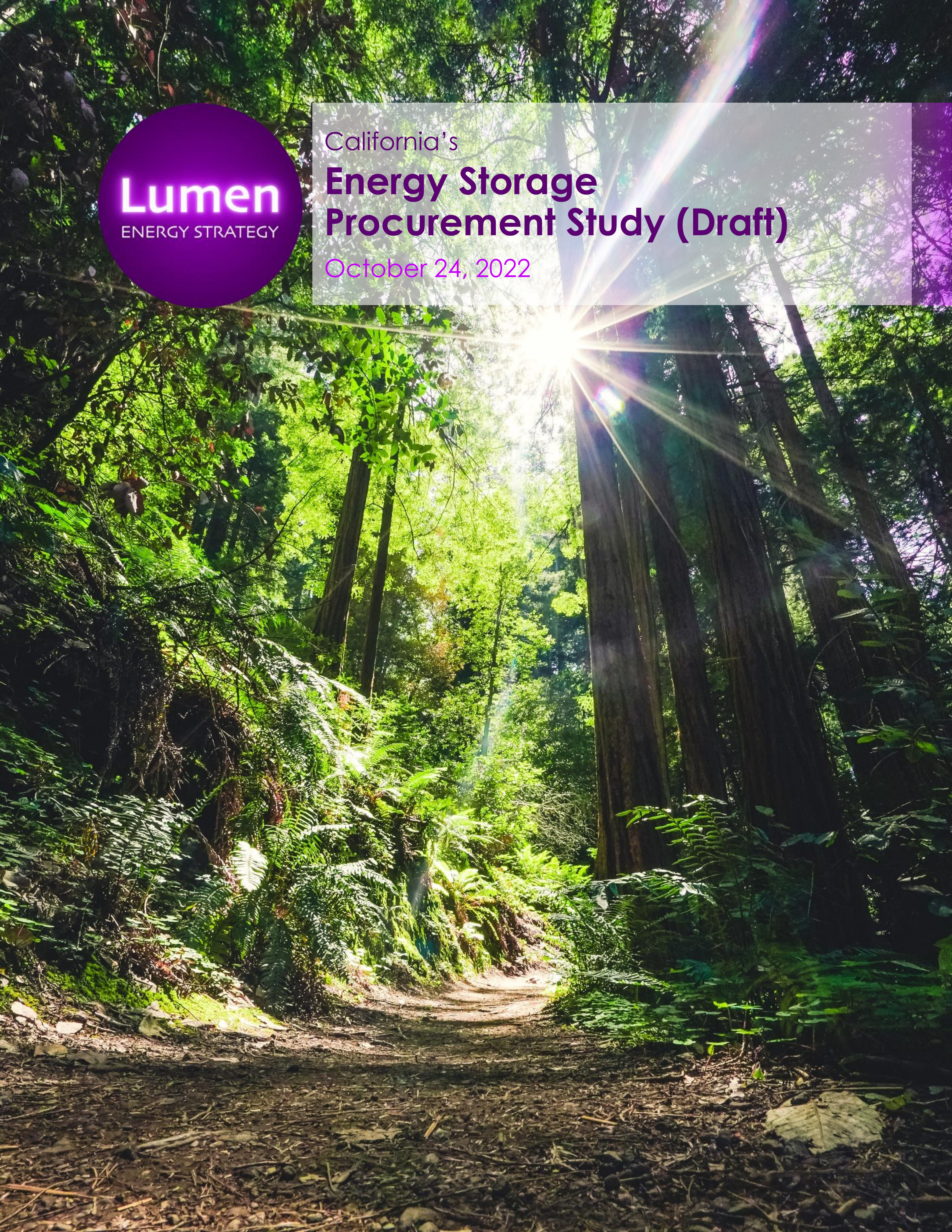
Lumen
ENERGY STRATEGY

California's

Energy Storage Procurement Study (Draft)

October 24, 2022



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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 = <u>$16/kW-month</u>) 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 = <u>$8/kW-month</u>). 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) 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 in front of the CAISO meter (transmission domain), on the distribution system behind the CAISO meter and in front of the customer meter (distribution domain), or behind the 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).

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 early stage 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 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 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 evaluation, with a special thanks to representatives of the CPUC, the California Energy Commission, the California ISO, the Public Advocates Office, Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, and the San Diego County Water Authority.

EXECUTIVE SUMMARY

The Energy Storage Procurement Study, required under California Public Utilities Commission (CPUC) Decision 13-10-040, aims to learn from historical stationary energy storage procurements and operations and to assess the evolution of California's stationary energy storage industry both historically and in the future. 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 incurred $73 million net cost per year on average for exploratory projects and incentive programs. 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 $23 million per year by the end of 2021. The cost of earlier exploratory projects and incentive programs will continue at $85 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 $830 million to $1.35 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–$1.55 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 1,350 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 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.

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.

