10	5	20	SCE	Nov-17	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT Irvine2 DRES	10	5	20	SCE	Feb-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	5	5
HEBT WLA1 DRES	50	25	100	SCE	Apr-19	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	25	25
HEBT WLA2 DRES	30	15	60	SCE	Mar-20	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	15	15
Stem Energy DRES - 402040	800	20	80	SCE	Aug-18	Lithium-Ion (NMC)	Third Party	Y	Local Capacity	20	20
BTM Battery non-CAISO	**1**	**0.1**	**0.5**							**0.1**	0
Discovery Science Center	1	0.1	0.5	SCE	Jun-14	Metal Hydride	Customer	N	Other	0.1	no data
PLS/TES	**804**	**10**	**60**							**10**	**6**
Ice Bear PLS - 431058	250	1.92	11.52	SCE	Jan-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431061	250	1.92	11.52	SCE	Apr-19	Thermal	Third Party	N	Local Capacity	1.92	1.92
Ice Bear PLS - 431151	150	1.28	7.68	SCE	Mar-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
Ice Bear PLS - 431154	150	1.28	7.68	SCE	Dec-20	Thermal	Third Party	N	Local Capacity	1.28	1.28
PLS/TES - Chaffey College	1	0.8	4.8	SCE	Jul-16	Thermal	Customer	N	PLS	0.8	no data
PLS/TES - Cypress College	1	0.7	4.2	SCE	Jun-18	Thermal	Customer	N	PLS	0.7	no data
PLS/TES - Mt San Antonio College	1	1.5	9	SCE	Mar-17	Thermal	Customer	N	PLS	1.5	no data
PLS/TES - Santa Ana College Central	1	0.53	3.18	SCE	Jun-19	Thermal	Customer	N	PLS	0.53	no data
Total Storage Across All Domains >>		**1,571**	**5,176**							**976**	**1,374**

Figure 3: List of energy storage resources included in the 2017–2021 historical analysis.

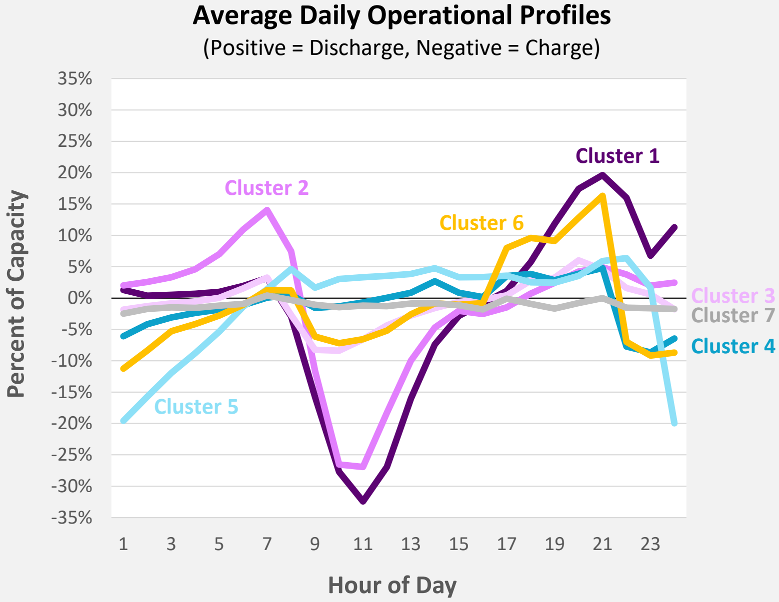


- Each pixel shows the correlation coefficient between daily charge/discharge profiles of two SGIP projects
- Projects with similar profiles have positive correlation (shown in dark blue)
- Groups identified using hierarchical clustering method, with additional adjustments based on further review of daily profiles

Figure 4: Cluster analysis of nonresidential SGIP-funded energy storage projects.

For non-residential SGIP-funded projects, we conducted an analysis to group 654 resources into 7 clusters based on each installation's interval-level operating behavior during the historical period. The results of the cluster analysis are shown in Figure 4 above, and the observed characteristics of the clusters are summarized in Figure 5 next page.

- Clusters 1, 2, and 3 have operating patterns synergistic with the grid: they charge during the day and discharge during the grid's morning and evening ramps into and out of solar generation periods. These resources are mostly schools and colleges, and they have a high solar attachment rate.
- Clusters 4 and 5 demonstrate a traditional demand charge management pattern that operates in discord with wholesale energy markets: storage is discharged steadily throughout the day, mostly unresponsive during morning and evening ramps, then charged at night.
- Cluster 6 operates similar to clusters 1–3, but with significant night charging when renewable supply is not abundant.
- Cluster 7 is a catch-all category for installations that operate with no clear use case consistent with how other non-residential installations operate.



Cluster ID	Project Count (# of projects)	Energy Storage Capacity (MW)	Average Roundtrip Efficiency (%)	Average Daily Discharge (hours/day)
1	96	17.6	78%	1.3
2	56	9.1	75%	1.1
3	82	23.6	75%	0.6
4	164	60.6	77%	0.8
5	22	9.7	83%	1.1
6	102	41.6	77%	1.2
7	132	43.0	65%	0.6
Total	**654**	**205.3**	**74%**	**0.9**

Cluster 1
- Midday Charge
- Evening Peak Discharge

Cluster 2
- Midday Charge
- Morning Discharge

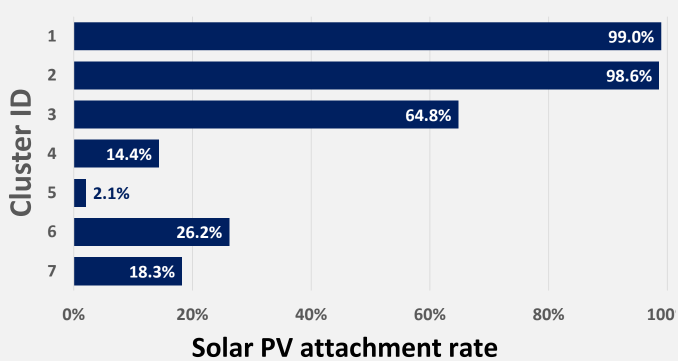
Cluster 3
- Midday Charge
- Morning+Evening Discharge
- Low Utilization

Cluster 4
- Night Charge
- Distributed Discharge
- Low Utilization

Cluster 5
- Extended Night Charge
- Distributed Discharge

Cluster 6
- Midday+Night Charge
- Evening Peak Discharge

Cluster 7
- No apparent charge/discharge pattern
- Low Utilization
- Low Efficiency



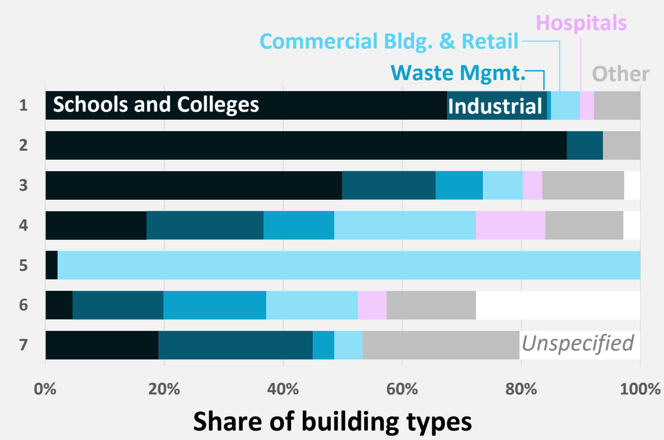


Figure 5: Observed characteristics of non-residential SGIP-funded installations (654 installations in 7 clusters).

Benefit-Cost Analysis

The foundation of the benefit-cost analysis in our study is the California Standard Practice Manual (SPM), which outlines methods for evaluating demand-side programs using various cost-effectiveness tests. The CPUC's 2019 decision under D. 19-05-019 provides guidelines for applying the Standard Practice Manual in an effort to move closer to "a consistent universal framework for assessing the cost effectiveness of all resources, both distributed energy resources and supply side resources." The approved framework adopts total resource cost (TRC) test as primary test for DER filings, and program administrator cost (PAC) and ratepayer impact measure (RIM) as secondary tests.

The scope of our evaluation includes operational energy storage projects across all grid domains, including transmission-, distribution-, and customer-sited projects. Our goal is to apply a consistent approach for projects in all domains, so the results can be compared and ranked across all projects. Even though the Standard Practice Manual was originally developed for distributed energy resources only, the underlying methodology and principles apply to all demand- and supply-side resources, which is why we used it as the foundation of this study.

Figure 6 below summarizes 4 main cost-effectiveness tests and corresponding perspectives:

- First two (participant and RIM tests) are not included because program participant vs. non-participant distinction does not apply to storage projects evaluated in our study. These two metrics typically inform potential cross-subsidies that are importanat for program and rate design, but that is not relevant to this study.
- Our benefit-cost analysis focuses on the total impact to all ratepayers, which is reflected in the perspective of the PAC test.
- We were able to calculate TRC only partially. While we included all societal benefits for all resources, actual project costs were available only for utility-owned projects. Costs of 3rd-party-owned projects under utility contracts are kept confidential, and they are not disclosed to the CPUC or utilities. Given the very diverse scope of procurements, domains, locations, and timelines considered in the study, we decided not to use generic cost assumptions to fill in missing data.

Cost-Effectiveness Test	Approach		
Participant Test	Measures quantifiable benefits and costs to the customers participating in a program	✗	**Participant vs. non-participant distinction does not apply to our study**
Ratepayer Impact Measure (RIM) Test	Measures what happens to customer bills or rates due to changes in utility revenues and costs (only non-participant)	✗	
Program Administrator Cost (PAC) Test	Measures net cost of a program as a resource option based on costs incurred by the utility or program administrator	✓	**For our study, this reflects total ratepayer impact excluding out-of-pocket participant costs**
Total Resource Cost (TRC) Test	Measures net cost of a program as a resource option based on total costs, including both participants' and utility's costs **Societal cost test is a variant of TRC test; (Key differences: lower societal discount rate, effects of externalities (e.g., air quality) and social cost of CO_2 emissions)*	**Partial**	**All benefit streams included, but the actual project costs are available only for a small subset of projects that are utility-owned**

Figure 6: Various cost-effectiveness tests and perspectives.

Energy and ancillary services value	Net of charging costs; Not included under total ratepayer benefits if under RA only contract
Resource adequacy (RA) capacity value	Includes system, local, and flexible RA
Transmission investment deferral value	Overlaps with local RA value; Considered only if storage defers an actual transmission alternative
Distribution investment deferral value	Considered only for distribution-interconnected and customer-sited storage
Avoided RPS cost	Based on avoided renewable curtailments
GHG emission reduction value	A portion of this is already captured under energy value; Considered only incremental value (if any)
Customer outage mitigation value	Private benefit to customers who install distributed storage; Not included under total ratepayer benefits

Figure 7: Benefit metrics considered in the study.

The table above shows various benefit metrics considered in our storage evaluation.

From a societal perspective we consider all benefit metrics listed above, although some can only be provided by distribution- or customer-sited energy storage projects, such as distribution investment deferral or outage mitigation.

Under total ratepayer perspective, we consider net benefits to all ratepayers as a whole. Accordingly, energy and ancillary services value is not included if a storage project is under an “RA only” contract, where the 3rd-party owner of the project keeps wholesale market revenues. Customer outage mitigation is also not included under total ratepayer benefit, as it is a private benefit to customers or communities who install energy storage as a distributed resource.

Bill savings provided by customer-sited storage projects, from societal or total ratepayer perspective, are not additive to other benefits. E.g.; If a residential battery reduces utility costs by $100 and saves $80 in electric bills to the customer who owns the battery, the total ratepayer benefit would be $100, of which $80 would go to the battery owner and remaining $20 would go to other ratepayers. For the purpose of this evaluation, we focus on the total ratepayer impact, and we look into individual bill impacts of customer-sited storage only to understand rate design related barriers towards meeting the state policy goals.

On the cost side, we focused on ratepayers’ share of project costs. For utility-owned storage, we compiled data on actual capital investments and operating costs of the projects based on information provided by the IOUs. For 3rd-party-owned storage, we compiled data on utility contract terms and payments based on in depth review of utility filings, contracts, and actual contract settlement information provided by the IOUs. As described earlier, the total cost of these 3rd-party-owned projects are not available; therefore, we were able to calculate final B/C ratios only from ratepayer perspective. However, we still separately calculate and show all gross benefits from a societal perspective to demonstrate progress towards value stacking.

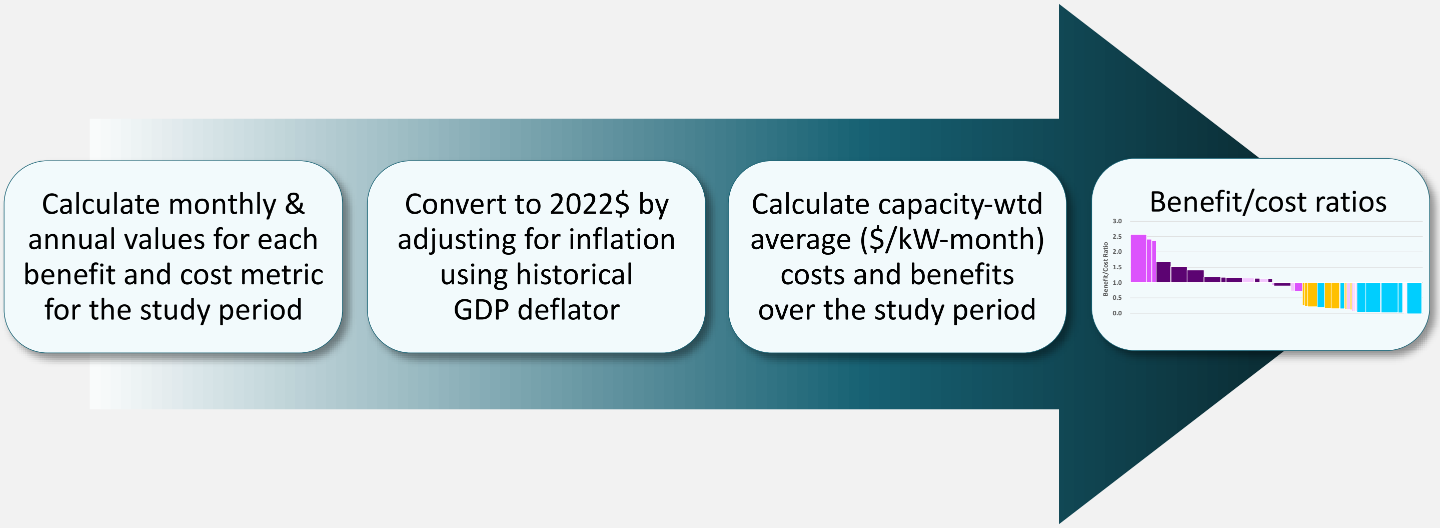


Figure 8: Calculation of benefit-cost ratios for final comparisons.

Figure 8 above shows how final benefit-cost ratios are calculated.

- We first calculate monthly and annual benefit and cost metrics in nominal dollars for each storage resource or groups of resources analyzed. Methodology for calculating each metric is described later in this attachment.
- We then convert the results to real 2022 dollars by adjusting for inflation using historical GDP deflator published quarterly at https://fred.stlouisfed.org/
- Since this is a retrospective study, we do not apply a discount rate or calculate present values.
- After we adjust for inflation, we calculate the total $ over the operational period within 2017–2021 and divide them by the total kW-month over the same period. This normalizes the results for storage capacity and duration of operations. It also accounts for any changes of the project capacity over time (e.g., due to phased development, degradation).
- Last step is to add up all benefits and add up all costs, then divide total benefits by total costs to estimate final B/C ratios that can be compared across projects.

Our evaluation covers only the initially years of operations of most energy storage projects, rather than their full economic lives. This creates an inherent bias against front-loaded cost recovery for utility-owned storage projects. For example, if we had two identical projects with same overall costs and benefits, but one is in the rate base and the other one is contracted, the project in the rate base would have a lower B/C ratio if only initial costs are considered. To address this issue, we estimate and use the levelized cost of lump-sum investments instead of revenue requirements.

Energy and Ancillary Services Market Value

Energy storage can provide various bulk grid level energy and ancillary services benefits, including:

- **Energy arbitrage** by charging at low-priced hours and discharging at high-priced hours,
- **Frequency regulation** by automatically responding to CAISO's control signals to address small random variations in supply and demand,
- **Contingency reserves (spin and non-spin)** to quickly respond in case of an unexpected loss of supply on the system,
- **Flexible ramping** by providing upward and downward ramping capability to help CAISO manage rapid changes in the system due to demand and renewable forecasting errors,
- **Voltage support** to help dynamically maintain stable voltage levels in the distribution system or transmission grid,
- **Black start** by self-starting without an external power supply and helping the grid recover from a local or system-level blackout.

Figure 9 summarizes how historical energy and ancillary services market benefits are calculated for each type of product.

For resources participating in the CAISO markets, we rely on actual metered data and resource-specific settlements in day-ahead and real-time markets.

For resources that are behind the CAISO meter and not participating in CAISO wholesale markets, we only include energy value estimated based on actual interval-level metered resource output multiplied by real-time LMP of the relevant sub-LAP. Sub-LAPs are CAISO-defined subsets of pricing nodes created to reflect price separation associated with the major transmission constraints within utility territories. For resource mapping, we first identified the areas covered by the clusters of pricing nodes for each sub-LAP and determined the closest sub-LAP for each storage resource based on geographic proximity using a GIS software.

	CAISO Market Participants (including demand response)	Non-Participant Behind CAISO Meter
Energy	Valued at resource-specific day-ahead market (DAM) & real-time market (RTM) prices and settlements	Valued at RTM sub-LAP price
Frequency Regulation		n/a
Spin/Non-Spin Reserve		n/a
Flexible Ramping		n/a
Voltage Support	Based on CAISO contract payments (if any)	n/a
Black Start		n/a

Figure 9: Calculation of historical energy and ancillary services market benefits.

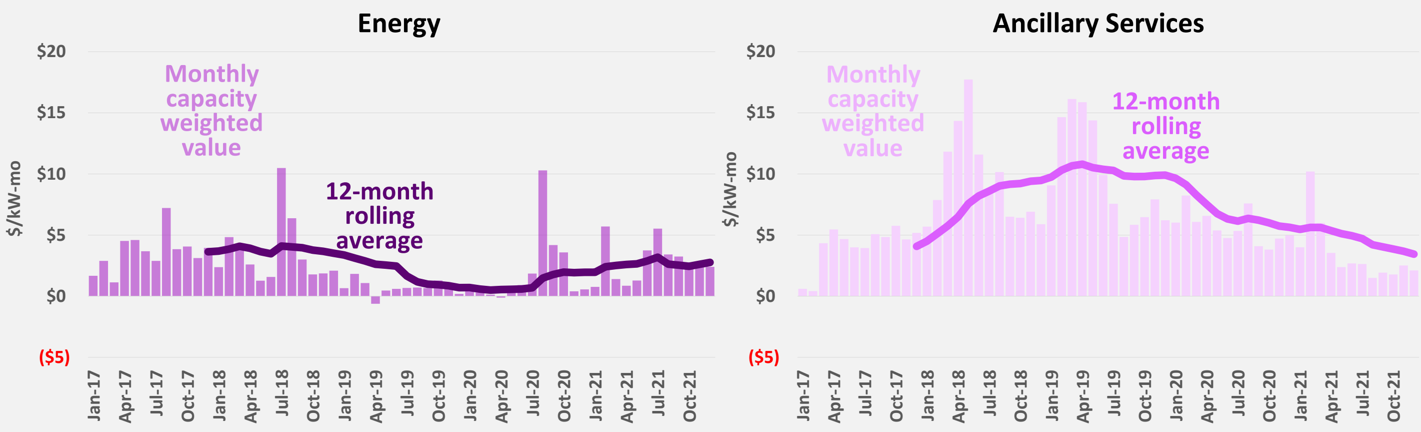


Figure 10: Average CAISO energy and ancillary services revenues across the storage fleet (in 2022$).

Figure 10 above shows the capacity-weighted average value of energy and ancillary services provided by the CAISO-participating energy storage projects included in our study. In the beginning of the study period, most of the early pilot projects' use cases included both energy and ancillary services with similar levels of value. During 2018–2020, significant revenue opportunities in the CAISO regulation market attracted many of the existing and new storage resources and resulted in use cases that are increasingly more focused on ancillary services. However, the ancillary services market is relatively small, currently averaging at around 400 MW for regulation up, 700 MW for regulation down, and 900 MW for spinning reserves. Starting in 2021, with significantly more battery storage connected to the CAISO system, the share of storage capacity used for ancillary services declined rapidly as the market started to saturate. This coincides with the overall wholesale market value proposition moving back to bulk energy time-shift.

Figure 11 compares historical energy and ancillary services revenues across all CAISO-participating storage projects included in our study. Each bar corresponds to a project, with the stacked value sorted from highest to lowest. The values are averaged over each project's operational period within the 2017–2021 timeframe. As shown, the largest share of historical market revenues came from regulation market for most of the projects, although this is rapidly changing. Other ancillary services revenues have been small, except for a couple of unique use cases focusing on contingency reserves. Energy revenues started to increase in 2021 and account for a large share of wholesale market revenues for the new projects.

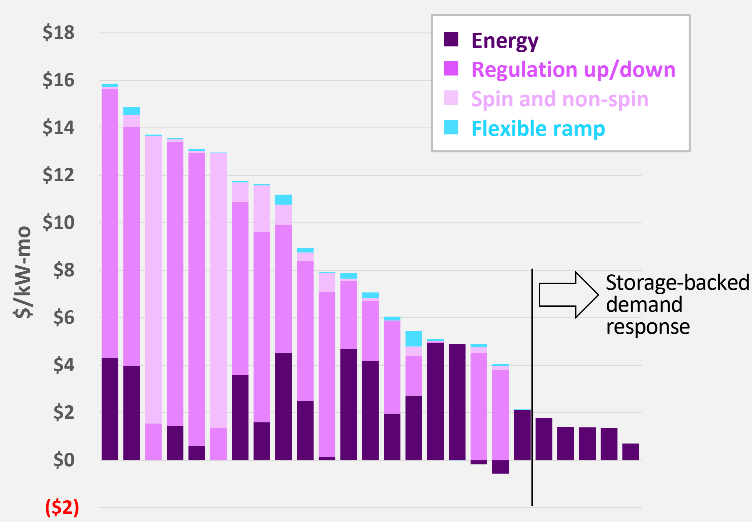


Figure 11: Average CAISO energy and ancillary services revenue by storage project (in 2022$).

For all distributed energy storage resources that do not participate in the CAISO wholesale market, we estimated their energy value based on metered output multiplied by real-time LMP of the sub-LAPs they are mapped to.

Figure 12 plots the estimated results for individual nonresidential SGIP-funded storage projects, where the colors indicate identified clusters based on their operating profiles. Projects in clusters 1, 2, and 3 yield higher energy value relative to other projects. Projects in cluster 6 performs slightly worse due to their practice of night charging. Most projects in clusters 4, 5, and 7 produce negative energy value, indicating operations at a net cost to ratepayers. Due to underused capacity, very few storage projects produce above $1/kW-month of value.

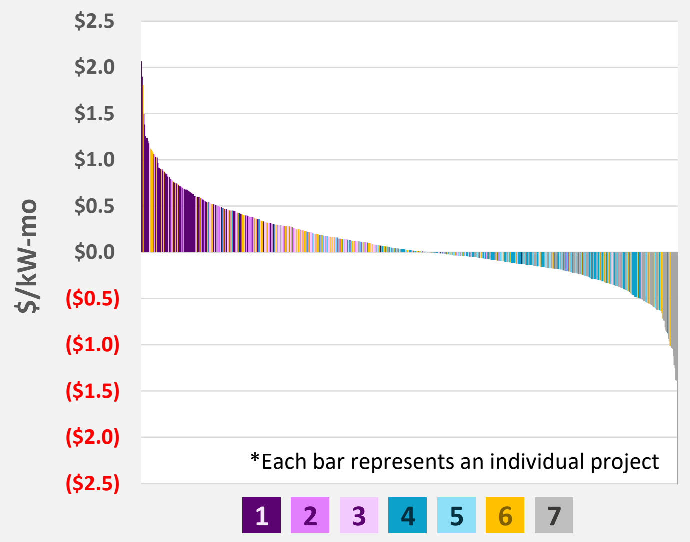


Figure 12: Average energy value of nonresidential SGIP-funded storage resources (in 2022$).

Figure 13 below compares the range of energy values across SGIP-funded projects and other customer aggregations procured under demand response (DR) contracts. For reference, we also included the energy value range for grid-scale transmission- and distribution-connected storage resources participating in the CAISO market. Although we could not access data to directly analyze residential SGIP-funded storage resources, we expect their behavior to be similar to nonresidential Clusters 1–2 with equally high solar PV attachment. Customer aggregations under utility DR contracts operate similarly to SGIP nonresidential Clusters 4–5 as they discharge steadily throughout the day, are unresponsive during morning and evening ramps, then charge at night. They do not participate in the CAISO marketplace and produce negative value on average. The CAISO-participating customer aggregations perform better than non-CAISO resources, but still below their potential. These resources produce $1/kW-month of energy value on average.

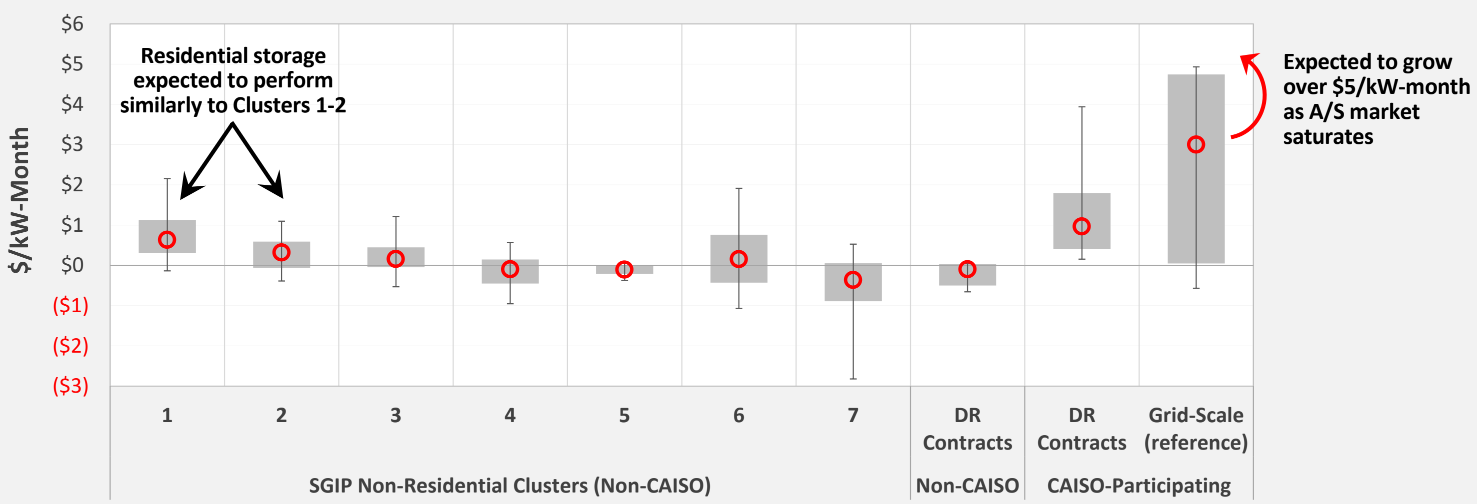


Figure 13: Average energy value produced by customer-sited energy storage (in 2022$).

* Red circle represents capacity-weighted average, gray bar represents P10–P90 range, and error bar shows minimum and maximum values across the group of resources analyzed.

Resource Adequacy (RA) Capacity Value

Energy storage resources can be available to discharge during peak periods to help with meeting the system RA, local RA, and flexible RA requirements to ensure system reliability in California.

Our analysis of the RA capacity value depends on the counterfactual, which varies for each individual storage resource depending on its location and circumstances under which it was procured. As shown in Figure 14 below, if a project addresses local RA need, the counterfactual case would include procurement of an alternative local resource. Depending on supply availability at the time of procurement, this could be a short-term contract to retain an existing resource in that local area or it could be a long-term contract or investment in new generation or demand response (DR) resource. The local RA need can also be addressed by upgrading the transmission system, but we found this alternative not to be applicable for the resources analyzed in our study.

If a project is not in a local capacity area, or it is in a local area that doesn't have a deficiency, that project may still be providing system RA capacity. In this case, the counterfactual would include an alternative system RA procurement of an existing or new resources, or possibly from imports into CAISO, depending on needs and supply availability at the time of procurement. The main difference from the counterfactuals considered in the local RA track is that the associated avoided costs would be from a system RA resource from a larger pool of potential resources and locations.

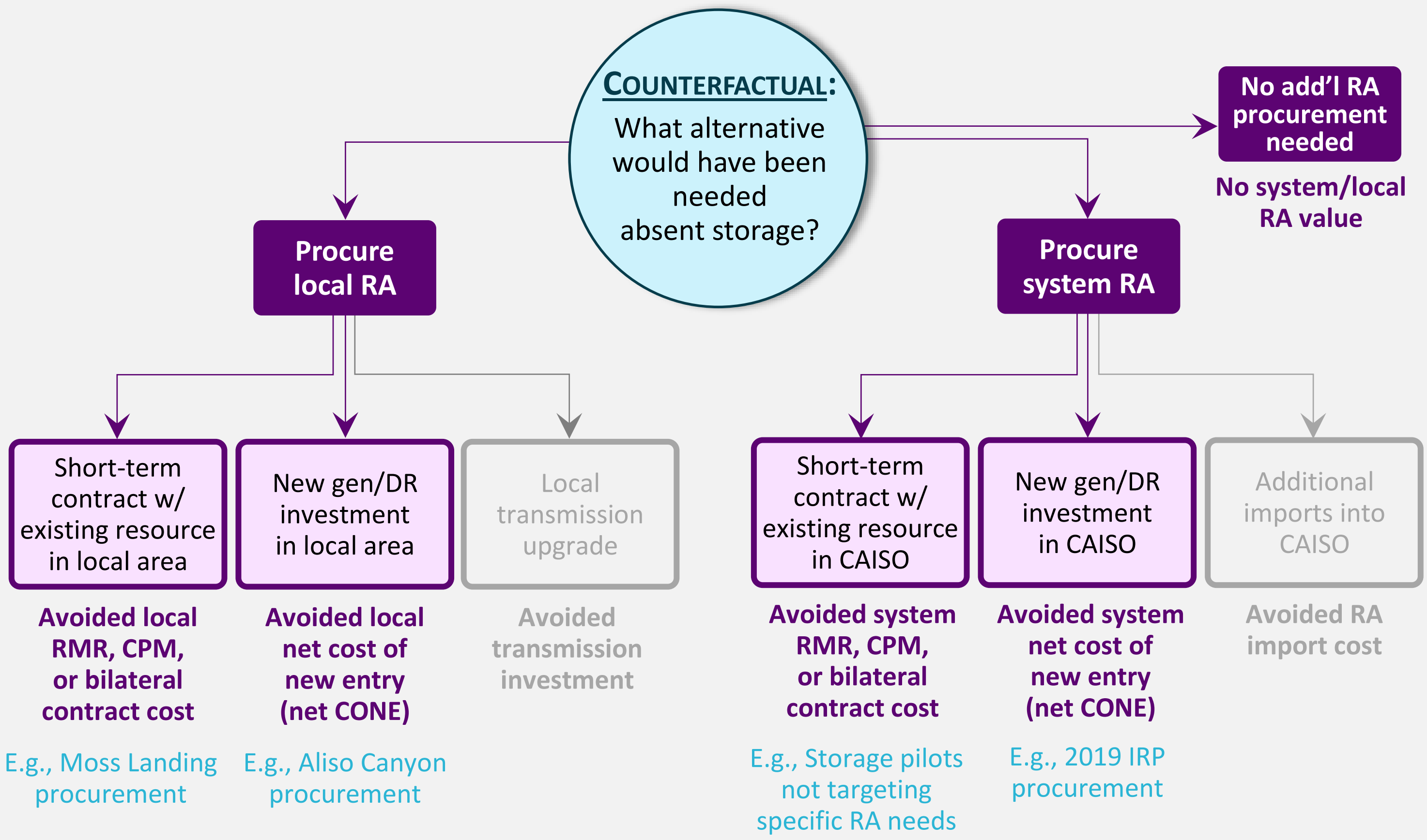


Figure 14: Calculation of historical RA capacity value based on counterfactual.

Most storage projects in our study were procured to address various reliability and resource adequacy needs in California. Specific RA needs, development timelines, and available alternatives depend on the procurement track, thus require a different counterfactual for the purposes of estimating RA capacity value. For each procurement track, we reviewed numerous documents including the underlying procurement orders, utility applications, solicitation materials, and related data and reports to develop counterfactual cases that reflect the specific circumstances under which the storage resources were procured.

An overview of the various procurement tracks and counterfactual cases is provided below:

SCE's 2013 LCR Western LA RFO selected 264 MW of energy storage, of which 182 MW was online by 2021. This was an all-source RFO to procure up to 2,500 MW of capacity in Western LA local area to address the need created by retirement of once-through-cooling (OTC) power plants. The RFO had a carve-out of minimum 50 MW of energy storage plus 550 MW of preferred resources, such as demand response, energy efficiency, and renewables. Storage was cost-competitive with other preferred resources and accounted for more than half of preferred resource capacity procured at the end. Without storage, it is likely additional gas-fired resources would be procured to meet the local capacity need. RA capacity value is estimated based on offer prices of marginal gas peakers participated in the same solicitation.

SCE's Preferred Resources Pilot (PRP) 2 RFO selected 125 MW of energy storage, of which 50 MW was online by 2021. Resources that became online are all distribution-connected storage resources. Several customer-sited storage procured in the same RFO got cancelled due to delays in approval process. The RFO intended to fill the gap from 2013 LCR RFO and help with the outstanding LCR need in Western LA driven by OTC and SONGS retirement. Timeline overlaps with the unexpected challenges created by the Aliso Canyon gas leak in southern California in 2016 so new gas-fired generation would not be a plausible alternative due to gas supply constraints in the area. Demand response (DR) is the most viable resource to consider in the counterfactual. RA capacity value is estimated based on non-storage DR cost for programs available in southern California at the time.

SCE and SDG&E's Aliso Canyon Energy Storage (ACES) RFOs procured nearly 100 MW of energy storage that began operations in 2017 to address local reliability issues caused by prolonged natural gas leak at Aliso Canyon. Gas leak was discovered in October 2015 and governor proclaimed a state of emergency in January 2016, requesting state agencies take all necessary actions to ensure reliability. CPUC required expedited competitive procurements of energy storage and the entire process was completed in record time: solicitations, development, permitting, construction, and interconnection of 7 projects in 9 months. Gas-fired generation would not be plausible due to gas supply constraints. DR is the most viable alternative for the counterfactual. RA capacity value is estimated based on non-storage DR cost for programs available in southern California at the time.

SCE's 2018 ACES 2 and LCR Moorpark RFOs resulted in a combined 195 MW of energy storage in the Moorpark area, of which 121 MW was online by 2021. Moorpark LCR needs were initially identified in 2013, driven by OTC retirements. Through an 2013 RFO, SCE contracted a 262 MW gas peaker, but CEC rejected permitting of the plant due to environmental concerns. CEC's decision was informed by a CAISO study finding preferred resource alternatives were feasible. SCE's 2018 solicitations addressed the remaining LCR need in Moorpark, along with localized resilience needs in Santa Barbara/Goleta area. Without storage, non-storage DR would be a viable alternative, but it would be difficult to scale within the local sub-area so counterfactual would include the cancelled gas peaker. Accordingly, RA value is estimated based on blended cost of the cancelled gas peaker plus non-storage DR up to 20 MW (original ACES 2 target).

PG&E's 2018 LCR Moss Landing RFO selected 567.5 MW of energy storage, of which 482.5 MW was online by 2021. PG&E's solicitation was open to energy storage resources only and intended to eliminate or reduce the need for reliability-must-run (RMR) contracts in the Moss Landing local capacity area. While PG&E was conducting the LCR RFO, CAISO identified and approved transmission upgrades to address the local need, but storage was needed to reduce risk of future deficiencies. In CAISO's 2022 LCR study, Moss Landing subarea would have a capacity deficiency if storage resources and Metcalf unit were not included. Based on this, counterfactual case is assumed to include an RMR resource, and RA capacity value is estimated based on the 2018 RMR contract prices negotiated for the Metcalf unit.

Figure 15 below summarizes the counterfactual cases and estimated long-term RA capacity values for the relevant procurement tracks.

Procurement Track	Specific RA Capacity Need Addressed	Type of Resource Procured in Counterfactual	Approach to Estimate RA Value	Estimated RA Value (2022$/kW-mo)
2013 LCR Western LA	Local capacity needs in Western LA to replace OTC & SONGS retirements	New gas peaker	Net CONE based on 2013 LCR RFO bids	**$16–$18**
Preferred Resources Pilot 2	Same as above; Fill in shortfall of Preferred Resources in 2013 LCR RFO	New demand response	Net CONE based on DR cost	**~$20**
Aliso Canyon Energy Storage	Urgent reliability needs in southern CA due to gas supply limitations	New demand response	Net CONE based on DR cost	**~$20**
Aliso Canyon Energy Storage 2	Same as above; PLUS local capacity needs in Moorpark	New gas peaker and DR	Net CONE based on gas peaker & DR cost	**$14–$16**
2018 LCR Moorpark	Local capacity needs in Moorpark to replace OTC retirements	New gas peaker and DR	Net CONE based on gas peaker & DR cost	**$14–$16**
2018 LCR Moss Landing	Local capacity needs in Moss Landing to replace existing RMR generation	Existing RMR resources	Avoided RMR cost based on Metcalf	**~$7**
Other	n/a	Existing generic resources	Short-term bilateral RA contracts	**$3–$8**

Figure 15: Summary of RA counterfactuals and estimated RA capacity value by procurement track.

For energy storage resources that were not procured for specific reliability or resource adequacy needs, we estimated their RA capacity values based on bilateral RA contracts executed by the LSEs. We relied on the historical RA price data compiled by the CPUC for 2018–2021. First, we filter the data for annual strips to get an estimate of average year-around RA prices, excluding short monthly or seasonal RA contracts. After that, to approximate marginal RA values, we use the 90th percentile (P90) of the RA prices for contracts executed within one year prior to delivery. Here, the use of P90 rather than the highest price is to exclude possible outliers of small RA contracts priced at a premium. The results are summarized in Figure 16 on the right.

	2018	2019	2020	2021
CAISO System	\$2.7	\$3.0	\$7.5	\$8.2
Bay Area	\$3.1	\$4.4	\$7.6	\$8.0
Big Creek-Ventura	\$4.0	\$4.4	\$7.6	\$8.3
LA Basin	\$3.4	\$4.5	\$7.8	\$7.9
San Diego-IV	\$2.9	\$3.9	\$7.5	\$7.9

Figure 16: Estimated marginal RA value based on short-term bilateral RA contracts (in 2022\$).

The prices shown above reflect combined value of system RA and local RA attributes. As highly flexible resources, energy storage can also provide additional value towards flexible RA needs to meet forecasted net load ramps.

Currently, CAISO divides the flexible RA needs into 3 categories:

- Base flexibility to meet the largest 3-hour secondary net load ramp,
- Peak flexibility to meet the difference between 95% of the maximum 3-hour net load ramp and 3-hour secondary net load ramp, and
- Super-peak flexibility to meet the remaining 5% of the maximum 3-hour net load ramp.

All resources providing flexible RA capacity are required to submit bids in CAISO day-ahead and real-time markets, where their must-offer obligation (MOO) depends on the category. Base flexibility resources must submit bids for 17 hours/day every day of the week. Peak flexibility resources must submit bids for 5 hours/day every day. Super-peak flexibility resources must also submit bids for 5 hours/day but only during non-holiday weekdays. The 5-hour window changes depending on the month of the year.

Energy storage is increasingly used to meet super-peak flexibility needs. According to 2021 DMM report, energy storage provided 371 MW of the super-peak flexible capacity, accounting for 86% of the capacity procured in that category. However, the overall flexible RA requirement was largely met by gas and hydro generation. Despite more stringent must-offer obligations, flexible RA procured for the base category well above the minimum requirement, and the excess was used towards meeting the requirements for peak or super-peak categories. This suggest there is still plenty of traditional resources procured for local or system RA capacity that can also provide flexible RA, and accordingly, incremental cost of procuring flexible RA would be minimal.

This observation is consistent with our review of the historical RA contract prices. Across all historical years, bundled prices of system/local RA + flexible RA were not higher than prices of system/local RA only. This is described in various CPUC Resource Adequacy Reports. We also ran a statistical analysis of the historical RA prices controlling for delivery periods and areas, and we found there was no price premium related to providing flexible RA during the 2018–2021 period. Given these findings, we set the flexible RA value of storage resources to zero in our study.

For energy storage resources participating in the CAISO market, we estimate RA capacity value based on their net qualifying capacity (NQC) at the project level. For the projects included in our study, the NQC determinations follow the CPUC's initial "4-hour rule" requiring energy storage resources to have at least 4 hours of duration to qualify for full credit. The NQC of resources with less than 4-hour of duration would be de-rated proportional to their durations (e.g., 2-hour storage gets 50% credit).

Behind-the-meter (BTM) distributed and customer-sited energy storage resources can provide capacity value either:

- By participating in DR programs that are integrated to the CAISO market on the supply-side, or
- As a load modifying resource under various retail incentive programs and rates.

For CAISO-participating BTM storage resources, we use their actual NQCs to calculate RA capacity value. If the NQC data is not available or the BTM resource does not participate in the CAISO market, we estimate capacity contribution based on actual net discharge during capacity-constrained periods. For our study, we focused on performance during the system emergencies in 2020–2021.

Figure 17 includes an example illustrating the operations of nonresidential SGIP-funded storage projects during the Stage 3 emergency that CAISO declared on August 14, 2020 between 6:36 pm and 8:38 pm. Each row shows the charge/discharge profile of an individual unit on that day, sorted by the clusters they are mapped to. On the left, CAISO load and aggregate storage output are plotted. Altogether, these nonresidential storage projects provided around 12 MW of energy during the emergency period, which corresponds to 6% of the 205 MW installed.

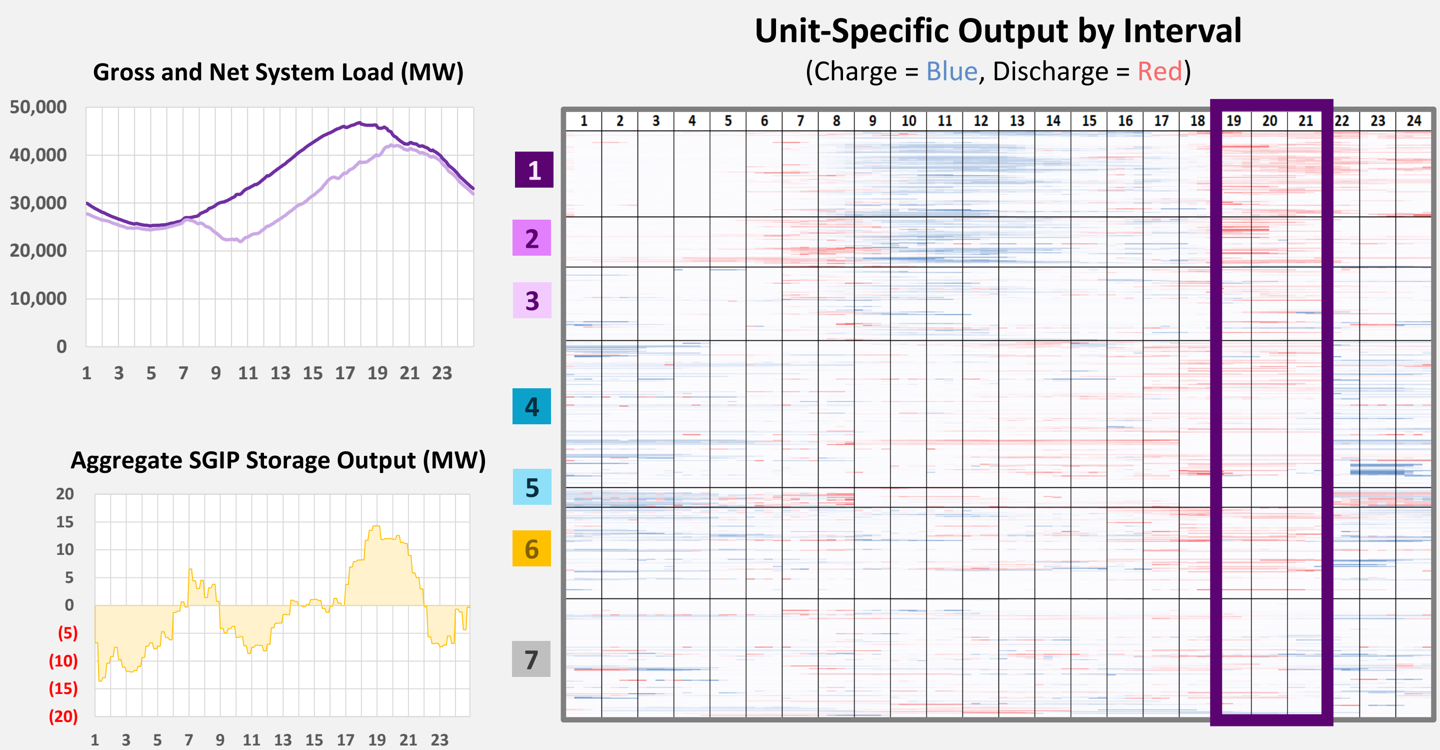


Figure 17: Nonresidential SGIP storage project performance during CAISO stage 3 emergency on August 14, 2020.

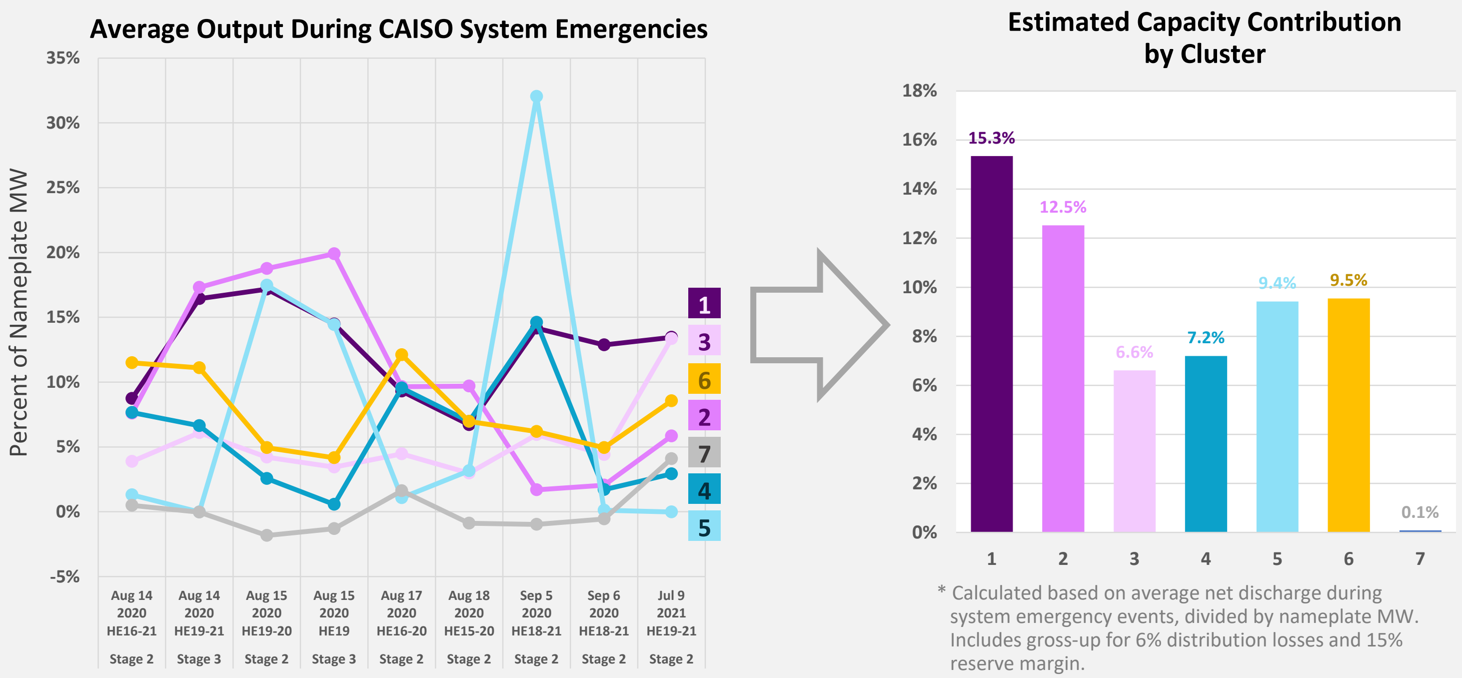


Figure 18: Observed capacity contribution of nonresidential SGIP storage projects by cluster.

Figure 18 above shows the estimated capacity contribution of nonresidential SGIP storage projects for each cluster, based on their operations during 9 system emergency events that took place in 2020–2021. All clusters except for cluster 7 discharged net energy on average during emergencies, based on which we estimated capacity contributions. Clusters 1–2 contributed more than others, providing 12–15% of each MW installed. Clusters 3–6 provided 7–10% of each MW, and cluster 7 provided no net relief.

Figure 19 shows the range of results for other distributed storage projects. Distribution-connected projects that do not participate in the CAISO market have been mostly unresponsive during system emergencies. Customer-sited storage under utility DR contracts met the capacity requirements defined in their contracts, but these requirements were not aligned with the evolving grid needs shifted to late evenings and extended to weekends.

Based on limited number of observed emergency events occurred during the historical period, the capacity contributions estimated here are *indicative* at best. Load-modifying distributed and customer-sited energy storage resources do not have a firm obligation to offer their capacity during system emergencies. Accordingly, their contributions can vary significantly from one event to another as shown in Figure 18. Nevertheless, many of these storage resources, especially ones that are paired with solar, have operating patterns that are synergistic with the grid needs and they are much more likely to discharge than charge when the grid is stressed. It is important to capture the associated benefits to the grid and not ignore it due to data limitations.

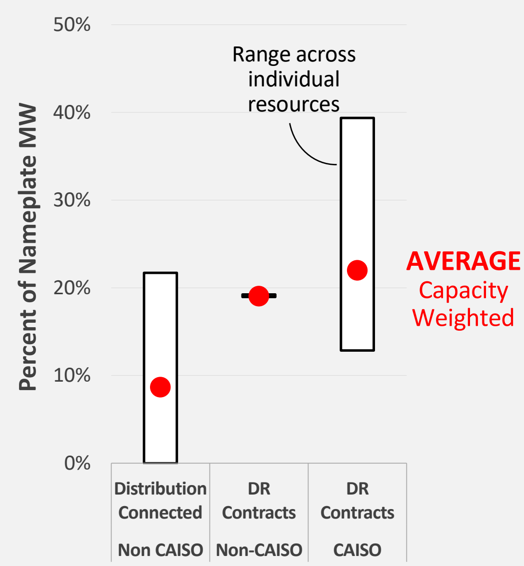


Figure 19: Observed capacity contribution of distribution- and customer-sited storage.

Transmission Investment Deferral Value

Energy storage resources can defer the need for transmission investments under two distinct use cases: (1) energy storage acts as an energy resource, alters load and generation balance to relieve transmission bottlenecks, and thus replaces transmission solutions that could do the same, or (2) storage is used by the system operator like a controllable transmission asset and could be operated, for example, to redirect power flow and prevent overloads on specific circuits.

Several energy storage projects operating during 2017-2021 were procured to meet local capacity needs driven by generation retirements or issues related to Aliso Canyon. Since these energy storage resources were procured under RA procurement tracks where the alternative is a generation or load resource, we allocate these services and benefits towards local RA capacity, rather than transmission deferral. As part of the CAISO's transmission planning, generating resources, including energy storage, are considered as alternatives to transmission investments. In 2017–2018 TPP, CAISO approved a 10 MW energy storage project as part of a combined transmission/generation solution to prevent overloads in the Oakland area. Development of that project has been hampered by changes in scope identified in subsequent TPPs and it is not clear if or when the project will be developed.

Development of energy storage projects operated as a controllable transmission asset is still in pilot phase. In 2017–2018 TPP, CAISO approved a 7 MW energy storage projects as a cost-effective solution to manage a transmission contingency that would interrupt service to the town of Dinuba. PG&E conducted a competitive solicitation in 2019 and selected a winning bidder. However, when the transmission need increased to 12 MW in a subsequent TPP, PG&E cited challenges with procurement and contracting.

Distribution Investment Deferral Value

If interconnected to the distribution system, storage can defer the need for distribution investments by reducing local peak loading on the distribution grid. While there have been several storage projects procured to defer distribution investment, many of these projects have either been delayed or cancelled. None of the operational projects included in our analysis deferred an actual distribution investment need, so this value stream is set to zero for all projects in the study.

One of the early pilot projects funded by an EPIC grant (Browns Valley) was deployed by PG&E in 2017 to demonstrate autonomous peak-shaving capability needed for distribution deferral use case. While the project provided valuable experience about this use case, as described in the final EPIC report, the project did not defer an actual distribution upgrade or investment.

Storage developed to act as a distributed energy resource and relieve constraints on the distribution system was explored through an incentive pilot, the CPUC's Integrated Distributed Energy Resources (IDER) proceedings. The pilot resulted in 6 contracts, four of which were canceled, and two were online in 2021. Of these two, one project (Acorn 1) became online in early 2021 and included in our study. However, the underlying distribution need went away due to reduction in load forecast, and the project did not defer an actual investment. The other distribution deferral project (Wildcat 1) got online in late 2021 and it was not included in the study due to not having sufficient operational history.

Storage developed to directly defer or avoid distribution investments is procured through an annual process under the CPUC's Distribution Investment Deferral Framework (DIDF). That process has not yet yielded an operational project. Many of the utility DIDF solicitations either resulted in no selected offers or were not held at all. Three out of the four DIDF offers ever selected were canceled and the fourth resource is due online in 2023.

Avoided RPS Cost

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which will get increasingly more challenging as California continues to decarbonize its electric system. As illustrated in Figure 20, charging of storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

Avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate benefits, we first determine the impact on renewable curtailments based on net charge of energy storage resources when there are actual curtailments on the system. It is important to differentiate curtailments driven by local vs. system-wide constraints. To do that we overlay CAISO's real-time 5-minute curtailment data with resource specific real-time LMPs. In an interval with curtailments, we assume a storage project impacted curtailments only if its nodal real-time LMP was zero or negative. If its nodal price was positive, it implies that storage unit was outside of the local area where curtailment occurred and there was a transmission constraint preventing from storage resource to reduce or eliminate that curtailment.

Based on historical data, we estimated that most storage projects were at locations subject to 1–2 hours of curtailments per day, on average. If the storage projects charged at full capacity in these hours, it would have translated to 30–60 MWh of monthly curtailment reduction per MW of storage capacity. Actual realized benefit during the 2017–2021 study period was much smaller because most storage projects focused on use cases that didn't help with renewable curtailments.

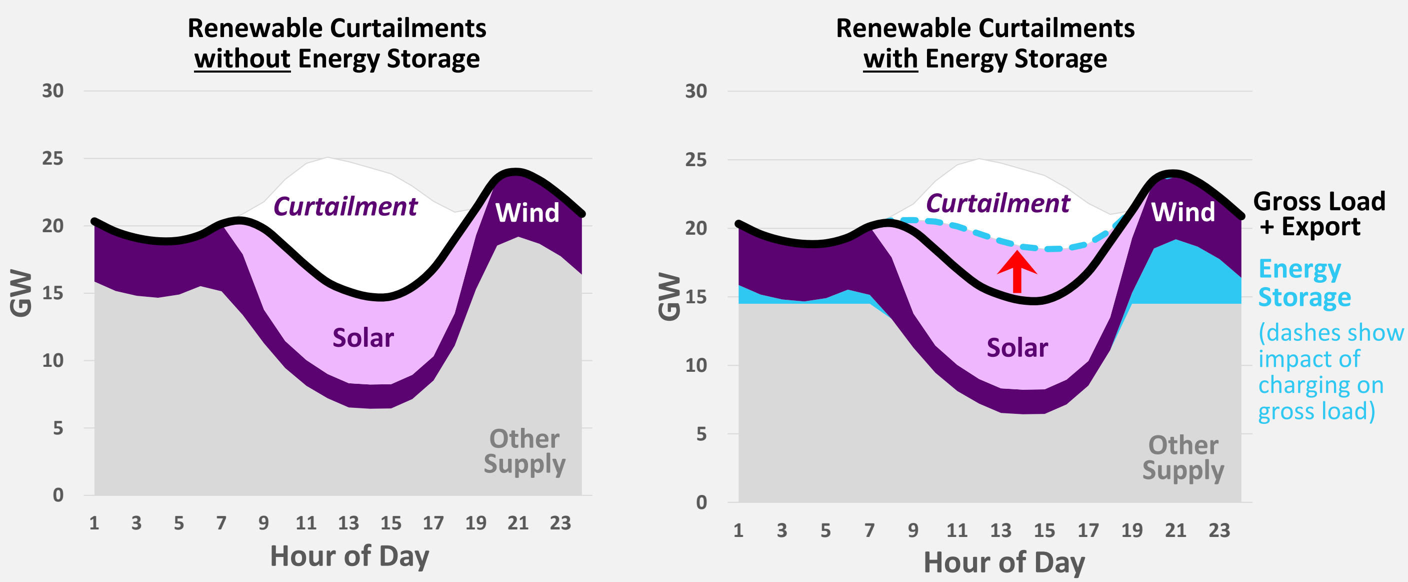


Figure 20: Illustration of energy storage impact on renewable curtailments.

Figure 21 below shows the average monthly impact of energy storage projects on renewable curtailments and the associated benefits monetized.

Project with the highest impact reduces an average of 25 MWh of monthly renewable curtailments per MW of storage capacity, which is closer to the lower end of our estimated potential. Most projects provide far less benefits, which is somewhat expected given the historical focus on ancillary services participation and other use cases that do not incentivize bulk energy time-shift. Lowest-performing resources are estimated to increase renewable curtailments by discharging energy in the middle of the day. These are thermal energy storage resources procured under permanent load shift (PLS) contracts reducing A/C loads in early afternoons, which overlaps with the periods when grid experiences renewable curtailments.

We monetize the RPS cost savings using the RPS adders published in CPUC's Power Charge Indifference Adjustment (PCIA) reflecting the incremental value of RPS-eligible energy based on historical transactions. For our study period, the RPS adders were in the range of $14–$16 per MWh, depending on the year. Accordingly, the storage project with the highest renewable curtailment impact is estimated to provide $0.42/kW-month of RPS benefits, and at the tail end of the distribution storage projects procured under the PLS contracts are estimated to increase RPS costs by $0.10/kW-month, on average.

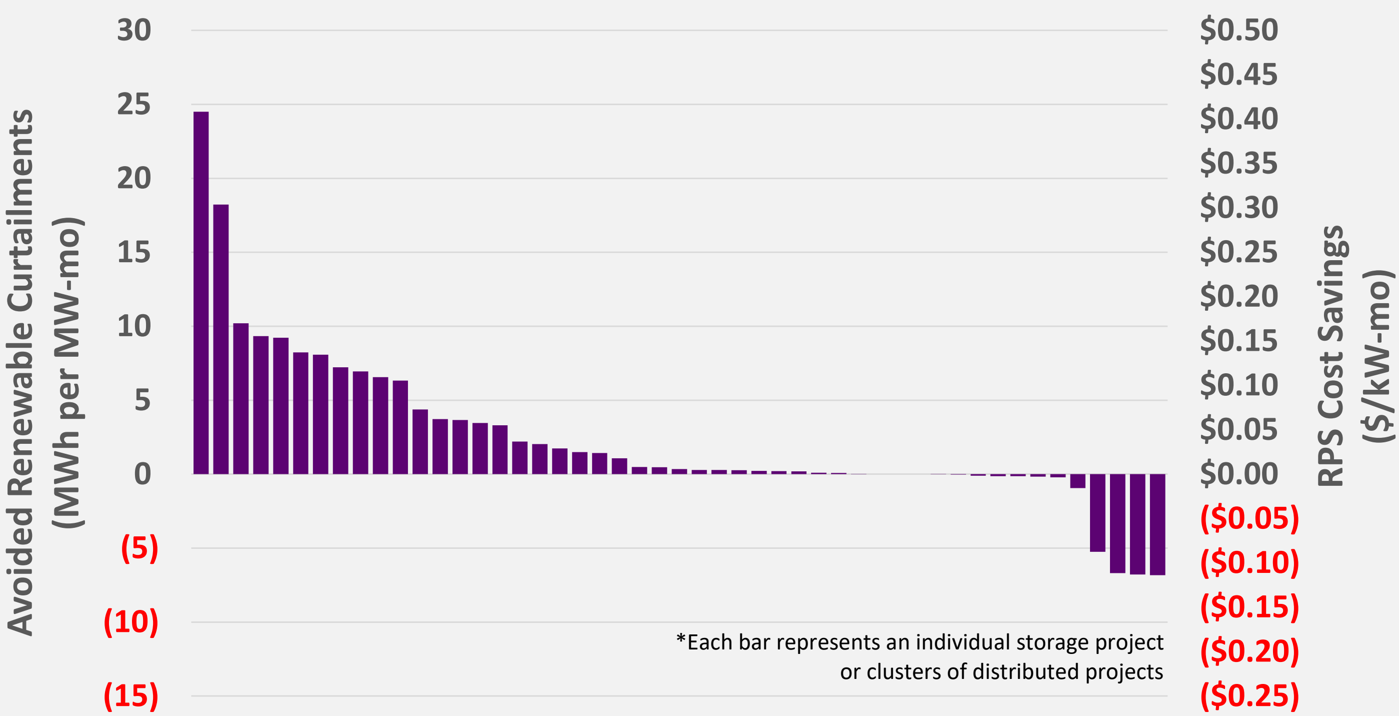


Figure 21: Estimated average renewable curtailment impact and associated RPS cost savings (in 2022$).

GHG Emission Reduction Value

We estimate net GHG emission impact of energy storage resources based on their actual energy output multiplied by historical marginal GHG emission rate at the sub-hourly interval level and added up over the study period. Energy storage reduces emissions at the marginal rate when discharging, and it increases emissions at the marginal rate when charging. We use the historical real-time marginal GHG signal created by WattTime to evaluate emission impact of SGIP projects. CPUC adopted the use of this GHG signal in 2019 under D.19-08-001 to align resource performance with the program's emission reduction goals. Under the approved methodology, the GHG signals are derived from 5-minute real-time marginal energy prices for each balancing authority in California. Within the CAISO, the GHG signals are calculated for each of the three IOUs: PG&E, SCE, and SDG&E.

Figure 22 below illustrates the distribution of marginal GHG intensity based on a heatplot of GHG signals used in the study. Blue indicates low emission rates and red indicates high emission rates. Pixels moving horizontally correspond to each 5-minute interval of the day, and pixels moving vertically correspond to each day of the year over the study period.

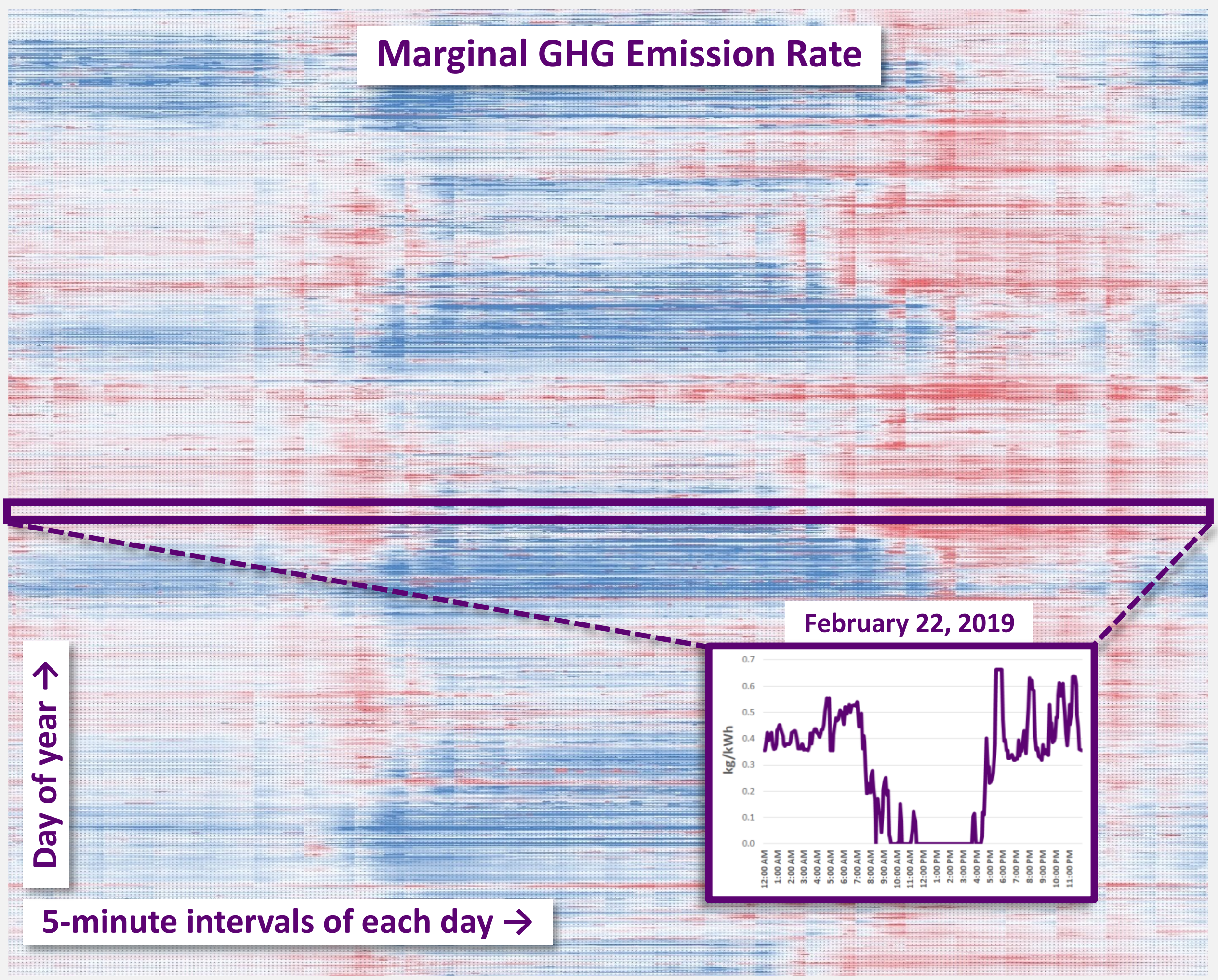


Figure 22: Heatplot of historical marginal GHG emission rates used in the study.

We apply the same methodology across all energy storage resources included in our study. For resources participating in the CAISO market, when they provide ancillary services, their emission impact is calculated to the extent it translates changes in actual energy charged or discharged. For example, if a battery sells regulation in the CAISO market and rapidly adjusts its output to follow AGC signals, it shows up as a part of the metered 5-minute charge and discharge reported by the CAISO, and we would calculate GHG impact as the regulation-related energy movements multiplied by the marginal GHG rate.

There may be a secondary GHG impact associated with the A/S capacity displacement, but we expect it to be small relative to GHG emissions associated with A/S-related changes in energy output. For example, consider an energy storage unit selling 1 MW of regulation up capacity when the marginal resource for regulation up is a gas-fired plant. If the storage unit didn't sell regulation, the marginal gas plant would need to increase its headroom by 1 MW to provide an extra 1 MW of regulation up capacity. By increasing its headroom, the gas plant ends up generating 1 MW less in the energy market, which means another resource, presumably with a similar emission rate, needs to be dispatched to make up for reduced energy from the gas plant. At the end, the net GHG impact associated with the regulation capacity would be relatively small and the overall GHG impact would be driven by regulation mileage and the related changes in energy output.

For energy storage resources to provide GHG reduction benefits, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG intensity to periods with high GHG intensity.

Energy storage is a net consumer of energy: it can retrieve less energy than the energy initially used for charging, due to operational losses. While most storage projects in California have relatively high efficiency in the of 80%–90% range when they operate regularly, their average efficiency drops significantly when they remain on standby for extended periods of time. To provide GHG emission benefits, it is essential for energy storage resources to have highly efficient operations.

Being efficient is necessary, but not sufficient for reducing GHG emissions. Storage use case also needs to allow for shifting bulk energy from periods with low marginal emissions (e.g., midday) towards periods with high marginal emissions (e.g., evening peak). Today's energy storage technologies are very flexible and can provide significant value by helping with grid's needs for frequency regulation. However, the signals for frequency regulation are typically not correlated with GHG intensity of the system, so this use case can result in net GHG increase after losses are factored in.

To benchmark results, we first estimated the average GHG emission reduction potential of energy storage, by simulating optimal dispatch under an energy time-shift use case (no ancillary services) with historical energy prices for 2017–2021. We accounted for market uncertainty by first solving for next day's hourly schedule using day-ahead LMPs, then evaluating economic dispatch deviations for each interval using real-time LMPs assuming only prices up to the current interval are known, before moving to the next interval. Based on these simulations, we estimated the average GHG reduction potential for a 4-hour energy storage to range from 7 ton/MW-month at 30% efficiency to 25 ton/MW-month at 90% efficiency, which is shown as dashed pink line in Figure 23 below. We also included an order of magnitude estimate of the GHG increase under a regulation only use case, shown as dashed purple line, although these values are illustrative and highly sensitive to mileage assumptions.

The actual GHG emission impacts of individual energy storage projects are shown as circles on the chart. To highlight the contrast, the CAISO-participating storage resources are split into 2 groups based on share of wholesale revenues from regulation service. CAISO resources with more than 75% revenues from regulation market are shown in red, and they contributed to a net increase in GHG emissions. CAISO resources with less regulation focus are shown in blue and they all reduced GHG emissions, even though most resources' contributions were far below their potential. Customer-sited nonresidential SGIP projects are shown in yellow, and their GHG impact depends on project cluster (see next page). Other storage projects that did not participate in CAISO marketplace are shown in gray. Most of these projects were underutilized and they were often on extended periods of standby, which translated to low operational efficiency and resulted in marginal increases in GHG emissions. In one distinct use case, storage was placed in an island to help a diesel generator maintain high output for NO_X control equipment function. While this may have reduced NO_X emissions, it also led to significant increase in GHG emissions because the diesel generator had to produce more energy to make up for losses of the battery system.

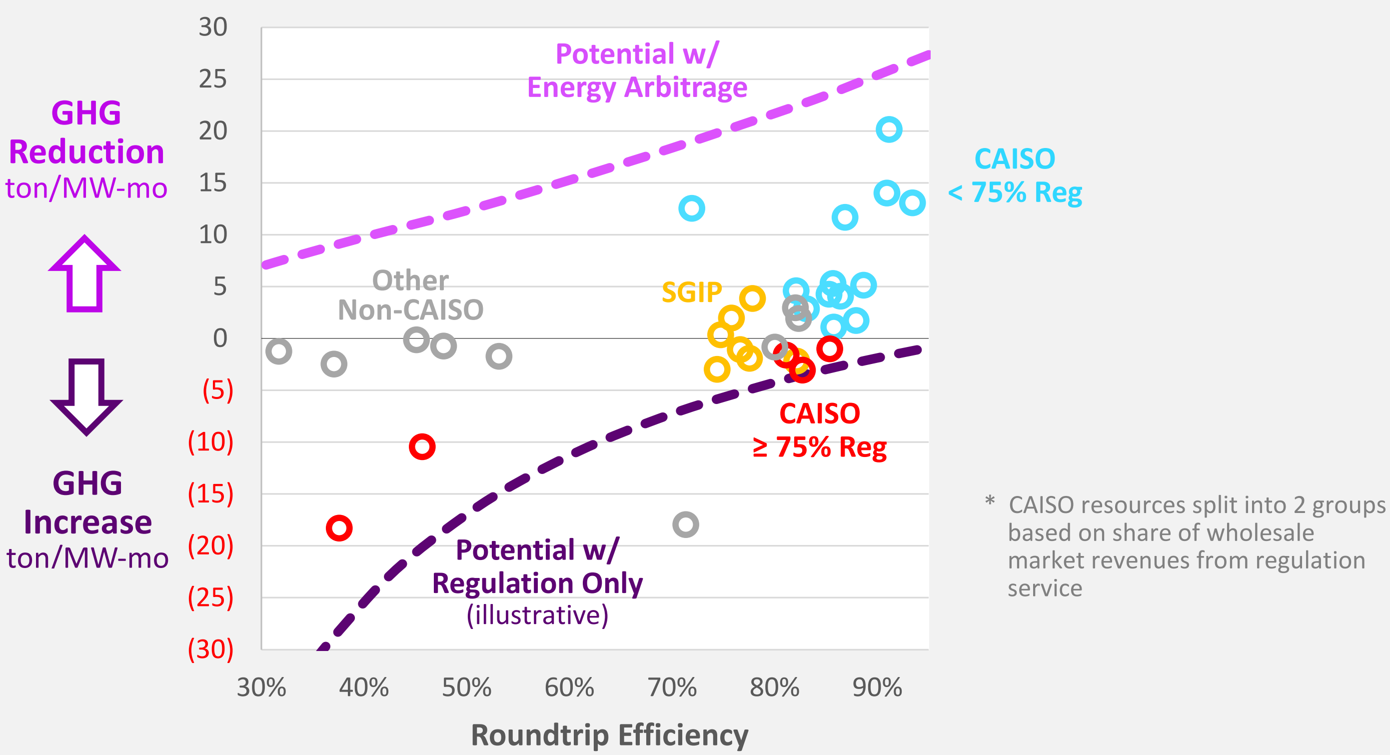


Figure 23: Estimated average GHG emission impact of energy storage resources.

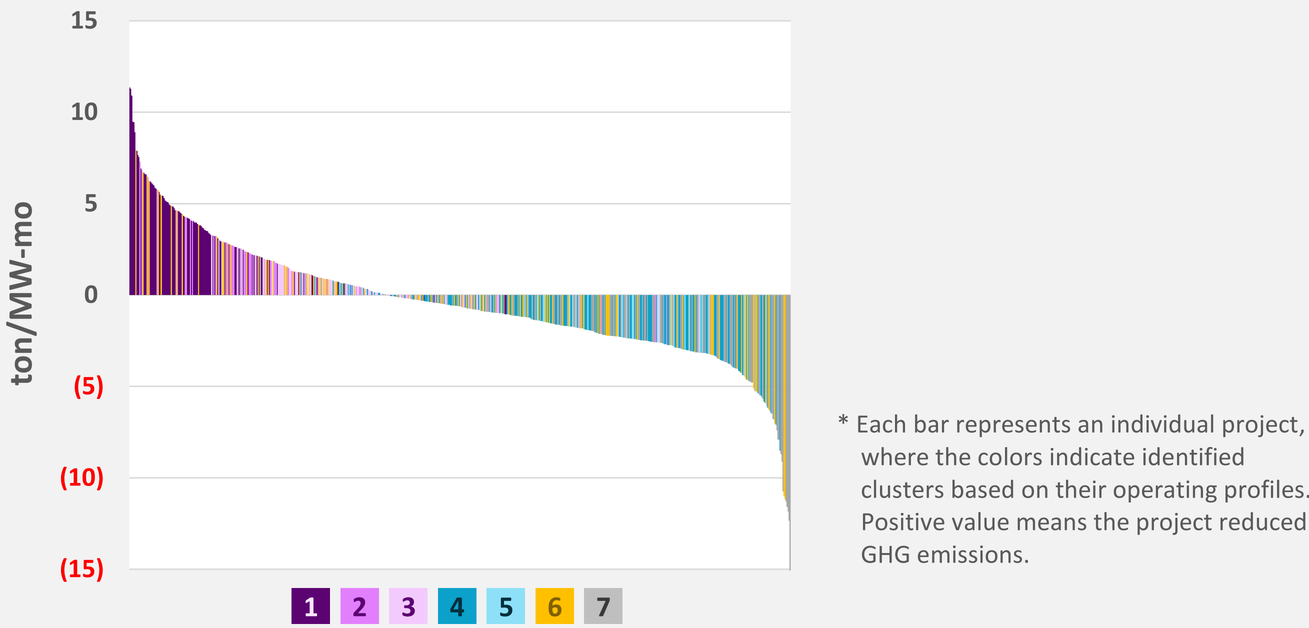


Figure 24: Average GHG emission reduction from nonresidential SGIP-funded storage resources.

Figure 24 shows the GHG impact of individual nonresidential SGIP-funded projects, averaged over their operations in the 5-year study period from 2017 to 2021.

- Projects in clusters 1–3 reduced GHG emissions, on average. As discussed earlier, storage projects in these clusters are mostly paired with solar and their operations typically involve midday charging when the system's GHG emission intensity is low, and either morning or evening discharge when the GHG emission intensity is relatively high.
- Clusters 4–7 account for around 70% of the SGIP storage capacity analyzed. Most projects in these clusters contributed to higher GHG emissions, as their use cases focused primarily on demand charge management and did not align well with GHG reduction goals of the program. Average GHG emissions increases are as high as 3 tons/MW-month at the cluster level over the study period, and as high as 16 tons/MW-month at the individual customer resource level.

The GHG emission increase associated with nonresidential SGIP storage projects were originally identified in the SGIP energy storage impacts evaluation report, published in late 2016. In response and after almost three years of study with stakeholders, in 2019 the CPUC adopted GHG emission reduction requirements and the use of a GHG signal to better align resource performance with the program's goals. Under the rules, new commercial projects after April 2020 are required to reduce GHG emissions by 5 kg per kWh annually, which translates to 0.83 ton/MW-month for storage with 2 hours of duration. This requirement is an outcome of the CPUC's stakeholder process, and it is well below the annual target CPUC Staff originally proposed and it is only a fraction of the potential we estimated for storage projects with access to grid signals.

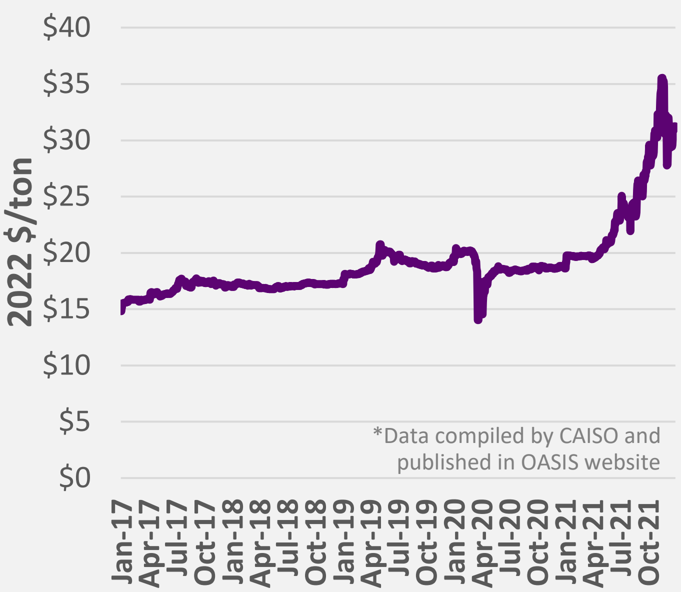
Even though the GHG rule for SGIP projects went in effect back in 2020, we have not observed its effect yet in operational data analyzed through September 2021 due to lags driven by exemptions for legacy projects and program enrollment timelines. The GHG requirements only apply to projects submitting applications after April 2020 and the approval process combined with operational data collection typically takes multiple years.

The GHG emission reduction value of energy storage projects includes two components:

1. Avoided short-term marginal cost of GHG abatement based on allowance prices observed in the cap-and-trade market,
2. Avoided cost of meeting GHG goals through additional investments in the electric sector based on the RESOLVE model GHG shadow prices used in CPUC's 2022 Avoided Cost Calculator, which is consistent with IRP studies.

Figure 25 below shows historical GHG allowance prices in the cap-and-trade market, based on data compiled and published by the CAISO. GHG prices have been around $15–$20 per ton through 2020, but increased significantly in the second half of 2021, trading at $25–$35 per ton in the secondary market, well above the auction reserve price setting the floor. GHG value based on prices seen in the cap-and-trade market are already reflected in the energy market prices and included under energy value of storage projects. The example in Figure 25 illustrates this based on a storage unit that charges in hour 14 when marginal GHG rate is low and discharges in hour 19 when marginal GHG rate is high. Associated energy value based on avoided cost is $15/MWh, of which $3/MWh is related to GHG costs.

Electric sector GHG targets implemented in the IRP studies may require new investments at a cost higher than cap-and-trade price. The "GHG adder" reflects this incremental cost of further reducing emissions to meet electric sector GHG targets. As described in the CPUC 2022 Avoided Cost Calculator documentation, the GHG adder is estimated to be zero through 2030 due to the amount of renewables already procured for reliability and tax credits. Consistent with this finding, we set the GHG adder to $0 for our study period 2017–2021.



	Hour 14	Hour 19	Avoided Cost
Storage	charge	discharge	
Marginal unit	efficient gas	inefficient gas	
Heat rate (Btu/kWh)	6,500	10,000	
Fuel cost ($/MMBtu)	$3.5	$3.5	
VOM ($/MWh)	$5	$5	
GHG rate (ton/MMBtu)	0.053	0.053	
GHG cost ($/ton)	$15	$15	
Fuel + VOM cost ($/MWh)	$28	$40	$12
GHG cost ($/MWh)	$5	$8	$3
Marginal Energy Cost ($/MWh)	$33	$48	$15

Figure 25: Historical GHG allowance price in the cap-and-trade market and illustration of how it impacts energy market prices and value.

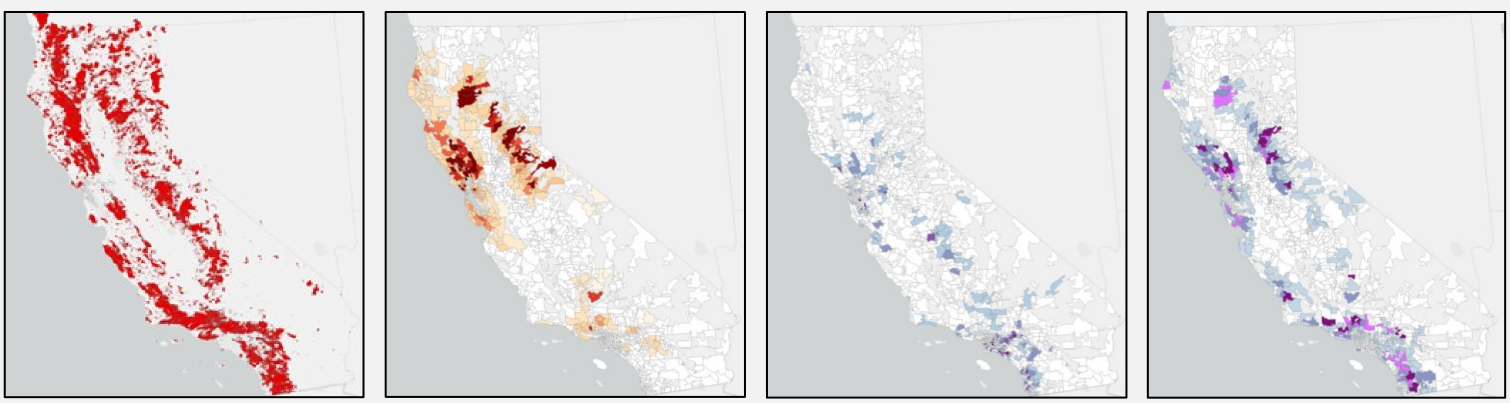
Customer Outage Mitigation Value

Customer outage mitigation is crucial component of resilient electricity service to meet essential loads and to protect vulnerable customers, communities, and critical facilities. On average around the country, sustained service interruptions to customers last about 1.5 hours at a time. Although this can vary widely across customers and circumstances, a typical customer can reasonably expect an hour or two of total outage time per year, possibly spread over multiple events.

Unfortunately, wildfire risks in the West have accelerated rapidly, revealing a complex relationship to electricity service and a strong dynamic of wildfire risks both to and from the grid. The IOUs have relied upon sustained day-long or multi-day outages to reduce ignition risks in the areas and times of the year with high risk of cascade into disastrous megafires. These Public Safety Power Shutoffs (PSPS) affect millions of people living or doing business in California, who can now reasonably expect multiple outages per year with each lasting several days at a time.

Our outage mitigation value estimates focus on these extended PSPS outages and impacts to customers. Energy storage (a) connected to either radial sections of the distribution grid or directly at customer sites, (b) co-located with a generation source such as solar PV, and (c) configured to operate during a grid outage hold the potential to mitigate the impact of extended outages lasting several hours or days. Standalone storage can also provide backup power during outage events, but for only a couple of hours unless they are significantly oversized.

In 2017–2021, customer outage mitigation value for SGIP installations was largely an untapped potential. In Figure 26 below, historical wildfire perimeters and PSPS areas compared to the distribution of nonresidential storage projects shows low spatial correlation. Recent storage projects funded under the SGIP Equity Resiliency budget are primarily installations that are paired with solar and concentrated in high wildfire threat areas. These projects however were not included in this study as they were mostly residential projects installed in 2021 and we could not access sufficient operational data.



Historical fire perimeters | Relative PSPS severity in total customer-hours | Distribution of nonresidential SGIP-funded storage installations | Distribution of storage + solar installations under SGIP Equity Resiliency budget

Figure 26: Comparison of various SGIP installations to wildfire threat areas.

To determine customer outage mitigation value, we first mapped nonresidential projects to the zip codes that experienced PSPS outages during the study period. We originally planned to track actual discharge and paired solar generation during outage events and estimate outage mitigation benefits at an assumed value of lost load. However, we later observed that the operational data during outage periods were incomplete and paired solar generation was also not included under the performance data collected from nonresidential energy storage projects. Given that, we adjusted our approach and focused on the "insurance value" of the projects against power service interruptions.

A key input to monetizing the outage mitigation benefits is the value of lost load (VOLL), which is typically linked to societal cost of outages. Although there are several studies and tools aimed at estimating VOLL, we found that there are currently no California-specific and statistically significant estimates of the cost of multi-hour and multi-day outages to customers available in the industry.

- A commonly cited LBNL/Nexant meta-analysis of 34 VOLL studies (Sullivan et al., 2015) focuses on short-duration outages lasting less than a day, and estimates average VOLL at $1–$3 per kWh for residential customers, $12–$22 per kWh for medium C&I customers, and >$200/kWh for small C&I customers (in 2013 dollars, for interruptions of 1–16 hours);
- Interruption Cost Estimate (ICE) Calculator also focuses on short-duration customer outages based on the LBNL/Nexant study and does not capture the full effects of long-duration (> 24 hours) outages;
- Under the microgrids proceeding, the CPUC's Resilience and Microgrids Working Group highlighted the Power Outage Economic Tool (POET) as a prototype extension of the ICE calculator, which is currently developed by LBNL in a pilot study for ComEd (Illinois), but it will be limited in its applicability to California until California customers are studied;
- A recent study in New England (Baik et al., 2020) found residential customers' stated willingness to pay at $1.7–$2.3/kWh in 2018 dollars to avoid a 10-day winter outage, but customer energy use and substitution options to meet essential needs (e.g., gas-fired heating) in New England are very different from California.

For our study, we assigned the outage costs for nonresidential customers at $30/kWh of essential load, which translates to $15/kWh of unserved load assuming half of customer's load is for essential activities. This value is similar to the interruption cost estimated in LBNL/Nexant study for medium and large C&I customers experiencing outages of 4–16 hours. For sizing, we assume essential load is equal to storage kWh. This is conservative because when paired with solar, the same storage system can support much larger levels of essential load. Figure 27 summarizes estimated outage mitigation values for nonresidential SGIP projects, averaged at cluster level. For projects paired with solar in PSPS areas, the average benefit is $16.1 per kW-month over the 5-year period. Standalone storage projects and projects outside of PSPS areas are assumed to have zero benefits. When they're included, the overall average benefit drops to $1.7/kW-month for the entire nonresidential SGIP portfolio.

SGIP Cluster ID	Total Energy Storage Capacity (MW)	Capacity Paired w/ Solar in PSPS Area (%)	Average Local Outages from PSPS (hrs/yr)	Average Outage Mitigation Value ($/kW-mo)	
				Paired w/ Solar in PSPS Area	All Energy Storage Projects
1	17.6	55%	47	$19.8	$11.6
2	9.1	25%	26	$12.6	$3.1
3	23.6	16%	41	$13.8	$3.4
4	60.6	3%	31	$13.5	$0.4
5	9.7	0%	-	-	$0.0
6	41.6	3%	50	$14.4	$0.4
7	43.0	7%	24	$10.7	$0.5
Total	**205.3**	**11%**	**40**	**$16.1**	**$1.7**

Figure 27: Estimated customer outage mitigation value of nonresidential SGIP projects by cluster (2022$).

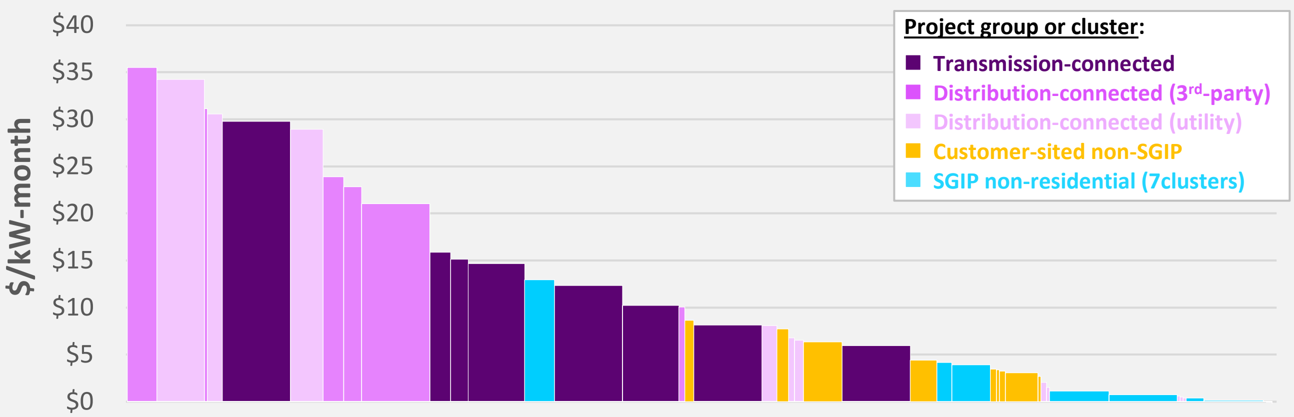
Total Societal Benefits

Figure 28 shows the total benefits from a societal perspective for the 2017–2021 operating period. Top chart shows the aggregate benefits color coded by project group or cluster. Bottom chart shows stacking of individual benefit metrics. Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited installations are aggregated into utility contracts or clusters.

The top-ranked resources provided \$20–\$35 per kW-month of average benefits over the 5-year period. These resources all participated in the CAISO wholesale markets and they did relatively well in stacking of energy, ancillary services, and RA capacity value. Many of them are distribution-connected projects that were procured to address various local RA and reliability needs.

Many of the recent large transmission-connected storage projects ranked in the middle, with higher focus on energy arbitrage and little/no ancillary services value. Their estimated RA capacity benefits were lower than the early projects procured for high-value local RA needs.

Customer-sited resources generally provided very low benefits due to lack of service to the transmission grid. However, one of the clusters of nonresidential SGIP projects provided relatively high resilience value by mitigating impacts of customer outages (shown in gray). Storage projects in this cluster are mostly paired with rooftop solar and located in areas that faced several Public Safety Power Shutoff (PSPS) events historically.



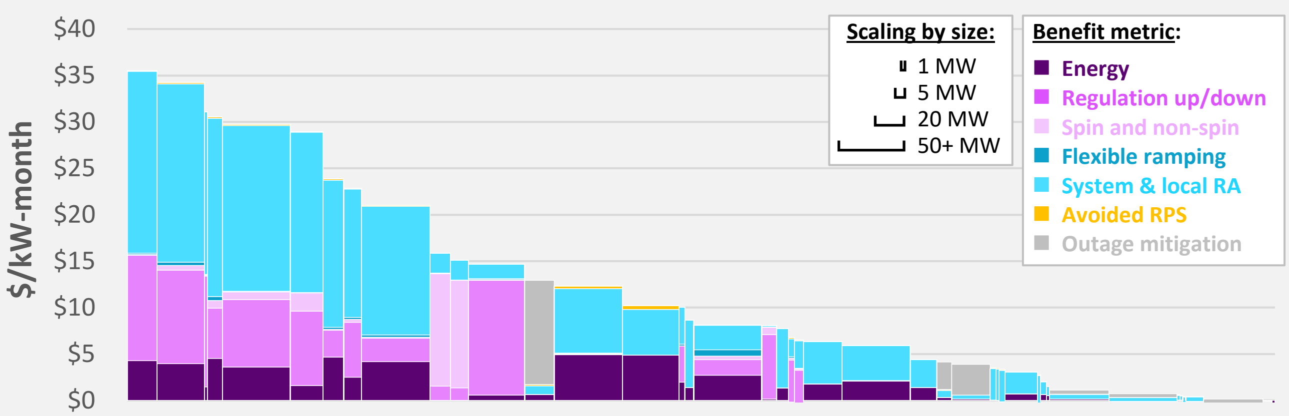


Figure 28: Summary of estimated societal benefits by project group (top) and benefit metric (bottom) (2022 \$).

Utility-Owned Storage Costs

Utility-owned storage projects account for 110 MW of the storage capacity included in our evaluation, as shown earlier in Figure 3 of this attachment. Many of them are relatively small, distribution-connected pilot and demonstration projects installed prior to 2017.

Figure 29 below shows their installed cost by online date on the left, with bubble sizes proportional to project sizes ranging from 25 kW to 30 MW. This cost data is compiled based on research of utility applications and CPUC decisions on various procurement tracks, supplemented with information provided by the IOUs. Earlier small pilot and demonstration projects are at the top of the curve, with most of them at $6,000–$11,500/kW in 2022 dollars. More recent projects in 2017–2019 were installed at a lower cost in the range of $2,000–$4,500/kW except for couple projects with very short durations. The cost trends shown here reflect an early phase of the learning curve and costs are expected to decline further. Newer utility-owned projects to be installed in late 2021 and 2022 have an estimated cost of $1,300–$1,700/kW, but those projects are not included in our historical benefit/cost analysis.

To develop a cost metric that can be compared against average benefits, and across all storage projects, we levelized capital and operating costs of the projects using utility-specific cost of capital assumptions. For retired projects, we amortized their costs over their actual lives. For projects under long-term service agreements and warranties, we amortized their costs over 15-year life assuming these service agreements get extended. For all other projects, we assumed 10-year economic life. Figure 29 shows the resulting levelized costs in $/kW-month (right) of capital and O&M costs. For projects that received state and other 3rd-party funding, we only included costs incurred by the ratepayers, net of external funds. As shown, the estimated levelized cost of these utility-owned projects are very high compared to today's cost levels. Most early pilot and demonstration projects have a levelized cost of over $100/kW-month, which is more than 10x higher than current costs of utility-scale storage projects. This is partly due to high capital costs, but also partly driven by extremely high operating costs of these early projects installed prior to 2015. Larger projects installed more recently in 2017 have levelized costs in the range of $25–$40/kW-month, which is also relatively high reflecting the storage market of that time, coupled with the cost premium of expedited procurement needed to address local reliability issues caused by prolonged natural gas leak at Aliso Canyon.

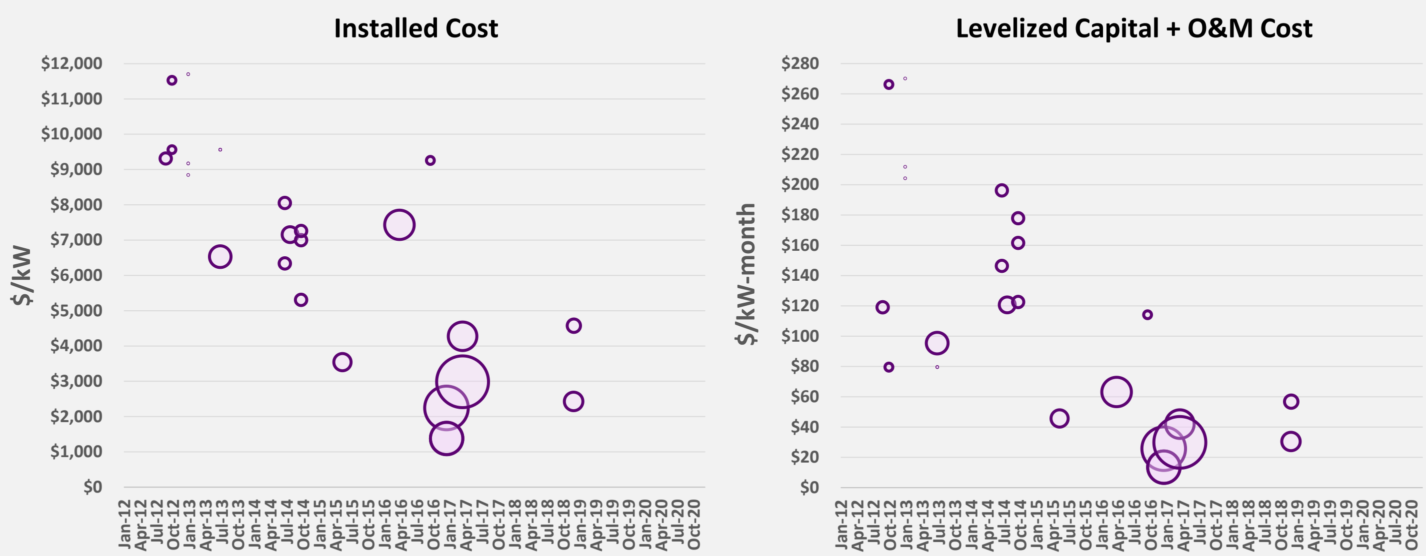


Figure 29: Cost of utility-owned storage projects included in the study (2022 $).

Third-Party Storage Contract Prices

While many of the initial pilot projects were utility-owned, a rapidly growing share of storage projects are procured under third-party contracts where the utility or load serving entity pays a contract price in exchange for the rights to the project's certain attributes. Most of the energy storage contracts executed by the California utilities have either a fixed flat price that remains constant over time or a price schedule escalating annually at a set rate.

Figure 30 below summarizes the energy storage contract prices for projects included in the study, with data aggregated by grid domain and type of contracts to preserve confidentiality. Overall, there is a wide range of prices depending on vintage, grid domain, procurement track, and project size. Earlier energy storage contracts were significantly more expensive across all grid domains, reflecting the high end of the ranges shown.

Recent contracts are predominantly with large transmission-connected energy storage projects, and they generally reflect the cost reductions seen in the storage industry. Among the operational transmission-connected projects included in the study, price was in the range of $6–$8 per kW-month for resource adequacy (RA) only contracts and $7–$22 per kW-month for all-in contracts where the utility gets all of the project's attributes for the contracted period. Many of the newer storage projects under development are contracted at $9–$14 per kW-month for all attributes, but those projects are not included in our historical benefit/cost analysis.

Under an RA only contract, the utility offtaker buys RA capacity and the third-party owner retains all other attributes. For example, they can participate in the CAISO energy and ancillary services markets and keep the associated revenues. This allows the owner of the project to offer project's capacity at a lower price point, relative to all-in contracts.

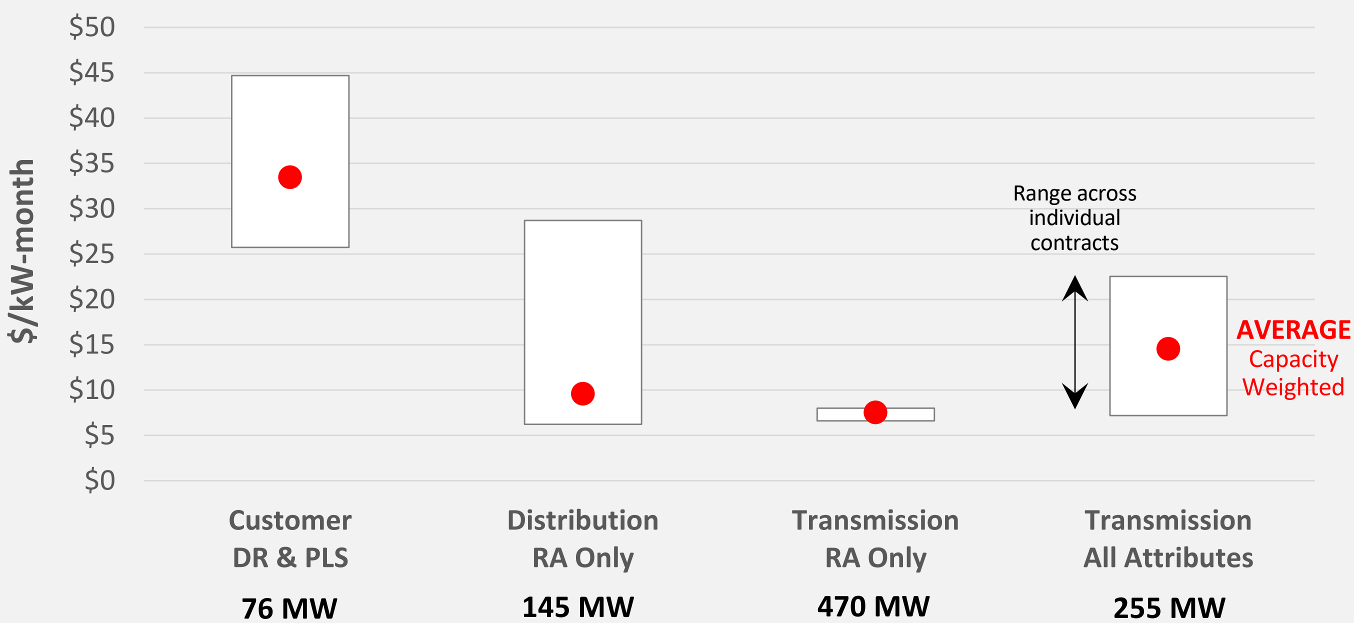


Figure 30: IOU third-party storage contract prices for storage projects included in the study (2022 $).

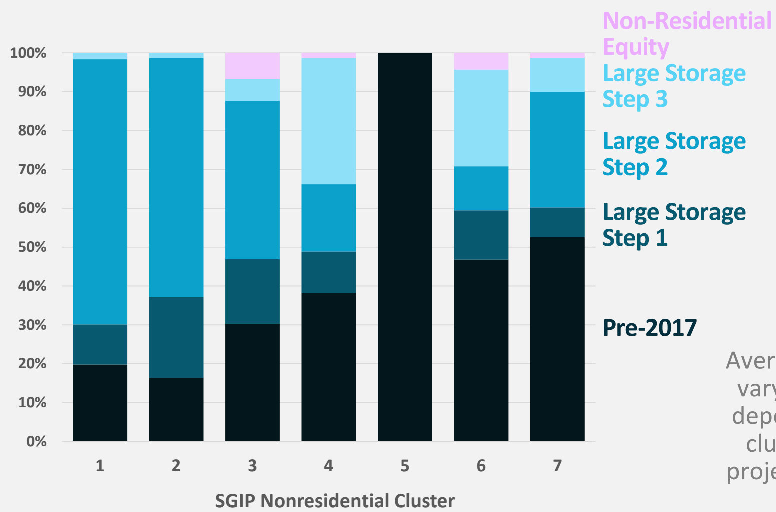
SGIP Project Incentive Payments

SGIP incentive payments are included as the ratepayer-funded portion of the costs for the SGIP storage projects in our study.

SGIP was established in 2001 to provide financial incentives for distributed generation. Standalone energy storage became eligible in 2011. Incentive levels for energy storage were initially set per kilowatt of capacity starting at $2,000/kW in 2011 and declining to $1,310/kW by 2016. The program went through a major transformation in 2016 and reallocated 75% of funding to energy storage, with incentive levels redefined per kilowatt-hour of capacity. Under the general budget, incentives are divided across five steps for large storage projects (> 10 kW), starting at $500/kWh in Step 1, declining to $250/kWh in Step 5. Most of the nonresidential SGIP-funded storage projects have only 2 hours of duration, as the incentives decline after the first 2 hours. For 2-hour storage projects, these incentives translate to $1,000/kW for Step 1, and $500/kW for Step 5. More recently, CPUC shifted focus to equity and customer resilience with increased budget and incentives for storage installations by lower-income, medically vulnerable customers who are in high fire-threat areas and at risk of outages due to utility Public Safety Power Shutoffs (PSPS) outages. The funds are also made available to critical facilities and infrastructure supporting community resilience in the event of PSPS or wildfire.

Figure 16 below (left) shows the mix of budget categories within each SGIP cluster we identified. Nearly all nonresidential SGIP projects with operational data for 2017–2021 were enrolled under program years prior to 2020, with incentives through Step 3. There are very few nonresidential projects enrolled under the equity budget (shown in pink) and no projects under the equity resilience budget.

The table in Figure 16 shows the capacity-weighted average incentive payments for each SGIP cluster, which varies from $750/kW to $2,174/kW (in 2022$) depending on the mix of projects by budget category. The table also shows the estimated levelized incentive costs in the range of $8–$25 per kW-month using utility-specific cost of capital assumptions and 10-year economic life.



Average incentives vary significantly depending on the clusters' mix of projects by budget category

Cluster ID	Average Incentive $/kW	Levelized Incentive $/kW-mo
1	$766	$9.3
2	$750	$8.1
3	$1,110	$16.1
4	$1,197	$17.7
5	$2,174	$25.4
6	$1,408	$21.0
7	$1,391	$19.1

Figure 31: Levelized incentive for nonresidential SGIP storage projects by cluster (2022 $).

Final Benefit-Cost Ratios

Figure 32 summarizes our ratepayer net benefit results for the 2017–2021 operating period, expressed as benefit/cost (B/C) ratios. The chart highlights the differences relative to a B/C ratio of 1.0, which indicates estimated benefits are equal to costs. About half of the analyzed storage capacity yielded more benefits than costs to ratepayers (B/C ratio above 1.0).Most bars on the chart represent an individual energy storage resource with the width of the bar showing relative MW capacity. Small customer-sited installations are aggregated into utility contracts or clusters with similar operational patterns. The bottom chart shows the underlying benefit and cost components. For storage under RA only contracts, energy and ancillary services values are not included as they are not ratepayer benefits. As explained earlier, there were no projects with T&D deferral benefits and the GHG reduction value is already reflected in energy value (no GHG adder). Avoided RPS costs were relatively small compared to core benefits from energy, ancillary services, and RA capacity.

Among all projects analyzed, top 3 of the third-party-owned distribution-connected resources performed particularly well compared to others. These resources provide high-value local resource adequacy (RA) capacity, and they participate in the CAISO marketplace. Transmission-connected resources and two utility-owned distribution-connected resources also performed relatively well, due to RA capacity service, participation in the CAISO marketplace for energy and ancillary services, and high efficiency achieved from daily operations. Customer-sited and some utility-owned distribution-connected resources performed the worst due to lack of service to the transmission grid and/or relatively high procurement costs. Low B/C ratio of these resources is not due to any inherent technological limitations. Rather, it reflects differences in use cases, priorities, and lack of access to grid signals that can be addressed by policy reforms.

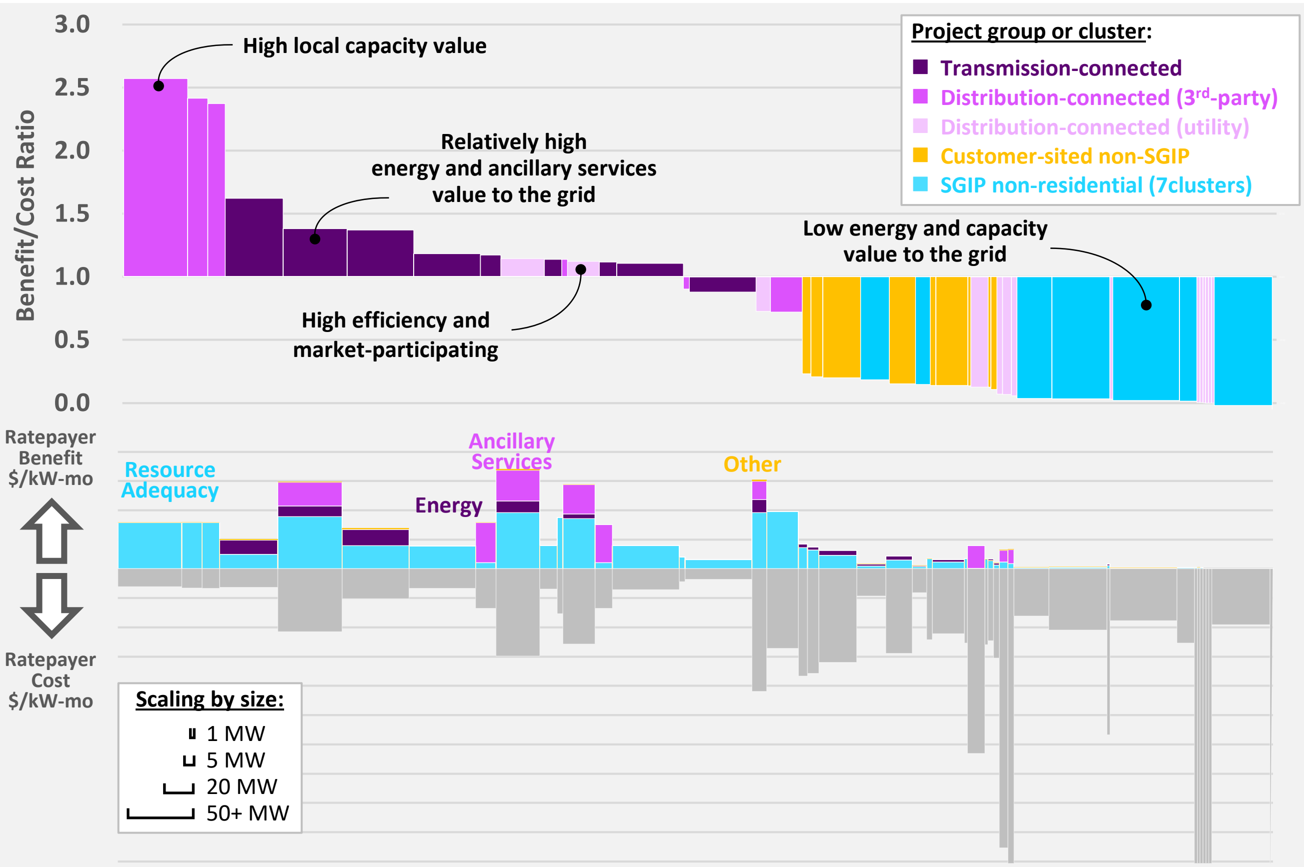


Figure 32: Summary of ratepayer benefit/cost ratio results (top) and underlying components (bottom).

Net Ratepayer Benefits over Time

In terms of absolute dollars, the benefit/cost ratios represent a portfolio-wide average of $72 million per year in net ratepayer cost over the 5-year study period. Exploratory pilots and incentive programs—including resources developed under pilots, demonstrations, SGIP, and/or first-in-kind procurement tracks—cost ratepayers an average $75 million per year. This is offset by $3 million per year net benefit from energy storage resources developed under mature use cases and procurement tracks. The $3 million per year is a diluted metric, which is derived from a total $16 million of benefits mostly incurred in 2021, but averaged over the entire 5-year study period.

The time profile of ratepayer impacts reveals three striking trends over time (Figure 33):

1. **Steady ongoing amortized investment cost of early utility-owned pilot and demonstration programs** (grey line) at almost $30 million per year;
2. **Steady buildup of net ratepayer cost of customer-sited installations** (yellow and turquoise lines) as the number of installations grow—due to lack of storage operations beneficial to the grid coupled with relatively high costs—reaching a rate of approximately $80 million per year by the end of 2021; and
3. **Recent growth in net ratepayer benefit of distribution- and transmission-connected storage installations** (magenta and purple lines) as the volume of capacity participating in the CAISO marketplace and providing local and system resource adequacy grows, landing at an annualized rate of $30 million per year by the end of 2021, which includes $22 million per year in net benefits produced by market-mature resources, plus $8 million from earlier market entrants.

These trends have key implications for future energy storage procurement and policy direction which we discuss in Chapter 3 of the main report (Moving Forward). The performance of more recent and market mature projects indicate an acceleration towards future growth in benefits. However, the net cost of earlier exploratory projects and incentive programs will continue at $89 million per year on average over their full amortization period.

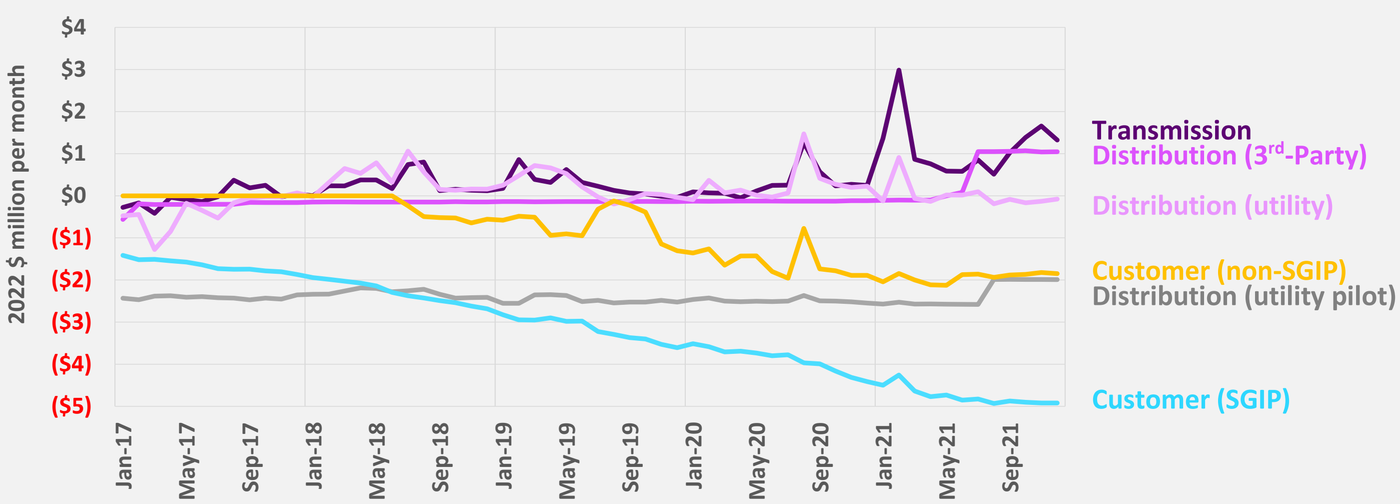


Figure 33: Net ratepayer benefits (costs) over time.

*Lump-sum capital costs or incentive payments are levelized over economic life of the projects.

Project Scoring towards State Goals

The CPUC decision D.13-10-040, which set the AB 2514 energy storage procurement target of 1,325 MW, identified 3 overarching policy goals:

- Grid optimization,
- Integration of renewable energy, and
- Reduction of greenhouse gas (GHG) emissions

A key objective of our study is to determine if the energy storage procurement meets these policy goals. We do this by developing scorecards for each project based on their operations during the 5-year period in 2017–2021.

Figure 34 below shows the list of services and associated benefits considered in our study. Our approach to scoring involves several steps, as summarized below:

1. First, we map each of the services and benefits to the stated policy goals, as shown in the table;
2. Then, we determine a project score for each service and benefit category based on the use case, utilization of capacity towards providing that service, and observed grid impacts;
3. Later, we calculate a normalized score (0–100) towards each policy goal by averaging individual scores for the relevant services and benefits mapped to that policy goal, and re-scale them so that project at the bottom gets 0 and project at the top gets 100;
4. Last, we develop the final project scores based on the average of their scores for grid optimization, renewables integration, and GHG emission reduction.

Contribution towards AB 2514 Goals

	Grid Optimization	Renewables Integration	GHG Emission Reduction
Energy time-shift	✓	indirect	indirect
Ancillary services	✓	✓	indirect
Resource adequacy (RA) capacity	✓		indirect
Transmission investment deferral	✓		
Distribution investment deferral	✓		
Avoided renewable curtailments		✓	indirect
GHG emission reduction			✓
Customer outage mitigation	✓		

Figure 34: Benefit metrics considered in the study and contribution to AB 2514 goals.