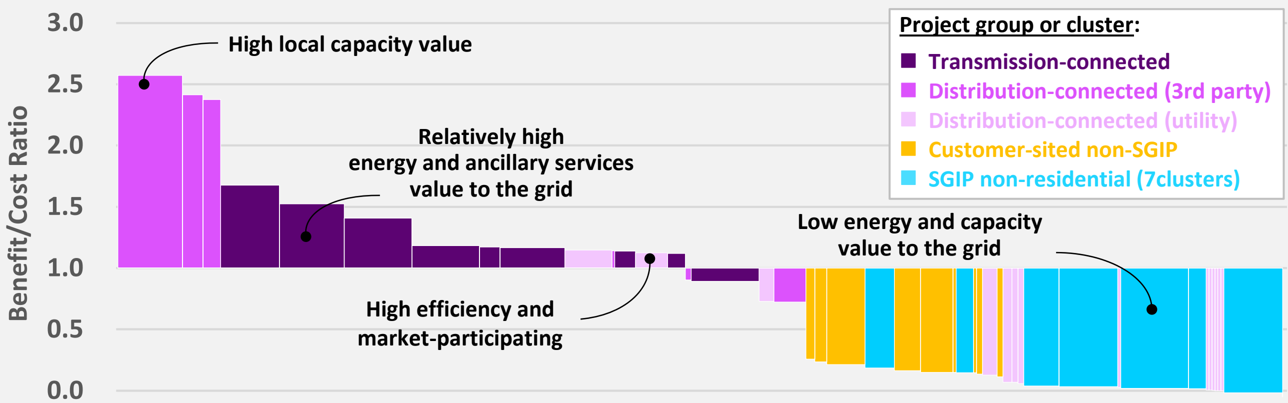


Figure 1: Summary of ratepayer benefit/cost ratio results.

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 to operate. 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 shown in 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

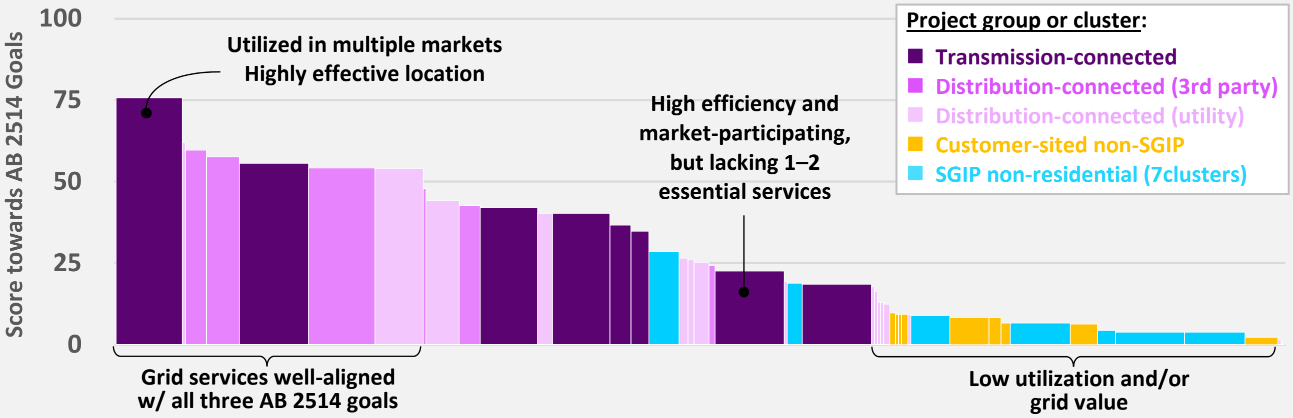


Figure 3: Summary of utilization towards Assembly Bill 2514 goals.

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 440 MW/990 MWh. Grid-scale installations grew from 130 MW/510 MWh or 10% of all installations in the country to 2,300 MW/8,800 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/9,000 MWh of mostly grid-scale online installations provided resource adequacy services. Another 3,200 MW/ 12,500 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 the worst and had operating patterns in competition with solar generation and indicative of demand charge bill management. These resources provided <u>negative</u> energy value and increased GHG emissions. This finding is consistent with the state's prior SGIP evaluation reports and corrective program requirements were effective in April 2020 for non-residential installations to respond to a marginal GHG emissions rate signal. However, the impact of the new performance requirement was not yet apparent during our evaluation period, likely due to the length of project development timelines and exemptions for legacy projects.

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 <u>negative</u> 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 overall 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 12 MW/28 MWh subset of resources were 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 250 MW/510 MWh non-residential installations under SGIP 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 load 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.

Three other relatively minor 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. Updates to the California Fire Code July 2021 set the stage for a more comprehensive and coordinated safety risk management approach in the state—but much work remains.

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 increase with increased renewables 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 40 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 72 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) 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 to longer duration configurations (6- to 8-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.

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.

Conclusions and 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. We recommend 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. We recommend:

- **Bring stronger grid signals to customers overall:** More generally, development of significantly stronger signals to customers on the time-varying value to the grid of storage operations is needed. 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.

- **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.

- **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.
  - 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 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 3rd-party-owned distribution-connected resources, and both existing and new resources must be positioned for multiple use applications. We recommend to:

- **Accelerate market transformation** including improvements to 3rd 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.

- **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, require all utility-owned installations and contracted third-party distribution deferral projects to seek participation in the CAISO marketplace.