Scoring for Grid Optimization Impacts

We consider several services and benefits contributing to grid optimization. By energy time-shift and ancillary services, storage projects help with more optimal scheduling and dispatch of resources in the wholesale markets, reducing the overall system production cost. By resource adequacy (RA) capacity, transmission deferral, and distribution deferral, storage projects help with meeting grid reliability needs more efficiently at a lower cost. By customer outage mitigation, storage projects increase resilience of the grid and reduce cost of power interruptions.

For each service, we developed an individual score based on utilization of projects' capacity towards providing that service, as described below:

- Energy time-shift score based on average daily energy discharge duration;
- Ancillary services score based on average ancillary services provided as a % of nameplate MW;
- RA capacity score based on RA capacity credit as a % of nameplate MW, with a 1.5x multiplier if procured under a specific LCR track and 1.25x multiplier if in a local capacity area but not procured for LCR;
- Transmission deferral score is set to zero for all resources as there were no actual transmission investments deferred during the study period;
- Distribution deferral score is set to zero for all resources as there were no actual distribution investments deferred during the study period;
- Customer outage mitigation score is set to 100 for distribution-connected storage resources with microgrid capability and customer-sited storage resources that are paired with solar and located in areas that have experienced PSPS outages during the study period. For SGIP-funded storage, calculated a cluster-level score that reflects the average of individual scores for projects within that cluster.

The overall grid optimization score is calculated as the average of individual scores for the services above. The results are shown in Figure 35 below.

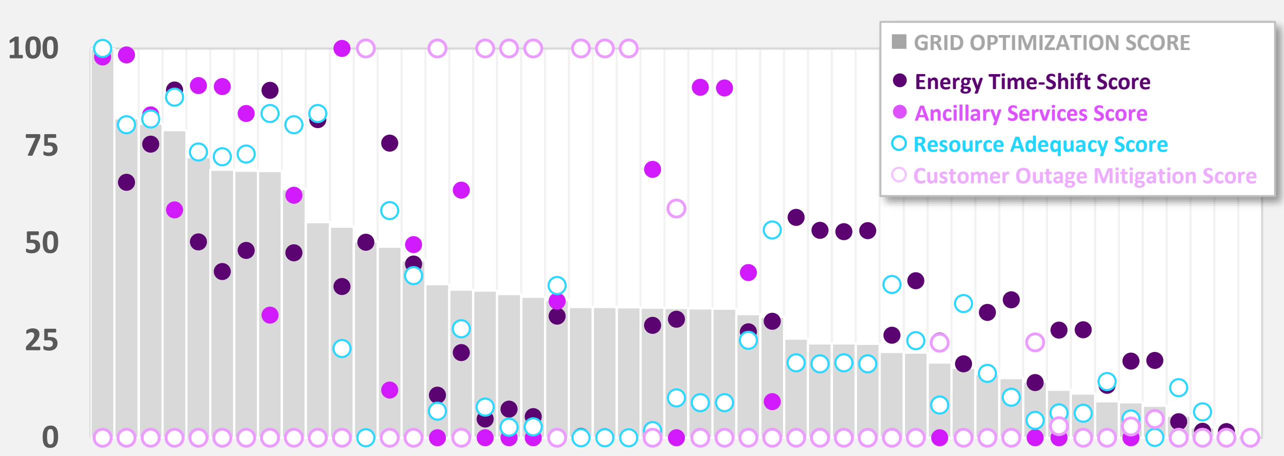


Figure 35: Grid optimization scores by project.

Scoring for Renewables Integration Impacts

Storage projects' contributions towards renewables integration have two components: one based on energy time-shift and another based on ancillary services.

- With energy time-shift, storage projects can enable renewable integration by charging when the system has oversupply to reduce the excess renewable energy that would otherwise get curtailed. Associated renewable curtailment impacts are calculated based on the analysis described to estimate avoided RPS costs as described earlier (see Figure 21). The associated scoring is normalized between 100 for the project with the highest avoided renewable curtailments and 0 for all resources that had increased curtailments.

- By providing ancillary services, storage projects help with meeting the flexibility needs to address increased variability and uncertainty of the net load driven by renewable generation. The ancillary services score is calculated as described under grid optimization section, based on average ancillary services provided as a % of nameplate MW.

The overall renewable integration score is calculated as the average of the scores for avoided renewable curtailments and ancillary services. The results are shown in Figure 36 below.

As discussed earlier in the report, many of the CAISO-participating energy storage projects focused on ancillary services over the study period 2017–2021. These projects scored relatively high in terms of their contribution to renewables integration goal. Top-ranked projects were able to provide modest levels of renewable curtailment reduction via bulk energy time-shift, stacked with high-value ancillary services in the CAISO market.

Distribution-connected storage projects that did not participate in the CAISO market, and customer-sited projects (both CAISO and non-CAISO) ranked at the bottom with very low scores as they did not provide any ancillary services and their charging were not aligned well with renewable oversupply.

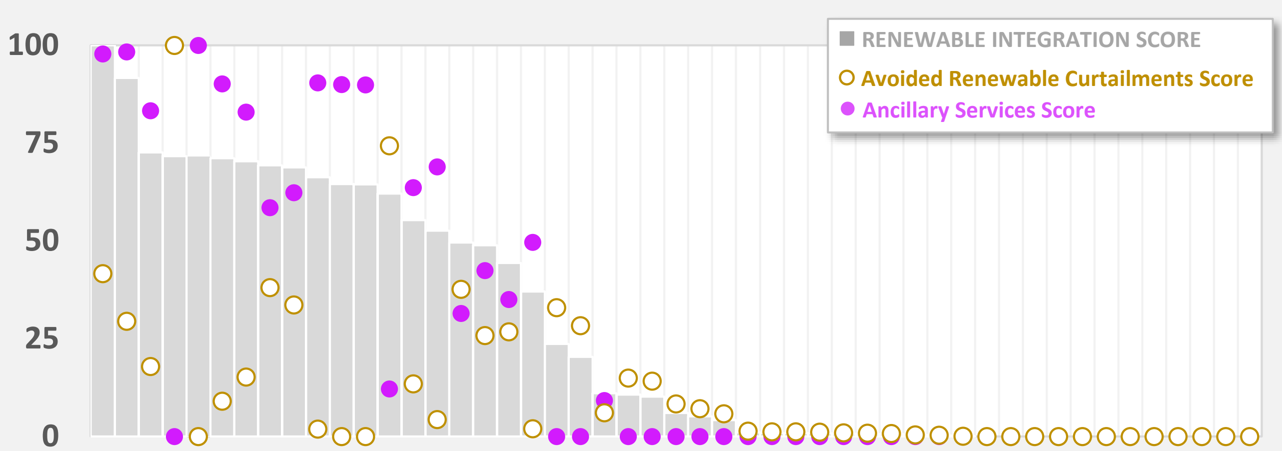


Figure 36: Renewable integration scores by project.

Scoring for GHG Emission Impacts

Energy storage use cases and the associated charge and discharge patterns impact the GHG emissions on the electric system. As described earlier in this report, we estimate net GHG emission impact of the energy storage resources based on their actual energy output multiplied by historical marginal GHG emission rate at the sub-hourly interval level and added up over the study period. Energy storage reduces emissions at the marginal rate when discharging, and it increases emissions at the marginal rate when charging. The results are shown in Figure 23.

As previously discussed, for energy storage resources to provide GHG reduction benefits, (a) they need to be highly efficient, and (b) their use cases should allow shifting bulk energy from periods with low GHG intensity to periods with high GHG intensity.

- The storage projects with the highest GHG emission reductions participated in the CAISO market and focused more on energy arbitrage, less on ancillary services. Projects with high ancillary services focus contributed to a net increase in GHG emissions as their charge/discharge patterns were uncorrelated with the GHG intensity of the system. With 10–15% average losses over time, they created more emissions when charging relative to emissions they avoided when discharging, which led to a net increase of GHG emissions.
- The GHG impacts of nonresidential SGIP projects vary by cluster. Clusters 1–3 reduced GHG emissions primarily by projects paired with solar PV and installed at schools, while clusters 4–7 contributed to higher GHG emissions as their use cases focused on demand charge management and did not align well with GHG reduction goals of the program.
- Other storage projects that did not participate in CAISO marketplace were mostly underutilized and they were often on extended periods of standby, which translated to low operational efficiency and resulted in marginal increases in GHG emissions.

The overall GHG emission reduction score is normalized between 100 for the project with the highest GHG emission reductions and 0 for all resources that had increased GHG emissions. The results are shown in Figure 37 below.

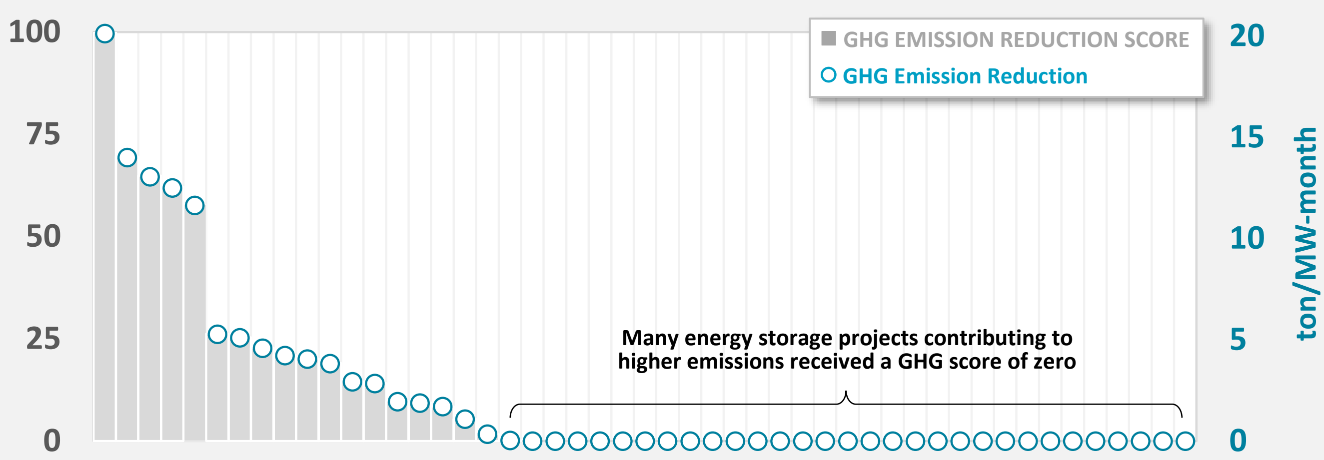


Figure 37: GHG emission reduction scores by project.

Final Project Scores

Figure 38 summarizes project scores on contributions towards meeting state goals of grid optimization, renewables integration, and GHG emissions reductions during the 2017–2021 study period.

Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited installations are aggregated into utility contracts or clusters. Final score (height of bar) is an average of 3 individual scores for grid optimization, renewables integration, and GHG emission reduction normalized between 0 (worst performance) and 100 (best performance) in each category.

As with our benefit/cost analysis results, third-party-owned distribution- and transmission-connected resources performed relatively well while customer-sited resources performed at the bottom. Three key findings highlight the importance of taking this more societal perspective and considering contributions to meeting state goals beyond what can be monetized in benefit/cost metrics:

- Many distribution-connected resources demonstrate relatively high utilization across multiple grid services and significant reductions in local renewable curtailments—despite not capturing the highest market values as reflected in their B/C ratios;
- Transmission-connected resources that rank lower here than in benefit/cost ratios provide fewer types of services compared to their peers (e.g., narrow ancillary services focus, low RA capacity) or have extended outages limiting their overall performance.
- Resources that provide negligible GHG emissions reductions or increase GHG emissions are given a score of zero in that category. Several resources did not contribute towards the state's GHG emissions reductions goals. Likewise, several resources did not contribute meaningfully to renewables integration.

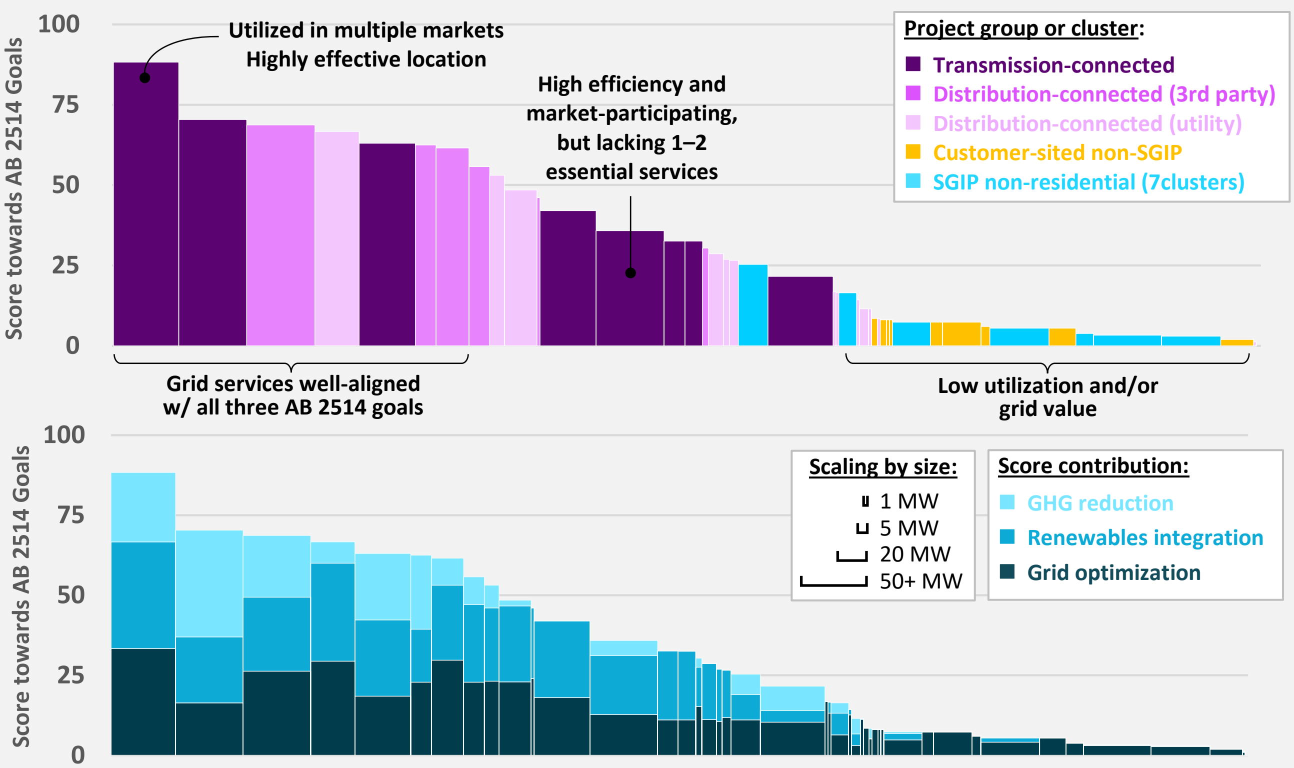


Figure 38: Final project scores towards state goals (top) and underlying components (bottom).

ATTACHMENT B: COST-EFFECTIVENESS OF FUTURE PROCUREMENT[1]

This attachment provides details on the special study of benefits and costs associated with additional energy storage procurement in California over the next 10 years.

As the state deploys more renewable energy resources to meet increasing clean energy goals, the value of various grid services provided by energy storage technologies will increase and more energy storage procurement will be needed. At the same time, marginal value of energy storage will start to decline at higher penetration levels due to saturation effects and characteristics of the cost-effective energy storage portfolio will continue to evolve. This study expands on the core evaluation of actual energy storage installations in California and utilizes a forward-looking modeling approach to analyze cost-effectiveness of future procurements by 2032 while considering the interactive and offsetting effects of renewables buildout and market saturation.

The goal of the study is to develop *indicative* estimates of the overall economic potential of energy storage projects that can provide broad, system-level benefits in California. Opportunities driven by specific local needs and incentives are not considered in this study scope. We expect the findings to supplement IRP-LTPP process and provide insights on future value drivers and emerging need for longer duration storage over the 10-year study horizon.

The study findings are also used to estimate the aggregate net benefits of the planned 13.6 GW of energy storage portfolio identified in the CPUC's 2021 Preferred System Plan.

CONTENTS

Study Approach and Analytical Framework

Our approach to evaluating cost-effectiveness of future energy storage procurement in California is organized around several steps, as summarized below:

1. **Develop storage cost and performance assumptions:** Select energy storage configurations to be considered in the study and determine their cost and performance characteristics
2. **Develop Base Case outlook for power prices:** Develop 10-year outlook for power prices starting with no energy storage on the system
3. **Simulate storage operations and market value under the Base Case:** Simulate hourly operations of storage under the price forecast developed in Task 2; Estimate net energy market value and RPS benefits from avoided renewable curtailments
4. **Estimate impacts of increased storage penetration:** Quantify how storage charging in low-prices hours and discharging in high-prices hours would impact dispatch of other resources on the system and resulting energy prices; Re-simulate market prices and storage operations at each penetration level to determine extent of market saturation and declining marginal values
5. **Estimate marginal capacity contribution:** Approximate ELCC curves based on marginal impact of storage operations on net peak demand across all 8,760 hours simulated, accounting for shifting and flattening of net peak periods when more storage is installed
6. **Estimate net CONE at various storage duration levels:** Calculate net CONE based on levelized cost minus energy value and RPS benefit, divided by marginal ELCC; Repeat calculations for 4-, 6-, 8-, and 10-hour storage
7. **Determine cost-effectiveness of additional energy storage:** Estimate how much energy storage can be deployed cost effectively by comparing net CONE estimates in Step 6 against each other and alternatives

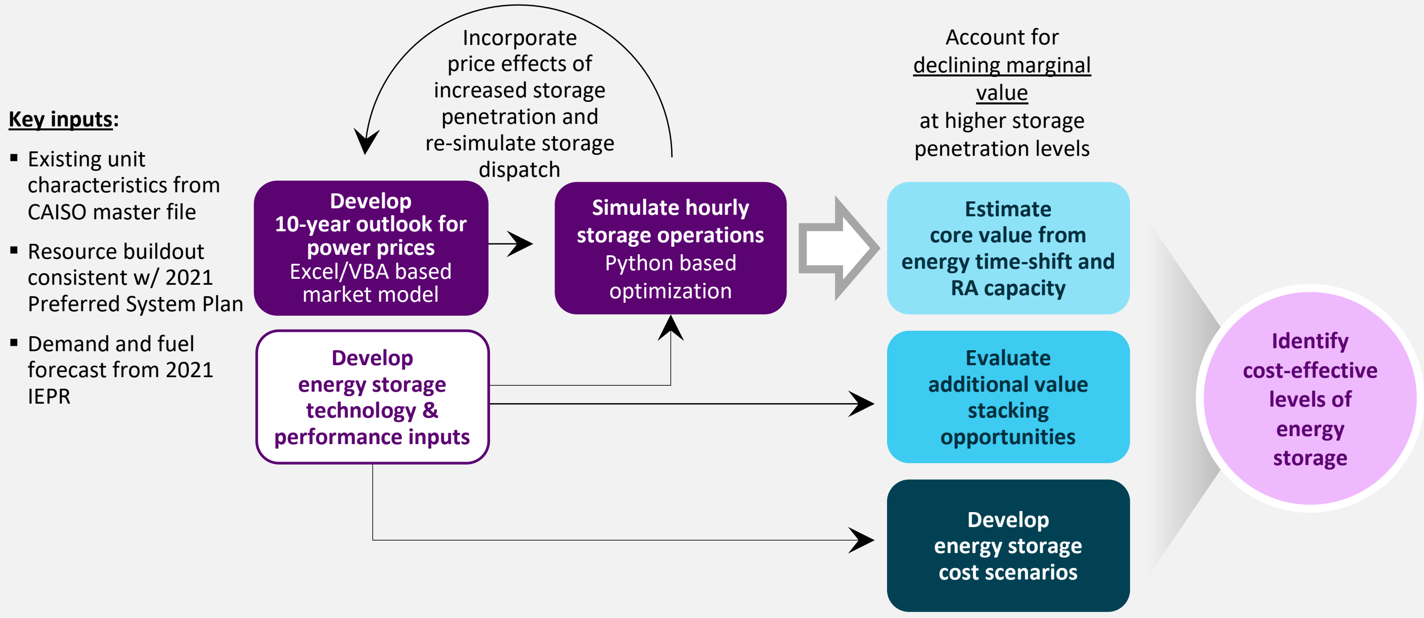


Figure 1: Study flowchart summarizing key tasks and analyses.

Storage Technology and Cost Assumptions

Figure 2 below summarizes energy storage configurations and characteristics considered in our study.

While our study approach is technology-neutral, we simulate energy storage operations and analyze value utilizing cost and performance assumptions based on lithium-ion batteries as they are the dominant technology accounting for the large majority of new energy storage capacity procured in California today.

In our analysis, we focus on large utility-scale energy storage projects operating on a stand-alone basis with a primary use case of energy time-shift and resource adequacy at the bulk-grid level. We consider energy storage with 4–10 hours of duration as we expect most of the system-level grid needs over the next 10 years can be addressed by storage systems that can provide up to 10 hours of continuous discharge capability at full output, although we recognize that longer duration storage will likely play an essential role to help California meet its deep decarbonization goals in the long-term beyond the 10 years considered here. (See **Attachment E** of our report for further discussion on alternative technologies and long duration storage.)

We assume 85% round-trip efficiency, which is in line with the actual performance of recently-installed battery projects participating in the CAISO markets. This means for each MWh of energy charged, the storage project will discharge 0.85 MWh of useful energy to be sent to the grid on average after losses and auxiliary use.

Our analysis considers 15 years of economic life during which storage performance is maintained with augmentation. Accordingly, our fixed O&M cost inputs are set to include cost of augmentation needed to counteract performance degradation and keep the energy storage system at rated capacity throughout its economic life.

Base Case with stand-alone storage operations
- Sensitivity analysis on co-located energy storage + solar to capture incremental tax benefits, cost synergies, and value impact of operational constraints (grid-charging, interconnection limit)

Primary use case: Energy time-shift and resource adequacy at bulk-grid level
- Ancillary services are not included due to small market size and need
- T&D deferral has untapped potential to provide locational value, but significant barriers exist for scaling (discussed in main report; outside the scope of this special study)
- Customer outage mitigation considered as a secondary use case for distributed storage

Storage duration of 4 to 10 hours
- Multi-day and seasonal energy storage will be needed to meet 100% decarbonization goals of California, but we expect grid needs over the 10-year study horizon can be met by storage up to 10-hour duration

Round-trip efficiency of 85% consistent with our analysis of actual storage installations in California and several other studies we reviewed in the industry

Economic life of 15 years with augmentation (no degradation)

Figure 2: Energy storage configurations and performance assumptions utilized in the study.

Installed cost of 4-hour utility-scale stationary battery storage is currently around $1,500/kW, consistent with our review of the cost data for projects owned by the California IOUs (see Chapter 1 of the report) and other public data (e.g., see reports from NREL and PNNL).

There is very little information on actual installed cost of systems with longer durations. To develop cost estimates for storage with durations of 6–10 hours, we used an approach utilized by NREL which splits the total cost of installations into two components: power- and energy-related costs. Power-related costs may include inverters, power equipment and controls, interconnection, etc. that would typically scale with kW capacity, and they stay the same regardless of duration. On the other hand, energy-related costs (e.g., battery pack) scale with kWh capacity, which means on a $/kW basis it increases proportional to duration level. Currently, energy-related costs including battery pack, EPC, and developer costs add up to approximately $300/kWh for utility-scale stationary battery storage, which accounts for 80% of the total installed cost for 4-hour systems ($300/kWh × 4 hours = $1,200/kW, out of $1,500/kW). We assumed the remaining 20% (equals to $300/kW) is from power-related costs.

Costs of battery storage have declined rapidly over the past decade, with lithium-ion battery pack prices now at >80% below the levels seen in 2010. Going forward, this trend is expected to continue as batteries get cheaper due to the electric vehicle (EV) industry's quest to reduce costs. However, the recent supply chain issues and rising raw material costs create significant uncertainty (at least for the near future). Recognizing this cost uncertainty, we developed three scenarios for the 2032 installed cost assumptions, with energy-related capital cost reductions of 20% to 60% relative to current levels, consistent with the range of projections in the industry.

Figure 3 shows the estimated total installed costs of utility-scale systems with 4–10 hours of duration. Total costs per kWh decrease slightly at higher durations because power-related costs are spread across larger kWh. In $/kW terms, installed costs increase significantly at higher durations because for a fixed level of kW capacity, systems with longer durations require more kWh and energy-related costs account for a relatively large share of total costs.

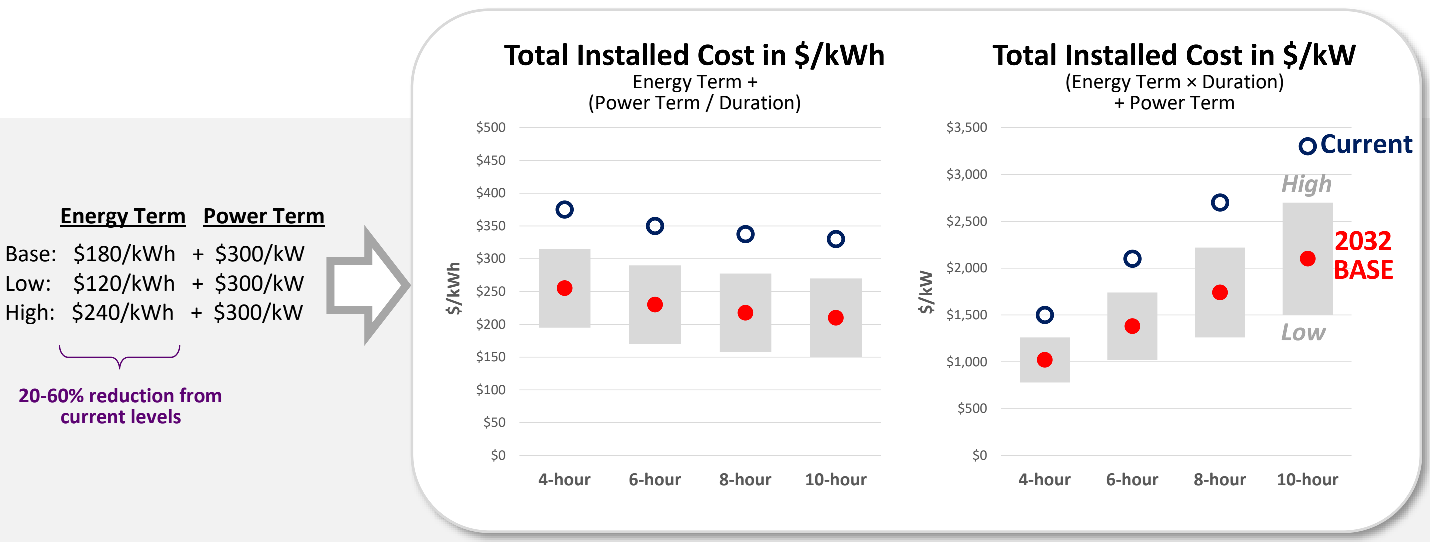
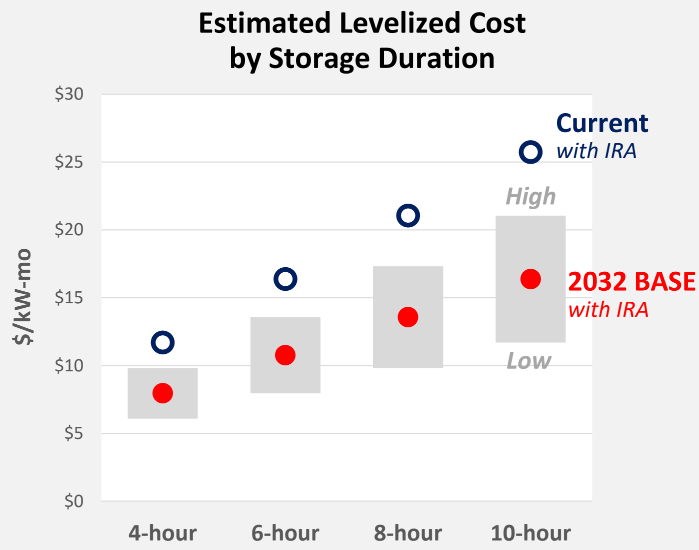


Figure 3: Installed cost assumptions for utility-scale energy storage systems (in 2022 dollars).

Project Life	**15 years** includes augmentation
Federal + State Taxes	**28%**
After-Tax WACC	**7%**
Depreciation Schedule	**5-year MACRS** w/ Inflation Reduction Act
Investment Tax Credit	**30%** w/ Inflation Reduction Act
Inflation Rate	**2.5% per year**
Fixed O&M Cost	**2.5% of installed cost** includes augmentation



* Level-real values in 2022 dollars escalating by inflation over time. Includes amortized capex and O&M costs including augmentation and battery replacement. Excludes charging costs.

Figure 4: Financial assumptions and estimated levelized cost of storage.

Figure 4 above shows our estimated 2032 levelized costs and the underlying financial assumptions. As discussed earlier, we assume 15 years of economic life during which storage capacity will be maintained with augmentation. For consistency, we set fixed O&M cost inputs at a level that includes augmentation costs in addition to other general O&M expenses.

We represent levelized cost values in $/kW-month (2022 dollars) including only capital and O&M costs. We do not include charging costs here because they are already considered when we estimate net energy market value of storage.

The 2032 estimates shown above are with the tax benefits of Inflation Reduction Act (IRA) of 2022, including investment tax credit (ITC) of 30% and treatment as a 5-year property under the modified accelerated cost recovery system (MACRS) rules for depreciation purposes. Figure 5 demonstrates the impact of these new tax benefits on estimated 2032 levelized cost of 4-hour standalone storage. For reference, the storage cost range based on utility contracts approved during the 2020-2021 period is also shown.

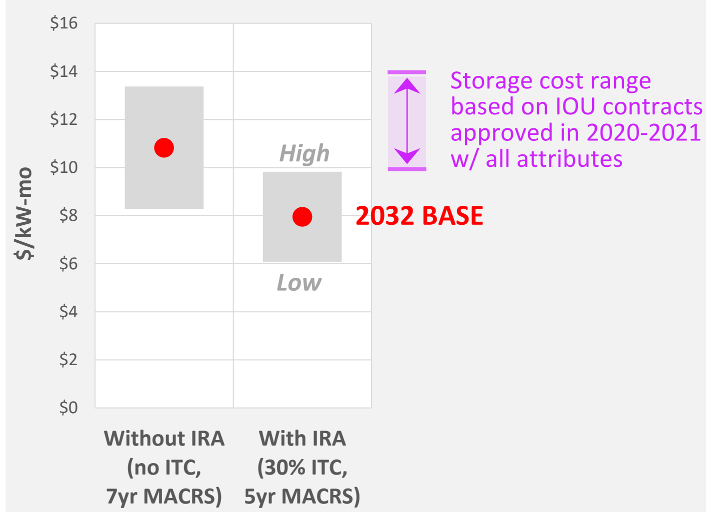


Figure 5: Impact of Inflation Reduction Act (IRA) on estimated 2032 levelized cost of 4-hour storage.

Energy Market Model: 2020 Backcast and Model Calibration

We built an Excel/VBA based energy market model that dispatches regional supply against a chronological hourly load to minimize total dispatch cost and estimate system-level marginal energy prices.

Model inputs include unit-specific resource characteristics based on CAISO master file, hourly managed system load, hourly solar and wind generation schedules, monthly energy levels for hydro generation, and daily fuel and GHG prices, and daily aggregate outage profile for thermal plants. Dispatch of large hydro resources assume to follow net load, subject monthly energy inputs and parameters calibrated based on historical data. Hourly import/export schedules modeled based on historical relationship between CAISO net load and net import levels accounting for seasonality and time of day. While unit commitment constraints are not fully included, the model applies a heuristic approach to enforce minimum runtime and ramping limits before final dispatch of resources are determined. Energy storage schedules are determined separately using a Python-based optimization module under a price-taker approach. The two models are run iteratively to ensure prices and storage operations are internally consistent.

Before simulating 2032 prices, we first created a “2020 backcast” to calibrate the model to track key price patterns including: daily and monthly shapes, price spikes during scarcity conditions, and low prices when there is oversupply. To do this, we populated our model with historical inputs reflecting 2020 day-ahead market conditions and benchmarked the results against actual market outcome. We ran several test cases to identify model refinements needed until results were reasonably close. Figure 6 below summarizes the results of this calibration process.

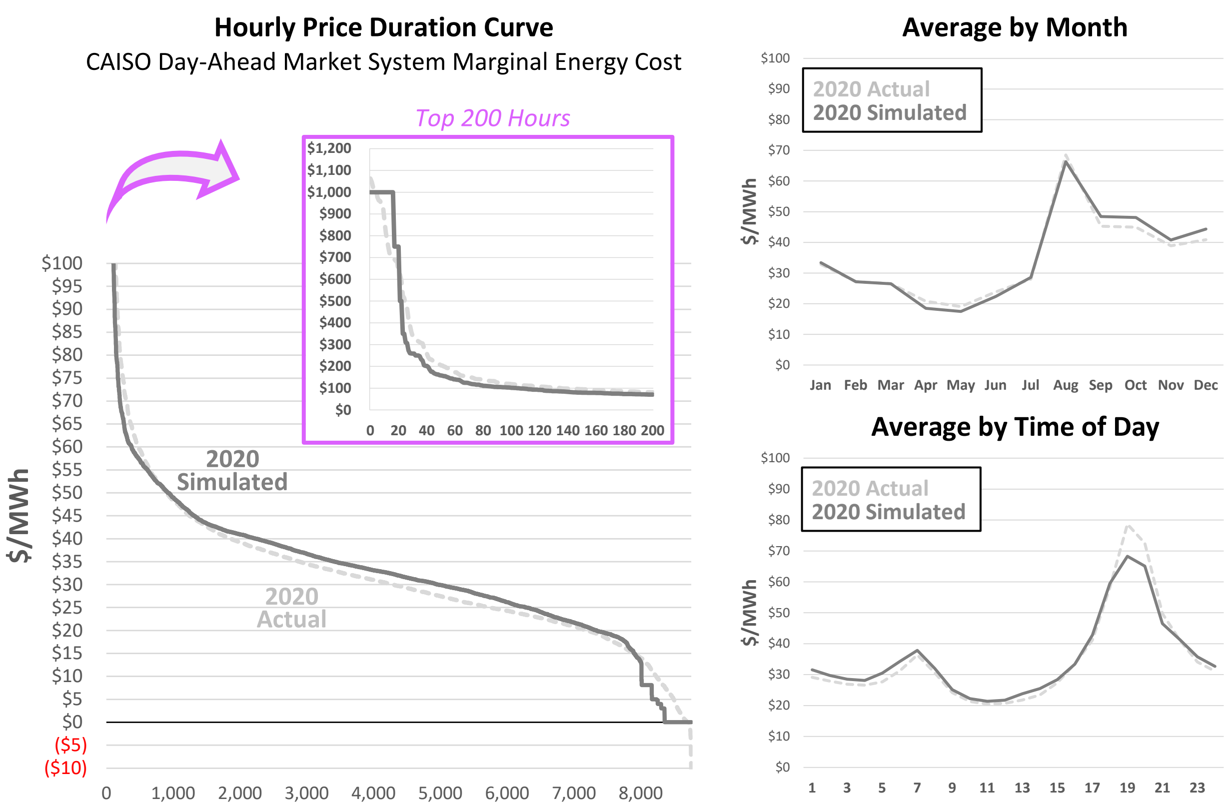


Figure 6: Comparison of simulation results against actual 2020 CAISO energy prices.

2032 Market Modeling Inputs and Assumptions

After the market model is calibrated, we developed inputs to simulate 2032 market conditions. Key model inputs and assumptions are summarized below:

- Unit characteristics for existing resources from CAISO master file as of December 2021
- Hourly load forecast based on CEC 2021 Integrated Energy Policy Report (IEPR) managed load under mid-mid scenario (Mid baseline demand, AAEE Scenario 3, AAFS Scenario 3)
- Resource buildout (except for energy storage levels) based on 2021 Preferred System Plan portfolio adopted by the CPUC, which includes:
  - 5.0 GW onshore wind (3.5 in-state + 1.5 out-of-state)
  - 1.7 GW offshore wind
  - 17.5 GW utility-scale solar
  - 1.2 GW geothermal
  - 0.1 GW biomass
  - 0.4 GW demand response
- Energy storage installations tested at various levels (up to 24 GW)
- Retirement of Diablo Canyon nuclear plant
- Retirement of Alamitos 3-5, Huntington 2, Ormond Beach 1-2, Redondo 5-6, 8 peaking units for OTC compliance
- Hourly renewable generation profiles for existing resources based on 2020 data (pre-curtailment)
- Hourly renewable generation profiles for new resources from CPUC Unified RA and IRP Modeling Datasets used to develop 2021 Preferred System Plan
- Monthly energy for small hydro resources at historical 2015-2021 average (data from CAISO)
- Monthly energy for large hydro resources at historical 2002-2021 average (data from EIA-923)
- Gas price forecast based on CEC Natural Gas Burner Tip Prices (September 2021) adjusted for transportation adder and other rate differences based on historical fuel price indices from CAISO OASIS website
- GHG price set to $32/ton (in 2022 dollars) which reflects the estimated 2032 price floor for the California cap-and-trade program
- Hourly import/export schedules modeled based on historical relationship between CAISO net load and net import levels accounting for seasonality and time of day
- CAISO net export limit set to 5,000 MW consistent with CPUC IRP modeling assumptions used to develop 2021 Preferred System Plan

Figure 7: Summary of 2032 model inputs and assumptions.

Simulation of Hourly Storage Operations

We determine the *marginal* energy storage schedules using a Python-based optimization module under a price-taker approach, which takes in hourly system-level prices from the market model as an input. We run the two models (market model and storage dispatch model) iteratively to ensure prices and storage operations are internally consistent.

In the optimization algorithm, the objective function is set to maximize annual energy and capacity value of the marginal storage resource.

- Energy value is calculated as hourly energy price ($/MWh) × storage output (MWh), added over all hours of the year. Hourly storage output can be positive (discharge) or negative (charge) so the estimated energy value is net of charging costs.
- Capacity value is calculated as capacity price ($/MW-year) × storage nameplate capacity (MW) × capacity credit (%). Capacity credit is estimated dynamically based on marginal impact on system's net peak load (see Figure 13).

Key operational constraints are as follows:

- Instantaneous storage charge and discharge levels cannot exceed nameplate capacity (MW).
- State of charge must remain within a set range (min 0%, max 100%) of energy capacity (MWh), equal to nameplate capacity (MW) × storage duration (hours).
- State of charge decreases by energy discharged.
- State of charge increases by energy charged, which reflects a 15% efficiency loss.
- Average cycle limited to 1/day (annual energy discharge cannot exceed 365 × energy capacity).
- Capacity credit cannot exceed the marginal impact on net peak demand.

Our energy storage dispatch simulations use prices that are comparable to day-ahead market outcome. More volatile real-time market prices can increase value of energy storage, but they cannot be captured with "perfect foresight". To account for effects of market uncertainty, but also recognize the ability of storage to respond to real-time market signals, we first simulate storage dispatch under day-ahead market prices, and then apply an approximately 35% adder derived based the historical analysis described in our main report.

Simulation Results and Estimated Storage Value

We started with a simulation of 2032 base case with no storage to create a reference against which we can measure cumulative impacts of adding storage. This base case highlights major changes from today's market conditions and some of the significant challenges that the system would have in the absence of energy storage.

Figure 8 below shows the resulting system-level energy prices, relative to 2020 levels. Charts on the left shows hourly prices sorted from highest to lowest and the chart on the right shows average daily price patterns.

These simulation results confirm that there would be a large increase in supply-constrained hours after Diablo Canyon and OTC retirements, combined with electrification efforts and other portfolio changes, if <u>system had no energy storage installed</u> in that future. We estimated there would be around 100 scarcity hours during which market prices are assumed to average at ~$1,000/MWh. Despite weather-normal demand inputs, this is five times higher relative to 2020 which was an extreme year with severe heat waves and multiple grid emergency events.

At the same time, the massive solar buildout needed to meet the state's clean energy and decarbonization goals increases oversupply in the middle of the day. With over 50 GW of installed solar capacity by 2032 (utility-scale + BTM) system will have significant amount of excess renewable generation above what can be exported, and that excess generation would need to be curtailed if it cannot be stored for later consumption. Accordingly, we estimate energy prices to drop to $0 (assumed floor) in most days between 9am and 3pm.

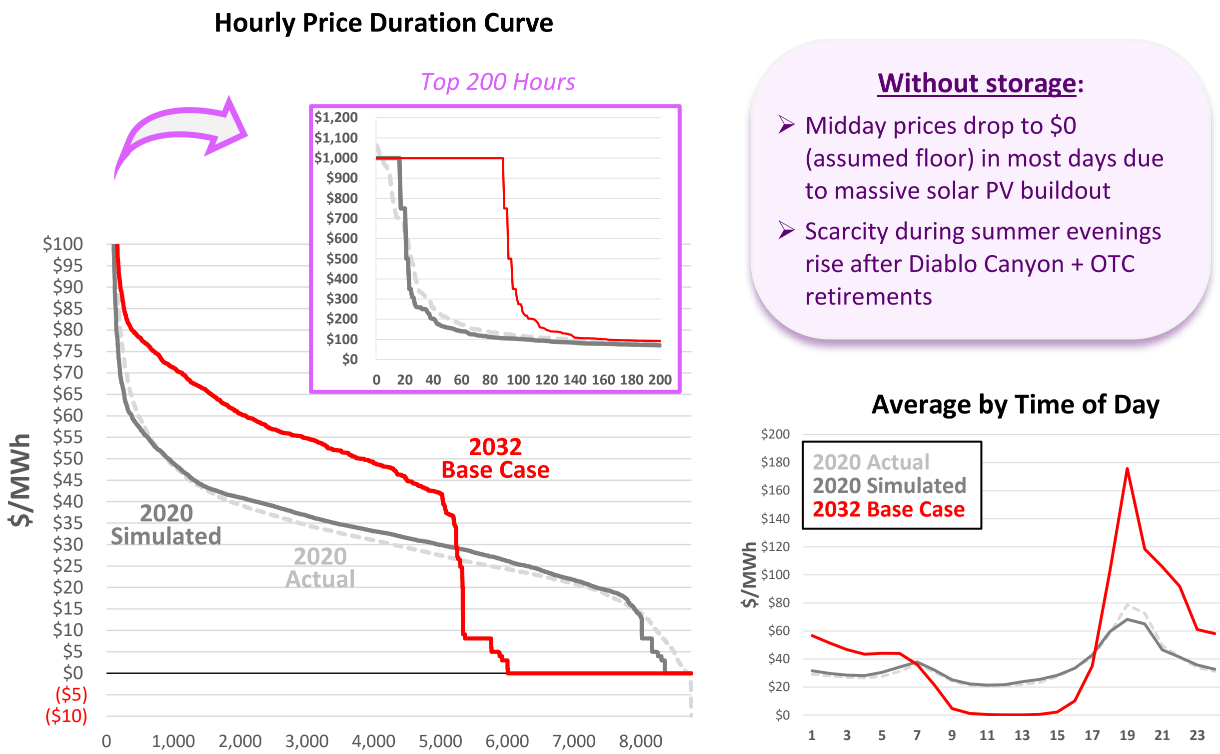


Figure 8: Simulated 2032 price patterns without energy storage.

We then re-simulated the 2032 market conditions with various levels of energy storage. As described earlier, we determine energy storage schedules using a Python-based optimization module under a price-taker approach. We run the energy market model and storage dispatch module iteratively to ensure prices and storage operations are internally consistent. We add energy storage in small increments (100 MW) to avoid convergence problems.

Figure 9 below shows the impact of energy storage on market prices. Although we tested energy storage buildout at highly granular levels ranging from 0 to 30 GW in 100 MW increments, we show here only results for 2.5 GW, 5 GW and 10 GW of storage to illustrate the overall direction and magnitude of changes on price patterns:

- The initial 2.5 GW of storage added to the system significantly reduces the evening price spikes and number of scarcity events. But it has little impact on renewable oversupply in the middle of the day and prices stay at the floor in most days.
- Increasing storage capacity to 5 GW further reduces evening prices and scarcity events, while also starting to lift midday prices.
- At 10 GW storage penetration, most of the simulated scarcity events go away (under normalized load, without extreme events) and daily prices get relatively flat as the spread between midday and evening peak prices are reduced due to storage operations.
- Accordingly, flattening prices reduce intraday energy arbitrage opportunities and results in declining energy value for marginal energy storage resources added to the grid (discussed next).

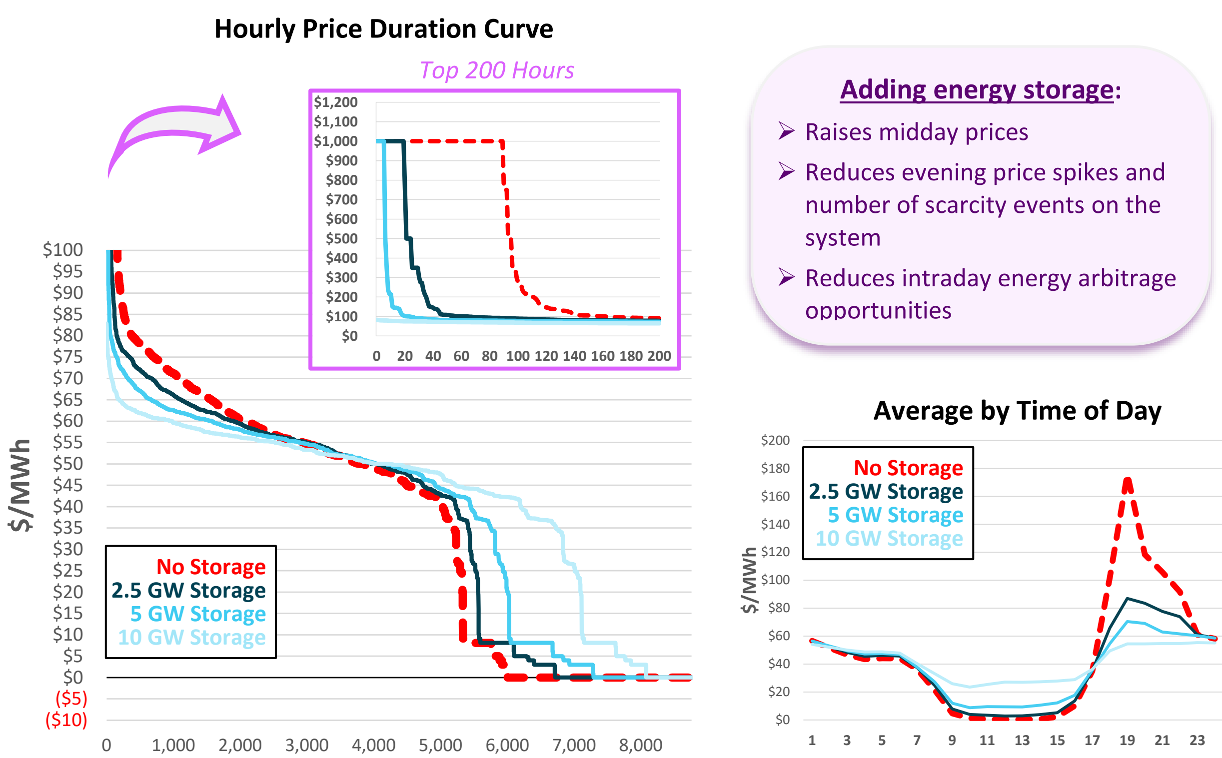


Figure 9: Simulated 2032 price patterns with various levels of energy storage.

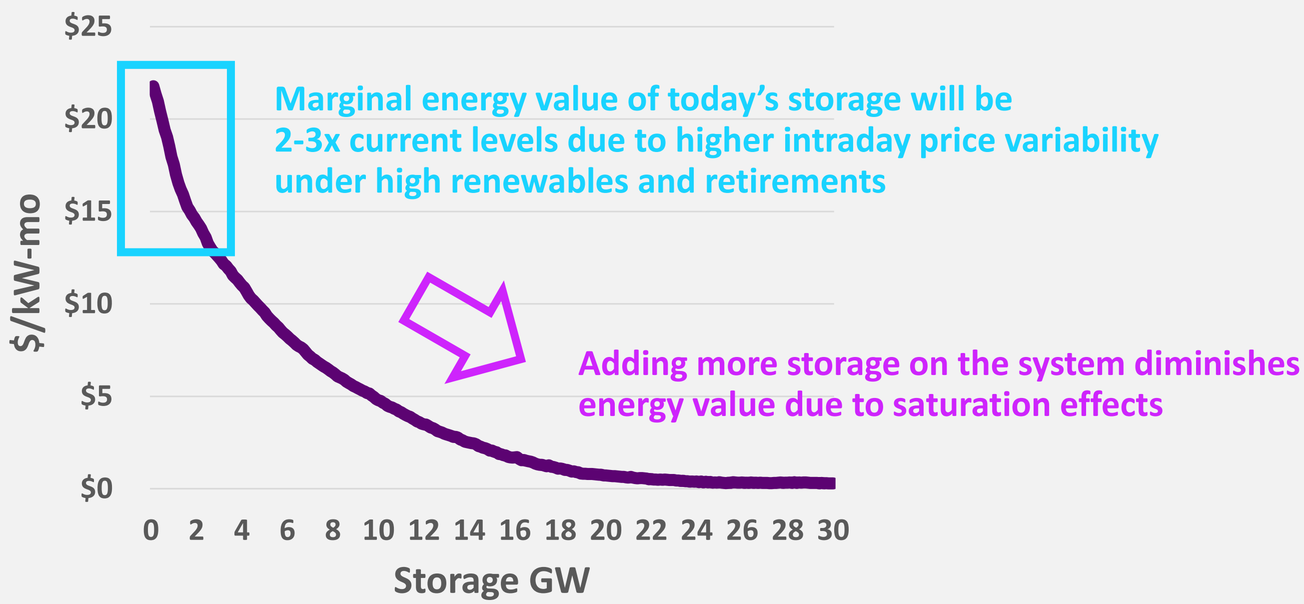


Figure 10: Estimated marginal energy value for 4-hour storage in 2032 (in 2022 dollars).

Marginal energy value reflects the energy value of the last storage MW added to the system, net of any charging costs. During the 2017–2021 period, intraday price differentials yielded energy value potential of $4–6 per kW-month for 4-hour storage participating in the CAISO energy market without ancillary services focus. We estimate that value would be 2–3 times higher in a 2032 electric system and renewable buildout consistent with the 2021 Preferred System Plan.

As shown in Figure 10 however, when the bulk-grid level energy storage penetration goes up, marginal value of adding the next MW declines. The storage portfolio provides significant value as a whole, but flattening of marginal energy prices increasingly signals market saturation and no more need for new entry for energy. The CPUC-adopted 2021 Preferred System Plan identifies a total need for 13.6 GW of battery storage by 2032, mostly with 4-hour duration. At that level, our estimated marginal energy value drops below $3/kW-month, which suggests that further development will likely require a combination of higher capacity payments, technology carve-outs and/or other storage incentives.

It is important to note the declining value curve shown here is intended to demonstrate saturation effects of storage, while keeping the rest of resource portfolio constant. As California moves closer towards its carbon neutrality goals by 2045, more clean energy resources will be needed on the grid, which will shift the value curve above the 2032 snapshot shown. Also, the weather-normalized inputs used in the analysis likely result in conservative estimates of storage value. This is because the additional value that storage can provide during extreme weather conditions would more than offset the value reduction under mild weather conditions. As discussed in the main report, understanding and incorporating the effects of climate change on frequency and magnitude of extreme events, and electric supply and demand is an area of active research and development. As more information becomes available, the analyses can be expanded to analyze the contributions and value of storage towards mitigating the impacts of climate change induced system events.

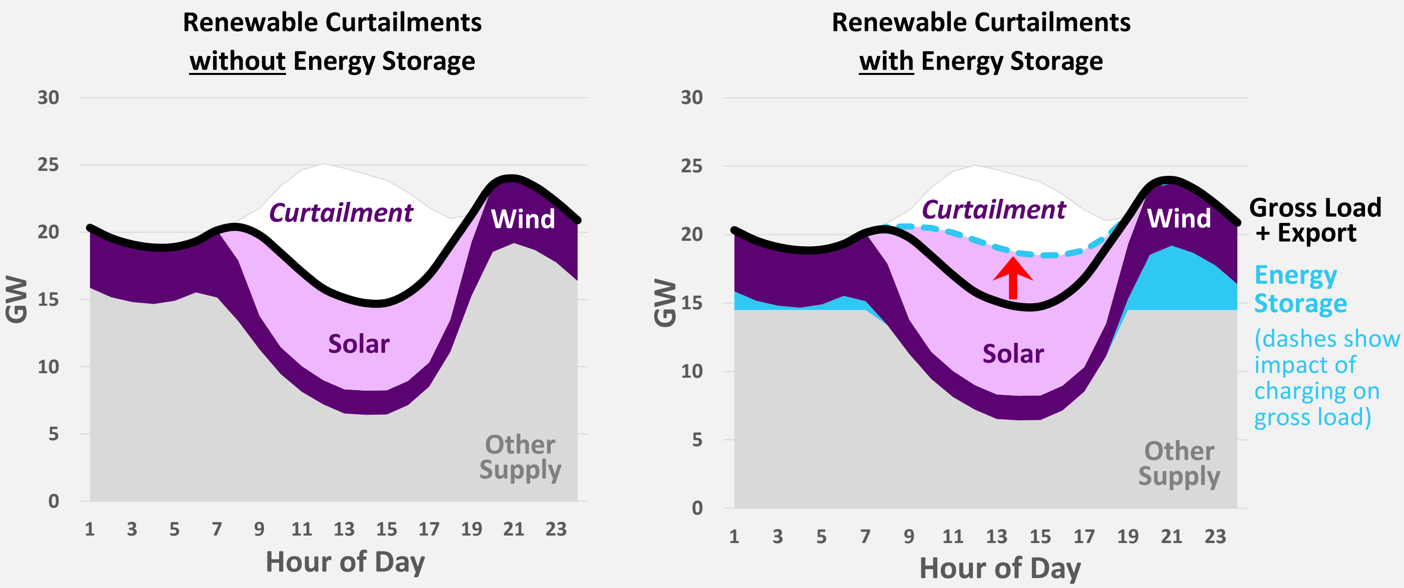


Figure 11: Illustration of energy storage impact on renewable curtailments.

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which will get increasingly more challenging as California continues to decarbonize its electric system. As illustrated in Figure 11 above, charging of storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

Avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate benefits, we first determine the impact on renewable curtailments based on net charge of marginal energy storage resources during simulated hours with system-level curtailments. The maximum potential benefit of 4-hour storage is around 120 MWh of monthly curtailment reduction per MW of storage capacity assuming 1 cycle/day and 4+ curtailment hours every day. Our estimated impact under 2032 base case with no storage is very close to this potential, but marginal benefits decline rapidly as more energy storage is added to the system.

We monetize RPS benefits based on renewable energy credit (REC) value adjusted for curtailments. We start with $15/MWh, which is consistent with the RPS adders in CPUC's Power Charge Indifference Adjustment (PCIA) estimates. This value reflects the average incremental cost of RPS-eligible resources based on recent transactions. We further adjust this value for marginal curtailments in our 2032 market simulations. For example, if a renewable resource needs $15/MWh of REC payments for each potential MWh that could be generated, but 50% of it gets curtailed on the margin, then effective marginal RPS cost would be equal to $15 ÷ 50% = $30/MWh.

Figure *12*12 below shows estimated impact on renewable curtailments and marginal benefits of 4-hour storage at different penetration levels.

Benefits of initial storage installations are relatively high because at low storage penetration levels, system would have more extreme oversupply and frequent curtailment events, and intraday energy time-shift more effectively addresses these challenges. When more storage is installed, the marginal benefit of adding the next storage MW declines because renewable oversupply is already partially mitigated and there are fewer curtailment events left to be addressed.

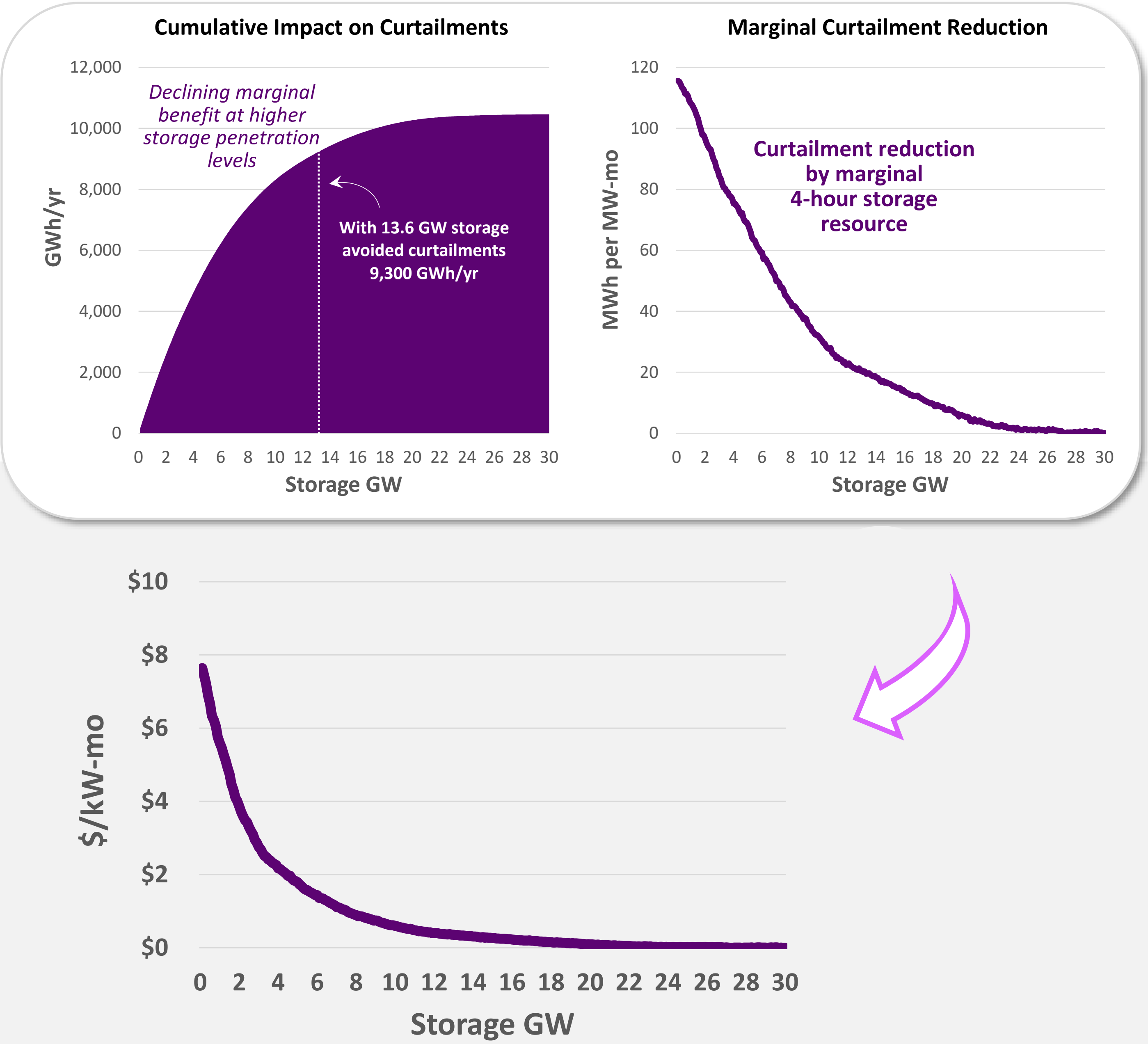


Figure 12: Estimated marginal renewable curtailment benefits for 4-hour storage in 2032 (in 2022 dollars).