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. We recommend 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**, 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 Division 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. We recommend 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 agencies 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.
- **Explore the safety-reliability link:** 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:** 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. We recommend 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).

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 counterfactual (which may require more complex modeling), 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 (Skinner) 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.

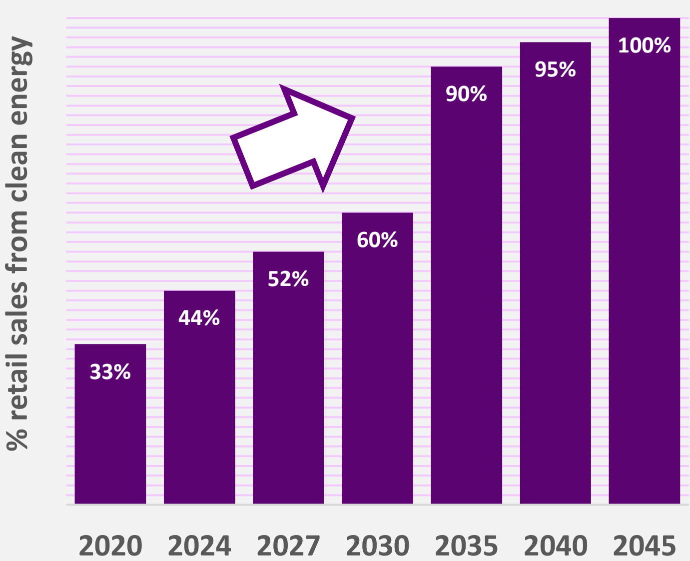


Figure 4: California's clean energy goals.

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

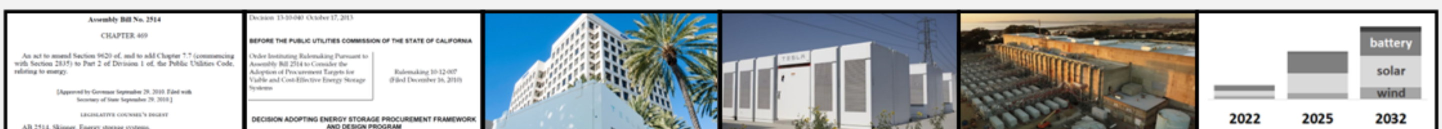
Figure 5: Scope of possible energy storage services.

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.



2010	2013	2014	2016–17	2018–19	2020–21
AB 2514	**D.13-10-040**	**Initial Use Cases**	**AB 2868** (2016)	**More Use Cases**	**System Reliability**
Requires consideration of energy storage procurement targets	Establishes 1,325 MW target and biennial procurement cycles	First cycle IOU energy storage procurement plans	Additional 500 MW energy storage	Local capacity procurements (Aliso Canyon #2, Moss Landing)	11,500 MW mid-term reliability procurements initiated
Purpose of energy storage includes: grid optimization, renewable integration & GHG reductions	Adopts procurement framework and design program	Local capacity procurements underway (OTC, SONGS retirements)	<u>Also</u>: SB 801 & fast-track Aliso Canyon-related procurements underway	First distribution investment deferral framework (DIDF) procurements	2021 Preferred System Plan (IRP): 13.6 GW energy storage by 2032
	Allows different evaluation protocols for bid selection	Pilots and incentive programs underway	Working group (CSFWG) develops DER evaluation framework	3,300 MW of system reliability procurements initiated	

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 2,300 MW/9,200 MWh were participating in the CAISO marketplace with several thousand MWs under active development. About 2,200 MW/8,800 MWh of mostly grid-scale online installations provided contracted resource adequacy services. Another 3,200 MW/12,800 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.

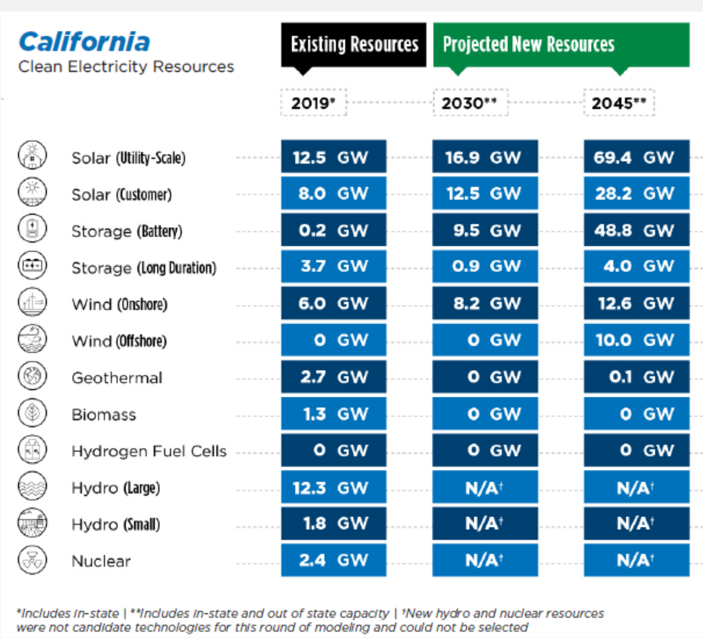
Even with maturation of the energy storage market important policy questions about the existing storage fleet remain. At the heart of this report is an analysis of actual energy storage operations, benefits, and costs in the 5-year study period 2017–2021. From this analysis we can better understand to 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.