Most of the recent energy storage procurements in California are driven by the emerging system reliability and resource adequacy (RA) needs. We expect this trend to continue as the state decarbonizes its electric system.

The ability of an energy storage resource to address reliability and resource adequacy needs depends on its instantaneous capacity (MW) as well as its energy capacity (MWh). A 1 MW/4 MWh storage resource has 4 hours of duration, which means it can provide up to 4 hours of continuous discharge capability at full output. For reliability events lasting longer than 4 hours, its instantaneous capacity would need to be de-rated accordingly. The overall capacity contribution would be a function of possible durations of reliability needs, relative to the duration of storage.

CPUC's initial "4-hour rule" required storage resources to have at least 4 hours of duration to qualify for full capacity credit. More recently, this has shifted to a probabilistic "ELCC-based approach" to recognize value of storage duration, dynamic interactions between renewables and storage, and saturation effects of storage. For the purposes of this study, we estimate capacity credit of storage based on its impact on CAISO's net peak demand. We optimize storage dispatch to maximize capacity credit (primary objective) and respond to energy price signals to increase market revenue (secondary objective). Our analysis relies on weather normalized load forecast and assumes energy storage has perfect foresight of system conditions. The possibility of extreme reliability events and real-time uncertainty is not modeled and may reduce capacity contribution of storage resources below estimated levels. While this deserves additional attention in future studies, we believe that the approximation implemented here sufficiently captures the key factors needed to identify value opportunities, including relative value of energy storage duration, renewable-storage interactions, and saturation effects.

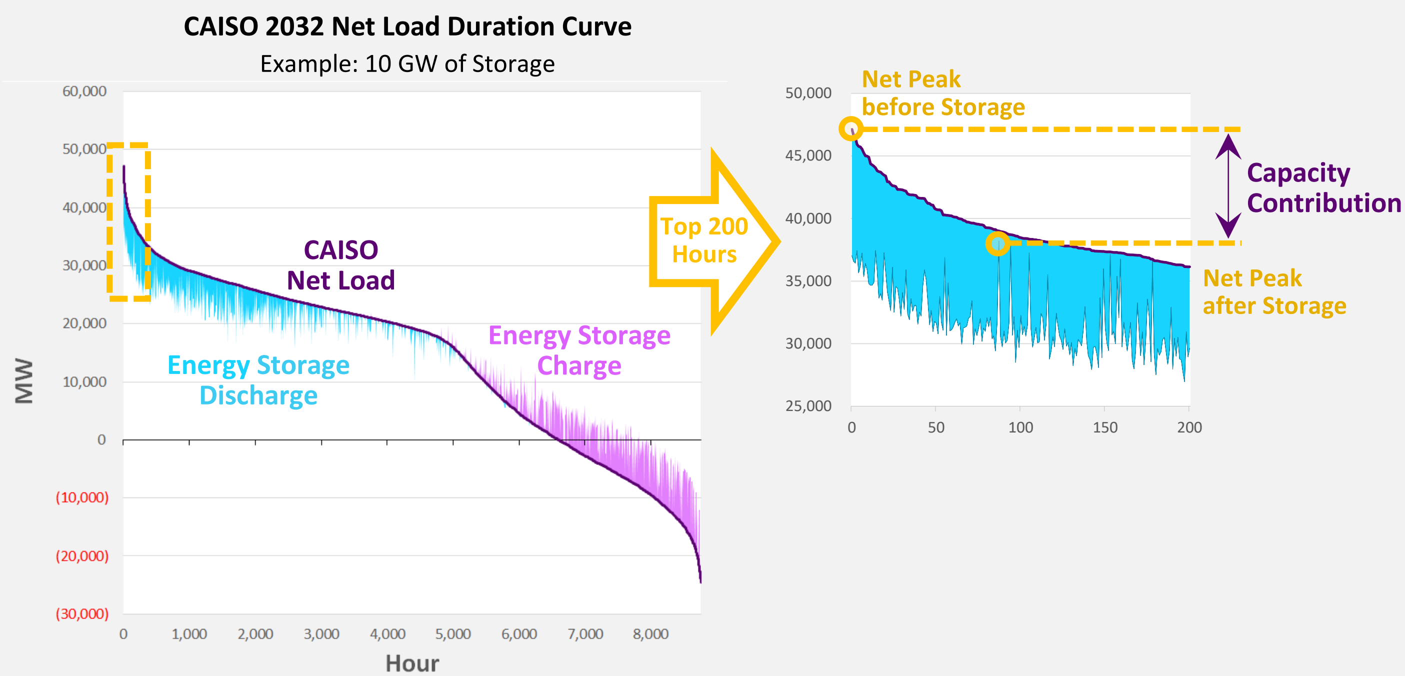


Figure 13: Illustration of energy storage capacity value based on impact on net peak demand.

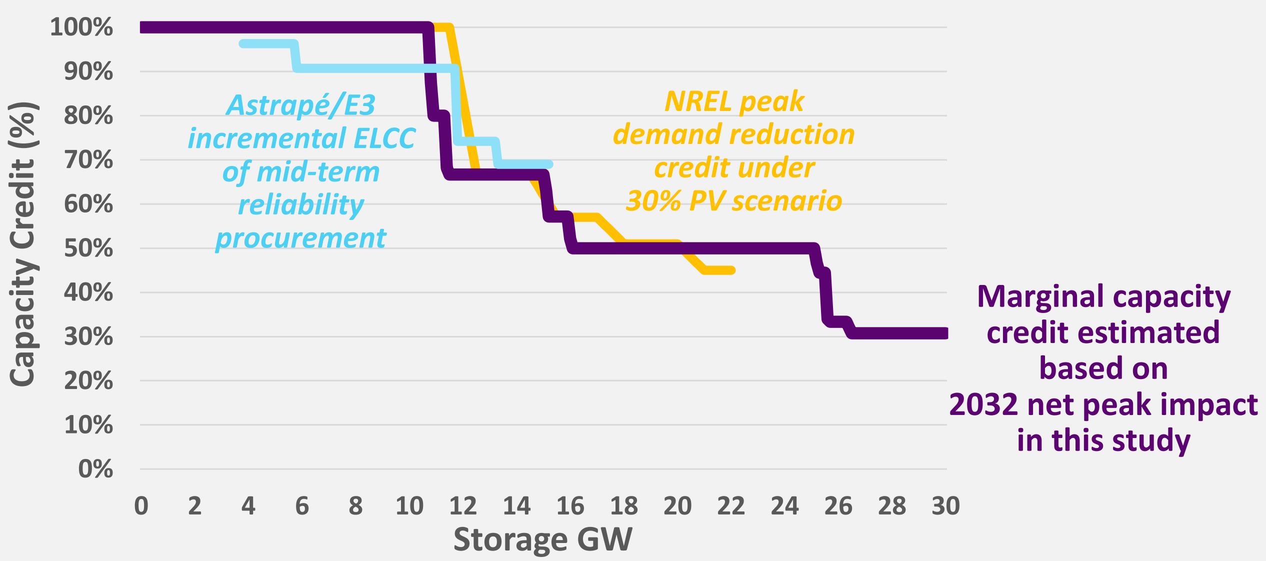


Figure 14: Estimated capacity credit for 4-hour energy storage in California.

Figure 14 above shows our estimated capacity credits for 4-hour storage at different penetration levels and benchmarks against other studies analyzing capacity value of energy storage in California. The marginal capacity credit remains high initially, but drops significantly after storage installations reach a certain level. This "tipping point" depends on how much solar is on the system. Adding solar reduces the duration of grid reliability needs and thus enables more storage at higher capacity credit levels, moving the tipping point. The chart also shows results from Astrapé/E3 study (2021) used to determine incremental ELCC values for Mid-Term Reliability Procurement and NREL study (2018) evaluating the potential of storage to provide peaking capacity in California under increased solar PV penetration. While final metrics are not directly comparable, as the studies model different years and assume different levels of solar PV installed, they show similar patterns on tipping point for 4-hour storage at around 12 GW of cumulative installed capacity.

The sudden drop of marginal capacity credit or ELCC value of storage is driven by the shape of net load in California. At high solar penetrations, net load is peakier with a relatively short window of capacity need in the evening. But when storage installations reach a certain level and flatten the evening net peak demand, getting the next MW of capacity requires a much longer duration, which reduces the capacity value of storage.

Figure 15 shows results for energy storage with durations up to 10 hours.

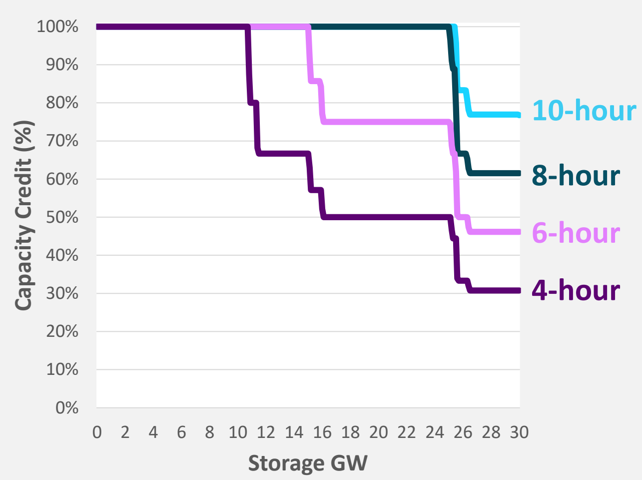


Figure 15: Estimated capacity credit by duration.

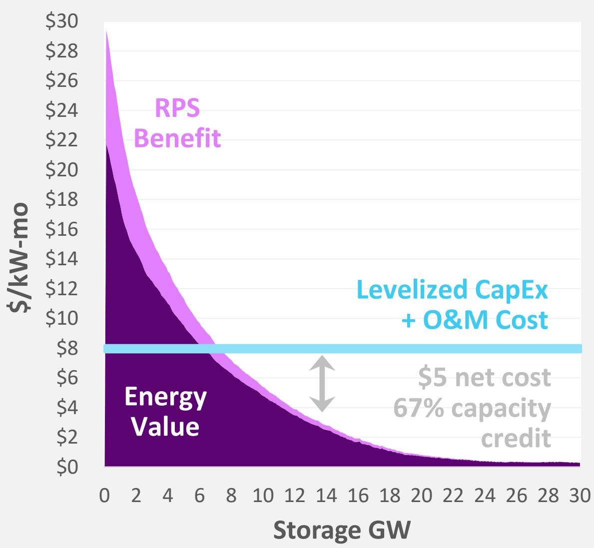
*Values for marginal additions in a system where bulk of the storage portfolio has 4-hour duration.

Estimated Net Cost of New Entry

California's ambitious GHG emission reduction targets combined with expected plant retirements, and climate change impacts on electric supply and demand create a significant need for new clean capacity resources on the system. For example, the CPUC's recent decision (D. 21-06-035) required procurement of at least 11.5 GW of additional net qualifying capacity (NQC) between 2023 and 2026. Energy storage is expected to meet a large share of this need.

A key metric to help with the evaluation of economic potential for energy storage is its net cost of new entry (net CONE) value at various storage penetration levels in California. Net CONE is the amount of capacity revenue that a resource would need to support its initial investment costs that are not covered by other types of benefits. In Figure 16 below, we show the calculations of net CONE of energy storage based on levelized capital and O&M costs *minus* non-capacity benefits (energy and RPS), normalized for the ELCC or capacity credit of the resource. The example illustrates how declining marginal capacity credit and other value streams can put upward pressure on net CONE for energy storage, even with anticipated cost reductions.

$$\text{Energy Storage Net CONE} = \frac{\left(\text{Levelized CapEx} + \text{Levelized O\&M Cost}\right) - \left(\text{Levelized Energy Value} + \text{Levelized RPS Benefit}\right)}{\text{ELCC or Capacity Credit of Energy Storage}}$$



Example for marginal storage at 13.6 GW:

- Levelized Cost (Capex + O&M) = $8/kW-month
- Marginal Energy Value = $2.7/kW-month
- Marginal RPS Benefit = $0.3/kW-month
- Marginal Capacity Credit = 67%
- Net CONE = ($8 – ($2.7 + $0.3)) ÷ 67% = **$7.4 per kW-month**

Figure 16: Calculation of marginal net cost of new entry (net CONE) for energy storage.

Figure 17 below shows the estimated net CONE of marginal storage resources built in a 2032 system, illustrating effects of storage cost assumptions (left) and duration (right).

Initial storage installations have a zero net CONE because estimated energy and RPS benefits in 2032 would be sufficient to recover costs if storage penetration remained low. Net CONE gradually increases at higher penetrations as estimated energy and RPS benefits decline, with big jumps when storage capacity credit drops.

Overall, 4-hour storage is more cost effective initially (as expected) but the gap with longer duration storage configurations closes as more storage is installed. We see crossover points after capacity credit of 4-hour storage plummets at around 12 GW. But the difference in net CONE levels remains relatively low until storage penetration exceeds 25 GW.

Altogether, these results suggest that further development of energy storage in California will require a combination of higher capacity payments, technology carve-outs and/or other incentives. Locational opportunities and additional value stacking (not analyzed) can further increase benefits and accordingly reduce net CONE of storage. The path for cost-effective long-duration storage (up to 8–10 hours) is in sight, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC or capacity credit modeling assumptions.

Given inherent uncertainties with future RA capacity needs and resource contributions, procurement efforts may have to pivot quickly and adjust target portfolios based on unexpected changes and new information. Battery storage systems and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost.

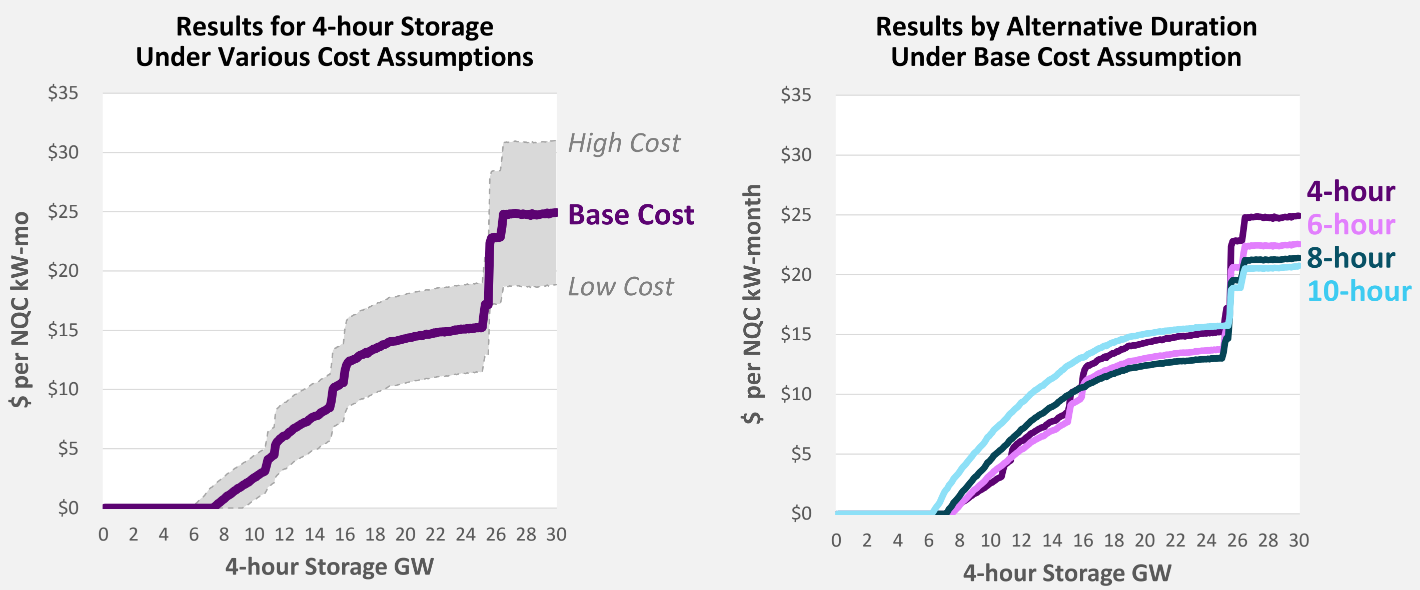


Figure 17: Estimated 2032 net CONE for storage (in 2022 dollars).

*Values are for marginal resource additions in a system where bulk of the storage portfolio has 4-hour duration.

Net Benefits of the Planned Storage Portfolio

Figure 18 shows estimated net benefits of the currently planned 13.6 GW of storage portfolio identified in the 2021 Preferred System Plan.

We calculate energy time-shift value and RPS benefits of storage based on the analysis described earlier in this attachment. For RA capacity, we assume marginal value would initially be at $8 per NQC kW-month, which is in line with the top 10% of historical RA contract prices for 2021 delivery. At higher penetrations, we assume RA prices will rise to net CONE of storage to incentivize new investments needed for reliability. This is conservative because without storage other much more costly alternatives would be needed to meet the reliability targets and the related cost savings would be higher than the RA capacity value shown here.

A large portion of the planned 13.6 GW storage buildout is already procured by the California LSEs. So, when evaluating net benefits of this portfolio as a whole, using current storage cost levels is more appropriate than the 2032 cost forecast developed for the marginal net CONE analysis presented earlier. The cost of storage based on utility contracts approved during the 2020-2021 period is within the range of $10–$14 per kW-month, which translates to an average of $120–$170 million/year for each GW of storage built. Under this cost range, we estimate a 4-hour energy storage fleet of 13.6 GW to potentially yield $835 million to $1.34 billion per year in net grid benefits, which corresponds to the cumulative area above the cost line in the figure.

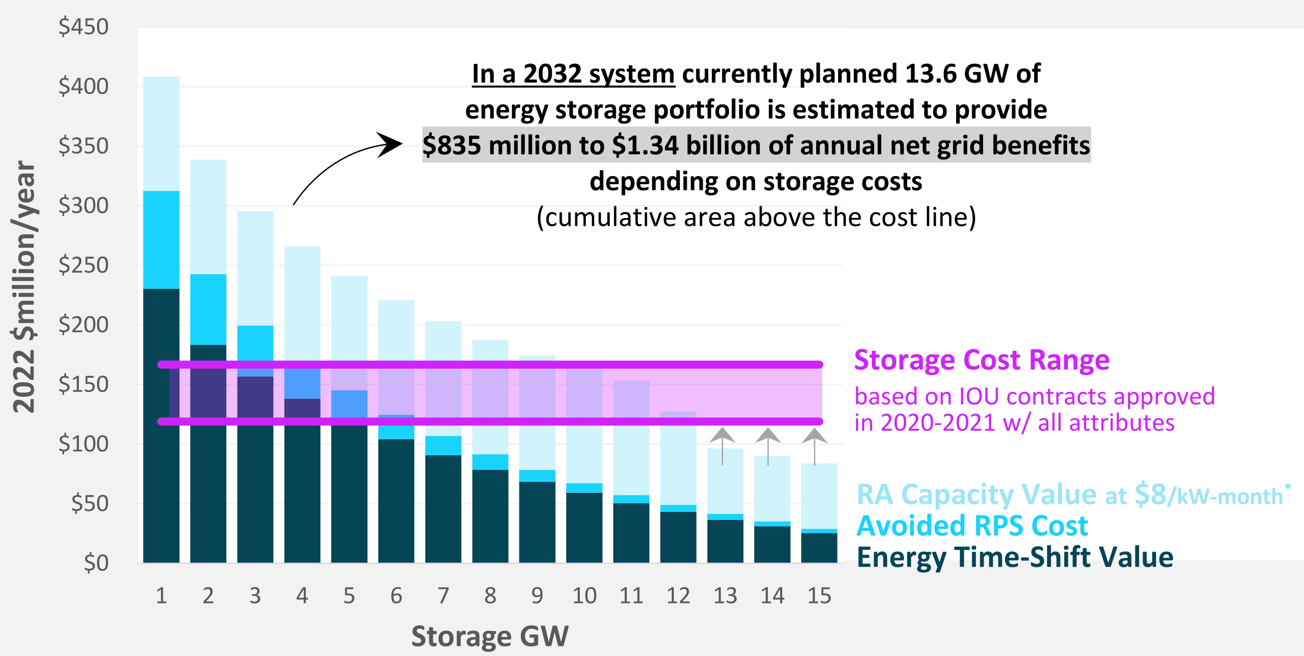


Figure 18: Incremental energy, renewables integration, RA capacity value of 4-hour storage in 2032 (2022 $).

* Marginal RA value is shown at $8 per NQC kW-month in line with the top 10% of system RA contract prices for 2021 delivery. At high penetrations, RA price would likely be higher to incentivize storage or other clean investments needed for reliability.

Key Observations

With the effects of increased renewables and upcoming retirements, energy time-shift value of today's storage will be at least 2–3x higher by 2032 relative to current levels.

As more storage is added, energy value and renewable curtailment reduction benefits will decline rapidly. Marginal value is estimated to drop below $3/kW-month when energy storage buildout reaches 13.6 GW by 2032 as included in the recently adopted 2021 Preferred System Plan portfolio.

This value decline coincides with an ELCC "tipping point" where capacity contribution of 4-hour storage is estimated to plummet at 10–15 GW level. Accordingly, capacity prices will need to rise significantly to enable future development of storage resources.

"Crossover point" for cost-effective long-duration storage (8–10 hour) is in sight over the next 5 to 10 years, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC modeling assumptions.

CPUC's shift from the "4-hour rule" to a probabilistic ELCC-based approach is a significant improvement to recognize value of storage duration, portfolio interactions between renewables and storage, and market saturation effects. But implementation is not yet fully tested, and more stakeholder input and transparency are needed to understand key differences in ELCC results across durations (or lack thereof) and make sure they signal the need for long-duration storage when the need arises.

Creating a "real option" to add more duration to battery projects at the initial design and procurement phase could support a timely and cost-effective transition for longer duration. Storage system and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost. Actual developers are taking advantage of this modularity in their market participation and development strategies.

ATTACHMENT C: COST-EFFECTIVENESS OF PEAKER REPLACEMENT[1]

This attachment provides details on the special study of the replacement of gas peakers in California with energy storage.

California currently has about 100 operating gas-fired peaking units with a total capacity of 10 GW on the system. These peaking units are needed mainly for reliability. They are far less efficient than other generators, so they tend to run in fewer hours only when peaking capacity is needed and/or when market prices are sufficiently high. Despite their low utilization, gas peakers are often responsible for significant amounts of GHG and air pollutant emissions because of their low efficiency, and their start/stop cycles are typically more emission intensive. Energy storage has the potential to mitigate adverse environmental impacts of the gas peakers by replacing parts or all of their output, while providing similar levels of capacity. California already demonstrated this as a viable use case by procuring several energy storage projects to address local capacity needs created by retirement of conventional plants, to eliminate the need for reliability must-run (RMR) contracts with existing gas plants, and to replace construction of a new gas peaker needed for local reliability.

In this study, we screen the cost-effectiveness of individual natural gas peaker units' replacement with energy storage under the challenging system conditions observed in 2020. We test alternative storage configurations, with respect to duration levels and whether they are developed on a standalone basis or paired with solar PV.

CONTENTS

Study Approach and Analytical Framework

Our approach to evaluating cost-effectiveness of replacing gas-fired peaking units in California with energy storage is summarized below:

1. **Collect peaker data:** Compile historical hourly generation and emission profiles for all gas-fired peaker units in California. Use 2020 as the "base year" during which there were significant system-level supply shortages.
2. **Analyze replacement scenario:** For each unit, use energy storage dispatch model to determine minimum level of storage capacity that can displace all of unit's historical generation. Optimize storage charge and discharge decisions to replace 100% of the peaker output while also maximizing market revenues under perfect foresight of nodal prices.
3. **Test alternative storage duration levels:** Run the peaker replacement analysis described above for storage with 4, 6, 8, and 10 hours of duration.
4. **Analyze costs and benefits:** For the smallest storage configurations identified above, estimate levelized costs and net market revenues, and compare incremental net costs across various energy storage duration levels and against going-forward cost of peakers.
5. **Analyze solar + storage sensitivity:** Re-run Steps 2–4 with a solar plus storage configuration.

The goal of the study is to develop an *indicative* unit-by-unit assessment of the economic feasibility of replacing peaker generation based on their operations under historical system conditions. We selected 2020 as it was an extreme year with severe heat waves and multiple grid emergency events. A similar approach can be used with forward-looking data inputs. But estimating real-time needs and operations of gas peakers under future market scenarios is a significant undertaking and left outside the scope of the study.

The study assumes historical output of individual peak units in 2020 is a reasonable approximation of the reliability needs met by those units. While we review and benchmark results against recent reliability and transmission studies by the CAISO, we do not include a power flow modeling or detailed assessment of reliability and resource adequacy needs in this study.

Data Collection on Peaker Operations and Emission Profiles

We compiled the unit-level hourly generation and emission profiles of peakers based on EPA's Continuous Emissions Monitoring Systems (CEMS) data using their Air Markets Program (AMPD) tool. The final unit list includes all of the gas-fired combustion and steam turbines in the CAISO system. We matched the unit list against CAISO resource list and EIA Form 923 data to make sure units that are part of combined cycle, combined heat and power (CHP) or cogeneration systems are not considered.

We identified 97 peaking units with a capacity adding up to 10 GW in total. Most of these units are located in CAISO-designated local capacity areas and over 75% of their installed capacity is in southern California. Figure 1 below shows the breakdown of peakers capacity analyzed by area and corresponding generation and emission levels based on 2020 CEMS data. In total, gas peakers generated 5.7 million MWh of total energy in 2020 at a capacity factor of 6.6% on average. They were responsible for almost 3 million tons of CO_2 emissions, which accounted for over 8% of total emissions from power plants in the CAISO footprint (even though they generated only 3.5% of total). Figure 2 shows the aggregate hourly generation profile, with highest output in August–September 2020 during extreme heat wave.

Utility Area	Local Capacity Area	Unit Count (#)	Unit Capacity (MW)	Total Generation (MWh)	Capacity Factor (%)	CO_2 Emissions Total (metric tons)	CO_2 Emissions Avg (ton/MWh)	NO_X Emissions Total (lbs)	NO_X Emissions Avg (lbs/MWh)
PG&E	Humboldt	0	0	-	-	-	-	-	-
PG&E	North Coast/North Bay	0	0	-	-	-	-	-	-
PG&E	Sierra	2	97	70,649	8.3%	33,322	0.47	45,082	0.64
PG&E	Stockton	0	0	-	-	-	-	-	-
PG&E	Greater Bay	15	1,281	546,657	4.9%	288,380	0.53	60,053	0.11
PG&E	Greater Fresno	9	437	140,617	3.7%	66,494	0.47	18,167	0.13
PG&E	Kern	0	0	-	-	-	-	-	-
SCE	Big Creek/Ventura	4	1,587	792,155	5.7%	406,514	0.51	58,541	0.07
SCE	LA Basin	40	4,526	2,705,766	6.8%	1,468,999	0.54	313,015	0.12
SDG&E	San Diego/Imperial Valley	21	1,418	816,610	6.6%	406,303	0.50	76,519	0.09
	CAISO System	6	493	682,661	15.8%	295,738	0.43	61,670	0.09
	TOTAL	**97**	**9,839**	**5,755,115**	**6.7%**	**2,965,750**	**0.52**	**633,046**	**0.11**

Figure 1: Summary of peaker capacity analyzed and their 2020 generation and emission levels

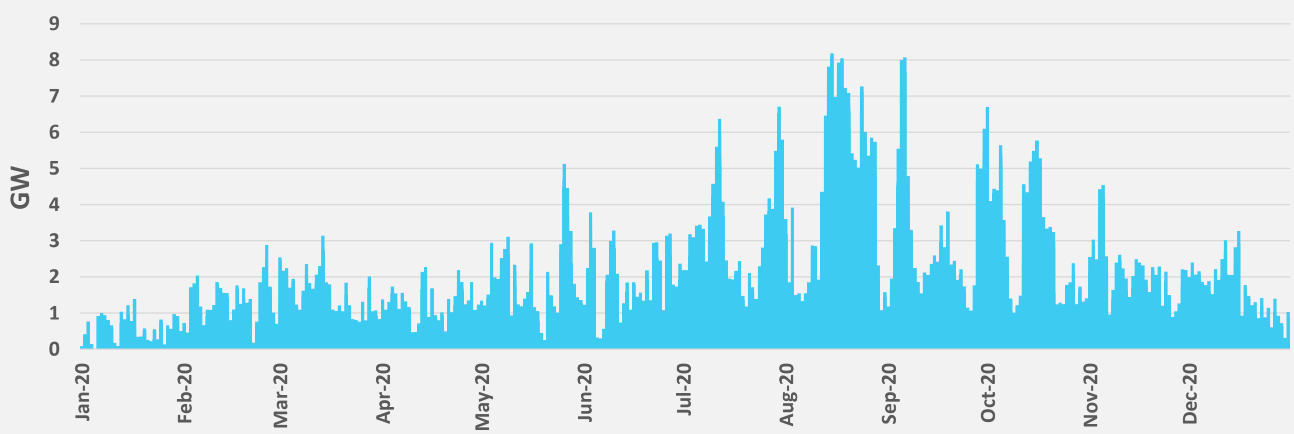
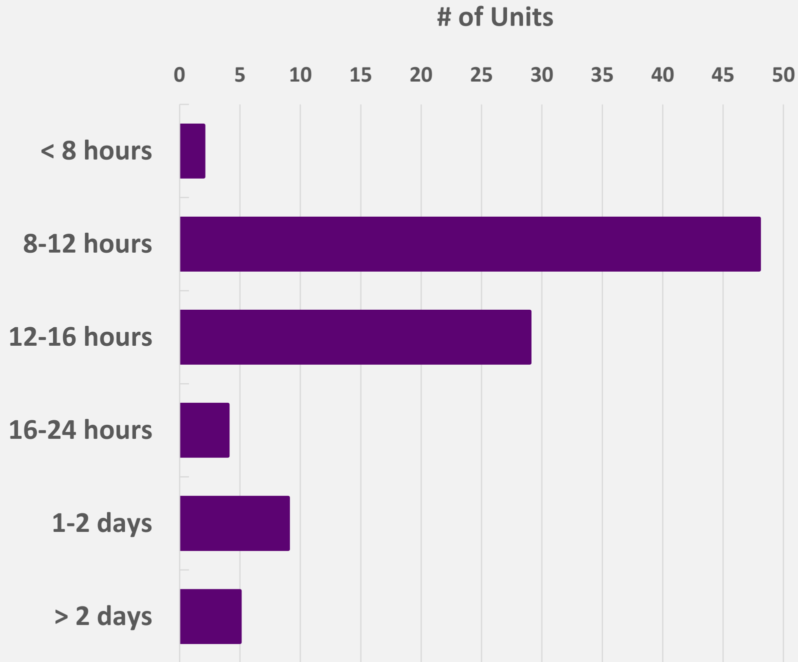


Figure 2: Aggregate hourly 2020 generation profile for the CAISO peaking units.



* Runtime is calculated as unit's cumulative energy output in a cycle divided by Pmax, rather than simply counting the hours in that cycle. This is to reflect duration need at full capacity. Periods when a unit operates below 30% of Pmax are excluded.

Figure 3: Distribution of peakers' maximum continuous runtime in 2020.

Figure 3 shows that most of the peaking units in California had at least one cycle during which they ran for 8 hours or more consecutively during 2020. We excluded the periods when a peaker operates below 30% of its capacity assuming that the unit is running during that time due to operational inflexibilities (such as minimum uptime) rather than a system reliability need. Applying this threshold effected only steam turbines that cannot turn on and off quickly.

Overall, 77 out of the 97 peakers analyzed had a runtime of 8–16 hours and 18 units had it above 16 hours. Only 2 units had a maximum runtime under 8 hours.

Peaker runtimes shown here impacts the minimum amount of storage capacity needed for replacement. For instance, If a 100 MW peaker has a maximum runtime of 10 hours at full load, it generates 1,000 MWh of energy during that cycle. Accordingly, at least 1,000 MWh of storage capacity would be needed to replace the peaker's output, assuming time between peaker's operating cycles are sufficient for a full recharge. Storage can be configured with different duration levels to meet the same 1,000 MWh need. If sized to match the MW capacity of the peaker, it would be a 100 MW storage with 10-hour duration. Alternatively, if the system has enough transmission capacity to interconnect larger MW, it can be sized at 250 MW with only 4-hour duration. Even though both configurations can replace the peaker's output in this example, their cost function and stacked value can be very different and need to be considered to determine which option is more cost effective.

Energy Storage Dispatch Analysis

For each peaking unit, we use Lumen's energy storage dispatch tool to determine minimum level of storage capacity that can displace all of unit's historical generation. The dispatch tool solves for minimum storage MW for a set duration level and optimizes charge and discharge decisions to replace 100% of the peaker output except when peaker operates at min load, while also maximizing market revenues under perfect foresight of nodal prices. We assume storage resources to have a roundtrip efficiency of 85% and apply an average of 1 cycle/day limit over the course of a year simulated.

The study considers four storage duration levels (4-, 6-, 8- and 10-hour) for the replacement of each peaker. Figure 4 shows a weekly snapshot of results for an actual case similar to the example described earlier. In this case, model evaluates replacement of a 100 MW peaker and finds that the smallest storage configuration to be 100 MW with 10-hour duration and 250 MW with 4-hour duration. While the primary goal is the replace the peaker's output (shown in red), storage also responds to LMP signals to stack energy revenue. For the week starting August 17, 2020, the 10-hour storage (shown in blue) charges from midnight to late morning at an average cost of $32/MWh and discharges in the afternoons and evenings at an average price of $94/MWh, which results in net market revenue of $393,000. The 4-hour storage (shown in pink) is much more flexible to take advantage of intraday price volatility, and charges at a lower average cost of $28/MWh and discharges during top-priced hours at an average price of $114/MWh, with a net market revenue of $577,000 for the same 7-day period.

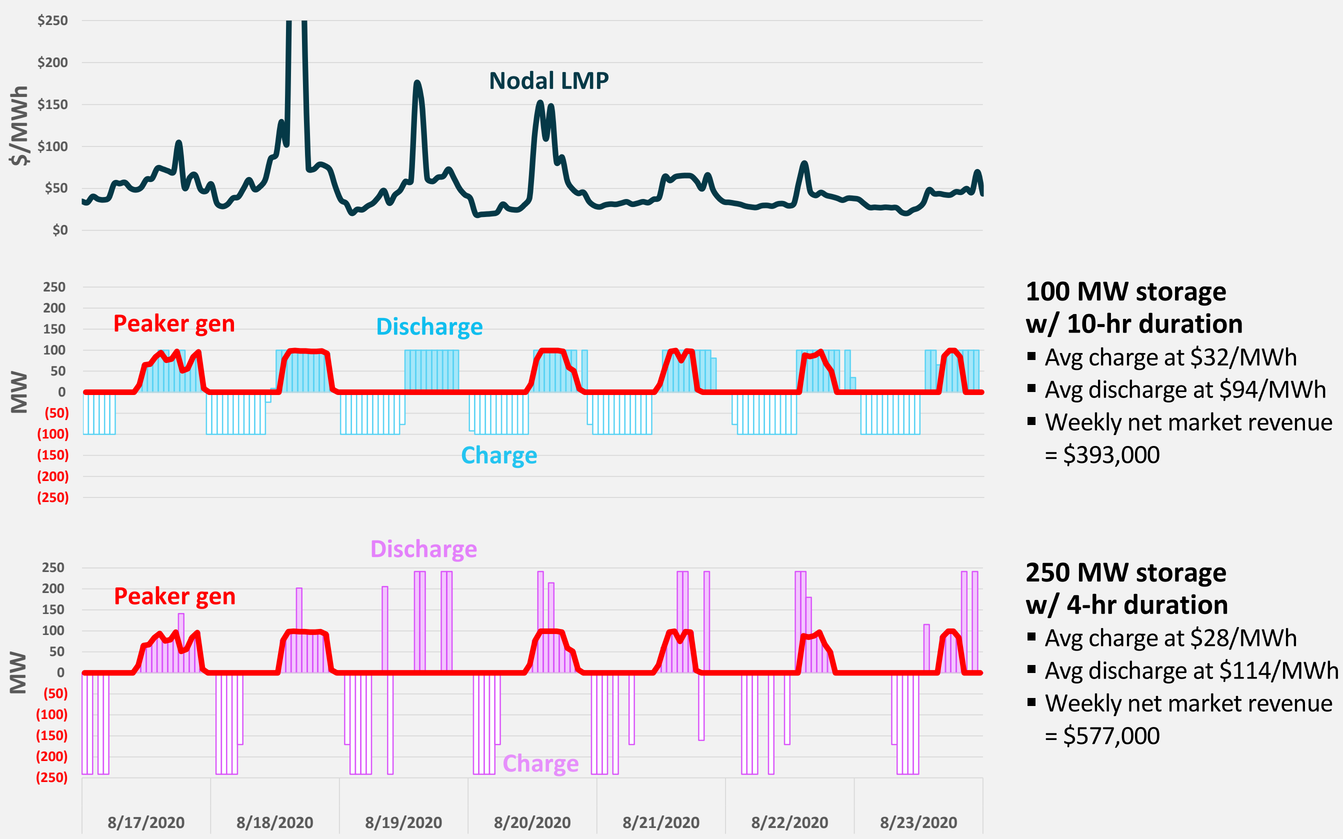


Figure 4: Illustration of optimized storage dispatch to replace peaker output and maximize energy revenues.

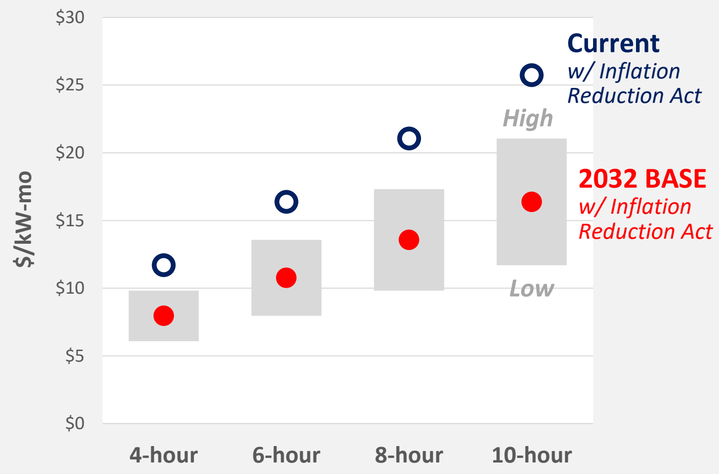
Net Replacement Cost

To determine cost effectiveness of the replacement scenarios, we estimate levelized costs and net market revenues for the smallest storage configurations identified at the unit level and compare incremental net costs across various energy storage duration levels and against going-forward cost of peakers.

For storage cost, we use the same assumptions developed for our study on cost-effectiveness of future storage in California; see Attachment B (Cost-Effectiveness of Future Procurement).

While our study approach is technology-neutral, we simulate energy storage operations and analyze value utilizing cost and performance assumptions based on lithium-ion batteries as they are the dominant technology accounting for most of the new energy storage capacity procured in California today.

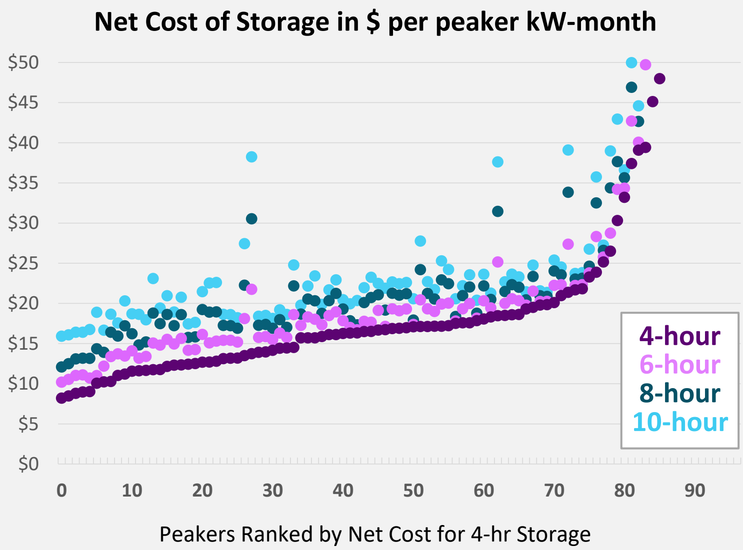
Figure 5 shows estimated levelized cost of storage expressed in $/kW-month (2022 dollars) including only capital and O&M costs. We consider charging costs when we estimate net energy market value of storage.



* Level-real values in 2022 dollars escalating by inflation over time. Includes amortized capex and O&M costs including augmentation and battery replacement. Excludes charging costs.

Figure 5: Estimated levelized storage cost by duration.

We estimate net cost based on levelized capital and O&M cost *minus* energy value, normalized for the peaker's capacity replaced. The final metric is in $ per <u>peaker</u> kW-month, which can be compared across alternative storage durations analyzed and benchmarked against going-forward cost of the peakers considered for replacement. Figure 6 shows results assuming storage cost at current levels.



- 4-hour storage has lower net cost than longer durations, because its energy value more than offsets cost of overbuilding MW capacity
- But overall net cost level above $10/kW-month is relatively high compared to peaker to-go costs

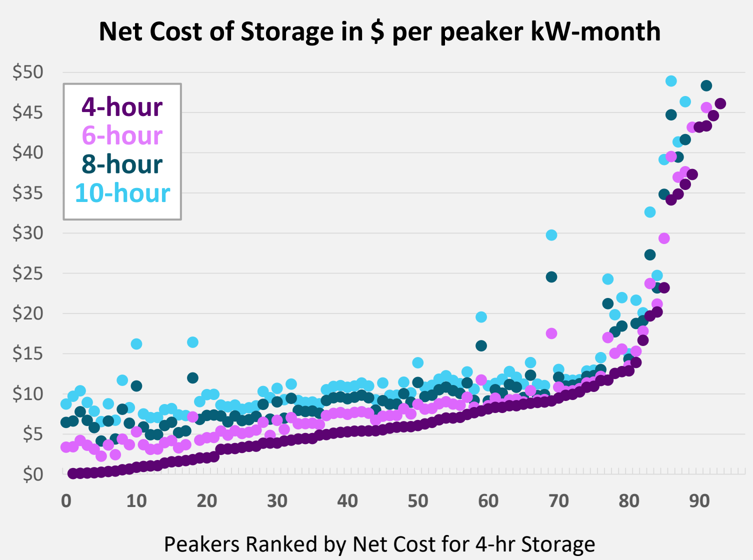
Figure 6: Estimated net cost of replacing peakers with standalone storage (current costs scenario).

The results suggest relatively high net cost levels above $10/kW-month because the options for replacing most peakers involve either significantly overbuilding storage MW or installing a storage configured to provide longer durations.

For the grid-scale battery systems, most of the installed costs are driven by energy-related costs such as cost of battery packs. As a result, building the same amount of energy capacity in MWh with a 4-hour duration costs only slightly more expensive compared to a configuration with longer duration. For example, we estimate the current levelized cost of 4-hour storage at $12/kW-month and 10-hour storage at over $25/kW-month (in 2022 dollars). At these cost levels, a 250 MW storage with 4-hour duration would cost $35 million/year, which is about 13% higher than a 100 MW storage with 10-hour duration at $31 million/year. Under historical prices analyzed, this cost differential would be more than offset by the incremental energy value that 4-hour storage can get by charging at lower-priced hours and discharging at higher-priced hours.

We ran a sensitivity case with approximately 40% lower storage costs, corresponding to the 2032 base case cost assumptions we developed for the study on value of future storage. With the assumed cost reductions, estimated net replacement cost drops under $8 per kW-month for 60 out of the 97 peakers. The results show 4-hour storage would still be more cost effective than storage modeled with longer durations, due to higher energy value they capture.

As discussed earlier, this study relies on analysis of peaker operations and market conditions in 2020 and effects of future market changes are not modeled. **Attachment B (Cost-Effectiveness of Future Procurement)** presents the findings of a separate study on value of future storage in California and show that increased renewables and upcoming retirements will increase energy time-shift value of today's storage, but marginal value decline as more storage is added. The study finds that "crossover point" for cost-effective long-duration storage (8-10 hour) is in sight over the next 5-10 years, but timing and magnitude of the need is highly uncertain and sensitive to ELCC modeling assumptions. Although the underlying study focuses on broad system-level benefits, we expect to see similar future trends in the local areas depending on relative levels of solar and storage added within the constrained zones.



- With assumed storage cost reductions, net cost of peaker replacement drops under $8 per kW-month for over half of units analyzed
- 4-hour storage still looks more cost effective than longer duration alternatives, absent interconnection limitations

Figure 7: Estimated net cost of replacing peakers with standalone storage (2032 base case cost scenario).

Solar + Storage Sensitivity

Pairing solar and storage can reduce the need for overbuilding MW or installing long-duration storage to replace the peaking units. There has been a growing interest in developing co-located solar + storage projects in California driven by cost synergies and tax incentives. One of the key benefits of pairing solar with storage is to achieve cost savings from shared infrastructure and interconnection. Until recently, only energy storage co-located with solar could get the federal investment tax credits (ITC) of up to 30%, which is now extended to stand-alone storage under the Inflation Reduction Act (IRA) of 2022. Although these cost savings and tax benefits reduce installed cost of the projects relative to stand-alone development, they also reduce the value due to additional operating constraints and interconnection limits.

For this sensitivity case, co-located solar resource and total grid interconnection capacity are both sized to match the nameplate MW capacity of storage. Storage is allowed to be charged only from solar output (no grid charging). Hourly profiles of the solar resources are based on actual 2020 zonal solar generation output. Figure 8 below illustrates how pairing solar and storage affects the results relative to standalone storage. Top 2 charts are from Figure 4, showing nodal LMPs and optimized dispatch of the 250 MW storage needed to replace a 100 MW peaker. The bottom chart shows the results under the solar + storage sensitivity. Because the paired solar also displaces some of the peaker's output, only 165 MW of storage capacity is needed, instead of 250 MW. Storage responds to market signals to maximize revenue, but total output is capped the interconnection limit and grid charging is not allowed.

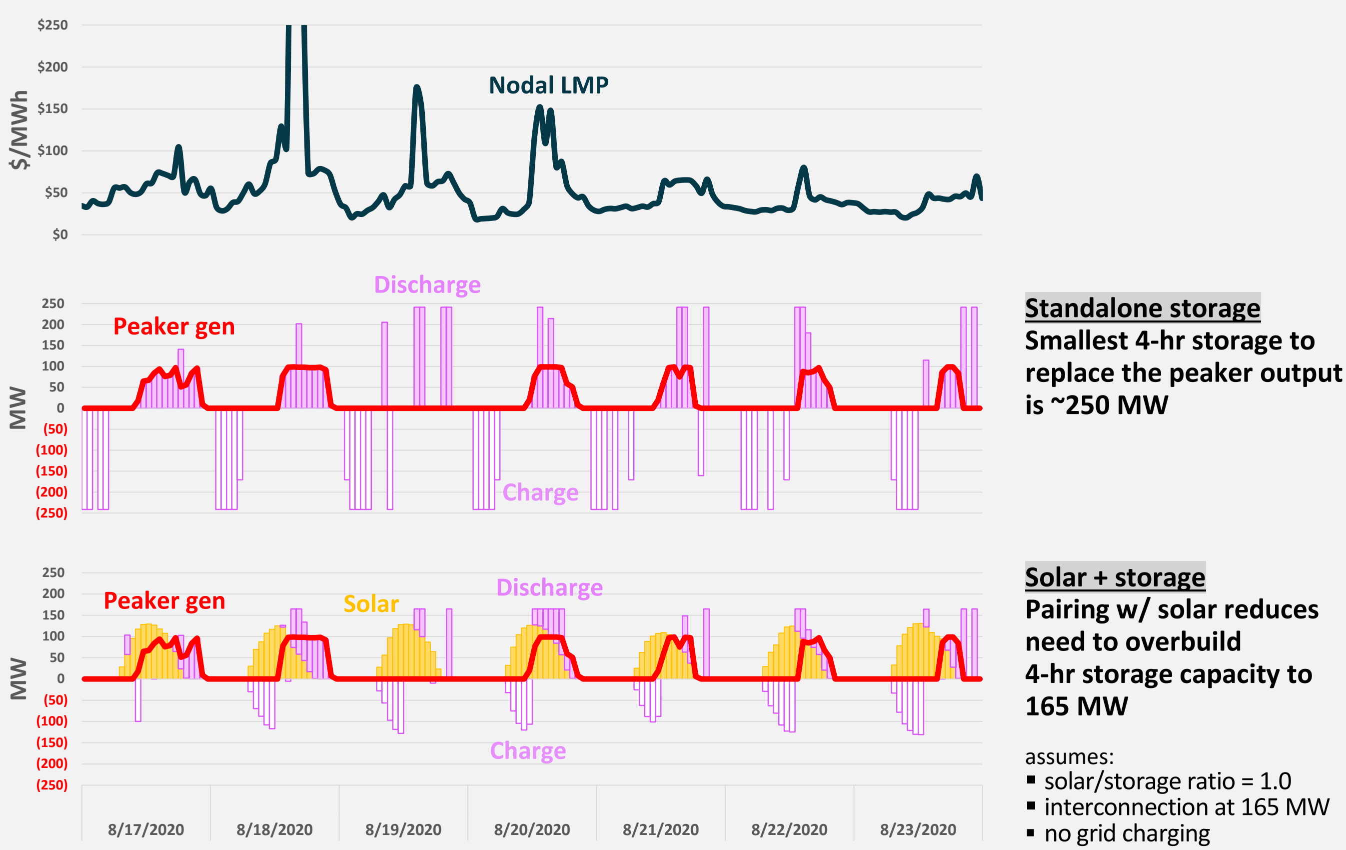


Figure 8: Comparison of simulated solar + storage operations against standalone storage.

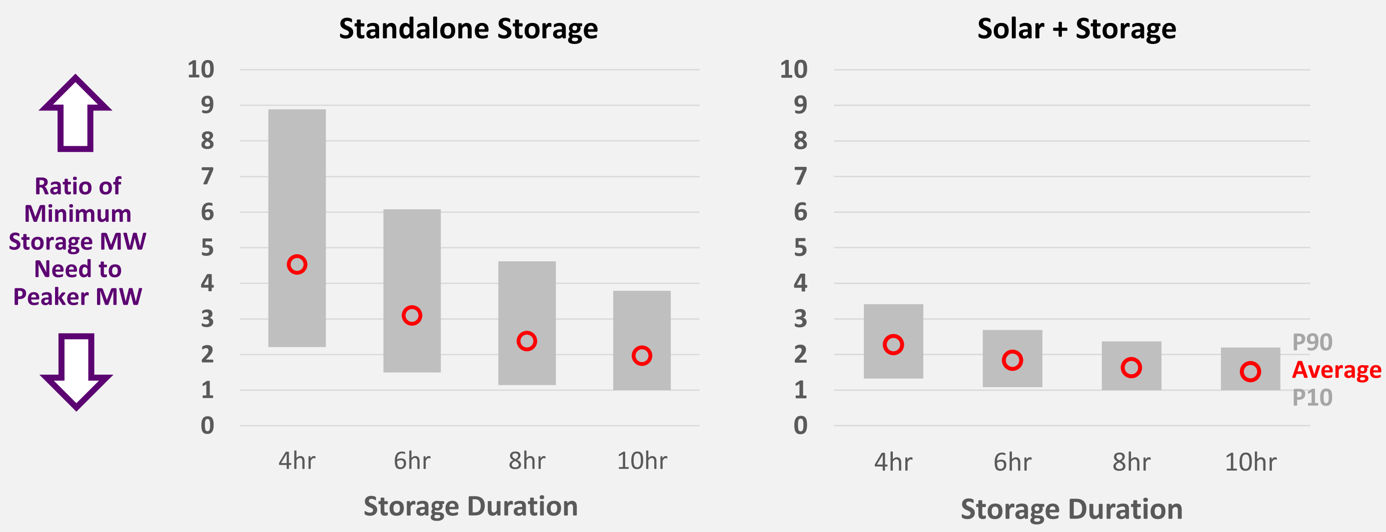
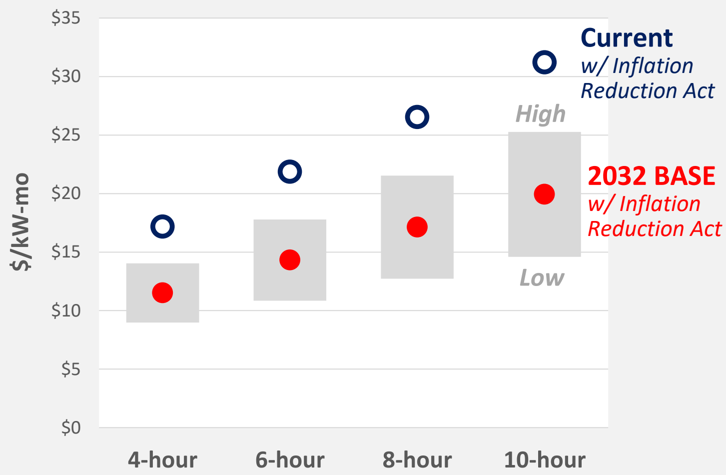


Figure 9: Minimum storage capacity needed for peaker replacement under standalone vs. hybrid development.

Figure 9 demonstrates the estimated need for overbuilding storage MW under standalone development, compared to hybrid development of solar and storage. To replace peaking units with standalone storage, storage MW needs to be 4.5x larger on average for projects with 4-hour duration. When paired with equal amounts of solar, the estimated average need for storage MW drops to 2.3x of peaker MW. Benefits of hybrid development is smaller for long duration storage. For example, for storage systems with 10 hours of duration, the average storage MW need is 2x for standalone projects and drops to 1.5x when paired with solar.

For the cost-benefit analysis, we start with the standalone storage cost assumptions discussed earlier. We estimate adding solar would increase levelized cost by $4–$5/kW-month in 2022 dollars relative to standalone storage, net of 30% ITC and cost savings associated with shared equipment and infrastructure.

Figure 10 shows total estimated levelized cost of solar + storage. As described earlier, solar resource capacity is assumed to match the nameplate MW capacity of storage. The 30% ITC benefit applies to capital cost of both solar and storage equipment. Cost savings relative to standalone development is assumed to be approximately $100/kW based on recent data from the NREL study.



* Level-real values in 2022 dollars escalating by inflation over time. Includes amortized capex and O&M costs including augmentation and battery replacement. Excludes charging costs.

Figure 10: Estimated levelized solar + storage cost.

Figure 11 below shows the distribution of estimated net cost of replacing peaker capacity under various storage configurations. For solar + storage projects, estimated net costs reflect levelized capital and O&M cost *minus* energy and REC value, normalized for the peaker's capacity replaced. Energy value is calculated under 2020 nodal prices and REC value is assumed to be $15/MWh, which is consistent with the recent RPS adders in CPUC's Power Charge Indifference Adjustment (PCIA) estimates.

Under current storage cost levels, replacement of the local peakers in California will likely require significant investments. With 4-hour storage, very few peakers can be replaced with standalone storage at $10/kW-month and over 70% of the peaker capacity would require more than $15/kW-month, which is several times higher than the current RA price levels. With longer duration storage, distribution shifts to higher cost brackets.

If the site or local area has sufficient land that can be used to install solar capacity, developing storage paired with solar can reduce net replacement costs. With current cost levels and extended tax credits under the Inflation Reduction Act, about 3.8 GW of peaker capacity can be replaced with hybrid solar and 4-hour storage at an estimated net cost of $10/per kW-month, another 3.5 GW at $10–$15 per kW-month, 1.3 GW at $15–$20 per kW-month, and the remaining 1.4 GW at $20/kW-month or higher.

Under a future cost scenario assuming installed costs decline by around 40% for storage and 20% for solar, economic feasibility of replacement scenarios improve further, especially when storage is paired with solar. With hybrid solar and 4-hour storage, net replacement cost drops below $5/kW-month for 9 GW *absent* interconnection and land use limitations (discussed next).

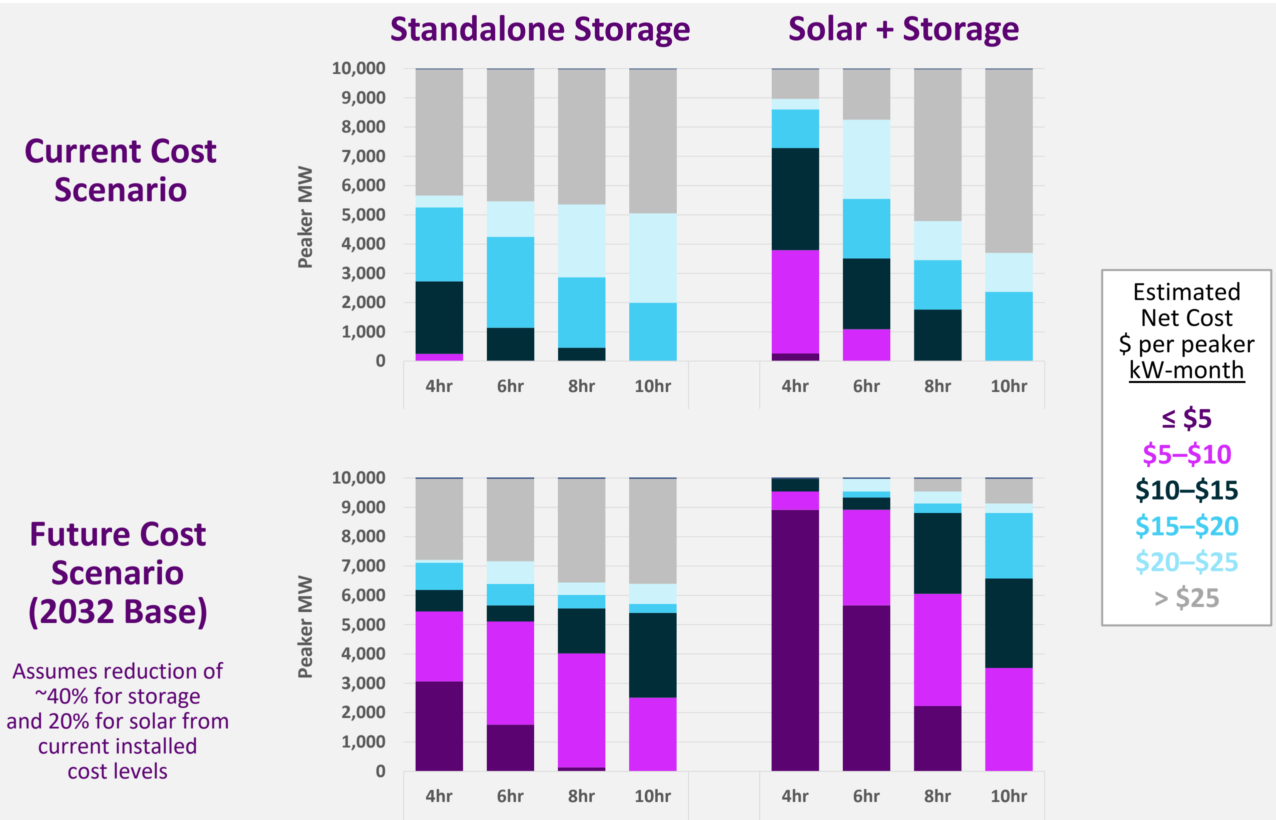


Figure 11: Distribution of net cost results with no limitations on grid interconnection (in 2022 dollars).

Impact of Grid Interconnection and Land Availability

As discussed earlier, all of the peakers in our analysis are located in CAISO-designated local capacity areas. Within these local areas, getting interconnection above what peakers' existing rights could be difficult and may require additional lead time to study deliverability and potentially result in network upgrade costs. Such limitations can prevent storage systems to be overbuilt.

While our study does not analyze interconnection capabilities at individual peaker sites or local areas, we included a sensitivity case with interconnection access of storage resources limited to 1.5x peaker MW. Figure 12 below shows the distribution of net cost results with this limitation, which makes a large share of peaker replacement options infeasible. Under this sensitivity, longer duration storage has more potential to replace peaking units if developed on a standalone basis. Pairing storage with solar creates some opportunities for 4- or 6-hour storage to more cost-effectively replace peakers, without exceeding the 1.5x interconnection limit.

Another important consideration is the land use for solar development, which is not included in our study. According to this LBNL report, recent utility-scale solar projects with tracking require 4 acres of land per MW installed. Therefore, replacing a 100 MW peaker with a 150 MW solar + storage would need around 600 acres of land. If land availability is limited in certain sites or local areas, pairing storage with solar may not be feasible.

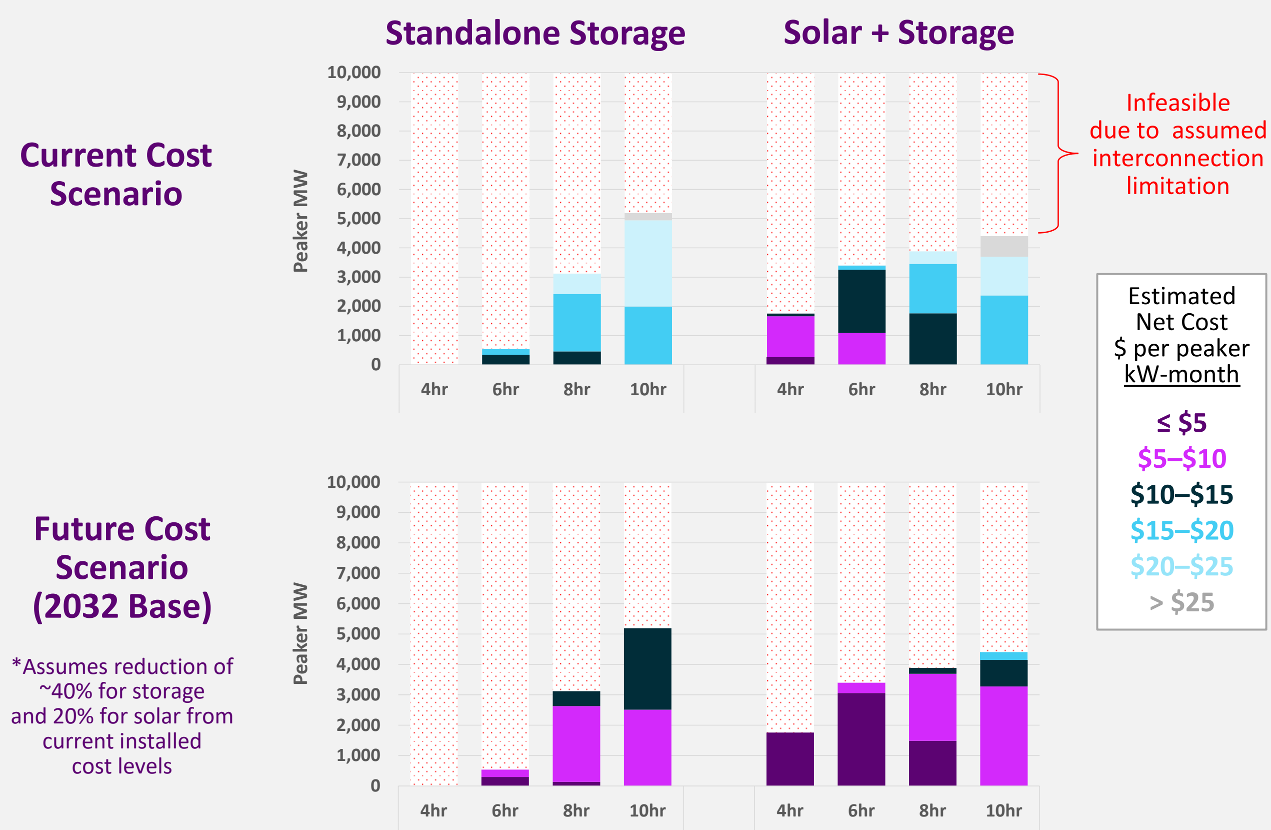


Figure 12: Distribution of net cost results with grid interconnection limited at 1.5x peaker MW (in 2022 dollars).

Key Observations

Most of the gas-fired peaking units analyzed (~10 GW total capacity) are in CAISO-designated local capacity areas and are needed for local reliability. In 2020, they generated a total of 5.7 million MWh accounting for approximately 3.5% of the total generation from resources in CAISO's footprint. Altogether, they were responsible for around 3 million metric tons of CO_2 emissions, which is slightly over 8% of total emissions from in-state generators.

Peakers' operations during 2020 suggest a reliability need over 8 consecutive hours for most of the units analyzed. This extended duration translates to an energy need that can be met by a variety of storage configurations with different mix of MW vs. duration, and developed on a standalone basis or paired with solar PV resources.

Replacing peakers' output with standalone energy storage would require either significantly overbuilding storage MW or installing long-duration storage at relatively high cost. Under current cost levels, net cost is estimated above $15/kW-month for over 70% of the total peaker capacity analyzed.

If the site or local area has sufficient interconnection capability, overbuilding storage MW with a 4-hour duration can be more cost-effective in replacing the peakers in California, than installing long-duration storage. Replacement with 4-hour storage requires more MW than storage with longer durations, but its higher energy time-shift value will likely offset incremental costs and make it more cost-effective under current/near-term outlook for battery costs.

Pairing storage with solar can significantly reduce net replacement costs. If the site or local area has sufficient land that can be used to install solar capacity, developing solar + storage can reduce the need for overbuilding MW or installing long-duration storage to replace peaking units, and accordingly results in lower net costs, relative to standalone storage. Co-location benefits such as cost savings from shared equipment and infrastructure and additional tax credits contribute to lower net cost, but these benefits need to be weighed against "lost" value associated with more stringent operational requirements such as inverter and interconnection limits, and grid charging constraints.

If storage (and solar) costs continue to decline as expected, economic feasibility of replacement scenarios will improve further, especially when storage is paired with solar. Under a scenario where installed storage costs drop from current levels of ~$350/kWh to $200–$250 per kWh and installed solar PV costs drop by ~20% from current levels of $1,000/kW to $800/kW, we estimate that net replacement cost could be below $5/kW-month for most of the peakers analyzed in our study.

Exactly how much peaker capacity can be replaced, however, will depend upon site-specific considerations, including: (a) the peaker's relative to-go costs to stay online, (b) whether or not the energy storage replacement can obtain interconnection rights to oversize its MW capacity relative to peaker's capacity, (c) charging and other operating constraints identified by the CAISO Local Capacity Technical studies, and (d) whether or not solar PV can be developed at a reasonable cost within the local capacity-constrained area.

ATTACHMENT D: PROCUREMENT POLICY CASE STUDIES[1]

California has the largest and most diversified energy storage fleet in the nation, and the fleet is growing rapidly. Customer installations grew from 61 MW at the start of 2017 to at least 582 MW by the end of 2021, largely driven by 468 MW of Self Generation Incentive Program (SGIP)-funded installations. Grid-scale installations grew from 130 MW/510 MWh or 10% of all installations in the country in 2017 to 2,300 MW/8,800 MWh or 44% of all installed capacity in the country by the end of 2021.

Energy storage is a key ingredient to the state's rapid transition to clean energy and deep decarbonization. The CPUC has continuously evolved its policies and explored innovative solutions to support this transition. However, California regulators still share many of the same policy and market adaptation challenges as we see in other states—increased shares of variable generation from renewables, an acceleration of weather and environmental stressors, and rapid development of distributed energy resources on homes and business *clash* with deep institutional practices that are particularly difficult to adapt. Policymakers, utilities, and other stakeholders in other states have brought forward a variety of innovative solutions to dissolve silos in planning and markets and to open the door to the wide range of benefits energy storage has to offer. In order for California policy to continue to innovate the CPUC will need to continue to explore and learn from a variety of policy and market approaches.

The goal of this attachment is to highlight effective energy storage procurement policies and programs in other states that might be helpful to the CPUC as it seeks to break down barriers to cost-effective and high-value energy storage investments in the state.

This attachment is based on a review of U.S. policies and programs for energy storage development, and of relevant industry publications and data. We focus on case studies in 5 states where we observe major steps towards overcoming institutional, market, or policy hurdles that limit the ability of energy storage to contribute to grid optimization, renewables integration, or GHG emissions reductions.

We start with a jurisdictional screening process to identify states that face renewables integration challenges and that have actual energy storage deployment and operational experience. Out of the screening results we select examples of energy storage-related policies and programs from 5 states that appear to be successfully improving the ability of energy storage to contribute to grid optimization, renewables integration, or GHG emissions reductions. We conclude with a summary of key observations.

CONTENTS

New York

New York accounts for about 6% of existing and planned energy storage capacity in the U.S. as of July 2022 (EIA 2022a). The state has relatively little capacity operational, but with most of the planned MW procured before 2021 the state is expected to soon see a wave of installations.

New York has one of the most aggressive energy storage procurement targets in the country. The state's June 2018 Energy Storage Roadmap outlines a multi-pronged policy approach for accelerated energy storage deployment (NY Agencies Staff 2018).

In December of 2018, the New York Public Service Commission (PSC) issued an Energy Storage Order establishing a statewide energy storage goal of 3,000 MW by 2030, with an interim target of 1,500 MW by 2025 (NY PSC 2018). The progress in state's energy storage procurement is facilitated by several state policies and programs, and by end of 2021 New York procured 1,230 MW of energy storage towards meeting that statewide goal (NY DPS 2022). In early 2022 state Governor Hochul announced plans to increase the energy storage goal to at least 6,000 by 2030 (NY State 2022).

Most of New York's energy storage procurement so far has been driven by the "Bridge Incentive" program for market acceleration, administered by New York State Energy Research and Development Authority (NYSERDA). The Bridge Incentive program provides partial funding for energy storage projects. It is similar to the Self-Generation Incentive Program in California, but in addition to customer-sited projects, the Bridge Incentive program supports bulk grid storage projects providing wholesale energy, ancillary services, and/or capacity. The Bridge Incentive program's "first-come, first-served" approach is not necessarily tied to value provided to grid.

Pairing with Renewables

New York's 2018 Energy Storage Order directed the IOUs to hold competitive solicitations to procure dispatch rights of at least 350 MW of bulk-level energy storage in New York by the end of 2022 (NY PSC 2018). The initial round of solicitations in 2019-2020 failed to meet these targets and resulted in procurement of only 130 MW of energy storage. Based on developer feedback and IOU petitions, in-service date deadline for storage resources is extended from 2022 to 2025 and the maximum contract term is increased from 7 years to 10 years.

Another 101.2 MW of energy storage is procured under NYSERDA's Renewable Energy Standard (RES) solicitations, which provide large-scale renewable projects the option to augment their development with energy storage. While under RES contracts, NYSERDA pays only for RECs generated by renewables, and projects paired with energy storage get additional points during bid evaluation. Proposers considering energy storage must submit two bids, one with and one without storage, needed to evaluate costs and benefits of the addition of energy storage facilities. Energy storage can be co-located with renewables or in a separate location in New York, but projects already under utility contract or receiving storage incentives from NYSERDA are not eligible.

Value of DER/Value Stack

Retail rate reforms are a crucial component of New York's integration of distributed energy resources. In 2017, New York started to transition from net metering to a new approach called the Value of Distributed Energy Resources (VDER) or Value Stack. Under the VDER approach, distributed energy resources (DERs) are compensated for up to 5 MW, depending on when and where they provide electricity to the grid. The VDER Value Stack compensates DER projects in the form of bill credits including their estimated energy value, capacity value, environmental value, demand reduction value, locational system relief value, and community credits. Co-located energy storage projects are eligible for environmental value and community credit only if they are charged exclusively from solar PV or wind.

VDER is the most common compensation mechanism chosen by the developers in New York to monetize the value of energy storage, the value of pairing with renewables, and value under a variety of use cases (NY DPS 2022). VDER so far has been successful to help projects monetize value, but actual performance of the energy storage resources is not yet evaluated.

Soft Cost Reduction

While battery energy storage hardware-related costs are mainly driven by national and global market conditions, "soft costs" such as permitting, interconnection, customer or site acquisition costs vary greatly by location. New York's 2018 Energy Storage Order identified high soft costs as a major barrier for energy storage deployment in New York and approved several initiatives to achieve soft cost reductions in the state. The initiatives include:

- Technical assistance for permitting agencies in New York to facilitate informed decision-making when they consider energy storage installations;
- Development of data platform with granular system and load data needed to reduce energy storage site identification and customer acquisition costs;
- Education of developers on storage solutions, economics, and market rules;
- Improved interconnection rules;
- DER portal to collect and provide access to non-propriety performance and financial information to build confidence in deployed systems and project economics; and
- Development of appropriate decommissioning and end-of-life actions and processes based on input from utilities, market participants, local communities, and state agencies.

The New York Public Service Commission also directed Department of Public Service Staff to prepare an annual report to keep track of installed cost of energy storage systems and document progress towards reducing soft costs in that year. To accomplish that, there has been increased emphasis in collecting detailed cost data from storage projects supported by various state initiatives in New York. For example, NYSERDA requires all applicants to submit data on total installed costs and a breakdown of cost components for hardware, engineering & construction, permitting & siting, and interconnection before they can receive any payments under the Bridge Incentive program.

Hawaiʻi

Hawaiʻi accounts for almost 2% of existing and planned energy storage capacity in the U.S. as of July 2022 (EIA 2022a). The state's existing and planned energy storage fleet reflects a high share of installations co-located with solar and wind farms. Hawaiian Electric Companies includes the state's three investor-owned utilities—Hawaii Electric Light Co Inc, Maui Electric Co Ltd, and Hawaiian Electric Co Inc—and serves five islands and 95% of the state's electricity demand (EIA 2022b).

Over the past decade Hawaiʻi has been a national leader in innovative clean energy deployments and policies. The state's innovations are, in part, motivated by a historical dependence on expensive oil for electricity generation and a variety of operational and infrastructure development challenges inherent to island and archipelago systems. In 2015 Hawaiʻi passed legislation to establish a 100% renewables target by 2045—3 years before any other U.S. state implemented 100% clean energy target. In the absence of a storage mandate, Hawaiʻi's grid-scale energy storage is procured largely through utilities' renewable solicitations to meet increasing RPS goals. Through multiple solicitations, the Hawaiian Electric Companies procured over 700 MW of storage capacity expected to be online in 2022–2023. Of that amount, 530 MW is co-located with solar generation, increasing RPS-eligible generation by about 16 percentage points. In 2020 Kauaʻi Island Utility Cooperative procured a unique hybrid hydroelectric + pumped storage hydroelectric + solar PV + DC-coupled battery energy storage project which will cover 25% of island's load. That project is discussed further in **Attachment E (End Uses and Multiple Applications)**.

Hawaiʻi's major changes to the industry's traditional electricity policy and planning paradigm, in support of a clean energy transformation, include:

- In 2015, the nation's first state target for 100% clean energy (100% renewables by 2045);
- At the end of 2015, an end to the net energy metering (NEM) tariff, followed by refinements to time-of-use rates, which is credited for significantly accelerating customer-sited energy storage attachment rates (Barbose et al. 2021);
- After 2017, development of a cross-grid domain integrated grid planning process that includes planning across all grid domains and a customer-focused survey and knowledge-sharing campaign, as part of Hawaiian Electric Companies' Grid Modernization Plan;
- At the end of 2021, a decision for Hawaiian Electric to transition away from cost of service regulation to performance-based rates, as part of developing a sustainable business model for the utility.

We focus on NEM and associated retail rate reform for our Hawaiʻi case study, due to its relevance to California's urgent need to develop significantly stronger grid signals to customers to enable energy storage use cases and operations that are beneficial to both customers and to the grid.

NEM and Retail Rate Reform

Hawaiʻi's NEM and retail rate reforms are crucial components of the Hawaiian Public Utilities Commission's efforts to align customer behavior with grid needs.

Under NEM Hawaiʻi saw a rapid increase in distributed energy resource adoption for many years. About 21% of single-family homes in the Hawaiian Electric Companies' service territories had rooftop solar in 2016 (Hawaiian Electric Companies 2017). In early 2014, when California's Duck Curve was only conceptual and not yet observed, the Hawaiian Electric Companies made industry headlines when it reported actual solar overgeneration and associated energy backfeed problems on neighborhood circuits with high solar PV penetration (Wesoff 2014; St. John 2014). Along with a success story of high customer solar PV adoption, the Hawaiian Electric Companies' challenges with energy backfeed provided the industry with an example of the dangers and costs of unhindered solar resource expansion without parallel advancements in the grid's ability to absorb solar generation when produced.

In October 2015 the Hawaiian Public Utilities Commission (HI PUC) made the decision to end the Hawaiian Electric Companies' net energy metering program to new participants (HI PUC 2015). Even with existing NEM customers protected from the change, this decision came with great controversy. Legal battles ensued, stakeholders argued over equity issues, and the customer-sited solar industry loudly contracted.

The HI PUC's October 2015 decision discusses how combination of NEM with "extraordinarily high" retail rates and "dramatic" cost reductions in renewables and storage was driving high DER adoption and a backlog of thousands of customers waiting to interconnect DERs (HI PUC 2015). The HI PUC also found that the NEM program was not designed for the high degree of DER adoption observed. Although it was clear NEM was not sustainable going forward, a permanent successor was not immediately identified. As an interim measure, customers with new DER interconnections were subject to a minimum bill and had an option to export to the grid in exchange for energy credits.

In September 2019 the Hawaiian Public Utilities Commission opened a proceeding to explore options for DER programs and rate designs more sustainable over the long-term (HI PUC 2019). Stakeholders submitted their advanced rate design proposals in March 2021 with a focus on design and implementation of default time-of-use (TOU) rates for residential and commercial customers. The Hawaiian Electric Companies proposed a 3-part TOU rate that would be mandatory for customers with DERs, and that would include evening on-peak, overnight, and mid-day periods (Hawaiian Electric Companies 2021). The Division of Consumer Advocacy (Consumer Advocate) proposed either a 3-part TOU rate with similar period definitions or a 4-part TOU including a morning peak period. Consumer Advocate emphasized long-run marginal cost as an efficient price signal, using CPUC as an example to follow, and recommended consideration of TOU combined with critical peak pricing (CPP) to signal for the more extreme grid-constrained times (Consumer Advocate 2021). Representatives of DER suppliers (DER Parties) proposed a 3-part customer bill, including a customer charge, a grid access charge, and TOU rates (DER Parties 2021). The DER Parties' proposed TOU rates include 3 periods with relative rate levels at a specific 3:2:1 ratio, for on-peak, off-peak, and mid-day periods, to optimize customer response (DER Parties 2021).

As of the time of this study the Hawaiian Public Utilities Commission has not yet made a decision on the advanced rate design track of its DER policies proceeding. The context of this proceeding has obvious parallels to issues faced by the CPUC and will be an important proceeding to watch for opportunities to learn from both commonalities and differences.

TOU rates in California, for example, are not sufficient to align the operations of customer-sited energy storage with grid needs. Compared to the California IOUs' 2-part TOU rates, more granular 3-part and 4-part TOU rates would better incentivize general charge and discharge patterns with the grid (e.g., charging during the day rather than overnight). However, TOU rates as the only dynamic pricing mechanism cannot capture the significant value energy storage can provide by fine-tuning charging and discharging at the specific times when the grid is constrained. For example, if time of use peak pricing is 4–9 p.m. a customer with 2-hour storage may automatically discharge from 4–6 p.m. even if the grid has the greatest need after 6 p.m. This is a reality we saw in 2020 and 2022, when CAISO had a Stage 3 Emergency on August 14, 2020 from 6–9 p.m., a Stage 3 Emergency on August 15, 2020 from 6–7 p.m., and an Energy Emergency Alert 3 on September 6, 2022 from 5–8 p.m.

Although painful for the customer-sited solar industry, the end of NEM appears to have facilitated growth in customer-sited energy storage use cases over the past 5 years. Overall, Hawaiʻi's transition away from NEM better incentivized self-consumption of solar PV by limiting or reducing compensation for grid exports. Also, despite a slowdown, the share of single-family homes in the Hawaiian Electric Companies' service territories with rooftop solar continued to grow to 32% in 2022 (Hawaiian Electric Companies 2022). According to a 2021 LBNL report, Hawaiʻi had the nation's highest storage attachment rate in 2020, with 80% of residential customers and 40% of non-residential customers who had solar PV also had a storage system installed. California, in contrast, is a distant second in the list, with a storage attachment rate to solar of 8% for residential and 2% for non-residential customers.

Arizona

Arizona accounts for about 5% of existing and planned energy storage capacity in the U.S. as of July 2022 (EIA 2022a). The existing fleet includes several large projects like the hybrid 280 MW concentrating solar power plus 6 hours of storage at the Solana Generating Station.

Storage investments are mostly driven by the utilities' corporate strategy. In early 2022 Arizona regulators voted to maintain RPS at 15% and rejected a proposed 100% clean energy rule that would include a 5% energy storage target (ACC, 2022a). The vote was in response to public opposition to the ratepayer cost of a renewables buildout in comparison to a future with mostly natural gas-fired generation.

Instead, utility initiatives such as Arizona Public Service Company's (APS) pledge to 100% carbon-free electricity by 2050 motivate clean energy and energy storage builds (ACC, 2022b). APS is the state's largest investor-owned utility, serving about a third of Arizona's electricity demand (EIA 2022b). The company's clean energy goals include significant investment in energy storage.

In 2019 APS announced an initiative to add **850 MW of battery storage by 2025**. The utility's plans stalled for two years after a catastrophic safety failure at the 2 MW/2MWh McMicken Battery Energy Storage System in April 2019. In 2021 APS resumed its energy storage development plans with enhanced safety protocols (see **Attachment F (Safety Best Practices)** for more discussion).

APS Residential Battery Pilot

APS developed and administers several demand-side management programs, including a residential battery incentive pilot for **customer-sited energy storage**. The pilot was originally developed as the Residential Energy Storage Pilot and was approved by the ACC in 2020 (ACC 2021). The original pilot was designed to offer customers up to $2,500 if they install a new battery system, enroll in a time-of-use rate plan, and commit to discharging during peak hours.

APS subsequently renamed the pilot the **Residential Battery Pilot** and refined its structure to offer customers two options:

(1) A data only option in which customers agree to connect to the utility's resource operating platform and share battery performance data, or

https://www.chargingrewards.com/apsbattery/

(2) A data plus dispatch option in which customers agree to sharing data and 80% of the battery's capacity with the grid during capacity-constrained periods (APS 2021).

Under this second option, customers receive an additional $1,250 up-front payment, and capacity sharing is limited to 100 events per year over 3 years. ACC approved $1.8 million for this revamped pilot in 2021 to run for 3 years.

APS' stated objectives of this pilot are to encourage customers to (a) charge during off-peak hours, (b) discharge during peak hours, and (c) share battery performance data. The utility stated intentions to use the collected battery performance data to "inform future efforts to scale distributed energy storage capacity on the grid" (APS 2021).

With relevance to California, this pilot is particularly innovative in its approach to collect and learn from data on customer-sited battery performance and operating patterns (regardless of capacity-sharing with the grid). Furthermore, the pilot's mechanism to call on a firm commitment from customers to share capacity under option #2 is a step closer to unlocking RA capacity value compared to voluntary response programs like California's ELRP and California's plea-based emergency alerts.

Nevada

Nevada has relatively little operational storage (25 MW in 2021) but installed capacity is expected to grow to over 1,500 MW by the 2023–2024 timeframe. Total existing and planned energy storage capacity as of July 2022 is about 8% of the U.S. (EIA 2022a). Sierra Pacific Power Company and Nevada Power Company, both of which conduct business as NV Energy, are the state's investor-owned utilities.

State RPS and utility IRPs are the primary drivers of storage procurements in Nevada. In 2020 the state set a 1,000 MW by 2030 storage mandate for NV Energy, but the utility already met most of the requirement by that time. The state's ambitious clean energy goals of 50% renewables and energy efficiency by 2030 and 100% goal by 2050 are expected to be met largely by solar. This would create challenges similar to those experience in California that can be addressed by energy time shift services provided by energy storage.

Solar plus storage projects rank high economically in renewable solicitations due to cost synergies, ITC applicability to storage, and improved RA capacity value. Most storage capacity procured in the state (95%) is co-located with utility-scale solar projects that are needed to meet future RPS. More recently, NV Energy's 2021 integrated resource plan identified two solar + storage projects to replace a retiring 522 MW coal plant.

Utility Contracts with Corporate Entities

In 2019 NV Energy signed a landmark deal with Google for 350 MW solar plus 250–280 MW co-located battery storage to serve the electricity needs of a large data center in Nevada. At the time, Google was reportedly the largest corporate purchaser of renewable energy in the world and had amassed over 5.5 GW in renewable energy contracts internationally—enough to match its total annual global energy consumption (NV Energy 2019a). The NV Energy deal supports Google's strategy to de-carbonize even further through renewable energy matched to consumption on an <u>hourly</u> basis, in recognition that *when* renewable energy is produced matters for electric sector GHG emissions reductions. The deal also serves NV Energy's needs for clean energy and capacity during summer evening peaks when the grid is most constrained. In 2020 the Public Utilities Commission of Nevada approved procurement of the Dry Lake Solar Project and the Chuckwalla Solar Project, each with co-located 4-hour battery systems, earmarked to serve the NV Energy/Google deal (PUCN 2020).

The parties structured their long-term energy supply agreement to serve both Google and other customers on NV Energy's grid. NV Energy procured the solar plus storage facilities on behalf of Google and in tandem with the utility's various resource planning processes. Once the solar plus storage projects are in operation (expected by January 1, 2024), Google is charged a fixed rate for all attributes of the project (energy, capacity, renewable credits) to serve its data center with a minimum of 70% renewable energy on average hourly (NV Energy 2019b). Some hours may be served at less than 70%, and some at more than 70%, but not over 100%. In other words, excess solar generation output that is not stored but injected to the grid is not counted towards meeting the contract's minimum renewable energy requirement. Over an entire year, the hourly renewable energy shares (capped at 100%) must average to at least 70%. In addition, Google receives a credit for residual capacity provided to the grid during grid-strained summer evenings (NV Energy 2019a).

In 2019 NV Energy estimated the deal would provide $3–11 million in customer benefits annually, and $19–165 million in total, depending on actual data center load and on a contract extension option (NV Energy 2019a).

Texas

Texas' independent system operator, ERCOT, had 833 MW of operational grid-connected battery capacity on its system by the end of 2021; 70% of that capacity was installed in 2021 (ERCOT 2022b). Installed capacity is expected to reach about 7,800 MW by 2024 (ERCOT 2022b). As of 2022 the state is second to California in quantity of total operational and planned energy storage capacity in the nation.

We include Texas as a case study due to its recent high volume of energy storage development and as a pronounced market and policy contrast to California. Without a state-level storage mandate or utility contracts, most energy storage in Texas is developed by independent power producers (IPP) as merchant projects. Texas demonstrates what types of energy storage use cases and services emerge as part of a viable private business proposition without policy intervention.

Energy Market-Driven Storage Duration

In contrast to the CAISO marketplace, ERCOT's marketplace is characterized by an "energy-only" approach to fixed investment cost recovery, associated scarcity pricing and more volatile energy prices, and energy prices that are highest during traditional peak periods during the day. As such, energy storage developers are highly incentivized to invest in instantaneous (MW) capacity—rather than energy capacity (MWh)—to capture market revenues during ERCOT's highest-priced hours and/or to provide ancillary services.

ERCOT's statistics on the distribution of durations in its energy storage fleet as of the end of 2021 demonstrate developers' focus on instantaneous capacity investments (ERCOT 2022a). Most operational batteries (97%) are designed with durations of two hours or less (Figure 1, top). One operational project has a duration of about four hours. Projects not yet commercially online but in an advanced stage of the interconnection process reflect similar duration trends. All batteries in advanced development are designed with durations of 2.5 hours or less (Figure 1, bottom).

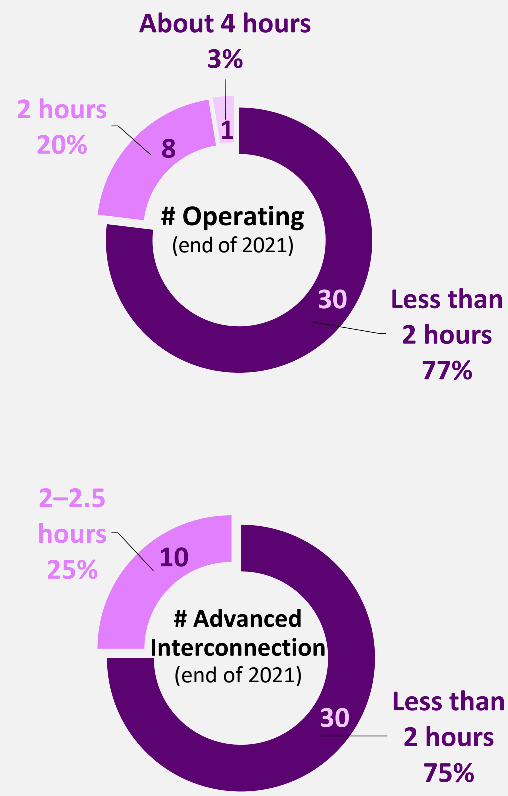


Figure 1: ERCOT's trends in battery energy storage duration.

Developers' focus on standalone storage reflects how operational constraints needed to capture co-location benefits (from tax credits and shared costs) can significantly reduce the market value of storage in Texas. Unlike in California, the highest-priced hours in ERCOT's energy market still occur during the day. Not being able to discharge at that time due to a solar charging requirement or a joint point of interconnection limit is detrimental to the economics of hybrid projects in ERCOT (for more discussion *see* Gorman et al. 2021). Around 70–80% of operational and planned energy storage MW is from standalone batteries. Solar plus storage accounts for most of the remaining, with some capacity co-located with wind farms and some co-located with thermal generation (ERCOT 2022a).

A February 2021 winter storm in Texas tragically resulting in hundreds of deaths exposed grid vulnerabilities to extreme weather (Svitek 2022; Cai et al. 2022). Absent policy intervention, in ERCOT's reactive investment market it is unlikely that developers will build energy storage with sufficient duration to support bulk grid reliability and resilience under new and changing environmental stressors.

Key Observations

NYSERDA's RES solicitations create an avenue for maximizing joint renewables plus storage value by requiring two bids from developers: one with and one without storage.

With the aim for better integration of distributed energy resources, **New York** transitioned from net metering to Value of Distributed Energy Resources (VDER) compensation in the form of bill credits for estimated energy value, capacity value, environmental value, demand reduction value, locational system relief value, and community credits.

New York's soft cost reduction efforts are centered around several data-driven initiatives to streamline permitting, siting, and customer acquisition, and to keep track of actual progress over time.

In the context of high distributed solar PV penetration, elimination of net energy metering along with retail rate reforms are crucial components of the **Hawaiian Public Utilities Commission's** efforts to align customer behavior with grid needs.

Arizona Public Service Company's Residential Battery Pilot demonstrates an innovative approach to (a) collect and learn from data on customer-sited battery performance and operating patterns and (b) establish a firm commitment from customers to share capacity with the grid during grid-constrained periods.

NV Energy's contract with Google for 350 MW solar plus 250–280 MW co-located battery storage demonstrates an innovative procurement approach to stacking customer-specific benefits with broader grid benefits.

Energy storage investments in **ERCOT** highlights the strong incentives for merchant developers to configure systems for very short durations to capture energy and ancillary services market revenues.

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ATTACHMENT E: END USES AND MULTIPLE APPLICATIONS[1]

Energy storage technologies are emerging as highly flexible resources that can provide a wide variety of services and value to the grid and customers. In this attachment, we provide a brief overview of these services and applications, summarize key state activities that aimed to unlock access to associated value streams, and discuss the progress made towards value stacking based on the results of our historical analysis of storage operations in California.

The storage resources included in our historical analysis are predominantly standalone lithium-ion batteries with durations of up to 4 hours, so we supplement our discussion based on industry research on hybrid storage resources, alternative technologies and long-duration storage, and transmission deferral use cases.

CONTENTS

Energy Storage Services and Value

Energy storage can offer a wide range of services and values depending on where it is interconnected on the grid, as shown in Figure 1. Electrically, when a resource gets closer to the end use customer, it can *potentially* provide more services and value. Storage resources interconnected directly to transmission system can provide wholesale market, resource adequacy and transmission services. Distribution-connected resources can provide the same set of services, plus distribution system services. Customer-sited resources could provide all of the above, plus a suite of customer-specific services, like bill management. This is consistent with the CPUC decision D.18-01-003 which adopted several rules to govern multiple-use storage applications.

		Grid Domains		
	Services to Grid and Cust.	**Tran.**	**Dist.**	**Cust.**
Energy & AS Markets and Products	Energy	✓	✓	✓
	Frequency Regulation	✓	✓	✓
	Spin/Non-Spin Reserve	✓	✓	✓
	Flexible Ramping	✓	✓	✓
	Voltage Support	✓	✓	✓
	Blackstart	✓	✓	✓
Resource Adequacy	System RA Capacity	✓	✓	✓
	Local RA Capacity	✓	✓	✓
	Flexible RA Capacity	✓	✓	✓
T & D Related	Transmission Investment Deferral	✓	✓	✓
	Distribution Investment Deferral		✓	✓
	Microgrid/Islanding		✓	✓
Site-Specific & Local Services	TOU Bill Management			✓
	Demand Charge Management			✓
	Increased Use of Self-Generation			✓
	Backup Power			✓

Figure 1: Scope of possible services for transmission-, distribution-, and customer-sited resources.

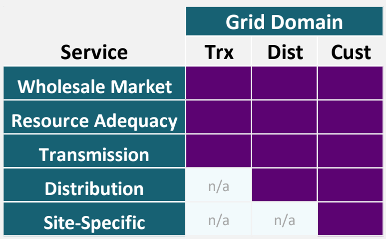
Potential storage services and associated value streams in California include:

- **Energy, or energy arbitrage:** Storage can move energy from one time to another by charging in off-peak periods when the prices are low and discharging during peak periods when high.
- **Ancillary services:** Storage can provide various ancillary services in the CAISO market, including frequency regulation by automatically responding to CAISO's control signals to address small random variations in supply and demand, and contingency reserves (spin and non-spin) to quickly respond in case of an unexpected loss of supply on the system. Storage resources can also provide voltage support to help dynamically maintain stable voltage levels in distribution or transmission systems, and blackstart to self-start without an external power supply and help the grid recover from a local or system-level blackout.
- **Flexible ramping:** Storage resources provide upward and downward ramping capability to help CAISO manage rapid changes in the system due to demand and renewable forecasting errors.
- **Resource adequacy (RA):** Storage resources can be available to discharge during peak periods to help with meeting system RA, local RA, and flexible RA requirements to ensure system reliability in California.
- **Transmission investment deferral:** Storage can defer the need for new transmission investments by charging during periods with low transmission use and discharging when local transmission system is constrained.
- **Distribution investment deferral:** If interconnected to the distribution system, storage can defer the need for new distribution investments by reducing local peak loading on the distribution grid.
- **Microgrid/islanding:** Distributed storage resources can improve resilience by supporting islanding and microgrid capabilities for sections of the distribution grid and thus help to mitigate the risk of power interruptions at the community level.

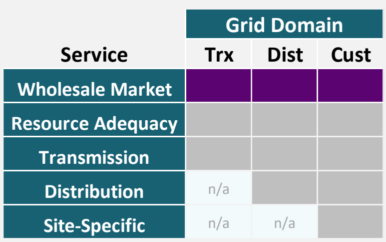
- **Site-specific customer services:** Storage resources that are interconnected behind the utility meter can help customers reduce their electric bills through time-of-use (TOU) bill management by charging when their retail rates are lowest and discharging when retail rates are highest, and demand charge management by reducing customer's net peak usage. Customer-sited resources can also provide backup power to mitigate impacts of power outages. If paired with solar PV, storage can increase use of self-generation by storing excess PV output during the day to use after the sunset.

Key Activities and Initiatives to Unlock Storage Value

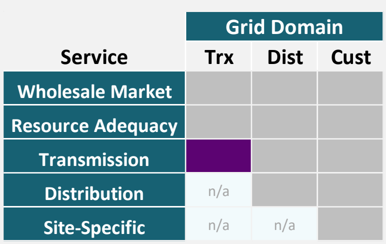
There has been a significant effort in the industry over the past decade to achieve full economic potential of energy storage resources by unlocking access to a variety of value streams. Key activities in California are summarized below. The purple color on the charts highlights types of services and value streams explored for energy storage at various grid domains.



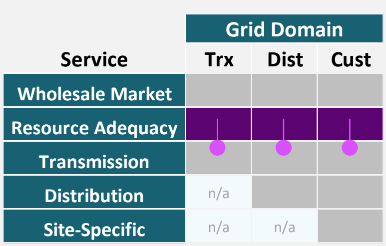
In 2018, CPUC approved D.18-01-003 which marked an important step towards enabling "value stacking" of energy storage systems that can provide multiple services to the grid. The decision adopted a joint staff proposal of the CPUC and CAISO to develop 11 stacking rules to govern multi-use-application (MUA) for grid-scale and distributed energy storage.



CAISO's energy storage and distributed energy resource (ESDER) initiative over the 2015–2021 period focused on various ways to improve ability of transmission-connected and distributed energy resources to participate in the wholesale markets. Separately, CAISO's ongoing energy storage enhancements initiative aims to improve optimization, dispatch, and settlement of energy storage resources through bid enhancements.



CAISO's storage as transmission asset (SATA) initiative kicked off in 2018 to explore how to enable storage provide transmission services while also participating in the wholesale markets, but the initiative is temporarily suspended until storage market participation model is further refined. CAISO transmission planning process (TPP) considers energy storage alternatives to transmission buildout and approved two projects in its 2017/18 TPP cycle.



Several storage procurements driven by local RA needs, including 2013-2016 LCR solicitations due to OTC and SONGS plant retirements in LA Basin and San Diego, 2016-2018 ACES solicitations to address reliability needs due to Aliso Canyon gas leak, 2018 LCR solicitations to meet local needs in Moorpark and Moss Landing. Local needs are determined based on CAISO LCR studies, which can be addressed local RA resources or transmission upgrades.

Service	Grid Domain		
	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

CPUC's Integrated Resource Planning (IRP) efforts led to two procurement orders to address system reliability needs: D.19-11-016 and D.21-06-035 requiring a combined 14,800 MW of net qualifying capacity (NQC) by 2026. Under the IRP procurement track, most of the resource need so far is met by standalone energy storage and storage paired with solar.

Service	Grid Domain		
	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

In 2016, CPUC adopted the Competitive Solicitation Framework under the Integrated Distribution Resources (IDER) proceedings and approved IDER incentive pilot to test distribution deferral. In 2018, CPUC established the Distribution Investment Deferral Framework (DIDF) to create an annual process to identify, review, and select opportunities for distributed energy resources to defer or avoid distribution investments.

Service	Grid Domain		
	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

Several utility pilots and demonstration projects were installed at the distribution system to test various services and storage use cases, including CAISO wholesale market participation, resource adequacy, distribution deferral, microgrid/islanding. Oakland Clean Energy Initiative (OCEI) under utility-CCA partnership selected distribution-connected projects to facilitate gas peaker retirement, which would otherwise require transmission upgrade.

Service	Grid Domain		
	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

Self-Generation Incentive Program (SGIP) was established in 2001 to provide financial incentives for distributed generation. Program is transformed in 2017 and allocated 75% of funds to storage. In 2019, CPUC adopted use of a GHG signal that reflects real-time emission intensity in wholesale markets to align performance with GHG goals. Same year, CPUC established Equity Resiliency budget for storage installations by vulnerable customers in high wildfire threat areas.

Service	Grid Domain		
	Trx	Dist	Cust
Wholesale Market			
Resource Adequacy			
Transmission			
Distribution	n/a		
Site-Specific	n/a	n/a	

In 2021, CPUC created the Emergency Load Reduction Program (ELRP) as a new Demand Response pilot to compensate electricity customers for voluntarily reducing their demand or increasing supply during periods of grid emergencies. This is a 5-year pilot program, started with commercial customers and extended in December 2021 to include residential customers.

At the federal level, there were two key FERC orders affecting wholesale market integration of storage:

- In 2018, FERC's Order 841 required the regional transmission organizations (RTOs) and independent system operators (ISOs) to enable participation of energy storage resources in wholesale energy, ancillary services, and capacity markets.
- Later in 2020, under a similar but broader scope, FERC's Order 2222 required RTOs and ISOs to open up wholesale markets to distributed energy resource (DER) aggregations, which includes distribution-connected and customer-sited energy storage, among other technologies.

Multiple-Use Applications and Value Stacking

In 2018, CPUC approved D.18-01-003 which marked an important step towards enabling "value stacking" of energy storage systems that can provide multiple services to the grid. The decision adopted a joint staff proposal of the CPUC and CAISO to develop 11 stacking rules to govern multi-use-application (MUA) for grid-scale and distributed energy storage.

These rules are summarized below.

1. Customer-sited storage can provide all services in any domain
2. Distribution-connected storage can provide all services except services in the customer domain, except for community storage
3. Transmission-connected storage can provide all services except services in the customer and distribution domains
4. All resources can provide resource adequacy, transmission, and wholesale market services
5. Reliability services must be prioritized
6. If multiple reliability services provided, reliability obligations must not conflict with each other
7. When contracting for reliability services, storage provides must demonstrate distinct capacity dedicated and available to that reliability service
8. Program rules, contract, or tariff relevant to each service provided must specify how the rules will be enforced, including through penalties for non-performance
9. In response to a utility request for offer, storage providers must list any services provided outside of the solicitation and update the list over time
10. Storage resources must comply with all applicable availability and performance requirements
11. Compensation is permitted only for services which are incremental and distinct; The same service must be counted and compensated only once

Figure 2: Summary of CPUC-adopted rules on multiple use applications.

For the historical benefit-cost analysis of energy storage projects in California, we evaluated projects across all grid domains based on their actual operations during 2017–2021. See **Attachment A (Benefit/Cost and Project Scoring of Historical Operations)** for details. Figure 3 shows estimated societal benefits averaged over operating period and normalized for MW capacity of the projects. Top chart shows the aggregate benefits color coded by project group or cluster. Bottom chart shows stacking of individual benefit metrics. Most bars represent individual resources with their widths showing relative MW capacity. Customer-sited storage installations are aggregated into utility contracts or clusters.

The top-ranked resources provided $20–$35 per kW-month of average benefits over the 5-year period. These resources all participated in the CAISO wholesale markets and they did relatively well in stacking of energy, ancillary services, and RA capacity value. Many of them are distribution-connected projects that were procured to address various local RA and reliability needs.

Many of the recent large transmission-connected storage projects ranked in the middle, with higher focus on energy time-shift and little/no ancillary services value. Their estimated RA capacity benefits were lower than the early projects procured for high-value local RA needs.

Customer-sited resources generally provided very low benefits due to lack of service to the transmission grid. However, one of the clusters of nonresidential SGIP projects provided relatively high resilience value by mitigating impacts of customer outages (shown in gray). Storage projects in this cluster are mostly paired with rooftop solar and located in areas that faced several Public Safety Power Shutoff (PSPS) events historically.

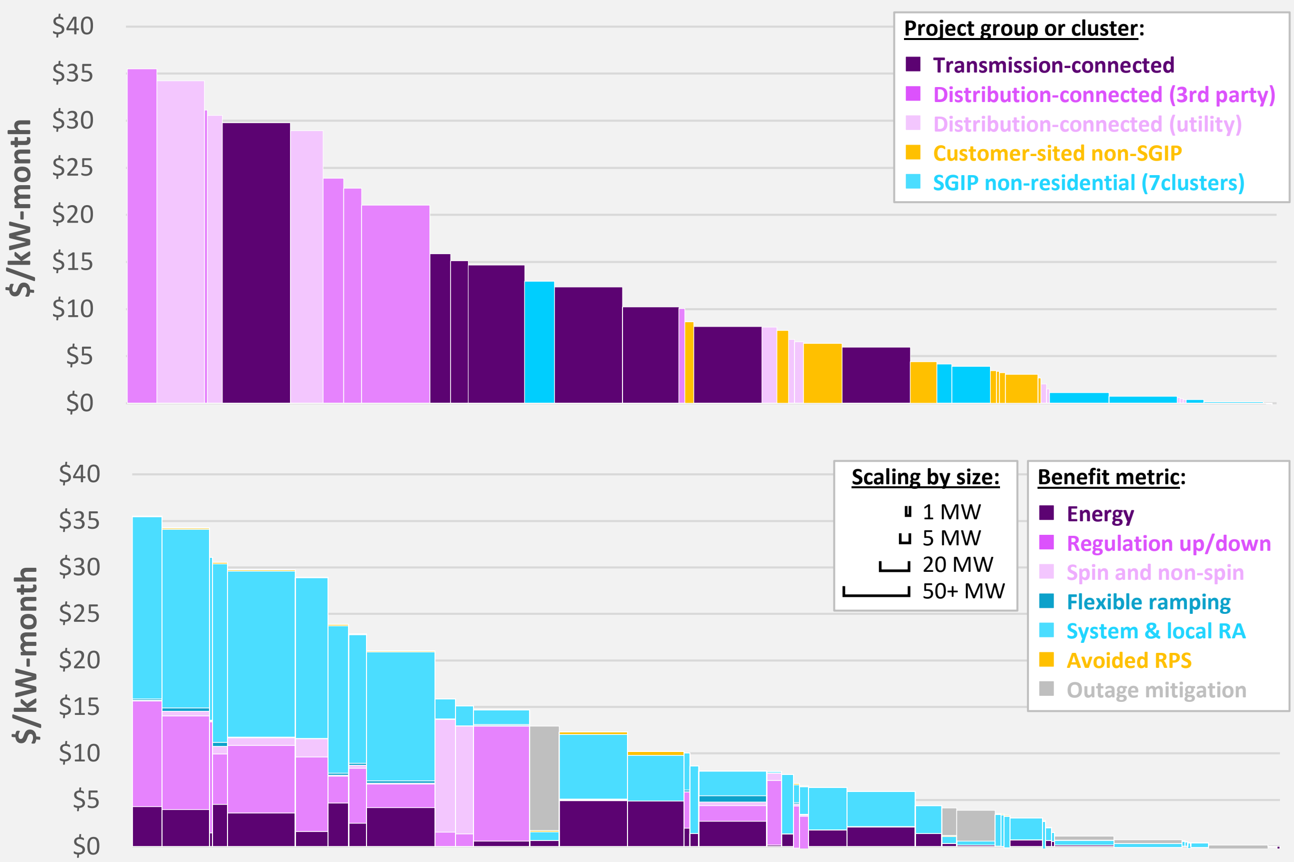


Figure 3: Summary of estimated societal benefits by project group (top) and benefit metric (bottom) (2022 $).

The storage projects with the highest levels of historical benefits are mostly distribution-connected resources that were procured to meet various local capacity needs driven by generation retirements (i.e., once-through cooling, San Onofre nuclear generators, Moss Landing generators) and issues related to Aliso Canyon. **Attachment A (Benefit/Cost and Project Scoring of Historical Operations)** describes the individual procurement tracks and the counterfactual cases developed based on specific circumstances of these procurement tracks, which we use to estimate local RA capacity values. Since these energy storage resources were procured under generation RA capacity procurement, where the resource alternative is a generation or load resource, we allocate these services and benefits towards local RA capacity rather than transmission deferral. However, local RA capacity value intersects with transmission deferral because without cost-effective local generation or storage, the alternative would be a transmission upgrade to reduce or eliminate local RA capacity need in the area.

None of these high-value local RA capacity distribution-connected projects provide distribution level services. As discussed in **Chapter 2 (Realized Benefits and Challenges)** of the main report, energy storage developed to defer specific distribution investments faced major challenges as the size and timing of identified needs changed over time. At least 9 projects earmarked for distribution investment deferral were canceled. One storage project originally procured for distribution deferral (under IDER) achieved commercial operations within the timeframe considered in our study. However, the distribution need driving the procurement of this resource disappeared due to a reduction in the utility's demand forecast. This resource participates in the CAISO marketplace and is able to provide benefits to the grid despite fluctuating needs on the distribution system. This highlights that the modularity of storage to "stack" a wide range of services, and to do so flexibly, may be beneficial to the distribution investment deferral use cases.

Customer outage mitigation is becoming an increasingly crucial component of resilient electricity service to meet essential loads and to protect vulnerable customers, communities, and critical facilities. Wildfire risks in California have accelerated and shifted rapidly in 2017–2021 along with utility use of extended planned outages of sections of the distribution system (Public Safety Power Shutoffs) as a mitigation tool. Accelerating weather and environmental risks point to higher future resilience needs at the community and customer levels that can only be addressed by distributed solutions. Transmission-connected resources cannot help when distribution sections are de-energized.

Distribution-connected microgrids can support community-level resilience, which is tested by the IOUs and stakeholders through several early pilots and demonstrations. Projects like SDG&E Borrego Springs microgrid brought this use case to technological maturity. But as described in the main report, these microgrid projects historically provided very little value to the grid as they were on standby for extended periods of time.

For customer-sited resources, outage mitigation was largely an untapped potential until recently. Most of the initial SGIP-funded energy storage capacity came from nonresidential customers who focused on bill management. Over past couple of years, however, residential installations started to drive the market growth. The Equity Resilience budget, established for vulnerable customers in high fire-threat areas and at risk of outages, accounted for over 50% of the new customer-sited installations funded by the SGIP in 2021.

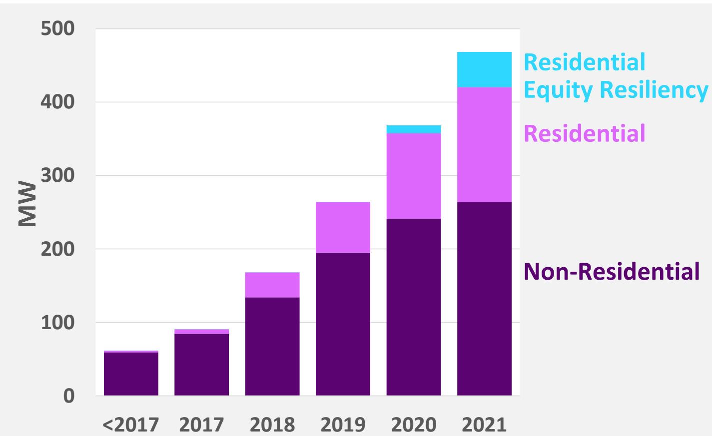
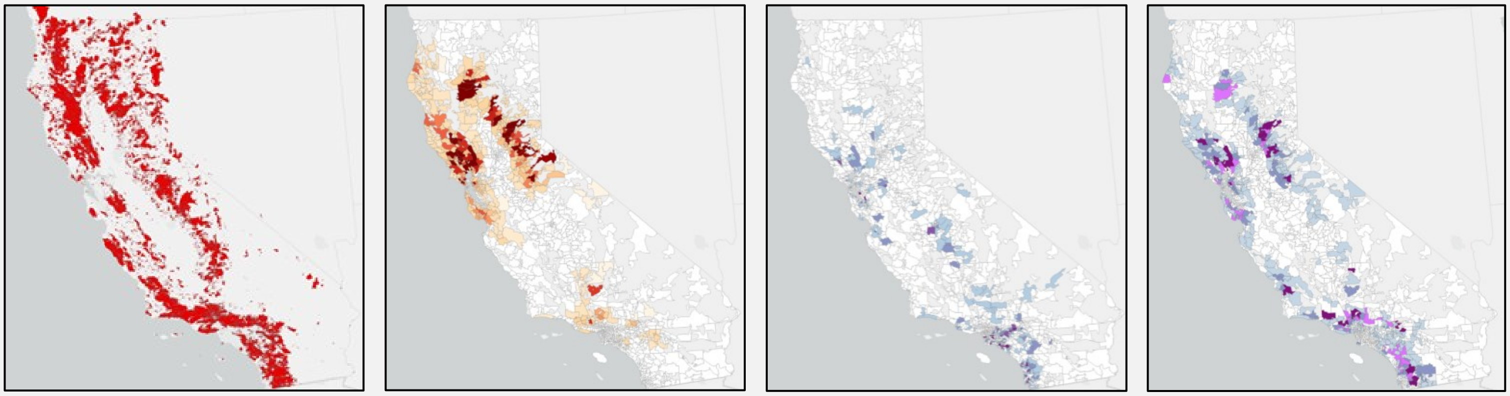


Figure 4: SGIP-funded installed storage capacity over time.



Historical fire perimeters

Relative PSPS severity in total customer-hours

Distribution of nonresidential SGIP-funded storage installations

Distribution of storage + solar installations under SGIP Equity Resiliency budget

Figure 5: Comparison of various SGIP installations to wildfire threat areas.

In Figure 5 above, historical wildfire perimeters and PSPS areas compared to the distribution of nonresidential projects shows low spatial correlation. Recent projects funded under the SGIP Equity Resiliency budget are primarily installations that are paired with solar and concentrated in high wildfire threat areas. SGIP projects in our historical analysis do not include these recent projects in high-risk areas, so the estimated customer outage mitigation values in our report are relatively low for most projects. Over the 2017–2021 period, we estimated the customer outage mitigation benefit to be $1.7/kW-month, when averaged across all nonresidential SGIP-funded projects. For the subset of these SGIP projects that are in PSPS areas and paired with solar PV, however, the average value is estimated to be in the range of $10–$20/kW-month (see **Attachment A (Benefit/Cost and Project Scoring of Historical Operations)** for details of this analysis). Going forward, we expect customer outage mitigation/resilience use case to be a primary driver of the future growth in distributed storage installations. The ability of these installations to stack grid benefits with customer resilience value is yet to be tested. The barriers are not technological. As discussed under **Chapter 3 (Moving Forward)** of the main report, it will be essential to bring stronger grid signals to customers and improve the analytical foundation for resilience-related investments.

Our study of future energy storage procurement in California (**Attachment B (Cost-Effectiveness of Future Procurement)**) investigated the need for and value of longer-duration storage (8–10 hours) over the next decade. The study found that creating a real option to add more duration to storage projects at the initial design and procurement phases could support a timely and cost-effective transition for a portfolio with longer duration storage. There are inherent uncertainties with future RA capacity needs and resource contributions, and procurement efforts may have to pivot quickly and adjust target portfolios based on unexpected changes and new information. Battery storage systems and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost. In our review of the actual grid-scale installations, we see that some developers are already taking advantage of this modularity in their market participation and development strategies by building the MW capacity first and increasing duration later when the need arises.

The 250 MW Gateway energy storage project is a great example for illustrating benefits of modular development when stacking multiple values. The project was initially deployed as a 1-hour battery in August 2020 and kept its duration at that level for almost a year, before adding more duration to meet its capacity obligations under multiple RA contracts starting in Q3 of 2021. During its first year of operations, the project remained primarily as a merchant resource participating in the CAISO's energy and ancillary services markets, and relying on wholesale market revenues. The project later increased its duration to provide RA capacity to various LSEs including PG&E, SCE, Direct Energy, and possibly other smaller entities. By the end of 2021, the project had an NQC of 175 MW, which implies 700 MWh energy capacity and 2.8 hours of duration. The project secured another RA contract with SCE for 75 MW starting in August 2023, and to meet that need, project's duration will likely reach 4 hours by the next year.