California Clean Electricity Resources

	Existing Resources 2019*	Projected New Resources 2030**	Projected New Resources 2045**
Solar (Utility-Scale)	12.5 GW	16.9 GW	69.4 GW
Solar (Customer)	8.0 GW	12.5 GW	28.2 GW
Storage (Battery)	0.2 GW	9.5 GW	48.8 GW
Storage (Long Duration)	3.7 GW	0.9 GW	4.0 GW
Wind (Onshore)	6.0 GW	8.2 GW	12.6 GW
Wind (Offshore)	0 GW	0 GW	10.0 GW
Geothermal	2.7 GW	0 GW	0.1 GW
Biomass	1.3 GW	0 GW	0 GW
Hydrogen Fuel Cells	0 GW	0 GW	0 GW
Hydro (Large)	12.3 GW	N/A†	N/A†
Hydro (Small)	1.8 GW	N/A†	N/A†
Nuclear	2.4 GW	N/A†	N/A†

*Includes in-state | **Includes in-state and out of state capacity | †New hydro and nuclear resources were not candidate technologies for this round of modeling and could not be selected

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

Going further out, even more storage will be needed. Figure 7 shows an indicative resource portfolio California needs to achieve carbon neutrality by 2045. 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 almost 1,900 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 about 1/3 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 2,300 MW/8,800 MWh or 44% of all installed capacity in the country. In early 2022, California's planned grid-scale energy storage represented 50% of all planned installations in the country. In parallel, customer installations under SGIP grew to 440 MW/990 MWh with 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 discussion of the development status of various technologies. 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 new 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." In 2012, technology-related barriers identified by the CPUC and stakeholders included "lack of commercial operating experience" and "lack of well-defined interconnection process" (Decision 12-08-016).

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.

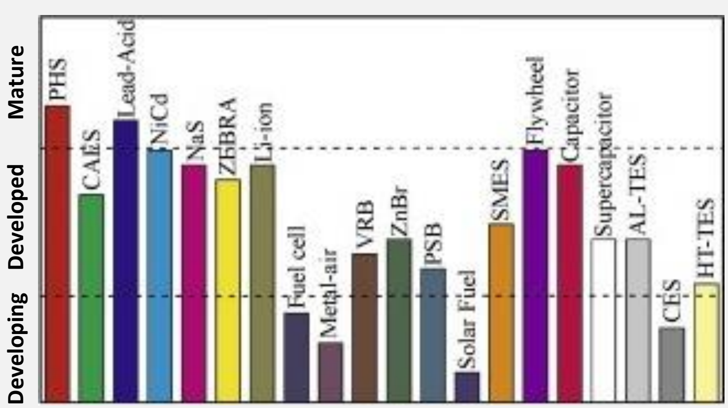


Figure 8: A 2009 assessment of storage technical maturity.

(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	2013	2016	2014	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
Public Funding Source	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.

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).

	# Installations	MW	MWh
Lithium-Ion (NMC) Battery	28	1,437	5,740
Thermal (Ice/Air/Chilled Water)	8	10	60
Hydroelectric Pumped Storage	1	40	240
TOTAL	**37**	**1,487**	**6,039**

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

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 1,487 MW/6,039 MWh grid-scale energy storage procured by the utilities that were (a) operational prior to mid-2021 and (b) counted towards the Assembly Bill 2514 goals and Decision 13-10-040 procurement requirements.

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 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 across all grid domains.

Customer-sited storage capacity grew from 61 MW at the start of 2017 to at least 582 MW by the end of 2021 (possibly not counting some privately-funded installations), largely driven by 468 MW of SGIP-funded installations. Distribution-connected storage capacity increased from 58 MW in 2017 to around 300 MW by 2021. Storage projects connected to the bulk transmission system remained under 100 MW until mid-2020 but grew to more than 2 GW 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.