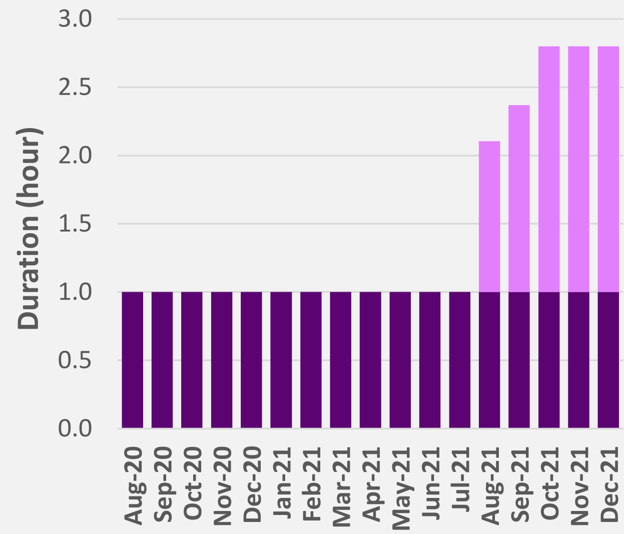


Figure 6: Estimated duration of the Gateway energy storage project over time.

*Values approximated based on monthly NQC of the project

Pumped storage hydroelectric technology can offer a unique way of value stacking across multiple sectors. Lake Hodges, which is the only pumped storage project in our historical study, began operations in 2012. The project was built partly to provide up to 40 MW of on-demand electric capacity in San Diego. But the primary driver of the project was to store water for emergency use for the region. This multiple use case allowed San Diego County Water Authority (SDCWA) offer the project's electricity-related attributes at a price beneficial for the SDG&E ratepayers. The project not only provided local RA capacity in the CAISO-designated San Diego-Imperial Valley area, but it also achieved one of the top energy time-shift values across all energy storage resources analyzed in our study. Overall, Lake Hodges is among the best performing resources in terms of 2017–2021 electricity ratepayer benefit/cost ratio and overall scoring.

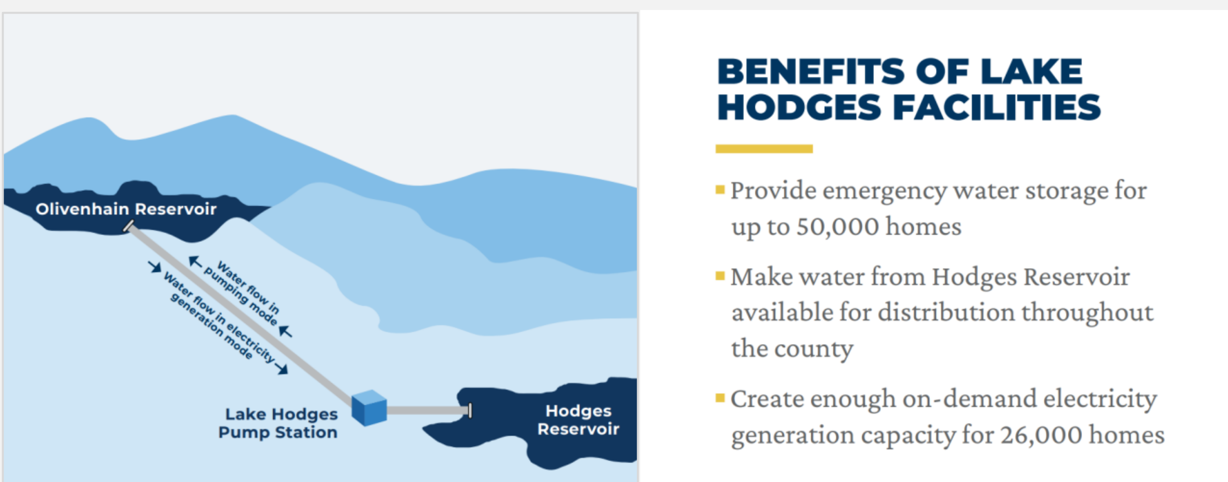


Figure 7: Overview of the Lake Hodges pumped storage project in San Diego.

Source: San Diego County Water Authority

Outside of California, the West Kaua'i Energy Project (WKEP) in Hawai'i is on track to become the nation's first solar + pumped hydro project. Kaua'i Island Utility Cooperative signed a long-term PPA for the project, which is expected to serve 25% of the island's load. When completed, the WKEP will be an integrated renewable energy, storage, and irrigation project with two segments:

- Upper segment will include a traditional hydroelectric facility to generate electricity (up to 4 MW) and provide water for irrigation needed to support agricultural activities;
- Lower segment will include a 20 MW of pumped storage hydroelectric facility, a 35 MW solar PV, and a 35 MW/70MWh battery. The battery will be DC-coupled with the solar array to firm solar output and harvest otherwise clipped energy.

The project is expected have a combined 240 MWh (12 hours) of energy storage capability to be used for shifting solar energy to peak periods. Also, the project's development efforts will include rehabilitation of existing reservoirs for public use and recreational activities.

In recent years, industry has increasingly focused on value stacking related to electricity-related services, driven by many different and creative ways batteries can be utilized in the grid. While this is important for cost-effective clean energy transition, looking at value stacking opportunities outside of electric sector is equally important when pumped storage investments are considered. For example, recent ANL report prepared for the DOE's HydroWIRES initiative describe a methodology to quantify non-energy benefits of pumped storage projects, including flood control, recreation, water supply, environmental benefits during droughts, and irrigation.

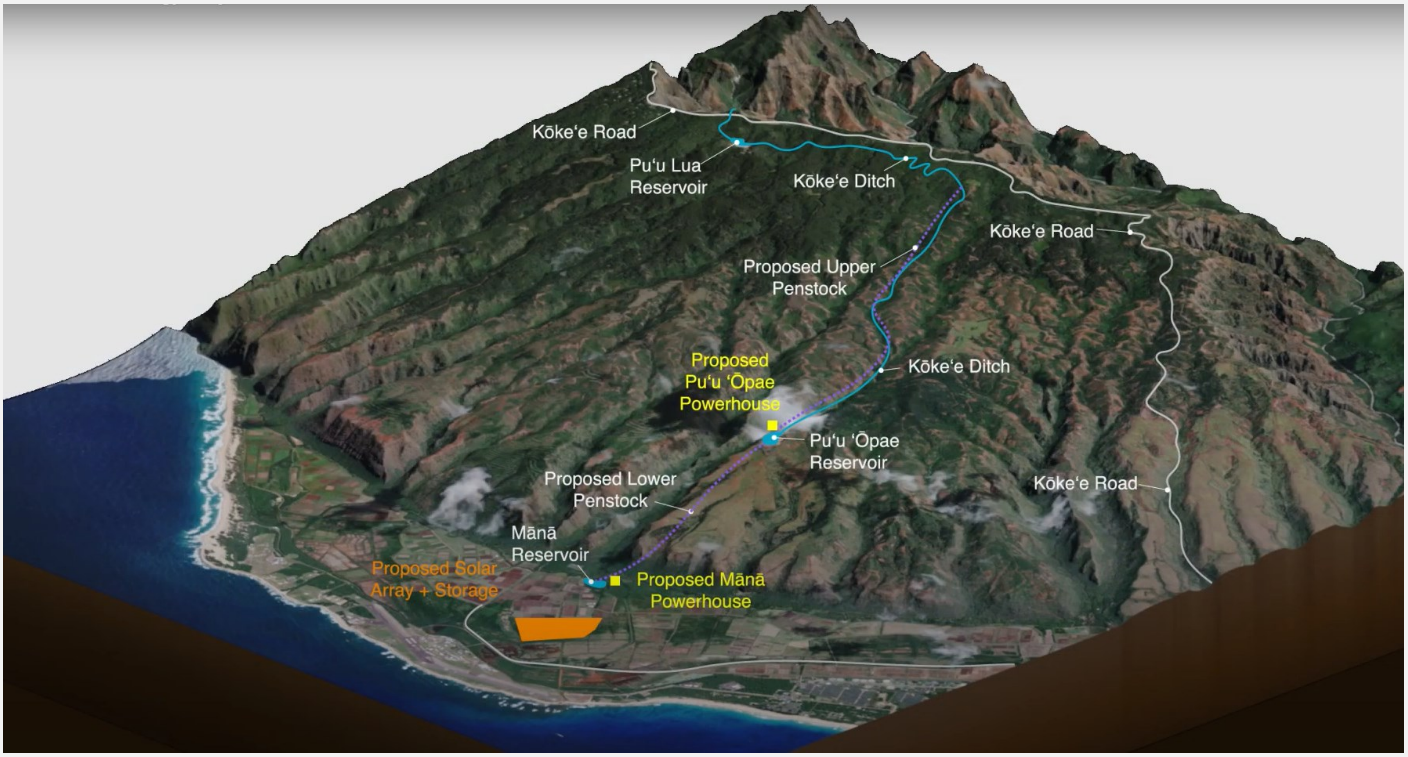


Figure 8: Overview of the proposed West Kaua'i Energy Project in Hawai'i.

Source: Kaua'i Island Utility Cooperative

Hybrid Storage Resources

There has been a growing interest in developing energy storage resources paired with renewables, especially solar. This is a trend we see in most regions, but especially in California and rest of the West. Even though most of California's operational storage capacity as of early 2021 were from standalone projects, solar + storage accounts for approximately half of new energy storage capacity currently under development in California as shown in Figure 9 above. Procurement of grid-scale energy storage projects connected directly to the transmission system is split evenly between standalone vs. hybrid resources, while procurement of distribution-connected storage is primarily from standalone resources. Within customer-sited storage resources, almost all residential installations are batteries that are paired with rooftop solar. On the other hand, about one-fourth of nonresidential projects are paired with solar, most of which are installed at schools.

Our study of actual storage operations during 2017–2021 considered projects procured by California LSEs under the CPUC jurisdiction that reached commercial operations by April 2021 for sufficient history to analyze. At the grid-scale, our historical study includes only a few hybrid projects, in which short-duration batteries (< 0.5 hours) were integrated with gas turbines to provide the fast response needed for spinning reserves in CAISO ancillary services market. All large solar + storage projects were still under development as of April 2021. Given that, our discussion of grid-scale hybrid resources is primarily research based. We also summarize relevant findings from our peaker replacement study, which is described in detail in **Attachment C (Cost-Effectiveness of Peaker Replacement)** of this report.

At the customer level, we analyzed actual operations of over 650 nonresidential SGIP-funded storage projects with a total capacity of 205 MW. About half of these installations (~35% of storage capacity) were paired with solar PV. We highlight key differences across project clusters with different levels of storage attachment rates.

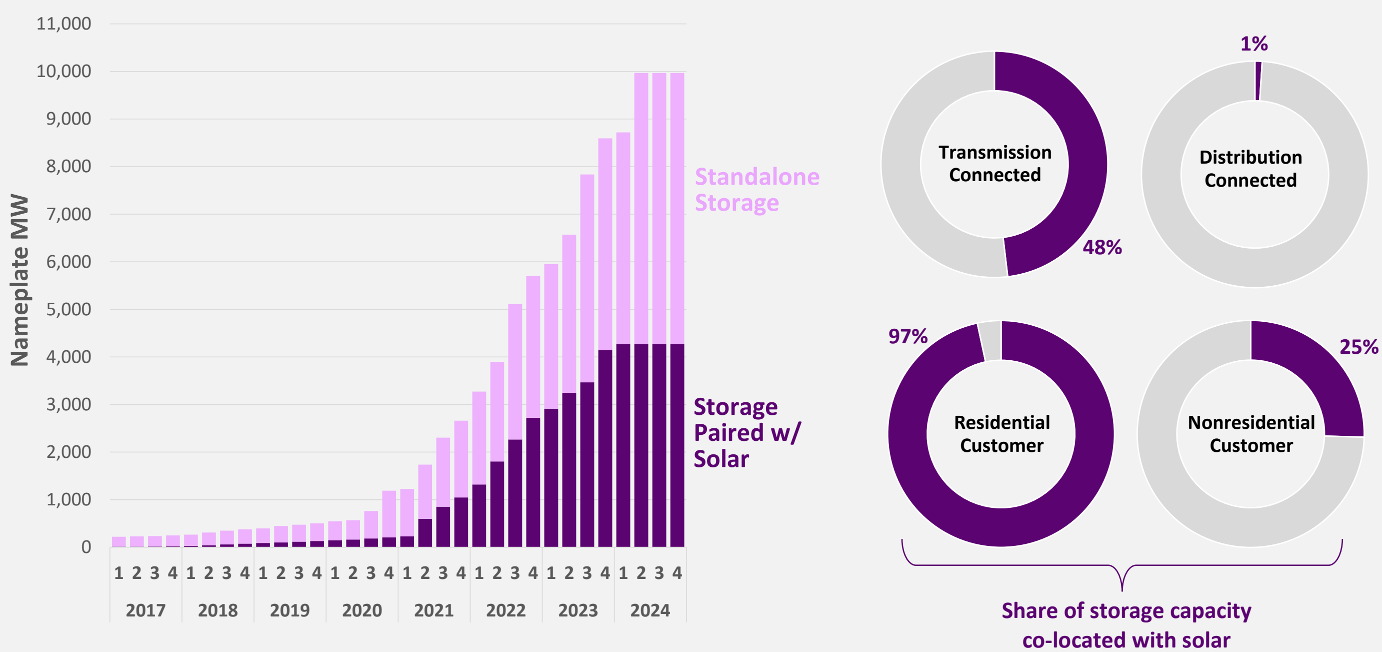


Figure 9: Standalone and co-located storage procurement in California as of summer 2022.

Relative to standalone development, co-located or hybrid projects can provide cost synergies and get additional tax incentives. A key benefit is the shared equipment and infrastructure that can help reduce equipment, interconnection, and permitting costs. A recent NREL report shows installed cost of grid-scale hybrid systems can be 6–7% lower than cost of solar and storage sited separately, which is illustrated in Figure 10 on the right.

While this cost difference may not seem large, it can be relatively important when the economics of incremental energy storage investments are considered in resource planning studies. In the example shown, marginal cost of adding storage would be around 12–14% lower under a hybrid configuration, compared to standalone projects (same $ delta, but divided by storage cost rather than total solar + storage cost).

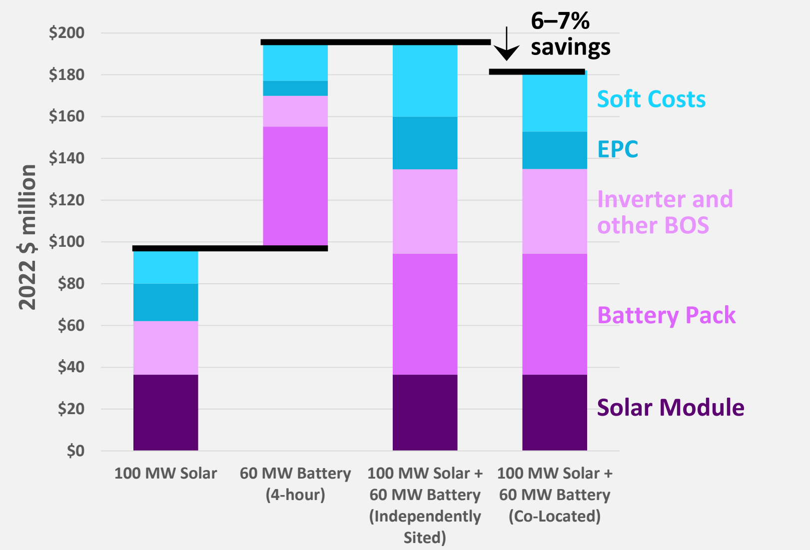


Figure 10: Cost savings of grid-scale hybrid systems relative to standalone development.

Based on data from (Ramasamy et al. 2021). Costs converted to 2022$ using GDP deflator and aggregated to broader categories.

Until recently, only energy storage co-located with solar would get federal investment tax credit (ITC) that could offset 26–30% of costs. The Inflation Reduction Act of 2022 extended the ITC to also standalone storage for up to 30% of their installed cost, which leveled the playing field for storage. If DC-coupled, co-locating solar and storage can also capture the solar energy that would otherwise be clipped and reduce the overall roundtrip energy losses. An important consideration is the interconnection process. Adding storage to an existing facility can reduce the cost and timeline for interconnection with the grid.

Taking advantage of co-location benefits also creates more restrictive operational constraints for storage, which reduces its value and needs to be weighed against benefits. For example, a recent LBNL study demonstrates that the lost value (called "coupling penalty" in the study) relative to independently-sited systems can offset most of the co-location benefits described above.

Until recently, a major constraint was the restrictions on grid charging to qualify for tax credits, but with the extension of tax credits to also standalone energy storage, this should no longer be an issue for new projects.

To realize cost synergies described above, co-located projects often share equipment such as inverters and keep their interconnection limit below the aggregate nameplate capacity of individual resources. This restricts the amount of energy that can be discharged by storage simultaneously when there is solar generation. Implications of this depends highly on solar penetration and can vary by region. For example, in Texas, where high-priced hours in the energy market often occur during daytime, limiting total energy from solar plus storage can be detrimental to economics of hybrid projects. On the other hand, in California, where storing solar output in the day and sending it to the grid later in the evening tends to be optimal, the lost value due to shared inverter or interconnection limit would be small. Total capacity of co-located or hybrid resources is capped at the interconnection limit, which may reduce their contribution towards RA needs. For solar + storage in California, this would have a limited impact. In the latest IRP studies, marginal ELCC for near-term resources is estimated at around 10% for solar and 90% for 4-hour battery. Solar + storage with an interconnection sized to solar MW would have the same NQC as resources sited and interconnected separately.

Co-location may potentially prevent storage resources to be placed at highest-value locations of the grid. For example, the same [LBNL study](#) mentioned above estimated that annual value of storage projects in CAISO at selected high-volatility nodes (top 20 percentile) is around $30/kW-year higher on average than the value of storage at solar nodes under 2012–2019 prices. While the exact value differential varies by the nodes selected and can change going forward, the overall magnitude of this result suggests that lost value due to siting constraints could offset a large portion of the cost savings from pairing storage with solar.

As a part of our study, we evaluated cost effectiveness of replacing the state's gas peakers with storage. For that evaluation, we analyzed historical operations of around 100 individual peakers under challenging system conditions of 2020. We found replacing peakers' output with standalone storage would require either significantly overbuilding storage MW or installing long-duration storage at a relatively high cost. If the site or local area has sufficient land that can be used to install solar capacity, developing storage paired with solar can reduce the need for overbuilding MW and/or duration, and result in lower net costs. Figure 11 shows the distribution of estimated net cost of replacing peaker capacity under various storage configurations. See **Attachment C (Cost-Effectiveness of Peaker Replacement)** of our report for study details and discussion of alternative storage configurations and scenarios analyzed.

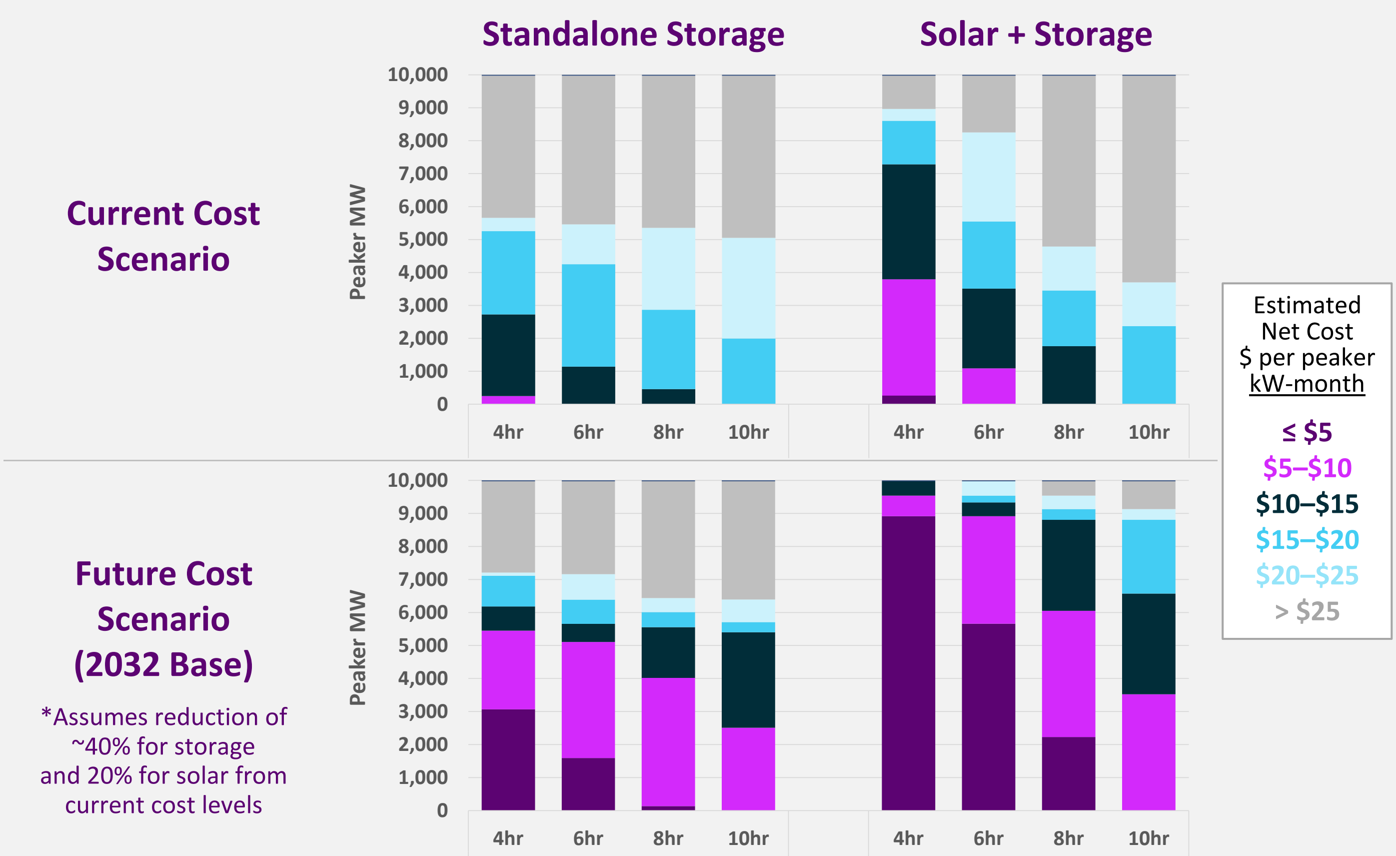
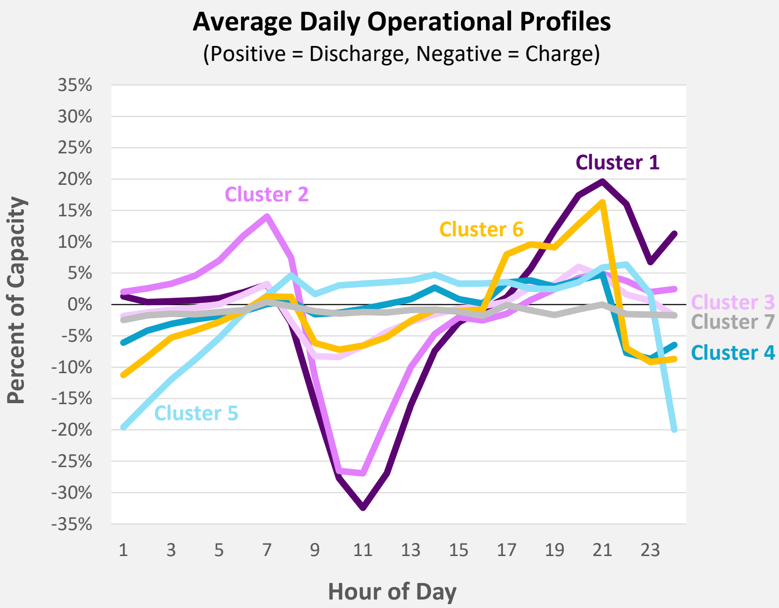


Figure 11: Distribution of peaker replacement net costs with no limitations on grid interconnection (2022 $).

* 4-hour storage configurations need to significantly oversize their MW (relative to peaker capacity) to meet total energy required during extended reliability events. Storage with longer duration needs less oversizing as it can provide same MWh with fewer MWs. See **Attachment C (Cost-Effectiveness of Peaker Replacement)** for study details and discussion of alternative storage configurations analyzed.

For non-residential SGIP-funded projects, we conducted an analysis to group 654 resources into 7 clusters based on each installation's interval-level operating behavior during 2017–2021. Projects in clusters 1–3 have operating patterns synergistic with the grid: they charge during the day and discharge during the grid's morning and evening ramps into and out of solar generation periods. These resources are mostly schools and colleges, and they have a high solar attachment rate. Projects in clusters 4–7 are mostly standalone batteries, and their use cases focus on demand charge management and does not align well with bulk grid needs. See **Attachment A (Benefit/Cost and Project Scoring of Historical Operations)** for details of our benefit/cost analysis and project scoring, including comparisons across SGIP clusters and grid-scale storage.



Cluster ID	Project Count (# of projects)	Energy Storage Capacity (MW)	Average Roundtrip Efficiency (%)	Average Daily Discharge (hours/day)
1	96	17.6	78%	1.3
2	56	9.1	75%	1.1
3	82	23.6	75%	0.6
4	164	60.6	77%	0.8
5	22	9.7	83%	1.1
6	102	41.6	77%	1.2
7	132	43.0	65%	0.6
Total	**654**	**205.3**	**74%**	**0.9**

Cluster 1
- Midday Charge
- Evening Peak Discharge

Cluster 2
- Midday Charge
- Morning Discharge

Cluster 3
- Midday Charge
- Morning+Evening Discharge
- Low Utilization

Cluster 4
- Night Charge
- Distributed Discharge
- Low Utilization

Cluster 5
- Extended Night Charge
- Distributed Discharge

Cluster 6
- Midday+Night Charge
- Evening Peak Discharge

Cluster 7
- No apparent charge/discharge pattern
- Low Utilization
- Low Efficiency

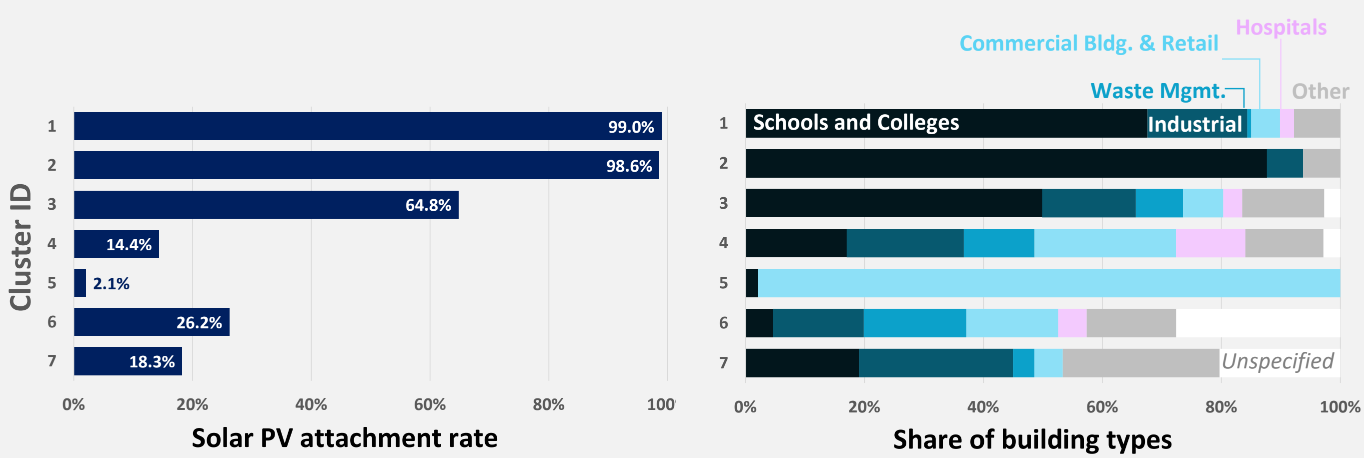


Figure 12: Observed characteristics of non-residential SGIP-funded installations (654 installations in 7 clusters).

Alternative Technologies and Long-Duration Storage

While lithium-ion batteries have dominated the recent energy storage development in California, rest of the U.S, and world-wide, there are several other energy storage technologies that can also provide grid services and benefits. Broadly, energy storage technologies that can support electric grids fall under 4 categories:

1. **Electrochemical energy storage** involves batteries using various chemistries to charge and discharge electricity through electrochemical reactions (oxidation and reduction) on two separate electrodes that are electrically connected. E.g., Lithium-ion, sodium-sulfur, redox-flow, and metal-air batteries.
2. **Chemical energy storage** systems store electricity in chemical bonds. E.g., Hydrogen produced by electricity used to split water molecules (electrolysis), which can be stored in caverns or pipeline, and later sent to combustion turbines or fuel cells to generate electricity.
3. **Mechanical energy storage** converts electricity into kinetic or potential energy, and later reverses the process to recover stored energy. E.g., Pumped storage, flywheels, compressed air energy storage, liquid aid energy storage.
4. **Thermal energy storage** systems store electricity as thermal energy by heating or cooling a material, and keep it insulated until energy is needed. Thermal energy can later be converted back to electricity or used directly in heating and cooling applications. E.g., Molten salt TES systems coupled with concentrated solar power plants, ice or chilled water TES systems used for commercial or residential cooling.

Most of the grid-scale energy storage systems procured in California today have a 4-hour duration, which means they can continuously discharge up to 4 hours at full capacity. This is a result of the high initial value of 4-hour storage in addressing current system reliability needs and lithium-ion batteries dominated the market due to their lower costs. But going forward, as California continues to decarbonize its electric system by deploying more clean energy resources, system flexibility needs and role of storage will evolve and longer duration storage systems will be needed.

Batteries are highly modular and there are no technical barriers to configuring them with longer durations. But most of batteries' installed cost is from energy-related costs such as cost of battery pack, which increases with duration. For instance, a battery with 8-hour duration costs around 1.8 times the cost of a 4-hour battery with the same nameplate MW. This cost structure makes it difficult to scale lithium-ion batteries cost effectively at longer durations above a certain level. Figure 13 compares cost projections for selected long-duration energy storage technologies based on a recent E3 study, which illustrates several emerging technologies have the potential to support multi-day or seasonal storage needs at a much lower cost than lithium-ion battery as California gets closer to 100% clean energy target.

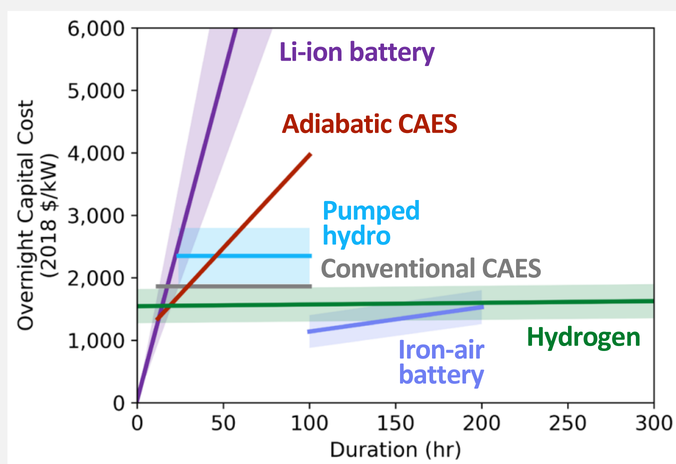


Figure 13: Long-duration storage cost projections for 2045.

(Go, Knapstein et al. 2022)

Future cost trajectories of these long-duration energy storage technologies are highly uncertain, as many of them are still in R&D or pilot phase, or they are subject to geological and site limitations. However, there have been major industry-wide efforts in the past couple of years to improve economic viability of long-duration storage technologies.

Some of the recent key activities are summarized below:

- In July 2021, the CPUC issued its midterm reliability decision D.21-06-035 ordering LSEs to procure 11.5 GW of capacity by 2026, with a 1 GW carve-out for long-duration storage.
- As a part of the 2022-2023 California spending plan, the state allocated $380 million of its budget for CEC to create a new program that provides financial incentives for emerging long-duration storage technologies, and $100 million to advance green hydrogen projects.
- At the federal level, in early 2020, DOE announced Energy Storage Grand Challenge program to accelerate development, commercialization, and utilization of next-generation energy storage technologies. Later in 2021, DOE also launched the Long Duration Storage Shot initiative aiming to reduce cost of grid-scale storage by 90% to a levelized cost of 5 cents/kWh in the next decade, for systems with 10+ hours of duration.
- Through the Bipartisan Infrastructure Law, which passed in November 2021, DOE is preparing to roll out the Long Duration Energy Storage for Everyone, Everywhere initiative with a $505 million of funding to support demonstration and pilot programs that can validate grid-scale long-duration storage technologies and address institutional barriers to technology adoption.

A key performance metric for storage resources is their roundtrip efficiency, which reflects the share of the energy used for charging that is retrieved during discharge. Lithium-ion batteries have a relatively high roundtrip efficiency in the range of 80–90% when they operate regularly, and they have a calendar life of 10–15 years.

Figure 14 compares efficiency and life of lithium-ion batteries against other storage technologies based on a PNNL report prepared for the DOE's ESGC effort. Long-duration storage is typically less efficient than lithium-ion batteries, which leads to higher charging costs. Redox-flow and zinc-based batteries have roundtrip efficiencies in the 65–70% range. Efficiency of thermal storage and conventional CAES systems is around 50% although adiabatic CAES technology can achieve a higher efficiency (55–65%) by capturing the heat during compression and using it later according to recent MIT study. Pumped storage hydro projects typically have 65–80% of roundtrip efficiency, and gravity-based storage systems at early pilot stages of development can potentially reach up to 80–90% of efficiency. Hydrogen storage (power-to-H_2-to-power) systems achieve a roundtrip efficiency of 30–40% after losses incurred during electrolysis, storage, and power generation.

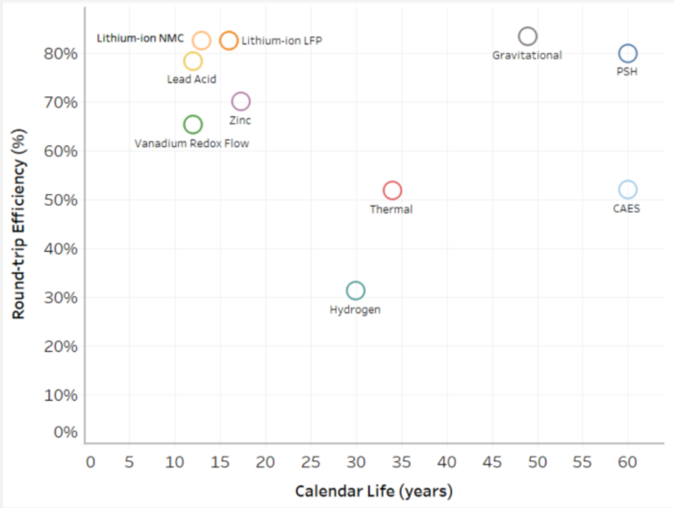


Figure 14: Long-duration storage efficiency and calendar life.

(Viswanathan et al. 2022)

Meeting deep decarbonization goals in California will require significant new solar and wind buildout relative to today's levels, which will inevitably create multiweek or seasonal mismatches between renewable energy supply and electricity demand. A major challenge will be to overcome high "charging" costs associated with very low efficiency levels of technologies that can provide such long durations of storage. For example, hydrogen storage has the potential to deliver fully dispatchable and highly flexible clean energy. But at 30–40% of roundtrip efficiency, it uses around 3 MWh for every MWh sent back to grid, which limits incremental benefits relative to overbuilding renewables and curtailing their output when there is excess supply.

The economic viability of very long-duration storage will partly depend on system needs for such durations of storage at deeper decarbonization levels, and how much of these needs can be addressed by resource and load diversification, and at what cost. The CEC recently adopted an ambitious 25 GW planning goal for offshore wind by 2045. A renewable portfolio with this much offshore wind would be more diverse and likely need less long-duration storage, relative to a solar-centric portfolio. Similarly, increased regional coordination and market development across Western states can better utilize the geographic diversity of both loads and resources, and accordingly reduce the need for long-duration storage. In the case of hydrogen storage, the economics also largely depend on future cost of green hydrogen production driven by economy-wide use cases for hydrogen. As discussed in an MIT study, hydrogen produced by electrolysis can be used directly as a fuel to support decarbonization of the industrial sector, which in turn can improve the utilization of electrolyzers and reduce per unit cost of hydrogen.

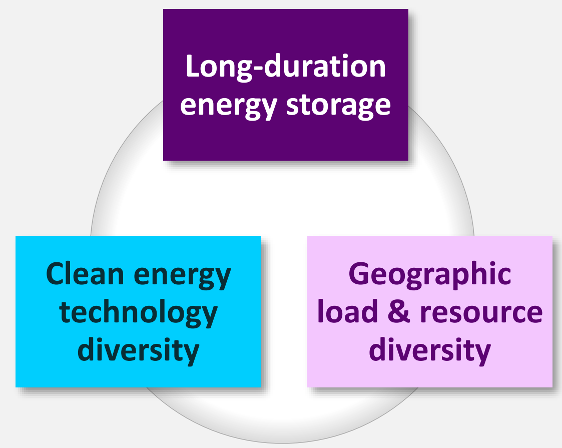


Figure 15: Pillars of deep decarbonization in the electric sector.

Most energy storage resources included in the CPUC Energy Storage Procurement Study's historical analysis utilize lithium-ion battery technology, but the set of resources analyzed includes pumped storage hydro, thermal energy storage, and alternative battery chemistries with durations up to 7 hours. See **Attachment A (Benefit/Cost and Project Scoring of Historical Operations)** of our report for details on our approach, assumptions, and key results of the benefit-cost analysis and project scoring.

Our evaluation also included two separate studies considering the role of longer durations (up to 10 hours) over the next decade:

- In the first study, we analyzed future energy storage procurement in California and found that the "cross-over" point for cost-effective longer-duration storage (8–10 hours) is in sight over the next 5–10 years driven by resource adequacy and reliability needs and value. See **Attachment B (Cost-Effectiveness of Future Procurement)** of our report for details of this study.
- In the second study, we screened the cost-effectiveness of around 100 individual gas peaker units' replacement with energy storage under the challenging system conditions observed in 2020 and found that replacing peakers' output with energy storage would require either significantly overbuilding storage MW or installing longer-duration storage. The study investigated economic trade-offs among various storage configurations, with durations of 4–10 hours and considering standalone development vs. pairing with solar. See **Attachment C (Cost-Effectiveness of Peaker Replacement)** of our report for details of this study.

As California approaches to carbon neutrality by 2045, the storage characteristics needed will evolve and shift towards durations above 10 hours. Through EPIC grants, the CEC has funded two parallel research efforts to develop a better understanding of the role and value of long-duration energy storage to support a zero-carbon future, with E3 and UC Merced leading these ongoing efforts.

Figure 16 below include preliminary results from the E3 study on value of long-duration storage, which shows how long-duration storage beyond 10 hours impact the future capacity mix and total portfolio costs by 2045. The study includes two core scenarios:

- The Reference Scenario builds on the CPUC's IRP Reference System Plan (RSP) and it assumes 100% of *retail sales* will be served by clean resources in 2045. In this scenario, the load associated with T&D and storage losses are not required to be served by clean resources. Accordingly, some of the gas plants are kept for reliability and they can run minimally.
- The SB100+ scenario has a more stringent target assuming 100% of *all loads* (including losses) are served by clean resources. Accordingly, all existing gas plants are forced to retire or retrofitted to use green hydrogen.

E3's initial results show vert limited amounts of long-duration storage built under the Reference Scenario, as the clean energy target less strict (100% of retail sales corresponds to around 75% of all loads served) and system needs can be sufficiently addressed by energy storage with up to 6 hours of duration. In the SB 100+ Scenario, however, the stringent clean energy target leads to substantial amount of long-duration storage, including multi-day and seasonal storage (shown in pink, yellow, and dark blue on the left chart). The study finds that achieving SB 100+ target in 2045 without long-duration storage would increase total portfolio resource costs significantly relative to the Reference Scenario, and availability of long-duration storage technologies can help avoid a large share of the incremental costs related to more stringent clean energy target (left chart).

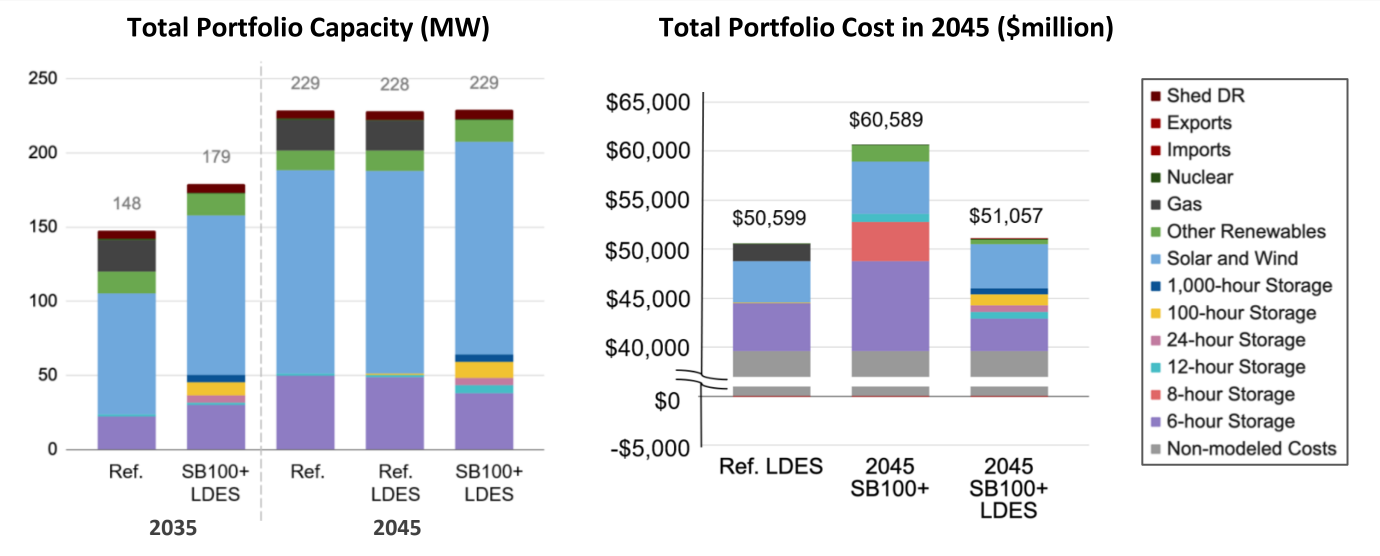


Figure 16: Impact of long-duration energy storage (LDES) on California's future resource portfolios and portfolio costs.

(Go, Knapstein et al. 2022)

Transmission Deferral Use Cases

The national discussion of transmission investment deferral indicates that energy storage can help to defer investments in the transmission system through two distinct use cases:

- In the first use case, energy storage acts as an energy resource, alters the load and generation balance in an area to relieve transmission bottlenecks (and/or provide ancillary services), and thus replaces transmission solutions that could do the same. A variety of generation and load resources could theoretically serve the same function.
- In the second use case, storage is used by the system operator like a controllable transmission asset. The resource could be operated, for example, to redirect power flow and prevent overloads on specific circuits. Since these use cases are deployed on either side of the legal and functional separation of generation and transmission (respectively), they are distinguished by who operates the energy storage resource, to what objective, and how the resource is paid for.

In California, energy storage has achieved scalability to help relieve transmission bottlenecks under the first use case. A total of 909 MW/3,579 MWh of energy storage resources operating in the 2017–2021 study period was procured to meet various local capacity needs driven by major generation retirements (i.e., once-through cooling, San Onofre nuclear generators, Moss Landing generators) and issues related to Aliso Canyon. Since these energy storage resources were procured under generation RA capacity procurement, where the resource alternative is a generation or load resource, we allocate these services and benefits towards local RA capacity rather than transmission deferral.

As part of the CAISO's Transmission Planning Process (TPP), generators and energy storage are considered directly as alternatives to transmission investments. In 2017-2018 TPP, the CAISO recommended approval a 10 MW of PG&E-owned energy storage project as part of a combined transmission/generation solution to prevent overloads in Oakland after the planned retirement of a gas peaker. The selected project under the Oakland Clean Energy Initiative (OCEI) had an estimated cost of $102 million. CAISO considered 3 other proposals including a new local generator, upgrades to existing transmission, and a new transmission line, with estimated costs ranging from $367 million to $574 million, well above the cost of the OCEI project. But the development of the project has apparently been hampered by changes in scope identified in subsequent TPPs and it is not clear if or when the project will be developed. Under the 2020–2021 TPP, CAISO identified two new 4-hour energy storage resources in the PG&E system as cost-effective solutions to mitigate local reliability needs in the Kern-Lament and Mesa 115 kV systems. As a result, two of the previously-approved transmission upgrades were put on hold pending procurement of storage resources at these locations.

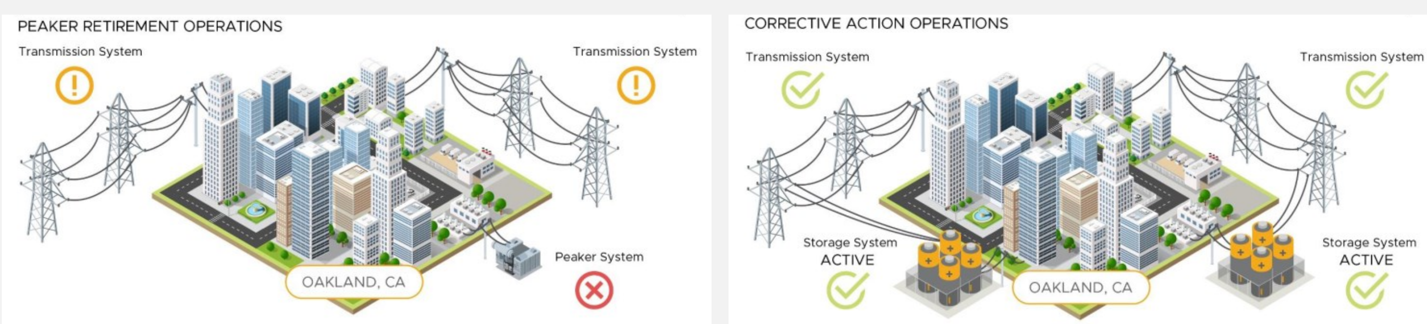


Figure 17: Illustration of how energy storage can address transmission needs driven by peaker retirements.

(Twitchell et al. 2022)

The second transmission deferral use case—storage operated as a controllable transmission asset—is still in a pilot and demonstration phase nationally with California as a leader. In 2017–2018 TPP, the CAISO approved a 7 MW/28 MWh energy storage projects as a cost-effective solution to manage a transmission contingency that would interrupt service to the town of Dinuba. PG&E conducted a competitive solicitation in 2019 and selected a winning bidder. However, when the transmission need increased to 12 MW in a later TPP, PG&E cited challenges with procurement and contracting. Assessment of transmission needs is a dynamic process and apparently in need of (a) a clearer understanding of how a specific need could fluctuate over time, and (b) procurement and contracting practices that better take advantage of the modularity of energy storage system and site designs.

A third use case—"dual-use" energy storage combining the two use cases above—presents major legal and policy challenges in that it envisions the operations of a single energy resource being split between generation and transmission functions. This use case is still in early development phase under initiatives led by the CAISO and the Midcontinent ISO (MISO). In 2018, CAISO launched the storage as transmission asset (SATA) initiative to explore how to enable energy storage projects provide cost-of-service based transmission services, while also participating in the wholesale electricity markets. This initiative is suspended until the storage resources' market participation model is further refined under the ongoing energy storage and resource adequacy initiatives. In the 2021–2022 transmission plan, CAISO noted that the SATA initiative is expected to remain on hold indefinitely based on recent developments, and the ISO will further explore market-based energy storage to meet transmission needs before shifting focus back to transmission asset treatment.

Other RTOs are also pursuing options for energy storage projects to function as transmission assets. In August 2020, FERC has approved MISO's proposal for storage to be treated like a "transmission only" asset (SATOA) with cost-based rate recovery. In the order, FERC highlighted that MISO's proposed tariff required that a storage facility qualifying as a SATOA must demonstrate it can address the transmission issue only as an asset under MISO's functional control, and not as a resource that participates in the MISO's markets. In its 2019 transmission expansion plan (MTEP19) MISO identified one SATOA project to address the reliability concerns in the Waupaca area of Wisconsin at a lower cost than the other wires and non-wires alternatives studied. The approved 2.5 MW/5 MWh battery project was initially planned to be in-service by December 2021, but it is now expected to be online in early 2023 according to ATC, the developer of the project. MISO has not identified any other SATOA projects under more recent transmission planning cycles.

Key Observations

There has been a significant effort in the industry, especially in California, over the past decade to achieve full economic potential of energy storage resources by unlocking access to a variety of value streams.

Historically, transmission- and distribution-connected storage resources participating in the CAISO wholesale markets did relatively well in stacking of energy, ancillary services, and RA capacity value.

Utility-owned distribution-connected resources developed for microgrid and other distribution-related services provided very little value overall, relative to their costs.

Customer outage mitigation needs, awareness, and value increased significantly after 2019 PSPS events, but lack of customer impact data makes it difficult to quantify resilience benefits of storage and the ability of distributed resources to stack grid benefits with customer resilience value is yet to be tested.

Storage served at scale as generators within local transmission-constrained parts of the grid, but no resource operated specifically as a transmission asset.

Developers utilized the modularity of grid-scale battery storage systems in their construction and market participation strategies to align services provided and storage capabilities needed over time, to maximize storage value.

Pumped storage hydroelectric technology can offer a unique way of value stacking across multiple sectors with non-energy benefits such as flood control, recreation, water supply, environmental benefits during droughts, and irrigation.

There has been a growing interest in California for developing energy storage resources paired with renewables, especially solar. Relative to standalone development, co-located or hybrid projects can provide cost synergies, but benefits need to be weighed against lost value due to more restrictive operational and siting constraints.

As California continues to decarbonize its electric system by deploying more clean energy resources, system flexibility needs and role of storage will evolve and longer duration storage systems will be needed. Timing and amount of the long-duration storage needs depend on the stringency of clean energy targets and extent of alternative measures taken, such as technology diversification (e.g., offshore wind) and increased regional coordination and market development across Western states.

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ATTACHMENT F: SAFETY BEST PRACTICES[1]

Due to the market readiness and scalability, installations of stationary lithium-ion battery energy storage systems are ramping up quickly to play a major role in California's clean energy portfolio. California's dependence on this technology is expected to grow from just over 2,500 MW at the end of 2021 to potentially tens of gigawatts by 2045. As installations accelerate, so does the urgency to address safety.

Over the course of one year, from September 2021 through September 2022, safety events occurred at each of the three separate (and distinct) grid-scale battery systems installed on California's Moss Landing site. These events, plus the industry's broader experience with safety events over the last decade, underscore the need to manage the risks stemming from hazardous materials in batteries and the unique properties of thermal runaway. For the safety and reliability of California's electricity system the CPUC and other stakeholders will need to continuously monitor and guide safe designs, development, maintenance, and operations of stationary batteries according to best practices.

Energy storage safety is a risk management issue—and a complex one. Large-scale battery systems in themselves are complex with many potential points of failure and potential situations that could lead to harm from fire, thermal runaway, or explosion. How these systems interface with the local environment is a challenge. Effective management and mitigation of these risks also require communication and coordination channels that are a challenge to develop given the number and scope of parties involved.

Historically, major safety-related events involved about 2% of large-scale battery storage installations in the U.S., occurred within 1–2 years of installation, and destroyed about 1–2% of its capacity. Based on this very limited information, for every 10 GW of new battery storage installed in California it would be reasonable to expect a handful of safety-related events at new sites, affecting operations of installations potentially several hundred MW in size. This outlook may change as we observe lithium-ion batteries age and as the industry evolves towards different technologies.

The observed range of outcomes of actual safety-related events provide opportunities to learn and improve battery technology. These events help us to better understand the risk profile of battery storage investments and the potential harm to people, communities, the environment, and electricity supply when risks are poorly understood, under-mitigated, or under-managed. Investigations and assessments of these events have driven and shaped the industry's efforts towards improving safety best practices.

This attachment aims to provide the most current understanding of safety best practices for stationary energy storage systems with a focus on lithium-ion batteries. We draw from industry studies, lessons learned from specific safety-related events, and expert opinion to summarize safety risks and remedies associated these installations. Although this attachment (and most of the industry's codes and standards we reference) focuses on lithium-ion batteries, many of the best practices we outline are translatable to other energy storage technologies as they reach commercial scalability.

We address three major questions:

- **What are the key safety issues**, considering actual events and types of safety impacts we observe?
- **What are current best practices**, including perspectives of regulators, utilities, technical experts, and energy storage developers?
- **What are the remaining concerns and next steps**?

CONTENTS

Definition of Safety

We define **safety risk** as the possibility of the following undesirable outcomes of energy storage installation and operations: harm to humans, harm to surrounding communities, and/or harm to the environment. These outcomes may have secondary negative impacts in the form of destruction of infrastructure and property, associated financial losses, and/or reduced reliability of electricity supply.

It follows that **safety** is our ability to mitigate and manage those defined risks of harm. For the purposes of this paper, energy storage equipment, hardware, and software safety reflect the ability of the installation, as it is designed and built, to mitigate and manage system failures that lead to undesirable outcomes. The effectiveness of safe operations, procedures, and processes depend upon the safety of a system's components and design. Safe operations, procedures, and processes also refer to additional actions involved parties take to further reduce risks over the life of an energy storage installation.

Specific safety thresholds, defining a "safe" versus "unsafe" installation, must be established by the regulatory authority as the acceptable amount of residual risk after mitigation and management efforts are in place. Generally, we find that public reactions and the evolution of safety codes and standards imply that any degree of direct harm to humans, the environment, or surrounding communities is unacceptable and should be avoided. A "safe" failure, for example, results in no harm to humans, communities, nor the environment—although it may result in complete destruction of the energy storage system. From a regulatory perspective, safety thresholds must also be in harmony with other regulatory objectives of reliable and resilient electricity supply, avoiding the harm of fossil fuel-based energy investments, and cost-effectiveness. <u>So, even a "safe" failure, as defined by safety codes and standards, is undesirable from an electricity regulator's perspective unless damage to the storage system and other infrastructure is minimal and recovery is within an acceptable timeframe.</u>

Best practices in safety are clearer and more effective if they are determined with these specific safety objectives and risk tolerances in mind. In this paper we do not speak for the CPUC on their safety objectives and risk tolerances. However, we do make the general assumption of an extremely low tolerance for any direct harm to humans, the environment, or surrounding communities. We also assume some desire to (a) synergize with efforts to support the reliability and resiliency of electricity supply, and (b) consider impacts on ratepayer cost-effectiveness.

Fire Versus Thermal Runaway

The main vehicles of harm from an energy storage system are uncontrolled fire and thermal runaway.

In our research and in various accounts of actual safety-related events we find a strong theme of confusion over the characteristics of thermal runaway versus fire. Specifically, we observe that insufficient knowledge transfer and coordination among the technical community, utilities, emergency responders, and regulators—on how thermal runaway is distinct as a chemical process, how to prevent it, and what to do if it starts—significantly contributes to undermanaged safety risk.

A few important characteristics of thermal runaway are as follows:

- Thermal runaway is a chemical reaction **distinct from fire** but with similar characteristics.
- Thermal runaway is similar to fire in that it is preceded by a temperature spike (which may or may not be due to a short circuit) and it releases significant heat and pressure once initiated.

- Lithium-ion battery cells in thermal runaway rupture and release large volumes of **toxic and flammable gases** including hydrogen fluoride. If the released gases come in contact with water they produce environmental contaminants including hydrofluoric acid (CDC n.d.).
- Thermal runaway is similar to fire in that it can lead to a catastrophic chain reaction, or **thermal runaway propagation**, if it is able to heat nearby battery cells beyond certain thresholds.
- If oxygen is present, **thermal runaway can also start a fire** as surrounding materials are overheated or damaged surrounding materials and with buildup of flammable gases.
- However, thermal runaway is distinct from fire in that it is an internal chemical reaction that **does not involve oxygen or flame**.
- Thus **thermal runaway cannot be stopped by firefighting techniques** to deprive fire of oxygen, nor can it be observed by presence of flame.

Propagation of thermal runaway through an energy storage system can be limited by two methods:

- The first method is to disperse its fuel—in this case, battery cells. As a practical matter fuel is best dispersed <u>prior to a thermal runaway event and as part of the design of the energy storage system</u>. This can be done by building a system with sufficient physical and/or thermal barriers between cells, modules, and racks.
- The second method is to cool thermal runaway enough to interrupt the chain reaction to surrounding cells. In practice, this has been most frequently attempted by application of large volumes of water spray, albeit with risk of worsening the situation depending on battery chemistry and packaging, arcing from energized equipment, chemical reaction and runoff (e.g., production of flammable gases, hydrofluoric acid), and/or steam-related damage to the system.

Water spray in controlled lab experiments has been shown to inhibit thermal runaway propagation temporarily and with extremely large volumes of water (Zhang et al. 2021; Long et al. 2013.). In practice, thermal runaway propagation in large stationary systems has not been successfully "extinguished" (a misleading fire-related term) by emergency responders once it starts. Limitations on exactly where water can be safely applied, coupled with the very large volumes of water needed, have made water spray as an emergency treatment of thermal runaway mostly ineffective with stationary energy systems in practice. Future system and site designs may improve the effectiveness of water applications. Overall, proactive and preventative measures to slow or limit thermal runaway through <u>energy storage system design</u> and to contain its impacts through <u>site configuration</u> are essential components of an effective risk management approach.

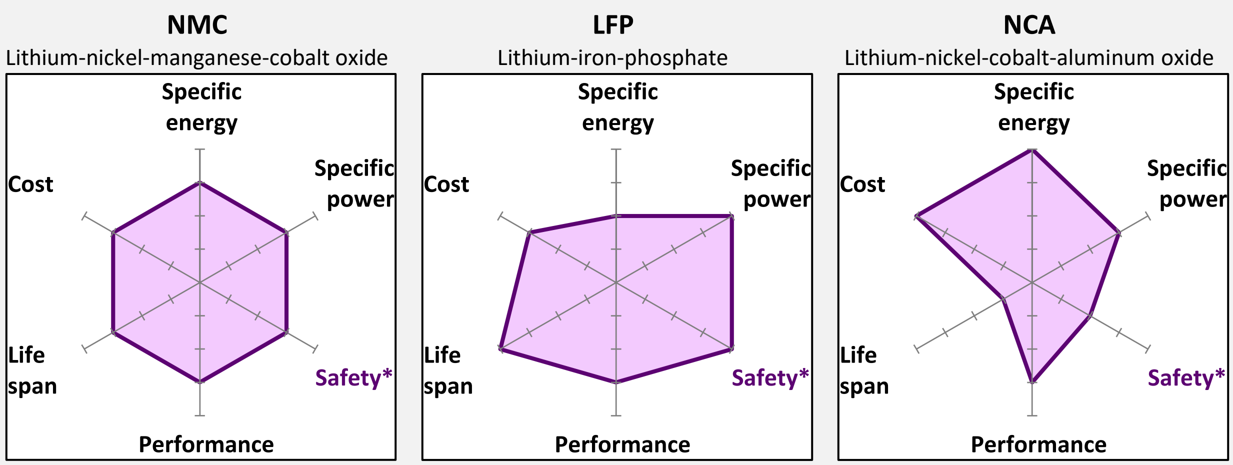
When faced with actual thermal runaway, industry literature and case studies indicate emergency responders' most effective response is to focus on site containment rather than on trying to "extinguish" thermal runaway—especially if responders do not have specific information about what it would take to stop or slow thermal runaway propagation at a particular site. This containment approach includes efforts to (a) prevent heat and flame from spreading to surrounding area and structures, (b) prevent toxic gas release from harming nearby people and communities, and (c) maintain a safe distance from the storage system and allow thermal runaway to self-extinguish. In the section below, "Case Studies of Safety-Related Events" we highlight some of the unmistakably brave but largely unsuccessful trial-and-error emergency responders have gone through when attempting to extinguish or slow thermal runaway propagation once it starts.

How Lithium-Ion Chemistries Compare

Underlying battery chemistries differ in how prone they are to thermal runaway and this is an important safety risk factor to consider. Battery chemistries have other tradeoffs that must also be considered in order to develop a market-ready and scalable technology (Figure 1).

In 2021 the dominant chemistry in global stationary battery energy storage markets—and in California's stationary battery energy storage fleet—is **lithium-nickel-manganese-cobalt oxide (NMC)**. NMC measures relatively well across many dimensions, including energy and power ratings, safety, performance under heat and cold, life span, and cost. Thermal runaway is typically triggered at 410°F (210°C) with additional risk at a high state of charge (Cadex 2019). In practice, however, cost and supply chain issues with cobalt, plus rare but dramatic safety failures and public scares, have driven developers and electricity system planners to consider alternative chemistries. Wood Mackenzie projects NMC market share in global stationary energy storage to drop from 60% in 2020 to 30% in 2030 (Wood Mackenzie 2020).

Lithium-iron-phosphate (LFP), by comparison, is projected to grow from 15% market share in global stationary battery energy storage in 2020 to 35% by 2030 (Wood Mackenzie 2020). LFP generally measures better in safety, power rating, and life span compared to NMC, with the tradeoff of a lower energy rating. Previously higher cost than NMC, LFP total installed costs dropped slightly below NMC by the end of 2021 (Viswanathan et al. 2022). LFP is more tolerant of full charge and high voltage, but it has higher stationary energy losses than NMC. Thermal runaway is typically triggered at a higher temperature of 518°F (270°C) regardless of state of charge (Cadex 2019). LFP is considered one of the safest lithium-ion chemistries.



*Thermal runaway triggered at **410°F** (210°C) with additional risk at a high state of charge

*Thermal runaway triggered at **518°F** (270°C)

*Thermal runaway triggered at **302°F** (150°C), with additional risk at a high state of charge

Note: Higher score reflects more desirable characteristics, e.g., higher cost score means lower cost.
Source: Modified from (Cadex 2019) and using updated cost data from (Viswanathan et al. 2022).

Figure 1: Key tradeoffs of lithium-ion battery chemistries.

Lithium-nickel-cobalt-aluminum oxide (NCA) also has a substantial global market share: about 15% in 2020. Wood Mackenzie projects NCA's market share to grow to about 20% by 2030 (Wood Mackenzie 2020). NCA is lower cost compared to NMC, but it measures worse in safety. Thermal runaway is triggered at a lower temperature of 302°F (150°C), with additional risk at a high state of charge as with NMC (Cadex 2019).

Risk Management of Complex Systems

Risk management of a complex system is a difficult process of addressing many layers of risks that are interrelated. Throughout this paper we refer to four layers of risk: points of failure, failure modes, system risks, and residual risk.

Points of failure. An energy storage system has many components especially considering the number of individual battery cells required for a lithium-ion battery system. Lithium-ion systems involve about 5,000 cells per MWh of capacity, which scales up to millions of cells making up the 300+ MWh systems being installed in the 2020s. Each cell and other component of the system is a potential **point of failure**—the risk of which can be minimized via quality control, testing, and ongoing monitoring and maintenance but cannot be entirely eliminated.

Failure modes. Failure of a single component (such as one cell) has the potential to trigger thermal runaway and instigate a cascading catastrophic event. Ex post investigations into actual events have yielded valuable information about how potential points of failure translate into **failure modes**. Failure modes are essentially points of failure expressed in the context of a broader situation, like overheating due to a short circuit or flaws in hardware design.[2] Development and refinements of industry-wide codes and standards, and adhering to them proactively, are crucial to addressing the risks of failure modes.

System failure. Risk management of an energy storage installation must also recognize it as a complex system in which failure modes can emerge and combine in unexpected ways. Failures within a complex system can have a multiplier effect on undesirable outcomes that are not well understood simply by summing the risks of individual failure modes. Ex post investigations into actual events and codes and standards address complex system risk to some degree and help us to understand how to mitigate large fires, thermal runaway propagation, and hazardous explosions. But guidance from these investigations and from even the most up-to-date codes and standards must be supplemented with local and site-specific expertise on a specific installation.

Residual risk. A prudent risk management approach accepts that, despite even the best risk management and mitigation activities, failures will happen at unexpected times and in unexpected places. Strategies to address this residual risk include plans to slow and contain fire, thermal runaway, and explosion if they do happen, and fail-safes to avoid cascades into the worst outcomes for people, the environment, property, and reliability.

[2] For example, see failure modes outline in (Chiu et al. 2013).

Safety Events in Context

All electricity infrastructure creates safety risk that needs to be managed through a combination of technology, design, and ongoing maintenance and operating procedures—battery storage systems are not unique in this. But as a relatively new technology and application many states are poised to invest significantly in, safety-related events draw widespread media coverage and public concern. What we know so far is that although these events are rare they can have dramatic impacts on the health of individuals and surrounding communities. These events can also have secondary impacts on the reliability of electricity supply to customers and on ratepayer costs.

At the end of 2019 the U.S. had 163 large-scale battery storage systems installed with 1,000 MW/1,700 MWh capacity with an average system size of 6 MW (EIA 2021). Up to that time only three known major safety-related events occurred, involving only 2% of installations. Those events resulted in destruction of 18 MW/14 MW of battery storage, or only 1–2% in terms of total U.S. capacity. All three situations, however, involved significant emergency response efforts, including one event in the city of Surprise, Arizona that resulted in severe injuries to several responders. All three also occurred about 1–2 years after initial installation of the systems.

Between beginning of 2020 and end of September 2021 large-scale battery storage MW capacity tripled in the U.S.: increasing by 2,200 MW to almost 3,300 MW (EIA 2022). Most of these new installations occurred in 2021. Within that timeframe in 2020 and 2021 another two events occurred at large-scale battery storage systems in the U.S. Relative to prior events, both were apparently minor events and perhaps reflecting evidence of industry improvements in safety risk management. It remains to be seen what unmanaged risks will be revealed at newly installed sites, as well as aging existing sites, over the next few years.

Each safety-related event gives the industry an opportunity to learn and improve battery technology and how we use it. These events drive a great deal of the industry's discussion around how to improve safety best practices and address risk management gaps that are revealed. The next sections summarize historical safety-related events, known and observed impacts, and lessons learned.

Case Studies of Safety Events

This section includes summaries of ten safety-related events with stationary energy storage battery systems in the U.S., plus discussion of events in Australia and South Korea.[3] To collect this information we reviewed technical reports, media and public accounts, and various assessments within the fire safety and energy storage research and policy communities. Our selected case studies include:

- **Kahuku Wind Farm**—August 2012 in Kahuku, Hawaiʻi
- **Elden Substation**—November 2012 in Flagstaff, Arizona
- **Franklin Facility**—August 2016 in Franklin, Wisconsin
- **South Korea**—2017–2018 in various locations
- **McMicken Battery Energy Storage System**—April 2019 in Surprise, Arizona
- **Industrial Warehouse**—June 2021 in Morris, Wisconsin
- **Grand Ridge Energy Storage Project**—July 2021 in Marseilles, Illinois
- **Victorian Big Battery Project**—July 2021 in Geelong, Australia
- **Dallas Energy Storage/Moss 300**—September 2021 in Moss Landing, California
- **Dallas Energy Storage/Moss 100**—February 2022 in Moss Landing, California
- **Valley Center Battery Storage Project**—April 2022 in Valley Center, California
- **Elkhorn Battery Energy Storage Facility**—September 2022 in Moss Landing, California

To understand the implications of each event, we focused on the following questions:

- What were the circumstances?
- Was anyone hurt?
- How much damage was done?
- How was electricity supply reliability affected?
- What were the main contributing factors to the impacts and severity of the event?

[3] For information about other safety events around the world we recommend starting with the Electric Power Research Institute's BESS Failure Event Database (EPRI 2022).

Kahuku Wind Farm—August 2012

Kahuku, Hawaiʻi

First Wind's wind plus storage installation in Kahuku included 30 MW of wind turbines and a 15 MW/10 MWh transmission-sited lead acid energy storage system contained within a 2,500 square foot warehouse. The energy storage system provided continuous voltage regulation, smoothing minute-to-minute wind output. Operations began in February 2011, followed by three incidents involving the energy storage system: one in April 2011, another in May 2011, then again in August 2012.

Image Credit: Jay Armstrong

Figure 2: Event at Kahuku Wind Farm—August 2012.

Due to the August 2012 event, wind farm operations were interrupted and the energy storage system was destroyed. It took over a year to bring the wind farm back online. In the process, First Wind abandoned an expansion project at the site. The energy storage system was replaced with a new Dynamic Volt-Amp Reactive (DVAR) system to provide the needed voltage regulation and the wind farm was brought back online in February 2014.

Emergency responders delayed entering the warehouse building for 7 hours in August 2012 due to safety concerns and awareness of chemical and physical hazards from the prior two incidents at the site. They attempted use of a dry chemical extinguisher and water directly to the site with limited success. Efforts then were focused on containing the observed fire to the energy storage building until it self-extinguished. The fire burned for 13 hours and smoldered for 36 hours, releasing significant smoke in the process. The warehouse building was apparently not designed for the hazard level and parts of it collapsed. No persons were reported harmed. A 2016 hazard assessment for the National Fire Protection Association concluded that, "These fires [at Kahuku wind farm] demonstrate the need for better understanding of ESS fires so that the owner and fire departments responding to these incidents can better prepared in the event of a fire." The event apparently resulted in about $30 million in damage.

Exact cause of the August 2012 fire was not publicized, although first alarm activation and visual evidence indicates fire origination within an inverter cabinet. Cause of the first two fires in April and May 2011 was linked to undersized capacitors contained in the battery system's inverters and led to litigation among the involved parties. The battery developer Xtreme Power had a significant portion of its business in Hawaiʻi and it filed for Chapter 11 bankruptcy protection in January 2014.

Elden Substation—November 2012

Flagstaff, Arizona

Arizona Public Service's (APS) lithium-ion energy storage system at Elden substation was a 0.5 MW/1.5 MWh distribution-sited pilot project installed in 2011 to better understand the benefits of storage including improved renewable integration and distribution system utilization. The battery system included

16 closed cabinets, each containing 28 sealed modules of 24 cells, within a 28’x8.5’x11.5’ container configured to be transportable on a flatbed trailer. The system was installed within the substation fencing.

In November 2012, after about 11 months of operations, the system was destroyed by fire and thermal runaway. The Flagstaff Fire Department observed 10–15’ flames and smoke upon arrival to the site. Responders were initially instructed not to flow water within 50–75’ of the fence housing the substation and they reported not being aware of the specific chemical hazards at the time. Flame lengths grew to an observed 50–75’ during the event. Responder efforts were to prevent fire spread to nearby forested area, extinguish fire, and cool the equipment. One responder experienced chemical exposure upon removal of a safety mask. The fire department cleared and turned the site over to APS after about 1.5 hours.

An in-depth root cause analysis conducted by experts at Performance Improvement International (PII) did not determine exact cause but identified 5 primary factors (“failure modes”) that contributed to the event. Two out of five contributing factors involved component failures initiating the event. PII found (a) severely discharged cells below the minimum voltage threshold (a measure of state of charge) at the origin of thermal runaway, and (b) controller software and system design that allowed and continuously attempted charging of cells below that threshold. The system previously had a “near miss” with thermal runaway due to these two factors in May 2012 and PII found the issues were not resolved at the time.

Another two factors contributed to thermal runaway propagation through the battery system. Hardware design was one contributing factor, including issues with design of the water cooling system, water leakage, insufficient separation of cells, and inability to isolate individual banks. The presence of electric faults was another contributing factor, including material and placement of busbars that caused melting and ground faults that aided thermal runaway.

The fifth contributing factor created delays in responding to the situation. Inadequate monitoring—including no temperature alarm, no status signal on failed relays, no daily checks, and alarms going to unattended stations—prevented situational awareness needed to address component failures more proactively. It should also be noted that the system vendor and utility’s emergency response plan did not prepare first responders enough to understand the specific hazards of the site nor immediate course of action for containing the fire and cooling the equipment.

Image Credit: Arizona Public Service Image Credit: Performance Improvement International

Pre-Event **Post-Event**

Figure 3: Event at Elden substation—November 2012.

Franklin Facility—August 2016

Franklin, Wisconsin

S&C Electric Company (S&C)—an electric power systems engineering and manufacturing company—manufactured and assembled power quality and energy storage systems at its facility in Franklin, Wisconsin.

In August 2016 a fire occurred at the facility involving a partially-assembled system of lithium-ion batteries within its shipping container (Figure 4). The energy storage system's fire suppression and containment system was nonfunctional as it was only partially assembled. Over 20 fire departments were involved, apparently due to the severity of the fire and weather conditions. Smoke was observed upon arrival at the site. One firefighter injury was initially reported although not part of final descriptions of the event. The Franklin Fire Department estimated damages on the order of $3 million.

Image Credit: National Fire Protection Association

During Event

Image Credit: Greentech Media

Type of Storage System Involved

Figure 4: Event at S&C's Franklin Facility—August 2016.

S&C stated the fire began in one of the DC power and control compartments of a battery rack within the energy storage system while the system was under construction. Once the fire started it spread to the adjacent batteries and initiated thermal runaway. Upon arrival, responders reviewed material safety data sheets, applied an alcohol-resistant aqueous film-forming foam per those instructions, then applied water for cooling which did not extinguish but helped limit thermal runaway to within the container. Thermal runaway self-extinguished after a few hours.

S&C's final public assessment of the situation included emphasis on a need for better information and training on fighting battery fires, noting that material safety data sheets are not enough. The company also outlined five elements of their approach to safety:

- Intelligent controls (their battery and power conversion system);
- Protective devices (fuses, AC circuit breakers, DC circuit breakers);
- Fire suppression systems;
- System design (power conversion system, battery components and systems, compartmentalization, and containerization); and
- Container.

South Korea—2017–2018

various locations

Energy storage systems in South Korea have received global attention in part due to the volume of fire incidents reported. The government launched a 5-month investigation in late 2018 and suspended deployment of new energy storage system installations in response to 23 fires in 2017 and 2018. Results of the investigation were announced in June 2019, identifying four primary causes:

- **Inadequate battery protective systems**, e.g., protection against overvoltage and overcurrent
- **Faulty operating procedures** and inadequate management of operating environment, thus exposing ESS to repeated condensation and dryness, leading to accumulated dust inside battery module and broken insulator
- **Improper installation** of energy storage systems
- **Lack of overall control systems** and lack of comprehensive protective and management system in which EMS, PMS, and BMS with different manufacturers were not operated together by a system integration (SI) business

In addition, investigators noted a practice of aggressive daily cycling, from zero state of charge to full state of charge, which is known to severely degrade batteries.

McMicken Battery Energy Storage System—April 2019

Surprise, Arizona

Arizona Public Service's (APS) lithium-ion McMicken energy storage system was a 2 MW/2 MWh distribution-sited project installed in 2017 for the purposes of facilitating new renewables on the grid with voltage regulation and power quality services. The system was installed adjacent to a substation and within its own fencing. The system included 27 racks, each containing 14 modules of 28 cells, within a 50'x13'x12' container the size of a large shipping container.

In April 2019, after about 2 years of operations, the system was destroyed by rapid thermal runaway over the course of 3 hours followed by an explosion. The system's temperature monitor, laser-based Very Early Smoke Detection Apparatus (VESDA), and Novec 1230 clean agent gas fire suppression system reportedly operated and responded as designed. A passerby reported smoke about 45 minutes after VESDA registered an alarm condition and the Surprise Fire-Medical Department was dispatched. At about the same time the battery developer (Fluence) and APS apparently had notified authorities. The first fire engine arrived about seven minutes later (at 5:49 p.m.). The Fire-Medical team observed a toxic smoke emanating from the battery storage facility and called for backup. About 30–40 minutes later the Peoria Fire-Medical Department's HAZMAT team arrived. The HAZMAT team entered the fenced area several times to take readings and assess the situation. About 1.5 hours later (at 8:01 p.m.) they opened the door to the container and an explosion described as "a jet of flame that extended at least 75 feet outward and an estimated 20 feet vertically" severely injured four members of the HAZMAT team. Additionally, four members of the Fire-Medical team plus one officer from the Surprise Police Department were sent to a hospital for overnight observation for chemical exposure. Post-event assessments and cleanup at the site were particularly difficult as the storage system was at a high (90%) state of charge.

Image Credit: DNV GL Image Credit: DNV GL

Pre-Event **Post-Event**

Figure 5: McMicken Battery Energy Storage System event—April 2019.

APS and LG Chem (the battery manufacturer) each commissioned technical analyses on the event which disagreed on the exact origin of thermal runaway. The APS analysis, conducted by DNV GL, found that thermal runaway was initiated by a voltage drop within one faulty battery cell. The LG Chem analysis, conducted by Exponent, rebutted this conclusion and instead found the cause to be a heat source external to the cells. A third analysis, conducted by Underwriters Laboratories (UL), did not address the topic of initial component failure and instead focused on emergency response and applicable design codes and standards. UL also issued a formal response to the DNV GL report to address inaccuracies it saw in DNV GL's description of the development process, scopes, and test methodologies of UL standards.

Beyond event initiation, the DNV GL report identified several factors contributing to event severity:

- **No thermal (or physical) barrier** between cells; module-to-module barriers insufficient
- The **fire suppression system** was designed to contain initial small fires and not to prevent or suppress cascading thermal runaway; no bulk cooling mechanism (such as water).
- Once the clean agent was discharged it took **45 minutes to visually confirm the potential fire** and dispatch emergency responders.
- **Flammable gases** accumulated from thermal runaway with no ventilation.
- **Emergency responders** did not have an extinguishing, ventilation, or entry procedure in the event of cascading thermal runway that would produce significant flammable gases.

DNV GL made several recommendations to address these contributing factors. It also noted a need for a more comprehensive risk management approach that would include input from, and communication among, the battery manufacturer, developer, and procuring utility.

UL's analysis identified several contributing factors related to lack of proactive education and training of emergency responders on battery energy storage system hazards and emergency procedures, limitations in sensory and communications systems for situational awareness, lack of ventilation to prevent an explosive concentration of gases, and a fire suppression system not designed for explosion protection. UL made a number of recommendations to improve situational awareness, and emergency preparedness and response.

This event halted APS' energy storage development opportunities. Two years later, in 2021, APS resumed energy storage development with enhanced safety protocols including:

- System design that anticipates failure; and
- Outdoor placement at least 100 feet away from any occupiable building space (Spector 2021).

In addition, a storage developer working with APS has highlighted the safety benefits of LFP battery systems and the need to increase coordination with first responders (Spector 2021).

Industrial Warehouse—June 2021
Morris, Illinois

In June 2021 significant thermal runaway propagation in batteries stored in an unlicensed solar and storage industrial warehouse led to a dangerous situation for the surrounding community and emergency responders. The site held approximately 100 tons of batteries.

Smoke and flames were observed over the course of about 1.5 days until contained by concrete, and it took weeks for authorities to declare the site fully under control. About 3,000 homes within a square mile southwest of the site were evacuated for 3 days due to large volumes of toxic smoke emanating from the warehouse. The governor issued a disaster proclamation and The Red Cross supplied food and water to the more than 300 first responders from multiple federal, state, and local agencies and organizations.

Image Credit: ABC7 Chicago

Figure 6: Event at an industrial warehouse in Morris, Illinois—June 2021.

The event started mid-day and responders reportedly began applying water spray until they were told the batteries would explode upon contact with water. By that evening responders had obtained and applied large volumes of a dry fire suppression chemical called Purple-K with no apparent effect. By the next evening, responders had consulted with the Illinois Environmental Protection Agency (IL EPA) and others and decided on an unconventional approach to smother the burning and smoking batteries with 28 tons of concrete. The concrete successfully extinguished visible flames and contained the toxic smoke from thermal runaway. Responders described the decision to use concrete as an effort to buy time while they sought advice and expertise from across the nation on how to best handle the situation.

After application of concrete responders and authorities connected with an expert who explained the nature of thermal runaway, why it was not stopped by the concrete, and why it needs to self-extinguish. Responders then focused efforts on the possibility thermal runaway would "break through" the concrete. They dug a trench to contain chemical runoff in case they would need to apply water spray. They continuously monitored the site and air quality until the site was declared under control.

Complexities with post-event cleanup included the need for residents to wipe down all surfaces with soap and water upon return to their homes, similar cleanup of public sites (such as playgrounds) by responders, and the need for contractors entering the warehouse to have appropriate protective equipment. Environmental damages are yet to be determined. According to the IL EPA may include contaminated runoff, air contaminants, and/or hazardous wastes. Two days after the event started the IL EPA referred the responsible party (Superior Battery Inc.) to the Illinois Attorney General's Office for enforcement. In its referral the IL EPA requested investigation into the cause of the event, site containment and inspection, site cleanup and restoration, and procedures to prevent future events. Superior Battery agreed to begin cleanup in October 2021 and is facing two lawsuits for danger to the public and the environment.

Grand Ridge Energy Storage Project—July 2021

Marseilles, Illinois

Invenergy LLC's 31.5 MW/12.2 MWh Grand Ridge Energy Storage Project was installed in May 2015 for the purposes of providing market-based regulation services. It was built on the site of an existing 210 MW wind farm, an existing 20 MW solar project, and an existing 1.5 MW/1 MWh energy storage system. The battery utilizes lithium iron phosphate chemistry.

In July 2021 an incident at the site destroyed one out of eighteen storage containers—or about 2 MW of the project. No persons were reported hurt, no environmental damage was apparent, and the incident received very little press. Fire was observed in the morning, and by mid-evening the visible flames were extinguished by responders. Responders were able to access the interior of the container and they applied water spray to cool the equipment. A responder reported the ability to apply water spray due to the battery's lithium iron phosphate chemistry (as opposed to the batteries involved in the Morris, Illinois incident—we are not aware of any advantages of LFP under water spray compared to NMC). Invenergy has said it is conducting an investigation.

Image Credit: Invenergy

Installation Pre-Event

Image Credit: LaSalle County Emergency Management Agency

During Event

Figure 7: Grand Ridge Energy Storage Project event—July 2021.

Victorian Big Battery Project—July 2021[4]

Geelong, Australia

The Victorian Big Battery Project is a 300 MW/450 MWh transmission-sited project installed at the end of 2021. The site design includes 212 Tesla Megapacks, each about 1.5 MW.

In July 2021 two of the 212 Tesla Megapacks were damaged while the project was in the process of initial energization testing. Smoke was initially observed by a site supervisor, then flames were observed shortly thereafter (Figure 8). When responders arrived they applied water externally to nearby exposure equipment and allowed the reactions to self-extinguish. Responders monitored the Megapack temperatures using thermal imaging cameras and drone technology, and in total it took 3.5 days until thermal runaway self-extinguished and the site was declared under control. Energy Safe Victoria (ESV, Victoria's safety regulator) conducted an investigation over the next two months, concluded the event to be a safe failure, and took a number of actions to prevent recurrence. ESV conditionally allowed Tesla to continue energization testing in September 2021. The testing and commissioning process continued and the site officially began commercial operations in December 2021.

The root cause was identified as most likely a cooling system leak in one of the Megapacks. The leak apparently caused an arc fault in the power electronics during the energization testing period, which created a heat spike that initiated thermal runaway in the battery cells. Immediate situational awareness was obscured by various systems not being fully integrated and operational at the time. The Supervisory Control and Data Acquisition (SCADA) system, which reports real-time battery system information to operators, was not functional as it required 24 hours to fully integrate with the project but the Megapacks operated for testing for only 13 hours. Then, when the Megapacks were turned off, the monitoring systems, cooling system, and battery protection system also turned off.

[4] Ozdemir 2021; ESV 2021; Kolodny 2021; Neoen 2021; Blum et al. 2022.

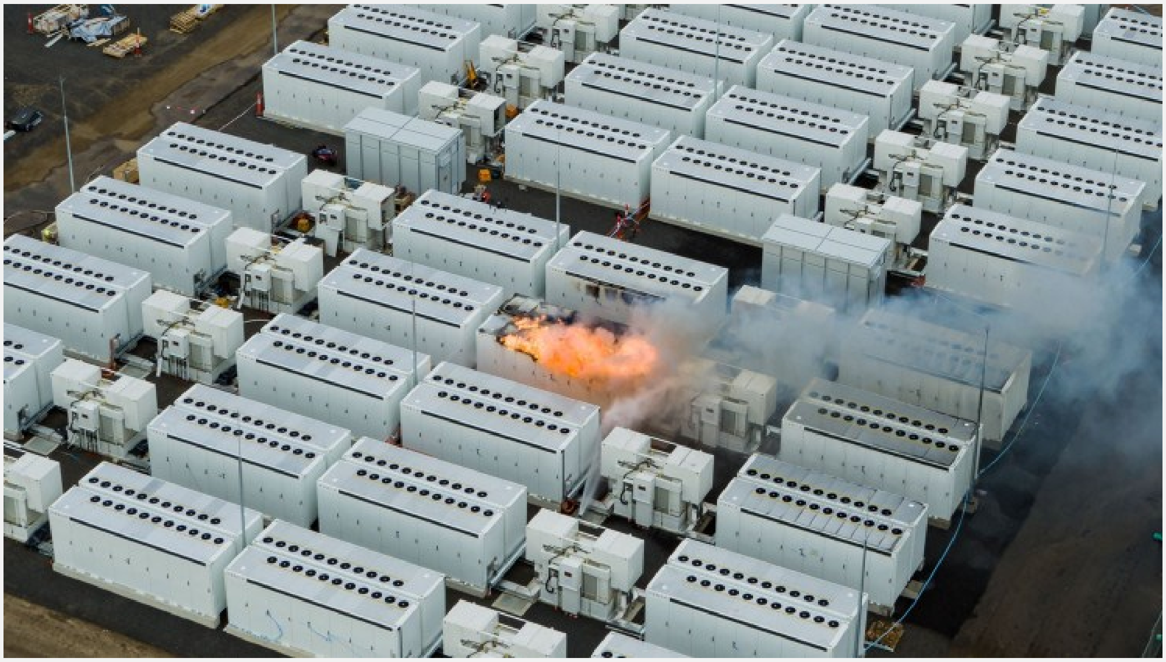


Image Credit: Fire Rescue Victoria

Figure 8: Victorian Big Battery Project event—July 2021.

How thermal runaway spread to an adjacent Megapack was of particular concern as the systems were evaluated under UL 9540A testing methods and their spacings were designed to mitigate inter-pack propagation. ESV required this issue to be addressed in Tesla's investigation. ESV also noted that, "Designers are also working to ensure that Megapacks are engineered to fully mitigate the risk of fire propagation from one unit to another under Victorian climatic conditions," suggesting that propagation to the second Megapack may have been aided by weather factors such as wind, ambient temperature, and/or humidity. An investigation conducted by Fisher Engineering, Inc. confirmed that untested wind speeds were a key contributing factor, reaching up to 36 miles per hour during the event compared to a maximum of 12 miles per hour under the UL 9540A testing environment. In an interview, ESV characterized this situation as a "near miss" when considering an event like this in the context of other times of the year with higher temperatures and stronger winds.

The investigation identified some needed enhancements to procedures, firmware, and hardware. It also noted a clear and effective emergency preparedness and emergency response process involving several parties: the developer (via system designs), facility staff, subject matter experts, and emergency responders. In an interview, ESV shared lessons learned and stressed the importance of (a) regulator engagement in safety review from the time of installation and throughout operations, (b) a better understanding of an installation's technology and its safety risks, and (c) a better understanding of interactions with the surrounding and natural environment.

California's Moss Landing Site

Moss Landing, California

The Moss Landing site hosts several large energy storage installations and has been the hub of a string of safety events in northern California.

The site was developed for a natural gas-fired power plant in the 1950s under the ownership of PG&E. In the late 1990s Duke Energy purchased the site and subsequently invested in a major refurbishment that included retirement of the original units 1–5, construction of units 6 and 7, and construction of two new combined cycle units (for more information see CEC 2000). At the end of 2016, then-owner Dynegy retired units 6 and 7. In 2018, Dynegy Inc. merged with Vistra Energy Corp. and Vistra owns the site as of the time of this report.

In late 2018 the CPUC approved two PG&E contracts to develop energy storage on the Moss Landing site. One RA contract with Vistra is for a 300 MW/1,200 MWh installation. The project is also known as "Phase I of the Moss Landing Energy Storage Facility," "Dallas Energy Storage 1–3," and "Moss 300." One engineering/procurement/construction (EPC) contract is with Tesla to develop a PG&E-owned installation. The project is formally known as the "Elkhorn Battery Energy Storage Facility." In 2020 the CPUC approved another PG&E contract with Vistra for a 100 MW/400 MWh installation known as "Phase II of the Moss Landing Energy Storage Facility," "Dallas Energy Storage 4," and "Moss 100." Moss 300 reached operations in late 2020, and Elkhorn and Moss 100 reached operations in mid-2021.

Each of these installations experienced a safety event over the course of a year (Figure 9). We discuss each event separately in the next few pages. Importantly, each installation reflects a distinct approach to site design. Moss 300 is built inside of a refurbished building that previously housed the retired gas-fired units' turbines. Elkhorn is built outdoors as an array of Tesla Megapacks—similar in design to the Victorian Big Battery Project. Moss 100 is developed within a new structure placed near the two operating natural gas-fired combined cycle units (Figure 10). In 2022 the CPUC approved another PG&E contract with Vistra to expand the site further with a 350 MW/1,400 MWh installation. Vistra has announced plans to continue building westward (inland) with an additional 750 MW/3,000 MWh energy storage in the future.

	Installation Name	MW	MWh	CPUC Contract Approval	Operating Status	Ownership	Safety Event
1	Dallas Energy Storage 1–3 /Moss 300	300	1,200	Nov 2018	Online Dec 2020	Vistra	**Sep 2021**
3	Dallas Energy Storage 4 /Moss 100	100	400	Aug 2020	Online Jul 2021	Vistra	**Feb 2022**
2	Elkhorn Battery Energy Storage Facility	182.5	730	Nov 2018	Online Aug 2021	PG&E	**Sep 2022**
4	*Moss 350*	*350*	*1,400*	*Apr 2022*	*Under Development*	*Vistra*	*n/a*

Figure 9: Battery storage installations and timing of safety events at the Moss Landing site.

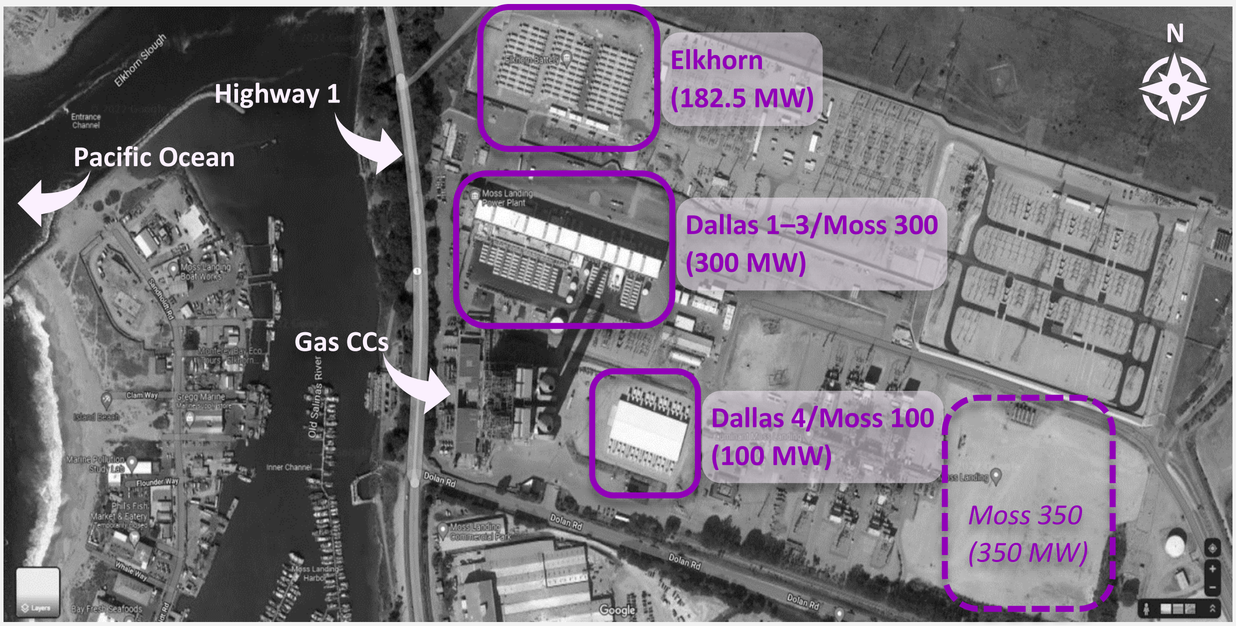


Image credit: Site image from Google Maps; annotated by Lumen.

Figure 10: Configuration of battery storage installations at the Moss Landing site.

Dallas Energy Storage 1–3/Moss 300—September 2021

Moss Landing, California

The Moss 300 installation is a 300 MW/1,200 MWh transmission-sited project owned by Vistra Corp. and installed at the end of 2020. The project includes three 100-MW battery arrays, with a total of 4,539 racks each containing 22 modules (Vistra 2022). The project is located within the Moss Landing site's existing and refurbished two-story turbine hall (Figure 10, Figure 11). The project is contracted by PG&E for local reliability purposes pursuant CPUC proceedings to replace retired natural gas-fired capacity.

Image credit: Vistra Corp.

Figure 11: Moss 300 building exterior and interior.

In September 2021, the North County Fire Protection District of Monterey County responded to a fire alarm at the Moss Landing site (Principi 2021). When they arrived, no fire was present but battery modules in Moss 300 had overheated and were producing smoke. Hazmat and environmental teams were also called to the scene. After inspection of the situation, emergency responders determined that the batteries were not in thermal runaway and the smoke was originating from other materials surrounding the batteries as the batteries overheated. Seven percent of the battery modules were damaged (almost 7,000 modules, or almost 320 racks), along with other facility equipment. No injuries were reported. In February 2022 another similar safety event occurred at Vistra's adjacent Moss 100 site. Vistra reportedly postponed its Moss 300 reenergization until further investigations could be conducted. Vistra did not bring the Moss 300 project (mostly) back online until late June 2022 (Colthorpe 2022)—almost a year after the September 2021 incident.

After a 5-month investigation, in January 2022, Vistra released a statement describing the facility, incident findings, and corrective actions (Vistra 2022). Vistra described the origin of the event as the combination of (a) a source of smoke at or near the facility's air handling unit and (b) due to a programming error, an overly-sensitive Very Early Smoke Detection Apparatus (VESDA) that was prematurely triggered. After the fire suppression sprinkler system activated, hose and pipe leaks sprayed water directly onto battery racks. Water also leaked from the upper floor onto battery racks on the lower floor. This type of water exposure caused short-circuiting and arcing, battery damage, and more smoke—which then let to continued VESDA activation.

Vistra's corrective actions include complete pressure-testing of the water delivery system, installation of a system to monitor for water leaks, VESDA re-programming, installation of smoke detectors in all air handling units, and sealing gaps in the facility's upper floor.

This incident at Moss 300 highlights the challenges with water as an effective fire suppressant but a potential risk with energized equipment. The Moss 100 event also highlights the sudden and significant impact safety events have on the electricity grid's resources: from a safety codes and standards perspective, and in terms of emergency response, this event was a safe failure. However, Moss 300 was on outage almost an entire year, including during the time of the year when California has the greatest need to move solar generation from daytime to avoid solar curtailments (spring) and during September when the grid is most stressed and in need of resources to help meet peak demand.

Dallas Energy Storage 4/Moss 100—February 2022

Moss Landing, California

Moss 100 is a 100 MW/400 MWh transmission-sited lithium-ion battery system installed in July 2021. The battery system is situated within a new standalone structure on the Moss Landing site (Figure 10, Figure 12). The project is contracted by PG&E for system reliability purposes pursuant to the CPUC's integrated resource planning proceedings.

In February 2022, the North County Fire Protection District of Monterey County again responded to an emergency call at the Moss Landing site (Principi 2022). No fire was found at the scene. This time, emergency responders found the Moss 100 fire suppression system was activated and spraying water. Vistra shut down the facility pending investigation and repairs, then brought it back online in late June 2022 along with the Moss 300 project—5 months after shutdown. No injuries from the incident were reported.

At the time of this report, the exact cause is not yet publicly clear. A Vistra statement (Vistra 2022) and news reports indicate that the cause may be similar or the same as the September 2021 safety event at Moss 300. Something triggered the facility's smoke detection equipment which was apparently overly sensitive due to a programming error. Then, apparently (but to be confirmed): the fire suppression system activated and sprayed water, water contacted the batteries due to water hose leak(s), which then caused the batteries to overheat, and surrounding materials released smoke as they melted/scorched.

Like the Moss 300 safety event, this incident at Moss 100 highlights the challenges with water as an effective fire suppressant but a potential risk with energized equipment. The Moss 100 event also highlights the sudden and significant impact safety events have on the electricity grid's resources: from a safety codes and standards perspective and in terms of emergency response this event was a safe failure. However, Moss 100 was on outage for 5 months, and in the time of the year when California has the greatest need to move solar generation from daytime to avoid solar curtailments (spring).

Image credit: Vistra Corp.

Figure 12: Moss 100 building exterior.

Image credit: Terra-Gen.

Figure 13: Valley Center Battery Storage Project.

Valley Center Battery Storage Project—April 2022

Valley Center, California

Terra-Gen's 140MW/560MWh lithium-ion installation came online in March 2022. The facility is designed as an outdoor array of containers (Figure 13). The project is contracted by SDG&E for system reliability purposes pursuant to the CPUC's integrated resource planning proceedings.

In April 2022 fire crews responded to a small electrical fire at the site (Roadrunner 2022). The fire triggered the battery system's fire suppression system which then extinguished the fire. The event was contained to one battery module and no injuries were reported. Further details on the cause of the electrical fire are not publicly available. Although light on data, we included this case study as an example of how properly-functioning fire suppression systems, which are designed to contain initial small fires, play an important role in mitigating safety risks.

Elkhorn Battery Energy Storage Facility—September 2022[5]

Moss Landing, California

The Elkhorn Battery Energy Storage Facility is a 182.5 MW/730 MWh transmission-sited project installed in August 2021. The facility is designed as an outdoor array of 256 Tesla Megapacks (Monterey County 2022c)—similar to the Victorian Big Battery Project. Along with Moss 300, the project is contracted by PG&E for local reliability purposes pursuant CPUC proceedings to replace retired natural gas-fired capacity.

[5] Most event information from Monterey County 2022a; Monterey County 2022b; Monterey County, 2022c; Monterey County, 2022d; KSBW8 2022.

On September 20, 2022 a fire was detected at about 1:30 a.m. and fire crews arrived shortly thereafter. Fire crews followed a pre-planned strategy, based on their training, to not attempt to extinguish the thermal runaway and to instead focus on protecting surrounding structures with water spray. The fire was extinguished in 5 hours by about 6:30 a.m., then the thermal runaway process continued and released gas (including hydrogen fluoride) into the surrounding community.

Local officials then issued a shelter-in-place advisory and closed nearby roads including Highway 1 in both directions (Figure 10). Residents were told to shut windows and turn off ventilation systems. The surrounding area was monitored for toxic gas levels. The shelter-in-place and road closures were ended at 6:50 p.m. on the same day. The fire was contained to one megapack and no injuries were reported.

Cause of the fire and thermal runaway are unknown publicly as of the time of this report. We included this case study as an example of an effective fire response strategy, and of the importance of communication and knowledge-sharing with the community and local officials.

News reports we reviewed indicated community confusion and concern about the nature and impacts of the toxic gas release. This highlights some challenges in knowledge transfer of safety events to local authorities and their communities. Community impacts from gas release of lithium-ion batteries in thermal runaway reached the national stage over a year prior (June 2021) with the industrial warehouse event in Morris, Illinois. Many important safety lessons were learned in that event that can be helpful to California communities.

Image credit: David Paul Morris/Bloomberg

Facility pre-event

Image credit: KION 46 News Channel

Community gas release during event

Figure 14: Elkhorn Battery Energy Storage Facility—September 2022.

Known and Observed Impacts

Based on these case studies we observe the following known and observed negative impacts of under-managed, under-mitigated, or residual safety risk:

- **Emergency responders and staff**—injury from fire or explosion; chemical exposure (air or contact) such as from released hydrogen flouride (HF) and phosphoryl fluoride (POF3) gases (*see* Larsson 2017).
- **Communities**—chemical exposure, chemical runoff, displacement from homes due to evacuation, shelter-in-place, temporary shut-down of local economy, fears of known and unknown risks.
- **Environment**—release of contaminants of concern, chemical runoff from emergency water spray such as hydrofluoric acid, and fire propagation.
- **Electricity infrastructure**—loss or partial loss of battery system and attached equipment.
- **Other property**—loss or partial loss of surrounding and adjacent structures.
- **Reliability of electricity supply**—outage or permanent loss of storage capacity, outage of other onsite electricity supply (e.g., wind turbines) during event and recovery period.
- Cost, time, and hazards of **post-event investigations and cleanup**.

It should also be noted that the more extreme events create some public backlash and have hindered storage market growth as ex post investigations and risk assessments take place. After the event at McMicken in 2019, for example, Arizona Public Service paused on its energy storage deployment plans for two years. Earlier in 2018, South Korean regulators deployment of new energy storage system installations in response to more than 20 fires in 2017 and 2018.

Lessons Learned from Safety-Related Events

Ex-post studies and assessments of safety-related events provide valuable information on specific failure modes and circumstances leading to catastrophic situations. This information has shaped development of safety codes and standards and other best practices. In addition, we observe several themes in lessons learned from safety-related events that continue to guide efforts to improve safety:

- A **need for more comprehensive and complete proactive risk assessment**—This was explicitly addressed in DNV GL's report on the McMicken event, but also apparent in the emergency response process of other events (DNV GL 2020). DNV GL noted that manufacturers, developers, operators, and utilities each have unique information on known and possible safety risks; and that they all need to communicate ahead of time to develop an assessment that combines their knowledge into a complete set of known, possible, and unknown hazards.
- Relatedly, a **need for more proactive coordination with emergency responders**—In nearly every safety-related event emergency responders were presented with very limited information on the hazards of the situation on-the-spot. They are consequently required to manage an emergency situation in which they don't have a full picture of what the hazards are, are not fully aware of the limitations of dry chemical suppressant, are not clear on when/where/how to apply water, and are not sure of when or how to approach or enter the structure. Emergency response plans are

needed that include proactive communication and training for both staff and emergency responders on relevant risks, what emergency events may look like, and how to handle them.

- **Need for integrated system supervisor with complete situational awareness at all times**—Installations designed to operate too remotely and/or with various detection and management systems monitored by multiple separate parties inhibit fast and efficient emergency response. A single integrated platform and/or coordinator for all operating and monitoring systems is needed. Also, events point to a need for situational awareness even when the batteries are offline.
- Codes and standards have evolved rapidly to address many types of component and system-level risks, but within limits. **Risk management activities beyond meeting codes and standards are needed** in order to address secondary impacts like reliability of storage and co-located electricity supply, and to establish broader multi-party coordination and communication protocols such as emergency response plans.
- **Events in other jurisdictions don't reflect some California-specific and local risks and implications**—such as local environmental extremes, grid outages during a heat wave or extreme wildfire weather and how that might affect the storage system, fire propagation from and to the storage system in certain locations, and water supply constraints.

Best Practices and Next Steps

This section summarizes best practices and next steps, drawing from lessons learned from safety-related events; efforts by federal, state, and local agencies; and other efforts by stakeholders and industry experts to enhance safety practices.

We divide risk management and mitigation activities into four components:

- Risk assessment
- Emergency preparedness
- System and site design
- Operations, diagnostics, and maintenance

Risk Assessment

The industry has learned a great deal through experience and ex post investigations about how specific failure modes can manifest, how design and operations can affect fire and thermal runaway propagation risks, and the range of severity of impacts on people and equipment. These events and experiences provide valuable information to guide development of best practices in safety.

As a result, best practices are trending towards more comprehensive proactive (ex ante) risk assessments of battery storage installations. *Who* should conduct an ex ante risk assessment, *why*, and *scope of risks* to assess depend on stakeholder perspective, and defining this perspective and its objective is important for an effective risk management strategy.

We focus on the type of risk assessment of ratepayer-funded installations involving the CPUC and utilities with the dual objective to minimize harm to people, communities, and the environment, and to maximize reliability and quick recovery in the event of a storage component or system failure. We propose the following risk management objective from this perspective:

Safety risk management objective: minimize harm to people, communities, and environment, and maximize reliability and quick recovery in the event of a component or system failure

In a complex system many sources and combinations of failures can contribute to risks. **Underlying battery chemistry and technology**, its inherent safety risks and failure modes, and how sensitive it is to fire and thermal runaway propagation is a key consideration. It is standard practice for manufacturers to provide material safety data sheets and/or emergency response guides which document a battery's chemical hazards and safe handling procedures.

More than a dozen codes and standards have been developed to identify and address safety risks of other **individual components of a battery installation** beyond the batteries themselves, including inverters, capacitors, battery management systems, and energy management systems. Going further, about a half dozen additional codes and standards identify and address risks of various **components assembled into an installation**. These include guides for ventilation and thermal management; for electrolyte spill containment and management; for installation, maintenance, and operations; and for managing electrical, fire, and shock hazards.

To assess risks more holistically at a **complete energy storage system** level (e.g., storage container and all contents and attachments), Underwriters Laboratories developed a test method (UL 9540A) for observation and evaluation of behavior of a replica system in an actual thermal runaway situation. This is a destructive lab test in which thermal runaway is instigated then observed—at the cell level, module level, unit/rack level, and installation level. A favorable test outcome, or "safe" failure, is essentially thermal runaway that self-extinguishes without significant propagation, flaming, or explosion. Less favorable outcomes provide guidance for additional risk mitigation and management that may be needed to meet fire codes and other safety objectives.

Codes and standards for an **entire built environment** (including immediate area and structures surrounding the storage container) identify and address various electrical, fire, and building safety risks. Projects that trigger review under the California Environmental Quality Act (CEQA) undergo additional risk assessment that helps to translate component- and system-level failures into risks to the surrounding people and environment. Tests results under UL 9540A, for example, can be assessed against a specific site plan and local environment in order to determine whether or not something like a fire wall needs to be built to provide extra protection to the surrounding area.

Next Steps for Risk Assessment

In many of the case studies we reviewed it is unclear to what extent the full spectrum of safety risks were assessed in advance and, if they were, how broadly these risks were communicated to all parties involved in risk mitigation and management. These experiences indicate a benefit to both the real-time battery system supervisors and their regulators having a more comprehensive understanding of how a specific battery systems' electrical and thermal stability can fail, types of hazards that can result, and potential secondary impacts on electricity system reliability and ratepayer costs.

One important next step in risk assessment of the utilities' energy storage procurements is to inventory and better understand each individual installation's safety risks. National and international codes and standards identify many—but not all—of the risk factors we observe in actual safety-related events.

Some **local or site-specific factors** may require additional consideration beyond codes and standards. Tests under UL 9540A, for example, are performed within a controlled environment where heat and gas release can be measured. Notably in the Victorian Big Battery Project event flames propagated to a second adjacent Tesla megapack despite the product having been subject to tests under UL 9540A. In its assessment of the event the Australian regulator, Energy Safe Victoria, emphasized a need for designers to consider Victorian climatic conditions to mitigate fire propagation.

Events like the Victorian Big Battery Project and industrial warehouse in Illinois highlight the dangers of gaps in 24/7 real-time situational awareness—even with the batteries offline. Thermal runaway and subsequent fire and propagation is a vulnerability of some batteries regardless of operational status of the battery system. Some additional consideration beyond codes and standards may be needed to better understand **grid or battery system outage as a failure mode**, how the outage might coincide with external stressors (such as a heat wave or high wildfire threat), how the outage affects monitoring and thermal management equipment, and consequences to fire and thermal runaway propagation risks.

Risks to grid reliability and ratepayer costs will certainly require additional consideration beyond codes and standards. After destruction of its battery system in 2012 the Kahuku Wind Farm was shut down for over a year until replacement equipment could be installed. After its September 2021 safety event the

Moss 300 facility was shut down for almost a year, coming (mostly) back online in June 2022 (Colthorpe, 2022). This type of impact on the operability and reliability of energy storage systems and any onsite generation could materially affect ratepayers, but it is not a risk factor considered within the scope of codes and standards. Complete and permanent destruction of the storage system under UL 9540A, for example, would be considered a favorable test outcome as long as flames, gas and chemical release, and explosion are sufficiently contained in that situation.

It should also be noted that **codes and standards are evolving rapidly** as the industry climbs the learning curve of energy storage safety. Safety measures at a new battery system installation could conceivably become out-of-date within months. Older, pre-2018 systems are almost certainly out-of-date with current best practices. Furthermore, consistency in interpretation of codes and standards may be a challenge. It will be up to storage system owners and their regulators to update their understanding of safety risks accordingly and determine if continued status quo operations are acceptable, if retrofits or updates are needed, or if decommissioning would be the best course of action. Although built to safety standards at the time of its installation in 2014, the design of SCE's Tehachapi was severely out of step with codes and standards by 2020 (SCE, 2021). The cost to retrofit to meet current codes and standards was a major factor in the decision to retire the facility in 2021 (SCE, 2021).

Once risks are identified and known, **proactive communication of those risks to all parties involved** is clearly an urgent and essential area for improvement across the industry. Nearly every safety-related event reveals major communication barriers that undermine risk mitigation and management efforts. Poor communication with local authorities and emergency responders is the most visible example of this to the public eye. In several safety-related events, responders were forced to assess risks on the spot by assembling information from various sources including materials safety data sheets, battery system supervisors, outside experts, and responders' own experience with fire and hazardous materials. Less visible is the essential communication among the many parties involved in developing and managing a battery system. In its investigation of the McMicken event, DNV GL observed that a more comprehensive ex ante risk management approach could have been achieved with better communication among the battery manufacturer, developer, and procuring utility on the key risks each party was aware of (DNV GL 2020). DNV GL suggested this knowledge transfer could be facilitated using a Johari window technique to reveal blind and hidden risks (DNV GL 2020).

Emergency Preparedness

No one can fully control or predict when or where a battery system failure mode leads to fire and thermal runaway propagation. Emergency preparedness is a mitigation strategy that assumes fire and thermal runaway propagation will happen, with a more focused objective of setting the stage for fast and efficient real-time mitigation of harm to people, communities, and environment. The more severe an emergency, the more mitigation objectives narrow to the most important goal: to protect the lives and health of people. Actual safety-related events have provided valuable information on where gaps in emergency preparedness lie and how they can be addressed.

Site designs are improving to include better situational awareness tools, egress for staff or other persons onsite, access for emergency responders, structural integrity to withstand extreme conditions, and physical buffers to protect surrounding buildings and landscape. Updates to codes and standards and their applications in recent years include enhancements to firefighting, preparedness for explosive gases and vapors, spill control, smoke detection, and signage. It has also become increasingly clear that site design and installation must include the input of local emergency responders who are experts in their community's terrain and weather patterns. Dr. Paul Christensen, a professor of electrochemistry at Newcastle University whose research focuses on lithium-ion battery fires and safety, summarizes this point: "If the design is approved, and then the fire and rescue service are brought in—that's the wrong way around." (Kolodny 2021) He also recommends:

- A monitoring system that provides internal visibility (e.g., within the storage container) at any time;
- Enough clearance for responders to maneuver around a system and direct a hose if needed; and
- Water access including onsite hydrants and capped pipes into the storage container to allow flooding with an external hose if needed (Kolodny 2021).

These guidelines are consistent with observations and activities of other experts in the field. Various monitoring systems need to be accompanied by staffing and process strategies for 24/7 situational awareness—whether the storage system is online or offline and under a variety of grid and environmental conditions. Depending on battery chemistry and technology, battery system designs may need to be modified in order to allow safe application of water in an emergency.

Proactive and robust emergency training and coordination among battery system operators, supervisors, and emergency responders is another area where the industry is adapting and innovating quickly. Best practices in managing safety risks acknowledge that all parties involved in real-time emergency response need to be trained on types of possible failures and hazards, how to identify them and assess the overall situation, and what course of action to take in different situations. Knowledge-sharing on the characteristics of thermal runaway, how it is different from fire, and its chemical and explosive hazards has been an area of particular focus. Emergency responders likely have significant experience with fire and/or chemical hazards, but they may have never seen or managed thermal runaway. In many of the safety-related events we observe fire responders put significant time and effort into attempting to extinguish thermal runaway like a fire, putting themselves at risk in the process.

Next Steps for Emergency Preparedness

As with risk assessment, national and international codes and standards are being continuously improved and they provide valuable guidance. But gaps remain particularly in consideration of certain installation-specific factors as well as communication among many parties to develop a coordinated risk management approach.

The most urgent and fruitful next step in emergency preparedness is for battery system owners and supervisors, their regulators, and state and local emergency responders to coordinate in a battery system **safety knowledge exchange**, then formalize that exchange through an established training program and updates to state and local requirements for battery systems (e.g., city fire code, permitting review process). In New York, for example, the New York State Energy Research and Development Authority (NYSERDA) developed training webinars and a guidebook for local governments including model (boilerplate) law for storage system requirements, a model permit application, a model inspection checklist, and information on how battery system safety is incorporated into state fire and building codes. They also provide technical assistance to local authorities.

Deep investigation into the McMicken event revealed that very little information was communicated to responders, forcing them to improvise in a dangerous situation. Timelines of other safety-related events indicate a similar problem at other sites. In addition to this general knowledge exchange, each installation must have an **emergency response plan** that is readily available in an actual emergency and that provides enough information to responders for quick situational assessment and best course of action. The plan should include information on how to identify and address thermal runaway specifically. It may be helpful to consult with the emergency responder community on the most useful elements of an emergency response plan from their perspective. A widely vetted emergency response plan could then be used as a model for other installations.

System and Site Design

Ideally, system design is informed by an initial risk assessment that points to specific design needs, such as ventilation for hazardous gas buildup. It should also be informed by an emergency preparedness strategy that identifies useful design-related emergency tools such as perimeter clearance and placement of fire hydrants. Although still in development, best practices in energy storage safety have made significant progress towards this type of integrated risk management strategy and that is what we highlight here.

A battery system contains many design elements and we do not discuss them exhaustively in this paper. But as the industry learns lessons from safety-related events a few design elements have become central to the discussion of best practices.

Lithium-ion NMC has thus far been the dominant **chemistry for battery storage systems**, but cost and supply chain issues with cobalt, plus rare but dramatic safety failures and scares, have driven developers and electricity system planners to consider alternative chemistries. After the event at McMicken in 2019 Arizona Corporation Commission (ACC) Commissioner Sandra D. Kennedy found utility-scale energy storage based on certain lithium-ion chemistries to “not [be] prudent and create unacceptable risks.” The letter suggested consideration of other technologies such as liquid flow, liquid metal, zinc air, nickel iron, and magnesium batteries—and consideration of non-battery storage. In 2021, Tesla announced plans to switch its Megapack chemistry from NMC to LFP (Plautz 2021). Wood Mackenzie projects NMC market share in global stationary energy storage to drop from 60% in 2020 to 30% in 2030, and for LFC to grow from 15% to 35% (Wood Mackenzie 2020).

If NMC is the chemistry of choice, its inherent safety risks can be addressed by **increasing physical and thermal barriers** between cells, modules, and/or racks. This reduces energy density and may increase costs but is crucial to slow or contain thermal runaway once initiated. Self-contained installations placed outside with sufficient perimeter clearance helps to protect surrounding structures and landscape. If the installation is placed within an existing building or structure, such as a warehouse, it may need additional physical separation.

The industry has pushed to improve **operating tools and fail-safes** in response to safety-related events. Battery management systems should be able to detect and fully isolate deteriorated or malfunctioning cells. Energy management systems should be tuned to avoid operational extremes that risk rapid cell damage (such as extreme charge discharge ramps, depth of cycle, states of charge). Battery and energy management systems should be able to talk to each other in order to better recognize and address potential issues—such as thermal runaway risk as a function of temperature and state of charge (Rosewater 2019).

Monitoring and situational awareness equipment are essential to address a failure mode quickly before it cascades into fire or thermal runaway propagation. This equipment includes temperature monitors and smoke detection equipment like a laser-based Very Early Smoke Detection Apparatus (VESDA). Other gas monitoring equipment may be needed to detect thermal runaway absent fire. Several safety-related events revealed the need for internal camera systems to visually confirm possible fire quickly and remotely without endangering staff or emergency responders. Depending on the system type and local climate a temperature control system (such as HVAC) and/or additional environmental monitoring such as humidity or fine particle sensors may be needed.