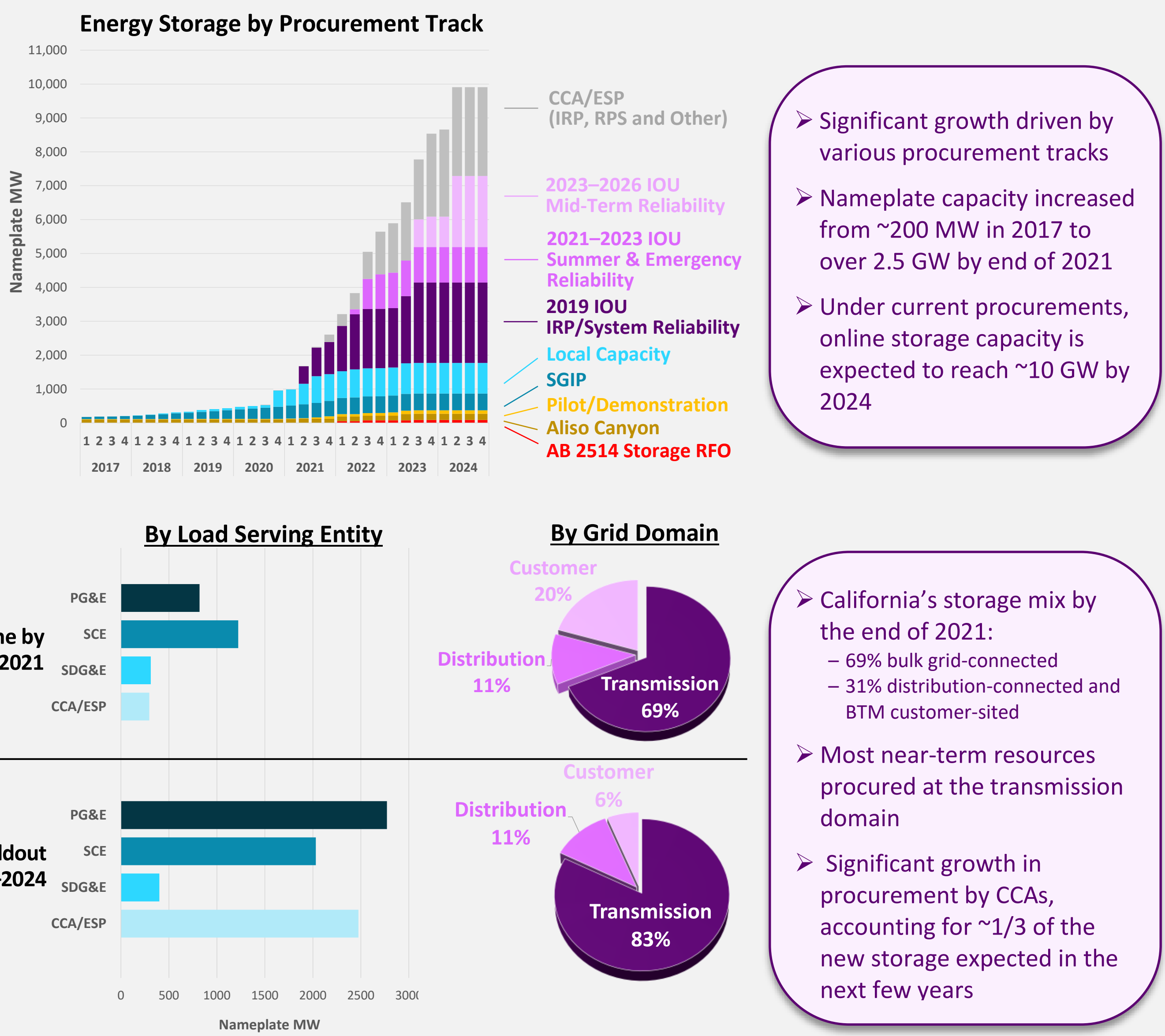


Figure 12: Summary of energy storage procurement in California as of Summer 2022.

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 storage installations in the U.S. based on data compiled by the EIA, excluding pumped storage hydroelectric storage. As of mid-2022, total installed capacity is just over 7,000 MW and is on track to grow to at least 24,000 MW by 2025. California holds 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, Hawai'i, 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.

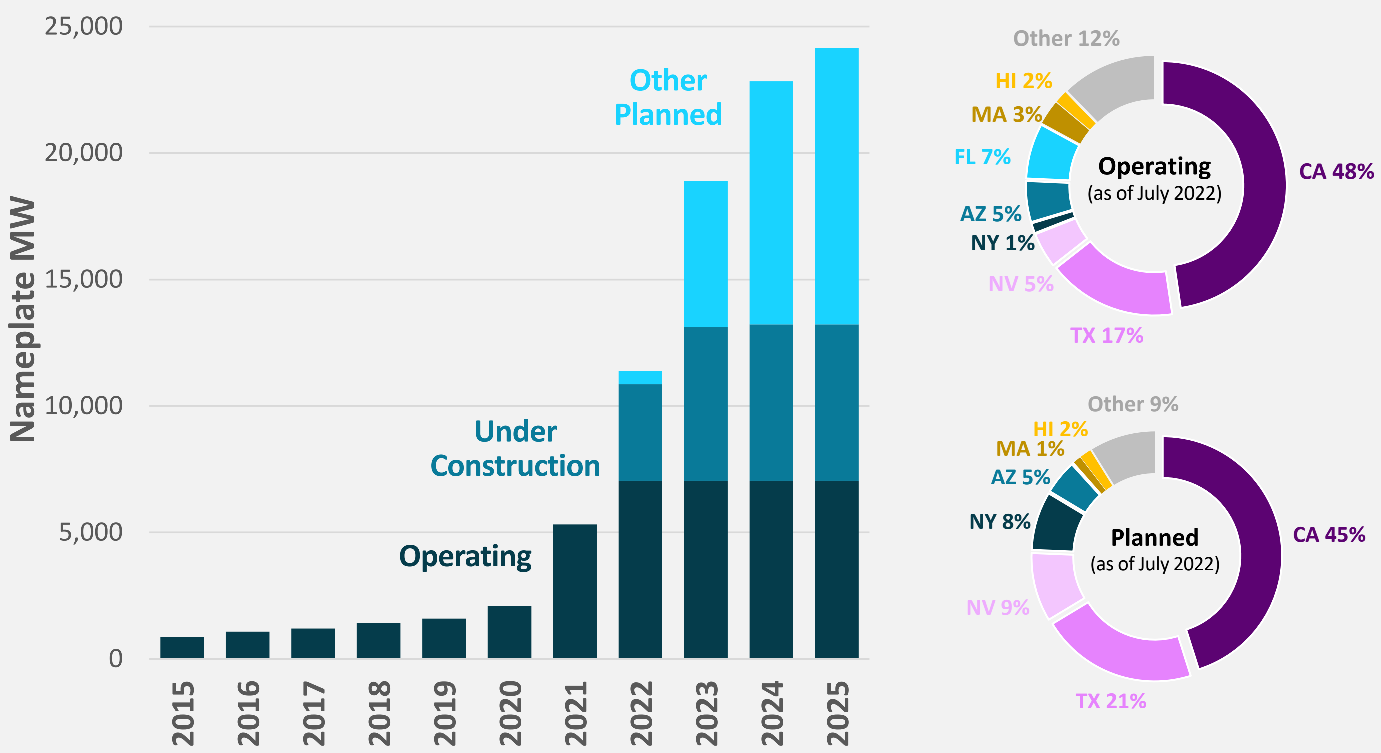


Figure 13: Existing and planned U.S. grid-scale energy storage installations.

*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 has declined from over $1,200/kWh in 2010 to $132/kWh in 2021, with a 6% drop from 2020 levels, according to BloombergNEF's annual 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 costs $20/kWh above the average. 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 a recent NREL report on cost of battery storage systems installed in early 2021, summarized in Figure 14. In 2022 dollars, battery pack costs are 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 totals 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 interconnection, sales & marketing, developer overhead and profit margin that are much higher for small residential projects than for grid-scale or commercial projects.

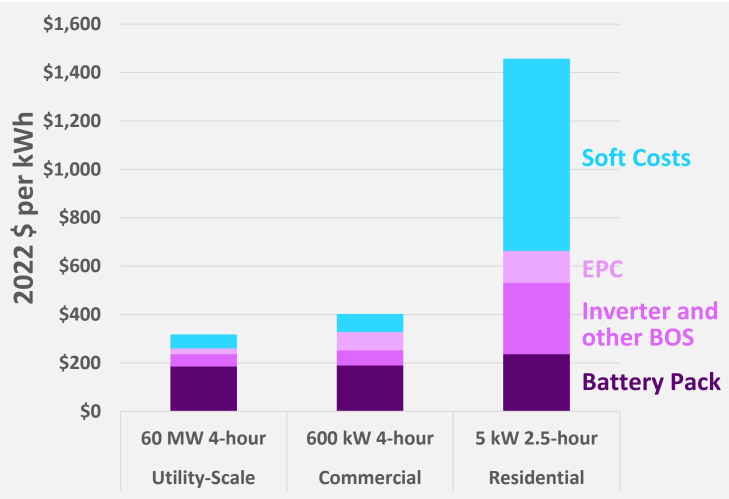


Figure 14: Installed cost of storage systems in 2021 (2022 $).

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 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 $1,200–$1,600/kW, except for a few very small projects above that range. With 4-hour duration, this translates to $300–$400 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.