The purpose of a **fire suppression and response system** has caused some confusion around safety-related events, mainly tied to confusion around the distinction of fire versus thermal runaway. Installation of a fire suppression and response system is standard practice and essential for control of fire within a system—hopefully before thermal runaway can initiate (fire can trigger thermal runaway). Once thermal runaway is initiated, however, fire extinguishing agents and techniques will not stop it. In practice, thermal runaway is only contained by (a) the physical and thermal barriers that were put in place as part of the system and site design and (b) if it can be safely applied, large volumes of water to cool the reaction. Accordingly, system and site designs that include **extra water supply** and a layout to safely apply water spray or flood the storage system are emerging as a best practice (Kolodny 2021). Designs with proper **ventilation** to prevent buildup of flammable gases such as via Pacific Northwest National laboratory's IntelliVent have become part of best practices (PNNL n.d.).

Containerized systems placed outdoors on a concrete pad, away from occupiable spaces, fenced, and with sufficient space for emergency responders to maneuver has become a standard site design for utility-scale storage. The site should include a fluid collection system for emergency response efforts to contain any potential chemical runoff. Appropriate signage is needed to warn staff and responders of various hazards. State and local fire and building codes may need to be updated to address the safety of a system placed indoors, even if the system is containerized.

Next Steps for System and Site Design

Next steps in system and site design safety best practices largely follow gaps in risk assessment as previously discussed. Lessons learned from safety-related events point to the need for designs to **better address local or site-specific factors, grid or battery system outage as a failure mode, and secondary risks to reliability and ratepayer costs**.

Large-scale systems trend towards containers placed outdoors but for **customer-sited installations** the best approach is not as clear. Safe placement and installation depends on a number of factors including local environmental conditions and it requires close scrutiny by local fire and permitting authorities. It also requires input from developers and installers to ensure rules are feasible and do not create major barriers to storage adoption. This process can be complex. The New York City Buildings Department and New York City Fire Department worked with stakeholders for several years to develop codes for indoor placement that fit both safety objectives and available technology (St. John 2017; St. John 2020). In general, any indoor placement—even in a garage—potentially restricts air flow and endangers the surrounding structure, property, and/or nearby people in the event of fire or thermal runaway. On the other hand, outdoor placement in unfavorable climate conditions like a hot, dusty, desert-like environment can pose its own risks. In 2017 Standards Australia drafted safety rules in a best practices guide (AS/NZS 5139) that would essentially ban indoor installation of lithium-ion battery systems (Colthorpe 2017a; 2017b). After significant backlash from stakeholders Standards Australia re-worked and finalized the rules in 2019 to allow indoor installation with certain protections like use of cement sheeting when adjacent to occupied space, clearance from appliances and room egress, and exclusion from certain hidden enclosed spaces and habitable rooms (Podder 2021).

The industry has identified **better integration of the many management and control systems** operating an energy storage system as a key area of needed improvement. Better integration means management and control systems that talk to each other, that incorporate inputs from **situational awareness monitors**, that communicate with an integrator software that performs higher-level system optimization functions, and that reports comprehensive status and operational data to system supervisors. As the industry makes technological advances in this space it would be prudent for both new and existing energy storage systems to utilize best in class software to the extent feasible. One potential advancement, for example, is in machine learning-based **predictive maintenance**. The software would utilize all historical system data and look for complex statistical relationships to proactively alert system supervisors of potential issues needing inspection. A key component to this and other integrator solutions that rely on a complete picture of the energy storage system will be **improved data collection and retention** of the system's data.

For an existing system, we recognize that migrating to new IT systems is a difficult process and that it requires testing to ensure the new system is working as designed. Similar issues arise with **compliance with rapidly-changing codes and standards** in general. Energy storage owners, regulators, and permitting authorities will need to monitor codes and standards developments and have a decision-making framework for allowing status quo operations, or requiring a retrofit versus retirement assessment of energy storage systems that no longer meet the latest safety guidelines.

Large utility-scale battery systems may need to be **tested and designed to address grid or battery system outage as a failure mode** in order to minimize (a) delays in responding to failures, and (b) secondary risks to reliability and ratepayer costs. The system should be designed to provide 24/7 situational awareness even in a grid or storage system outage situation. If the grid is functioning normally but the storage system is on outage, the configuration should be designed to minimize downstream outages of co-located electricity supply (such as solar or wind).

Operations, Diagnostics, and Maintenance

Best practices are trending towards hardware and software solutions to improved operations, diagnostics, and maintenance in system designs. But even with the best information technology in place, system design alone cannot address the need for 24/7 oversight and routine checks by knowledgeable and experienced persons.

An energy storage system can include many different detection and management tools, such as temperature and smoke detection, fire suppression, battery management, power control, energy management, and site management. These systems can potentially be monitored by different parties. Best practices trend towards **providing supervisory staff with a more complete picture** of what is going on with the system. Beyond technological solutions this includes a streamlined communication and decision-making process. It also needs to include training on the types of risks involved and types of situations that could occur, and training on an emergency response plan.

The industry has learned a great deal in the past few years about how different **operating use cases and operating practices** affect battery cell degradation and safety risks. Experiences in South Korea, for example, highlighted the need to avoid overcharging and aggressive cycling. Those experiences also demonstrated the need to consider and manage the day-to-day operating environment. Warranty or operating contract terms may set preferred operating parameters as a starting point. Battery system operators may also set their own preferred state of charge operating range (to avoid very low and very high states of charge) or ramping and cycling operating limits.

Routine visual inspections and equipment tests are a standard practice. In California, for example, the County of Santa Clara Development Services Office developed a field inspection checklist for residential battery storage systems in 2015 that has been held as a model for the state. In 2017 the CPUC's Safety and Enforcement Division (SED) collaborated with stakeholders to develop an inaugural safety assessment checklist (CPUC SED 2017). The checklist includes an emergency plan; regular inspections of equipment by companies or utilities; and inspections of interconnection equipment, structure, detection and protection systems, fans and cooling equipment, electrical, battery module, and hazardous materials policy by SED inspectors.

<u>**Next Steps for Operations, Diagnostics, and Maintenance**</u>

Data collection and retention is becoming increasingly important as system monitoring, management, and control tools advance and as operating use cases become more sophisticated. Experts at Sandia National Laboratories emphasize the importance of data acquisition systems that include remote access and 30 or more days of on-board memory (for example *see* Schenkman 2020). Larger data reservoirs will likely be needed as systems become more predictive. Relatedly, regular **software and firmware updates** are becoming increasingly important, including tests and checks to ensure the updates installed and are performing correctly (for example *see* Fioravanti et al. 2020).

As discussed earlier in system and site design, **predictive maintenance tools** using machine learning models are on the technological frontier. These models would utilize all historical system data and look for complex statistical relationships to proactively alert system supervisors of potential issues needing inspection.

Routine inspections by local or state authorities will need to consider the increasing importance of software and firmware in energy storage operations, diagnostics, and maintenance.

Key Observations

Energy storage safety is a complex risk management issue that involves many parties.

Historically, major safety-related events involved about 2% of large-scale battery storage installations in the U.S., occurred within 1–2 years of installation, and destroyed about 1–2% of its capacity.

In 2021 and 2022, safety events in California are increasing along with the state's acceleration of large lithium-ion battery installations.

The definition of energy storage system "safety" from an electricity regulator's perspective considers both direct impacts (e.g., harm to humans, the environment, or surrounding communities) and impacts on the reliability and resilience of electricity supply.

Lithium-ion batteries are unique from other electricity supply resources in their ability to rapidly decompose through a fire-like and extremely hazardous process called thermal runaway.

Public and industry confusion over the difference between fire and thermal runaway is a major source of misinformation on appropriate management of lithium-ion battery safety risks.

Although large volumes of water spray can help limit thermal runaway propagation, thermal runaway is best addressed proactively through energy storage system design and site configuration.

Lithium-ion chemistries differ in their vulnerabilities to thermal runaway. The industry is trending away from the more sensitive NMC chemistry and towards the more stable LFP chemistry.

Risk management of complex systems must consider multiple layers of risk, including: points of failure, failure modes, system risks, and residual risk.

Case studies of safety-related events demonstrate a range of failure modes and situations, offer valuable information on known and observed impacts, and point to themes in lessons learned.

Risk management and mitigation activities include four components: risk assessment; emergency preparedness; system and site design; and operations, diagnostics, and maintenance.

California's next steps in risk assessment are to investigate (a) **local or site-specific factors** that heighten or change risk profiles, (b) **grid or battery system outage** as a failure mode, (c) **risks to grid reliability and ratepayer costs**, (d) procedures for keeping the storage fleet up with **codes and standards**, and (e) methods for **improving communication and knowledge-sharing** among all parties involved.

California's next steps in emergency preparedness are to build a robust and ongoing **safety knowledge exchange** and ensure **emergency response plans are well vetted within that safety community** including local officials and emergency responders.

California's next steps in system and site design mirror next steps in risk assessment, including steps to (a) ensure designs **better address local or site-specific factors, grid or battery system outage as a failure mode, and secondary risks to reliability and ratepayer costs;** (b) **improve battery management systems, control systems, and learning from historical system data;** and (c) consider **retrofit versus retire** options for systems that no longer meet codes and standards.

California's next steps in operations, diagnostics, and maintenance include improvements in **data collection and retention, software and firmware upkeep, and predictive maintenance**.

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ATTACHMENT G: END OF LIFE OPTIONS FOR LITHIUM-ION BATTERIES[1]

Use of lithium-ion batteries in California is growing rapidly in multiple sectors, leading to a growing waste stream. Lithium-ion batteries are hazardous waste and must be treated as such in final disposal to mitigate harm to humans and the environment. Battery recycling and repurposing offer the potential to postpone the cost of disposal, to reduce the state's overall waste stream, to reduce cost and supply constraints to new battery production, and even to provide a second life use case for electricity grid services. The degree of synergy in the state's laws, policies, and knowledge-sharing across the electricity, transportation, and small electronics industries will likely have a major impact on the state's ability to realize these benefits.

The goal of this attachment is to provide the CPUC and its stakeholders an overview of end of life options, their scalability, and their tradeoffs—and an overview of important industry trends and policy ingredients that will influence the sustainability of the lithium-ion battery lifecycle.

This attachment is based on a literature review of industry publications and research papers. We also highlight two business case studies that reflect the industry's current successes and challenges with recycling and repurposing lithium-ion batteries.

We start with an overview of the volume of lithium-ion battery usage and end of life options, with some discussion of technical maturity, tradeoffs, and challenges in practice. We then summarize challenges and uncertainties in business models and economics with a focus on the costs and economic viability of recycling and repurposing options. We conclude with summaries of going-forward policy challenges for spent lithium-ion batteries and of our key observations.

This attachment presents a high-level summary for policy use and it includes simplifications of the underlying battery science and technical papers. The recent scientific record is rich with insights and suggestions for future study of the lithium-ion battery aging process (degradation) and end of life options. For more detail we recommend review of the publications referenced at the end of this attachment.

CONTENTS

[1] This is an attachment to the CPUC Energy Storage Procurement Study © 2023 Lumen Energy Strategy, LLC and California Public Utilities Commission. No part of this work may be reproduced in any manner without appropriate attribution. Access the main report and other attachments at www.lumenenergystrategy.com/energystorage.

Size and Types of Lithium-Ion Battery Waste Streams

Electricity. In California's electricity industry, stationary energy storage installations are expected to grow by up to almost 2,000 MW per year of mostly 4-hour lithium-ion storage across all grid domains, with 13,571 MW new battery storage by 2032 and 48,600 MW new battery storage by 2045. Batteries retired from stationary applications do not present a clear repurposing opportunity and will likely need to be either recycled or disposed of. Due to larger battery system size and regulatory environment, spent grid-scale energy storage batteries are relatively straightforward to track and route to the appropriate recycling and disposal channels compared to the transportation and small electronics industries. Smaller and more distributed customer-sited battery installations that are retired may pose some tracking and collection challenges similar to what we see in transportation today. Assuming a 15-year useful life (which is debatable and dependent on actual use case; battery degradation is discussed further throughout this attachment) California's waste stream from large stationary applications would not be expected to ramp up significantly until about 2035.

Transportation. In transportation, however, two factors contribute to the industry's expectation of a spent battery "tsunami" (Reid 2021) and associated pressures to quickly develop end of life options. The first factor is EV batteries are used more aggressively than in stationary applications, resulting in faster degradation and a shorter expected useful life. Tesla's EV battery warranty period, for example, is up to eight years and declines based on mileage (Tesla 2022). The second factor is the rate and depth of EV adoption in some parts of the world, like California, indicates that a wave of spent EV batteries is imminent. Based on historical EV sales (CEC 2022), in 2026 California will have a stock of almost 400,000 EVs that are 8 years or older, growing thereafter by at least 100,000 vehicles per year. As early as 2026, therefore, California could see major growth in its spent battery waste stream. The timeline of actual EV battery degradation to retirement condition, however, is under observation and could take longer than 8 years. In a 2022 interview a Nissan representative reported that observed battery lives are much longer than originally expected and suggested that batteries could remain useful in EVs for 15–20 years (Reid 2022). If this observation is indicative of the industry as a whole, which remains to be seen, California's wave of spent EV batteries could be postponed to 2033 or later.

Regardless of timing, lithium-ion batteries retired from transportation present a significant volume of potential second life capacity for use in stationary energy storage applications. The state's stock of registered light-duty battery and plug-in hybrid electric vehicles (EVs) on the road reached over 800,000 vehicles by the end of 2021 (CEC 2022). Future EV stock is expected to grow to up to 10 million vehicles by 2032 in a high bookend scenario (Bahreinian 2021). Translating these volumes to the electricity industry, spent batteries from 1,000,000 EVs roughly equate to about 7,000 MW/42,000 MWh potential capacity for grid services.[2] How long repurposed batteries would last in their second life is still unclear. How to harvest these batteries for repurposing and ensure they can economically and predictably perform as stationary energy storage over a given period of time also remains to be seen.

Spent EV batteries not (or no longer) suitable for use as stationary energy storage present a major opportunity to recover valuable cathode materials, through recycling, for new battery production. In 2018 California passed Assembly Bill No. 2832 (Dahle), requiring formation of a Lithium-Ion Car Battery Recycling Advisory Group (AB 2832 Advisory Group) to develop recommendations to the state legislature. AB 2832 sets a policy objective to ensure that "… as close to 100% as possible of lithium-ion batteries in

[2] Assuming 60 kWh original battery capacity per vehicle, degradation to 70% capacity at the time of repurposing, and 6-hour charge/discharge rates in stationary use.

the state are reused or recycled at end-of-life in a safe and cost-effective manner." As part of its review, the bill requires the AB 2832 Advisory Group to consider repurposing of EV batteries as stationary energy storage systems.

Small electronics. In small electronics, lithium-ion batteries power a wide variety of devices like cell phones, computers, toothbrushes, and toys. The total volume of small lithium-ion batteries in the state's waste stream is unclear. In the period 2017–2021 California battery recyclers collected about 385,000 pounds per year of lithium-ion batteries (DTSC 2022). Lithium-ion batteries from e-waste do not represent a significant total volume of energy storage capacity from the electricity industry perspective, but they present a major recycling and hazardous waste management challenge as these batteries easily contaminate general waste streams. Small lithium-ion batteries also present an opportunity to recover valuable cathode materials for new battery production.

Overview of End of Life Options

End of life options for lithium-ion batteries fall into three general categories: recycling, repurposing, and disposal (Figure 1). Repurposing extends the life of a battery in whole, and recycling harvests a subset of materials for use in a new battery. All pathways eventually lead to some form of disposal.

Recycling. The cathode material in lithium-ion batteries includes high-value metals such as lithium, cobalt, nickel, vanadium, and manganese. Cathodes represent about half of the cost of the battery cells in an electric vehicle (BloombergNEF 2021) and are the main driver of the value proposition to recycle or repurpose batteries.

Recycling options reflect three main methods to recovery of cathode materials: direct, pyrometallurgical, and hydrometallurgical (Figure 2). Other critical materials—like the graphite used as the anode in a battery cell—can also be recycled. Scientific literature offers rich exploration of recycling methods and the tradeoffs of each. A meta-analysis of lithium-ion battery recycling research identified almost 700 journal articles published globally and in the 2017–2021 timeframe (Baum et al. 2022).

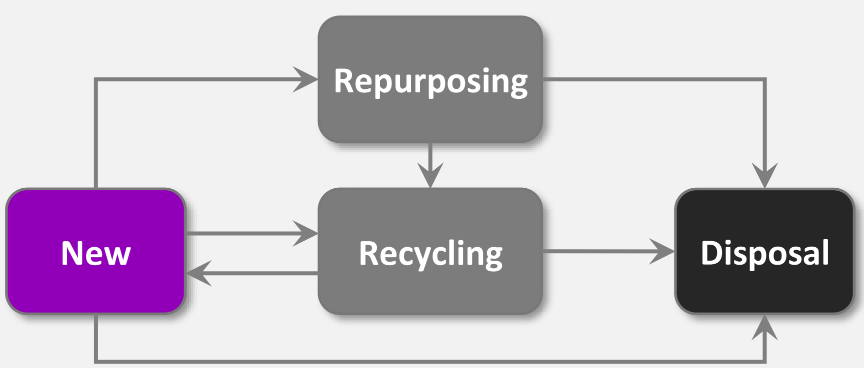


Figure 1: End of life routes for lithium-ion batteries.

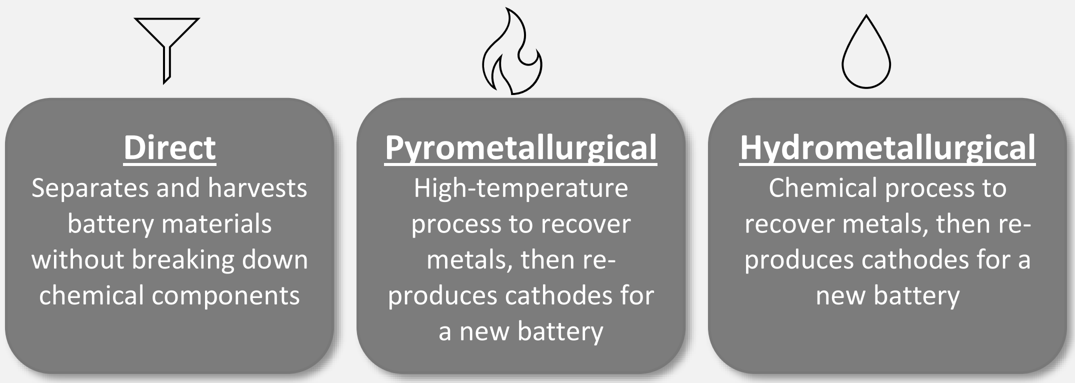


Figure 2: Prominent methods for recycling lithium-ion batteries.

Direct recycling separates and harvests battery materials without breaking down chemical components, with a focus to recover and recondition cathodes for a new battery. Direct recycling is expected to result in high materials recovery, an attractive value proposition, and relatively low emissions and pollution compared to other recycling methods—but it is in a pilot phase. The main challenge with direct recycling is that it relies on sorting and pre-processing that is so finely tuned to an exact type and chemistry of battery that it cannot scale to accommodate the realities of a diverse waste stream or a waste stream that changes over time as technologies evolve (Chen et al. 2019). Argonne National Laboratory's ReCell Center is leading R&D activities to address this and other challenges with direct recycling (Argonne, n.d.).

Pyrometallurgical recycling requires battery pretreatment (e.g., shredding or crushing), utilizes a high-temperature process (on the order of 1,200–1,800°F) to recover metals from a spent battery, then re-produces cathodes for a new battery. This process is used widely in electronics waste processing but not designed specifically for lithium-ion battery recycling. Lithium is particularly difficult to recover with traditional pyrometallurgical recycling methods and new methods are under development for better lithium recovery (Chen et al. 2019). Pyrometallurgical recycling is high cost and results in the worst environmental impacts compared to other lithium-ion battery recycling methods (Mohr et al. 2020).

Hydrometallurgical recycling requires battery pretreatment (e.g., sorting and crushing), separates cathode metals using chemical solutions, then re-produces cathodes for a new battery. Hydrometallurgical recycling produces lower CO_2 emissions than pyrometallurgical recycling but it requires wastewater treatment (Mohr et al. 2020; Mrozik et al. 2021). This type of recycling is viewed as well-suited for lithium-ion batteries, it performs well in terms of materials recovery, and it is potentially economically viable for some cathode chemistries (Yao et al. 2018; Chen et al. 2019). Hydrometallurgical methods are in use for lithium-ion battery recycling by several companies around the world.

	Direct	Pyrometallurgical	Hydrometallurgical
Commercial readiness (specifically for lithium-ion batteries)	Worst	Better	Best
Value proposition	Best (est.)	Worst	Better
Materials recovery performance	Best (est.)	Worst	Better
Pollution impacts of recycling process	Best (est.)	Worst	Better

Figure 3: Key tradeoffs to lithium-ion battery recycling methods.

Figure 3 summarizes key tradeoffs of lithium-ion battery recycling methods. Although direct recycling has the potential to yield the highest value proposition, has the highest materials recovery performance, and results in the least pollution impacts, it is still in a technology development phase. Hydrometallurgical recycling is in some respects a better option because it performs better than pyrometallurgical recycling across these dimensions, and because is in commercial deployment now.

Many of the challenges with recycling, however, lie in creating clear buyer and seller accountability for proper handling of batteries, and in development of tracking, collection, and transportation processes between the spent battery owner and the recycling facility.

California's AB 2832 Advisory Group, led by the California Environmental Protection Agency (CalEPA), published its final report on EV battery recycling in 2022 (Kendall et al. 2022). The group's two core policy recommendations focus on defining who is responsible for ensuring a battery is properly reused, repurposed, or recycled. Their first recommendation, a "core exchange and vehicle backstop" policy, assigns responsibility of tracking a particular spent battery to (a) the most recent manufacturer of that vehicle/battery and (b) any dismantler who removes the battery from the vehicle. The most recent manufacturer could be the original manufacturer of a new vehicle/battery, a refurbisher, or a repurposer. The second recommendation, a "producer take-back" policy, assigns responsibility to the vehicle manufacturer to take back a spent battery at the customer's request and at no cost.

The AB 2832 Advisory Group also developed 12 supporting policies designed to improve:

- Tracking data for individual batteries and access to individual battery information;
- Development of a reuse, repurposing, and recycling business ecosystem; and
- "Reverse logistics" including collection systems and transportation of spent batteries to facilities for reuse, refurbishment, or recycling.

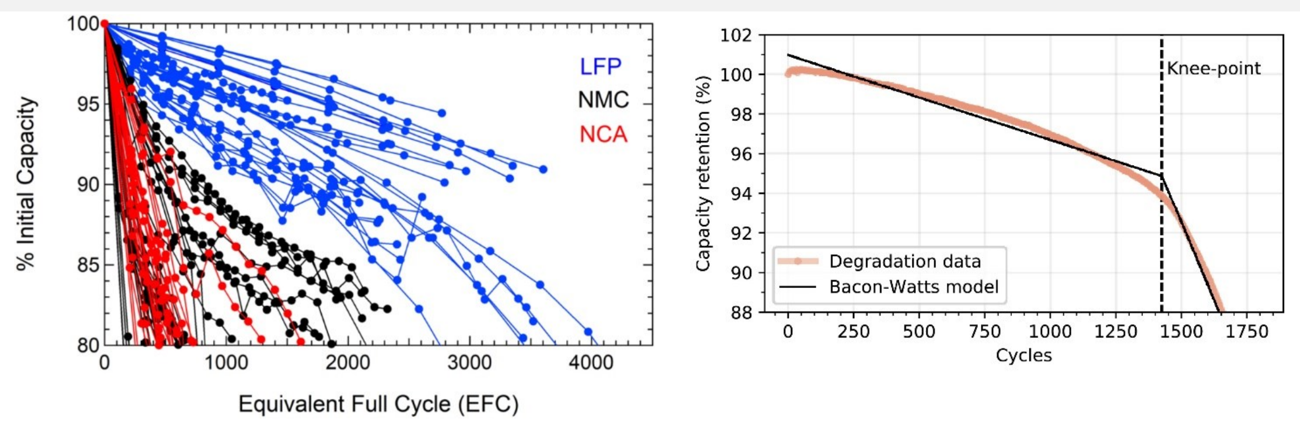
Some materials we reviewed mention lead-acid batteries as an example of a mature battery technology and its well-understood recycling and end-of-life processes. For instance, one study points out that lead-acid batteries have a "mature supply chain and high recycling rate (>99% in the United States and Europe)"—although recycling and repurposing issues are mostly outside of the scope of that study (MIT 2022). Another study uses the example to warn of the dire consequences of an insufficiently regulated recycling industry when the materials include highly toxic substances like lead (Mrozik et al. 2021). They discuss how the lead-acid recycling industry in some areas are highly polluting with uncontrolled lead emissions.

Repurposing. Lithium-ion battery repurposing options depend on the battery's condition, including its history of thermal, electrical, or mechanical abuse, and to what degree the battery is degraded from its first use operating practices. On the topic of repurposing, most literature we reviewed is focused on repurposing electric vehicle (EV) batteries for use as stationary energy storage. This use case is in an early pilot and demonstration phase.

Lithium-ion battery peak (kW) and energy (kWh) capacity degradation is a function of how it is used and of its environmental conditions. Degradation is most simply represented as a single degradation curve, with the number of charge/discharge cycles on the x-axis and the share of functioning capacity on the y-axis (Figure 4, left). Actual degradation varies dramatically depending on actual use of the battery and environmental conditions during its life. Degradation curves typically demonstrate a sharp decrease in the first few cycles, followed by a period of linear degradation, then a rapid decrease after a "knee point" (Fermín-Cueto et al. 2020) (Figure 4, right). Exposure to high or low temperatures, overcharge or undercharge with voltage exceeding certain high/low thresholds, and aggressive cycling in low/high state of charge ranges have each been shown to accelerate degradation significantly. (Edge et al. 2021) provides a useful summary of the extensive scientific literature on lithium-ion battery degradation.

Factors that accelerate degradation also contribute to increased safety risks. **Attachment F (Safety Best Practices)** provides examples of safety consequences of under-voltage (e.g., event at Elden Substation in November 2012) and aggressive cycling (e.g., events in South Korea—2017–2018), as well as the importance of power and thermal management systems.

In addition to capacity degradation, loss of a battery's ability to hold a charge reduces its usefulness in secondary applications. Lithium-ion batteries are characterized by relatively low self-discharge rates but a battery's "thermal history" (particularly, exposure to high temperatures even if momentary) can significantly affect its self-discharge rate (Seong et al. 2018) and thus its ability to hold a charge.



(a) Capacity degradation curves based on number of full cycles and battery chemistry (Preger et al. 2020)

(b) Estimation of knee-point onset in a capacity degradation curve (Fermín-Cueto et al. 2020)

Figure 4: Examples of lithium-ion battery degradation curves.

Exactly when a battery retires from transportation may depend on each EV user's appetite for reduced battery performance. EV manufacturer warranties provide some indication of broadly-unacceptable battery performance. Tesla, for example, guarantees 70% retention of battery capacity over a warranty period of up to eight years (Tesla 2022). The AB 2832 Advisory Group notes that battery retirement from EV use is "generally assumed to be between 70–80% [remaining battery capacity]" (Kendall et al. 2022). Batteries below 70% capacity retention may still be useful as stationary energy storage. But it is questionable whether a highly degraded battery—such as one close to or past its knee point—would be sufficiently useful or reliable for stationary energy storage applications.

The highest value stationary energy storage applications are energy time shift, including daily cycles, RA capacity and performance during grid emergencies, and performance as backup power. Stationary energy storage applications do not have the same energy density requirements as an EV and thus an installation can be expanded to a larger footprint with more battery packs to offset reduced capacity of each battery pack. But second use batteries would need to reliably hold a certain state of charge for at least a day to provide energy time shift and RA capacity services, and for several days to provide reliable backup power. Accelerated self-discharge and/or unexpected knee point crossover would be problematic to a battery's ability to provide valuable stationary energy storage use cases.

The AB 2832 Advisory Group notes that repurposing of EV batteries for use as stationary energy storage "… is a relatively new industry and data about performance is uncertain because of the uneven degradation of battery cells over time…" Currently, no standard data collection or testing methods for determining the quality of second life batteries are in place. The AB 2832 Advisory Group also points out that "the CEC is funding several ongoing demonstration projects in California." As of 2022 these CEC research projects are in an early stage and results are pending.

Disposal. Recycling and repurposing postpone or reduce the waste stream, but battery materials will eventually be disposed of. Two important issues on disposal of lithium-ion batteries as hazardous waste are: (1) the pollution risks of the battery's hazardous materials, and (2) how and to what degree disposal routes are controlled to manage those risks.

Hazardous materials held or produced by spent lithium-ion batteries include hydrogen fluoride and other gases, metals (particularly nickel and cobalt), chemical compounds, and various other reactions with water (e.g., hydrofluoric acid) and other substances that each are highly toxic to humans and to the environment (Mrozik et al. 2021). Pollution pathways include gas and dust release into the air, and soil and water contamination—notably from landfill leachate (Mrozik et al. 2021). (Mrozik et al. 2021) offers a comprehensive discussion of pollution sources, pathways, and consequences.

Appropriate handling and landfilling of lithium-ion batteries from small electronics has proven particularly difficult to control. Small lithium-ion batteries can easily enter general waste or recycling processes undetected and thus result in an uncontrolled release of hazardous materials. Batteries landing in the general waste stream contribute to the rising number of fires originating from lithium-ion batteries in landfills, recycling centers, and waste transportation—causing injury, service disruption, property damage, and release of a variety of toxins (U.S. EPA 2021; Mrozik et al. 2021). Decomposition in general waste landfills—rather than those designed for hazardous waste—and illegal dumping pollutes even further, notably via leachate that contaminates soil and water (Mrozik et al. 2021).

In 2022 California passed two pieces of legislation, Senate Bill No. 1215 (Newman) and Assembly Bill No. 2440 (Irwin), designed to significantly improve the collection of spent lithium-ion batteries from small electronics for appropriate recycling and disposal routes.

Proper disposal of larger batteries from EVs and stationary applications is more straightforward than small electronics but it is not without challenges. Battery tracking and collection systems that establish regulations, provide easily-accessible routes for disposal, and effectively penalize for non-compliance are important ingredients to a sustainable end-of-life ecosystem.

Value Propositions for Recycling and Repurposing

This section provides a high-level overview of the current status of the economics of lithium-ion battery recycling and repurposing, including a discussion of key risks to the value propositions and how policies can help.

(Lander et al. 2021) We highlight this study as a demonstration of the key factors and issues impacting the economics of recycling. The authors expand upon prior technoeconomic studies of recycling EV lithium-ion batteries by estimating the net profitability of direct, hydrometallurgical, and pyrometallurgical recycling domestically (in the United Kingdom) versus overseas including transportation costs. They analyze net recycling profits across several lithium-ion chemistries, including the three dominant chemistries lithium-nickel-manganese-cobalt oxide (NMC), lithium-iron-phosphate (LFP), and lithium-nickel-cobalt-aluminum oxide (NCA). They found that viable value propositions are possible, but strongly dependent on “transport distances, wages, [battery] pack design and recycling method” (Lander et al. 2021). Their results also demonstrate the importance of battery chemistry: chemistries with nickel and cobalt (NCA and NMC) produced higher revenue and net recycling profits, all else being equal.

Specific analytical findings in (Lander et al. 2021) indicate:

- Due to lower cost, hydrometallurgical recycling yields a higher net profit than pyrometallurgical.
- Domestic hydrometallurgical recycling of NCA and NMC is close to break-even and may be improved through cost economies of scale.
- LFP recycling is not profitable except under the hypothetical direct recycling method.
- Actual battery pack designs significantly affected recycling cost: the cost and complexity of disassembly of a representative commercial LFP pack (Nissan Leaf), for example, made LFP recycling profitability significantly worse.
- Due to a wide range of estimated international transportation costs to specific countries, the profitability of sending materials overseas for recycling is unclear.

Lithium-ion batteries as a mixed waste stream. We do not know how future battery technologies and chemistries will evolve. For now, it is reasonable to expect that the flow of spent lithium-ion batteries will include a variety of battery types, each with a different value proposition for recycling and each requiring a different approach for disassembly, sorting, and other recycling pretreatments. Policies that (a) set the stage for mixed collection and processing streams and (b) help recyclers track and identify differences in battery types out of those mixed streams, such as policies outlined by the AB 2832 Advisory Group, will likely be critical to a healthy recycling ecosystem.

Policy role for attractive recycling value propositions. Battery chemistries with high-value cathodes like nickel and cobalt have a clearer value proposition for recycling, and with it a higher chance that the private sector will develop a recycling ecosystem on its own. Policies can be supportive by improving spent battery tracking, collection, and reverse logistics as emphasized by the AB 2832 Advisory Group. Policies can also help the recycling industry build enough economies of scale to be profitable, and build some of that infrastructure and expertise ahead of the upcoming wave of spent EV batteries. For nickel and cobalt specifically, policies that support recycling of these minerals will also help to (a) relieve global supply chain pressures on new battery production and (b) reduce the volumes of these minerals in the waste stream and their pollution risks.

Policy implications of poor recycling value propositions. Battery chemistries without cobalt or nickel, like LFP, appear to have a poor recycling value proposition and thus the private sector is not likely to develop a recycling ecosystem on its own. Battery chemistries in both transportation and in stationary energy storage have begun to trend away from NMC and towards LFP—in part driven by its more stable chemistry and in an effort to improve safety (*see* **Attachment F (Safety Best Practices)**). LFP battery chemistry is also preferable to NMC from a final disposal perspective due to its lower pollution risks. If California sets goals to reduce the lithium-ion battery waste stream and/or create more of a circular lifecycle for lithium-ion batteries, then relatively strong recycling standards, incentives, and accountability will be needed for battery chemistries like LFP—and possibly for non-cathode materials in <u>any</u> battery. A major recycling innovation like direct recycling—if its high rate of materials recovery and low cost can be proven at commercial scale—would relieve that policy pressure, but the path of this innovation is unclear at this time.

This situation reflects an important tension among the industry's trends in battery types and chemistry, recycling value proposition, and related policy pathways that is reminiscent of challenges in recycling plastics (*see* Steinbauer 2021). Just as not all *technically* recyclable plastic polymer types have a viable *financial model* for recycling, not all lithium-ion battery types, chemistries, or materials have a clear recycling value proposition. Although they may be technically recyclable today, many batteries and battery materials are unlikely to actually be recycled without a strong policy framework.

Depending on the state's recycling objectives, policies may need to be developed beyond collection and sorting—to clarify what materials must be recycled and address the economics of the recycling process itself. The goal here would be to ensure those materials are not produced in the first place, and/or actually recycled rather than disposed of after collection and sorting. California's 2021 Circular Economy Package, aimed at addressing the realities of the plastics recycling value proposition and towards building a more circular plastics lifecycle, provides guidance that may be more generally useful for battery recycling. Integration of recycling standards and recycled materials with domestic battery production policies will likely also be an important element to development of a circular lifecycle for lithium-ion batteries.

Recycling Business Case Study: Li-Cycle

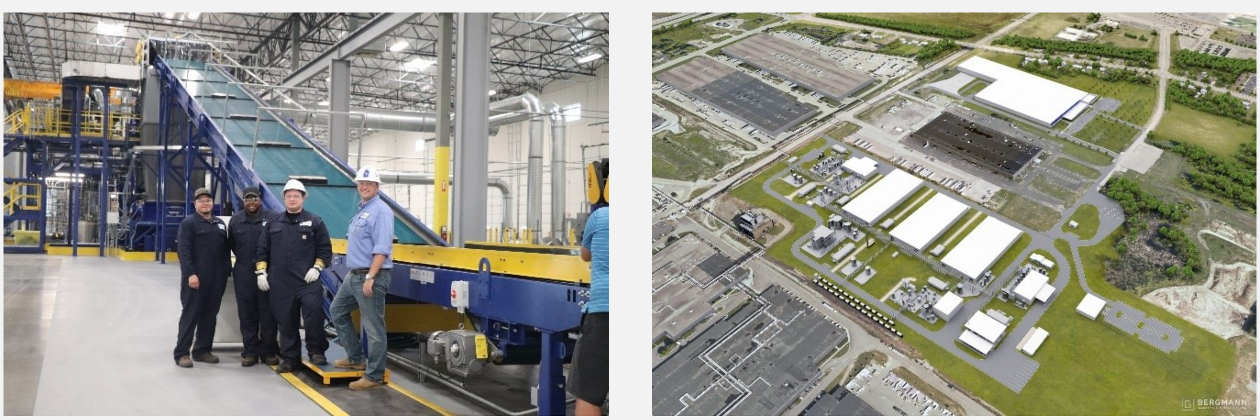
Li-Cycle, founded in 2016, is a lithium-ion battery recycling company based in Canada and operating North America and Europe (*see* li-cycle.com).

Over its initial 6 years, Li-Cycle focused on developing the infrastructure and logistics to collect spent lithium-ion battery materials, recover critical cathode minerals (nickel, cobalt, lithium, and manganese), and sell the recovered minerals to the commercial market. Through about 2019 the company was in an initial pilot and demonstration phase. In 2021 Li-Cycle became a publicly-traded company on the New York Stock Exchange (NYSE: LICY), and as of 2022 the company is in an initial investment and commercial expansion phase towards its target annual processing capacity.

At the core of Li-Cycle's recycling infrastructure and logistics is the company's Spoke & Hub Technologies™ (Figure 5). The "Spokes" are distributed collection points where battery materials are pre-processed into a pulverized "black mass" of electrodes, then sent to a centralized "Hub" for hydrometallurgical processing into mineral powders. Li-Cycle's Spokes are designed to intake a variety of battery formats: "from 'powder to pack', meaning all materials from cathode powder through to full EV packs can be processed…" (Li-Cycle Corp. 2022b). Li-Cycle also describes its Spoke pre-processing as "battery chemistry agnostic" (Li-Cycle Corp. 2022a) which implies some flexibility to adjust to future changes in the recycling value proposition.

In 2021 Li-Cycle's battery recycling sources by volume were 49% transportation original manufacturer equipment including recalls, 27% manufacturing scrap, 20% consumer electronics, and 4% energy storage systems (Li-Cycle Corp. 2021). Li-Cycle appears to follow a staged approach to process recycling sources as they evolve over time: first from small electronics, then transportation, then stationary energy storage.

Li-Cycle is implementing an innovative strategy to developing its recycling infrastructure and logistics *ahead* of the industry's expected wave of spent EV batteries. As battery manufacturing has accelerated in recent years, Li-Cycle taps into <u>manufacturing scrap</u> as both a major supply of recyclable materials and as an opportunity to develop relationships with battery manufacturers. Battery manufacturers would ultimately be among the buyers of final Hub products. As of October 2022 Li-Cycle has three operational Spokes in North America, close to battery manufacturing plants. Li-Cycle's first commercial Hub is under construction in Rochester, NY and expected online in 2023.



(a) Arizona Spoke (b) New York Hub Design (in development)

Figure 5: Li-Cycle's Spoke & Hub facilities.

(Images credit: Li-Cycle)

Li-Cycle's business strategy and key innovations highlight the importance of (a) the value of critical cathode minerals to a viable recycling financial model, (b) the flexibility to pre-process a mixed waste stream, in terms of spent battery source (e.g., small electronics, transportation, stationary), format (e.g., pack design), and chemistry, (c) connecting to a wide range of sources for recyclable materials, and (d) "closing the loop" with battery manufacturers who are buyers of the recycled product.

Value proposition for repurposing. Repurposing spent EV batteries for use as stationary energy storage is still in an early pilot and demonstration phase. Although the cost to repurpose and to ensure reliable battery performance are unclear, the potential benefits are meaningful.

In **Chapter 3 (Moving Forward)** we discuss how stationary energy storage can support state goals at a large scale through the high-value energy time shift and RA capacity use cases. Energy storage installed in the distribution and customer grid domains can also provide communities and individual customers who are most vulnerable to grid outages and weather extremes significant additional value as backup generation.

Repurposing studies we reviewed find economics that are favorable but highly dependent on ability to determine battery condition, quality, and performance levels.

For example, in 2015, National Renewable Energy Laboratory (NREL) researchers published a study on barriers to repurposing EV batteries. They find repurposing cost can be as low as $20/kWh nameplate capacity and that second use batteries could last up to 10 years, but these results hinge on the ability to identify and exclude batteries with faulty cells (Neubauer et al. 2015). Similarly, (Kamath et al. 2020) find that EV batteries repurposed for stationary energy storage yield a lower levelized cost of electricity than new batteries, but that uncertainties in battery quality and availability need to be addressed.

The AB 2832 Advisory Group's policy recommendations to improve tracking and information collection on individual batteries can help de-risk repurposing cost and second life battery performance. Even so, used batteries may still be viewed as undesirable or risky by consumers. Depending on the state's waste management goals, additional policies may be needed to further reduce performance risk, reduce the soft costs of collecting and installing re-purposed battery packs, and/or incentivize utilities and customers to use repurposed batteries even when the equivalent cost of a new battery is similar.

Repurposing Business Case Study: RePurpose Energy

RePurpose Energy, founded in 2018, is a California startup focused on developing testing for used EV batteries, and reassembly and controls for reuse in stationary applications (*see* www.repurpose.energy).

In 2019 the company developed a 60 kW/275 kWh demonstration project using a collection of Nissan LEAF battery modules. In 2020 RePurpose Energy began a research project with the California Energy Commission to (a) validate ability to provide resilience services, (b) provide a cost comparison to new batteries, and (c) characterize degradation rates during second life (CEC, n.d.).

RePurpose Energy's commercially-available second-life battery product—a modular 20-foot 1.2 MWh container—is due for launch in 2023. Their technologies are aimed at reducing the costs and risks of repurposing and of battery performance in its second life. RePurpose Energy's technological innovation is based on machine learning models to rapid-test batteries, optimization models for reassembly into a stationary system, and state-of-the-art battery management systems to optimize battery performance.

Going-Forward Policy Challenges for Spent Lithium-Ion Batteries

California has taken important steps to support development of a recycling ecosystem for lithium-ion batteries, but much legal and policy work remains.

The state's number one challenge is to first secure the hazardous waste stream, all the way to final disposal and regardless of recycling and repurposing options. Two bills passed in 2022 (SB 1215 and AB 2440) advance the state's ability to control the waste stream and pollution from lithium-ion batteries in small electronics. In parallel, the AB 2832 Advisory Group's policy recommendations to the legislature set the foundation for EV battery tracking and accountability for battery reuse, repurposing, and recycling. Their recommendations could be expanded to dovetail with SB 1215 and AB 2440 and establish regulations to track and route all batteries into appropriate recycling, repurposing, and hazardous waste disposal facilities. (Mrozik et al. 2021) also suggests filling key knowledge gaps in pollution impacts, including (but not limited to) seeking a better understanding of what waste streams actually look like and measurement of actual pollution impacts. The aim here is to fully understand, minimize, and hopefully eliminate lithium-ion contamination in human and environmental systems by directing all spent lithium-ion batteries into the appropriate recycling, repurposing, and disposal facilities.

The state's second major challenge is to minimize or postpone the final disposal stream as much as possible. This can reduce pollution risks and relieve expensive new battery supply chain constraints by pushing hazardous materials and of other critical battery materials back into useful applications, in support of a more sustainable and circular lithium-ion battery lifecycle. This is achieved by routing as much of the waste stream towards recycling and repurposing as possible, but it may require the state to define exactly what materials in the waste stream it wants to minimize. Key issues to address include the logistics and economics of recycling and repurposing. And these need to be addressed quickly enough to keep up with the waste stream as it grows over time. The AB 2832 Advisory Group's report includes recommendations that would would improve the availability of individual battery information and reverse logistics to the recycling and repurposing facilities. Other supporting policies include those that help to reduce the costs of recycling and repurposing (including investment in innovations like direct recycling), policies that motivate customers and utilities to demand repurposed batteries and batteries made with recycled materials, policies that provide a procurement backstop if the private financial value proposition remains poor, and policies that discourage first-life use of materials have an unacceptably low recovery and recycling rates.

Key Observations

Lithium-ion batteries are expected to produce a significant and growing stream of hazardous waste from the electricity, transportation, and small electronics industries. In California, growth is expected to accelerate as early as 2026 but as late as mid-2030s if EV batteries last longer than originally expected.

End of life options include recycling, repurposing, and disposal. Recycling and repurposing options are largely in an early pilot and demonstration phase.

Recycling methods include direct, pyrometallurgical, and hydrometallurgical. Recovery of cathode metals is the key value driver of the recycling option.

Hydrometallurgical recycling is currently the most attractive commercially-ready method of recycling due to its lower cost, higher materials recovery, and lower pollution impacts compared to pyrometallurgical recycling. Direct recycling promises significantly lower cost and higher materials recovery—but is still in a technology development phase.

Lithium-ion battery technologies and chemistries are varied, producing a mixed waste stream, and resulting in significant differences in the cost of recycling (e.g., pack disassembly, sorting, and other pre-processing) and in the expected revenues from various recycled materials.

Repurposing of EV batteries for stationary applications is technically feasible, could provide significant grid value, and is potentially scalable to large volumes. However, the overall value proposition is still unclear and in an initial demonstration phase. Uncertainties in battery condition and degradation over its second life pose a significant risk in the viability of second life use cases.

One core objective of disposal laws and policies is to minimize illegal dumping and circulation through general waste streams. Appropriate disposal of batteries from small electronics is particularly challenging. In 2022 California passed two pieces of legislation (SB 1215 and AB 2440) designed address this challenge.

Battery tracking and information, collection, and reverse logistics to its next life stage (recycling, repurposing, or disposal) are key areas for policy development, as emphasized in California's AB 2832 Advisory Group 2022 report to the Legislature.

Recycling processes will need to be closely monitored for pollution impacts, drawing from lessons learned in the lead-acid recycling industry.

Recycling policies will likely need to address the issue of poor recycling value propositions of many types of batteries and battery materials. The state's challenges with plastics recycling and California's 2021 Circular Economy Package legislation can provide guidance for going beyond battery collection and sorting to truly close the loop to a circular battery lifecycle.

Depending on the state's waste management goals, policies may be needed to motivate electricity customers and utilities to use repurposed batteries that are close in cost to new batteries.

Overall, the state faces two major challenges as lithium-ion battery waste streams grow in the near future: (1) to secure the hazardous waste stream all the way to final disposal, and (2) minimize or postpone the final disposal stream in support of a more sustainable and circular lithium-ion battery lifecycle.

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ATTACHMENT H: STAKEHOLDER ENGAGEMENT[1]

Stakeholders had a significant role in shaping the scope of this CPUC Energy Storage Procurement Study. The CPUC issued a Request for Information in early 2020 to determine desired study scope, timeline, and contractor requirements, then engaged with stakeholders over a period of six months to make necessary refinements. Assessment of safety-related best practices is included in the core study scope. This evaluation also includes several "special studies" to inform future policy developments, including: review of other energy storage procurement policies in practice, models for stacking multiple services and value at once, analysis of cost-effectiveness of future procurements and natural gas peaker replacements, and documentation of end-of-life options. Safety best practices and these special studies are considered in the overall assessment and recommendations, with further detail in attachments.

The goal of this attachment is to provide the CPUC and its stakeholders an overview of the stakeholder process throughout this study, key issues raised by stakeholders, and how their feedback and engagement shaped and enriched the study's analytics, key observations, and recommendations.

The authors are grateful to the many stakeholders who contributed by providing data and feedback to this study, with a special thanks to the CPUC, California Energy Commission, California ISO, Public Advocates Office, Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, San Diego County Water Authority, and California Energy Storage Alliance.

CONTENTS

Study Timeline and Key Dates

The CPUC Energy Storage Procurement Study launched in March 2021. Three 4-hour workshops were held with stakeholders at major study milestones to share study progress and to collect feedback. Prior to the third stakeholder workshop a draft report was posted publicly for stakeholder comment, including seven attachments. After each workshop, stakeholders were invited to share their feedback through an online survey.

Figure 1 below shows the overall timeline of the study. Key dates draft materials were shared with stakeholders are:

May 26, 2021	Workshop #1 to provide a study introduction and draft evaluation framework
September 30, 2021	Workshop #2 to present a final evaluation framework and initial observations on project use cases and operations
October 24, 2022	Draft main report posted for stakeholder review
October 31, 2022	Draft report attachments A–G posted for stakeholder review
November 4, 2022	Workshop #3 to share draft study findings, conclusions, and policy recommendations

All stakeholder workshop presentations and draft report materials are available for download at www.lumenenergystrategy.com/energystorage.

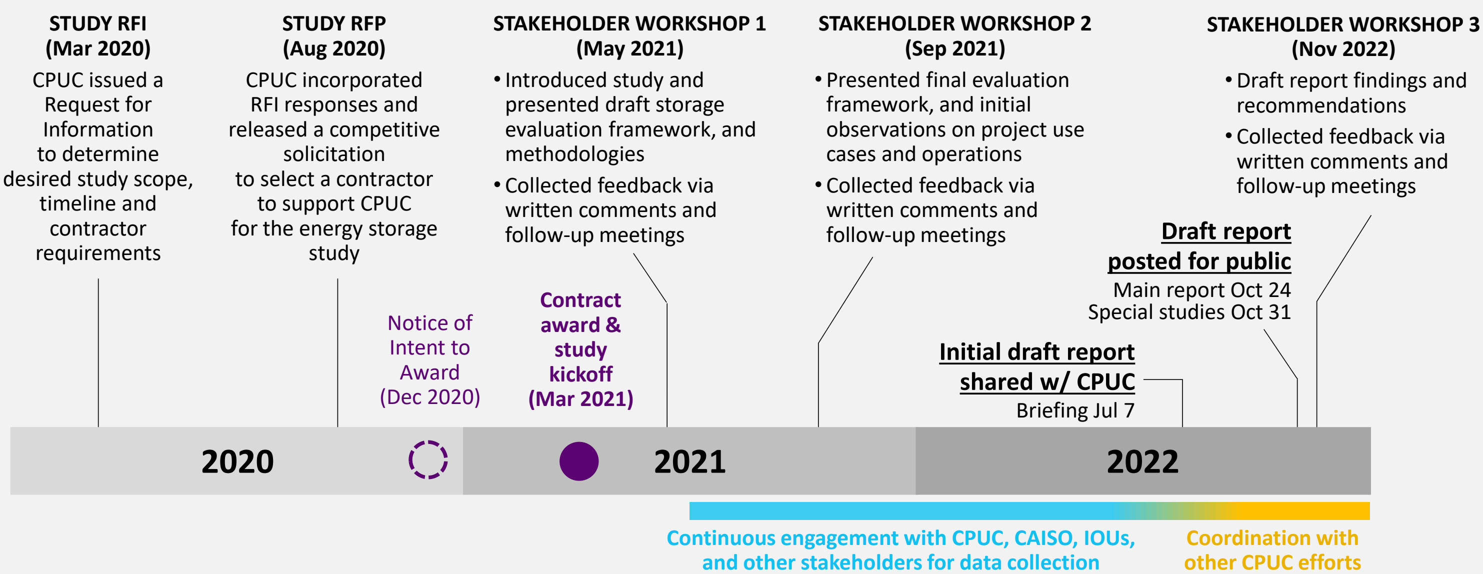

Figure 1: Study timeline and stakeholder engagement.

Scope and Methodology Refinements/Workshop #1

In workshop #1, held May 26, 2021, the study team discussed the study motivation and purpose, scope of energy storage resources included in the analysis, the study evaluation framework, and proposed benefit and performance metrics.

The audience included a large share of utility and regulator representatives, along with CAISO, community/customer, developer/engineer/technical, researcher/academic representatives. Most audience members were generally optimistic of the value of energy storage—as indicated in their response to a live multiple choice poll with “energy storage is a crucial ingredient to achieving California’s clean energy goals” or “energy storage clearly has a great deal of value—we need to figure out how to quantify or monetize that value.” The study team encouraged questions during the workshop and requested additional feedback through an online survey form completed by June 9, 2021.

Workshop #1 survey questions were structured to allow stakeholders to click on one of two radio buttons “I like the proposed methodology described in the workshop” or “It needs additional consideration (add comments below)” on any or all of the following 13 topics. With the latter selected, stakeholders could add comments for clarification.

1. Energy and ancillary services market (monetized benefits: avoided cost)
2. Voltage support and black start (monetized benefits: avoided cost)
3. System and local resource adequacy capacity (monetized benefits: avoided cost)
4. Flexible resource adequacy capacity (monetized benefits: avoided cost)
5. Transmission and distribution investment deferral (monetized benefits: avoided cost)
6. Distribution- and customer-level outage mitigation (monetized benefits: avoided cost)
7. Customer bill management and use of self-generation (analyzed for barriers to providing grid-level services)
8. Impact on GHG emissions (monetized benefits: avoided cost)
9. Impact on renewable curtailments and RPS cost (monetized benefits: avoided cost)
10. Application of CPUC cost-effectiveness tests (ratepayer impact, total resource cost, societal, utility/program administrator cost)
11. Scoring towards meeting AB 2514 goals of *grid optimization* (utilization of capacity towards providing grid services)
12. Scoring towards meeting AB 2514 goals of *renewable integration* (utilization of capacity towards providing the specified subset of grid services)
13. Scoring towards meeting AB 2514 goals of *GHG emissions reductions* (total metric tonnes avoided per kW or kWh of energy storage project capacity)

Three stakeholders responded through the survey. The study team also followed up with stakeholders over email and/or conference calls on questions that came up during the workshop.

Stakeholder feedback overall was largely supportive, with most suggestions in alignment with the proposed evaluation framework. Feedback generally fell into three categories: suggestions refining study scope of work, needs for clarification on benefit and cost metrics, and suggestions for framing the study on energy storage market evolution. The study team refined the study accordingly, and prepared materials to provide further clarification on analytical approach in workshop #2.

Data Collection and Stakeholder Outreach

Data collection began early in the study timeline and continued throughout the study. The evaluation framework could not have been executed without the significant efforts of the IOUs, CAISO, and CPUC to compile data on energy storage operations, characteristics, and procurements.

Throughout the study data collection and analytical process the study team engaged in outreach to stakeholders. The study team engaged in dialogue with CalCCA, California Energy Commission, California Energy Storage Alliance, California ISO, Clean Coalition, Direct Energy, Lawrence Berkeley National Laboratory, Long Duration Energy Storage Association of California, LS Power, Pacific Gas and Electric, Plug to Grid Strategies, Protect Our Communities, Public Advocates Office, Renewables America, San Diego County Water Authority, San Diego Gas & Electric, Southern California Edison, Stem, The Center for Community Energy, Thule Energy Storage, Verdant Associates, LLC, and WattTime. Within the CPUC, the study team sought feedback from a wide range of subject matter experts.

Draft Analytical Results/Workshop #2

In workshop #2, held September 30, 2021, the study team began by discussing feedback from the prior workshop. The rest of the workshop included discussion of the data collection process; preliminary findings on energy storage market evolution; preliminary results on energy and ancillary services market value, GHG emissions impacts, and impacts on renewable curtailments; draft RA capacity counterfactuals; and findings relevant to customer outage mitigation benefits.

As in the first workshop, the audience for workshop #2 included a large share of utility and regulator representatives, as well as CAISO, community/customer, developer/engineer/technical, researcher/academic representatives. This time, live polling questions focused on outage mitigation-related experiences. About 30% of the audience affirmed they live in an area subject to PSPS. Only a few had backup power installed, mostly not in response to PSPS. These polling questions facilitated further discussion at the end of the workshop on customer outage mitigation benefits, a particularly difficult benefit category to quantify.

The study team encouraged questions during the workshop and requested additional feedback through an online survey form due by October 15, 2021.

Workshop #2 survey questions were—again—structured to allow stakeholders to click on one of two radio buttons, but this time selecting between “I agree or mostly agree with this statement (add comments below)” and “I disagree or mostly disagree with this statement (add comments below).” Stakeholders had the option to answer this question on any or all of the following 6 preliminary study findings:

1. DATA COLLECTION: “Improvements to data collection, retention, and centralization are crucial to understanding and evaluating cross-domain investments like energy storage.”
2. EVOLUTION OF ENERGY STORAGE: “California’s market for energy storage development shows significant growth, cost decreases, and expansion of services available.”
3. MULTI-USE APPLICATIONS: “The storage market has made progress with multi-use applications, but challenges remain: most customer-sited resources and many distribution-sited resources do not participate in the CAISO wholesale marketplace and operations are not in alignment with wholesale market signals; no actual specified transmission wires deferrals are observed, and distribution wires deferrals are limited.”

4. ENERGY & A/S MARKET AND GHG IMPACT: "We observe the following situations and use cases increase GHG emissions and energy costs: ancillary services as a primary use case; use cases with storage mostly on standby; use cases not integrated with a wholesale market signal."
5. RENEWABLE CURTAILMENT IMPACT: "Avoided renewable curtailments so far are relatively small, although we see evidence that this value stream will grow over time as the state moves towards its 100% clean energy target."
6. CUSTOMER OUTAGE IMPACT: "Customer outage mitigation may be a significant resiliency benefit stream for distributed storage and vulnerable customers, but extremely limited information on Value of Lost Load makes this impact difficult to estimate."

One stakeholder responded through the survey. The study team followed up with multiple stakeholders on the topic of customer outage mitigation value specifically. The study team also had follow-up meetings with stakeholders to discuss other questions that came up during the workshop, mostly on the topics of GHG emissions savings calculations and findings. Generally, stakeholder feedback was positive and supportive of the preliminary study findings.

Draft Report and Recommendations/Workshop #3

The study team posted a draft report for stakeholder review and comment on October 24, 2022 and draft report attachments A–G on October 31, 2022. On November 4, 2022 the team held workshop #3 to discuss the report structure, key study results, and draft policy recommendations.

The study team encouraged questions during the workshop and requested additional feedback through an online survey form completed by December 2, 2022. Due to the volume of material, and at the request of stakeholders, the survey completion deadline was extended to December 9, 2022.

Three stakeholders responded through the survey. The study team followed up with multiple stakeholders to either collect additional feedback or confirm they decline to comment. Feedback generally fell into four categories: items needing clarification of existing material in the report, additional references or context that could potentially supplement material in the report, ideas for further study that might be addressed by future energy storage evaluations, and ideas for further study that are best addressed through other types of studies. The study team reviewed each piece of feedback carefully to determine if edits to the report would be appropriate and implemented changes to the report.