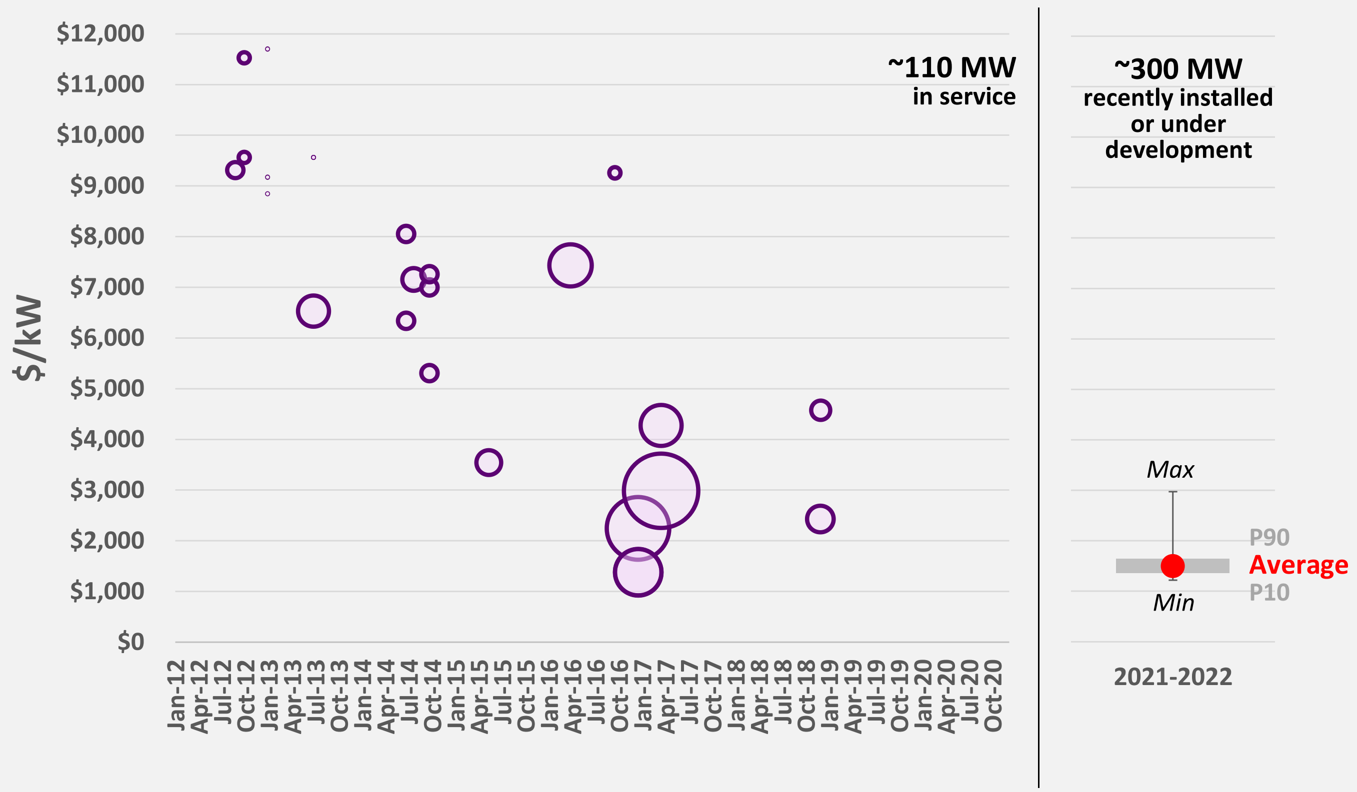


Figure 15: Installed cost of utility-owned storage projects in California (2022 $).

While many of the initial pilot projects were utility-owned, a large share of more recent storage projects 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 16 below summarizes the 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, 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 owner 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.

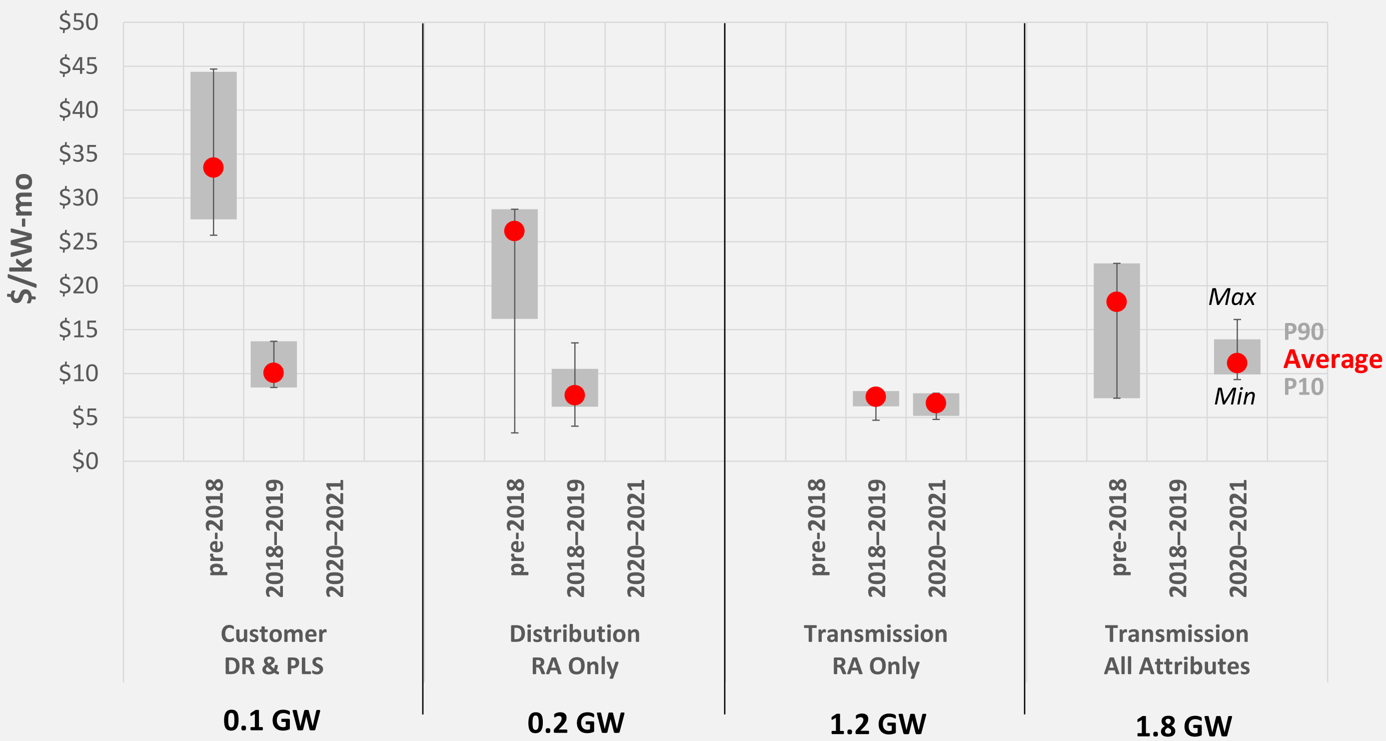
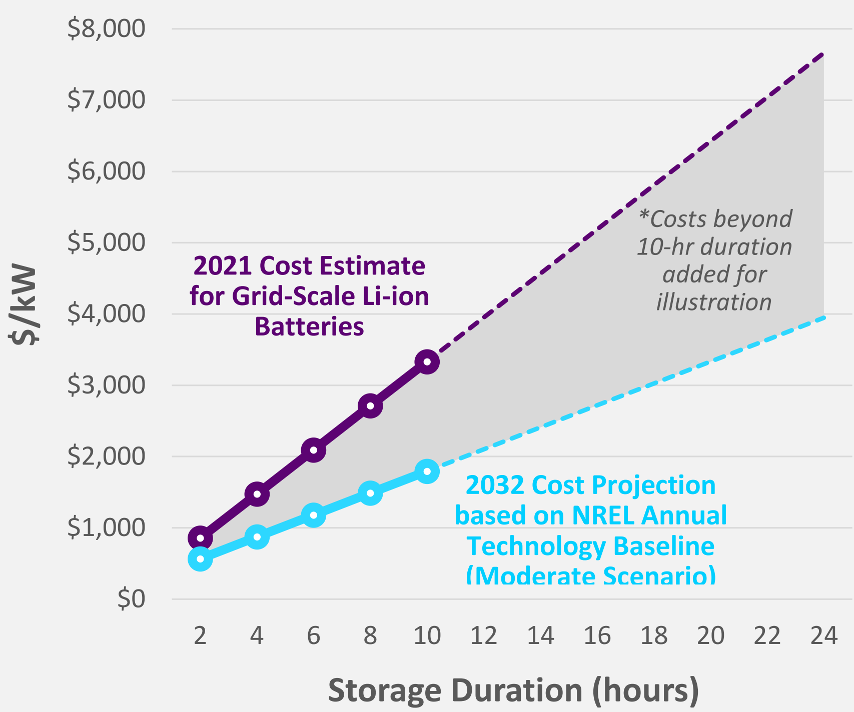


Figure 16: IOU third-party storage contract prices by grid domain and CPUC approval year (2022 \$).

Most of grid-scale energy storage systems procured in California today 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 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. 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 crossover point for cost-effective 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 CAES 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.

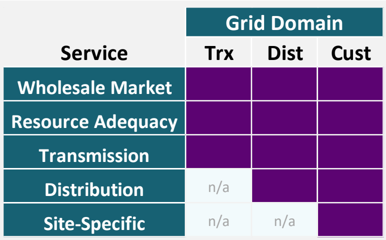
Potential storage services and associated value streams include:

- **Energy time-shift:** Storage can move energy from one time to another by charging in off-peak periods when the prices are the lowest and discharging during peak periods when the prices are the highest.
- **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 can also provide voltage support to help dynamically maintain stable voltage levels in the distribution or transmission system, 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 in order 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 providing backup power to isolated sections of the grid and mitigate the risk of power interruptions at the community level.

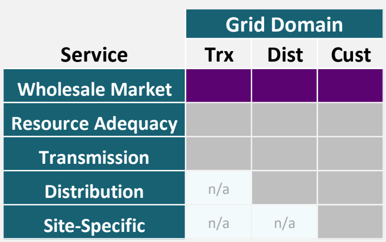
- **Site-specific customer services:** Storage resources that are interconnected behind the utility meter can help customers reduce their electric bills through time-of-use (TOU) bill management by charging when their retail rates are lowest and discharging when retail rates are highest, and demand charge 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

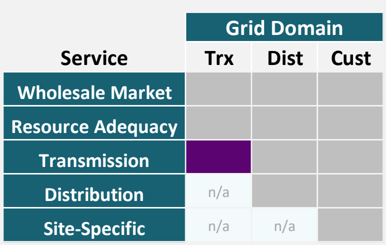
There has been a significant push in the industry over the past decade to achieve full economic potential of energy storage resources by unlocking access to a variety of value streams. Key activities in California are summarized below. The purple color on the charts highlights types of services and value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



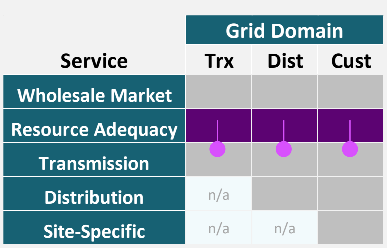
In 2018, CPUC approved D.18-01-003 which marked an important step towards enabling "value stacking" of energy storage systems that can provide multiple services to the grid. The decision adopted a joint staff proposal of the CPUC and CAISO to develop 11 stacking rules to govern multi-use-application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

	Grid Domain		
Service	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.

	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 2017 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 markets to align resource performance with the program's emission reduction goals. Later in that year, CPUC also established the SGIP 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 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.

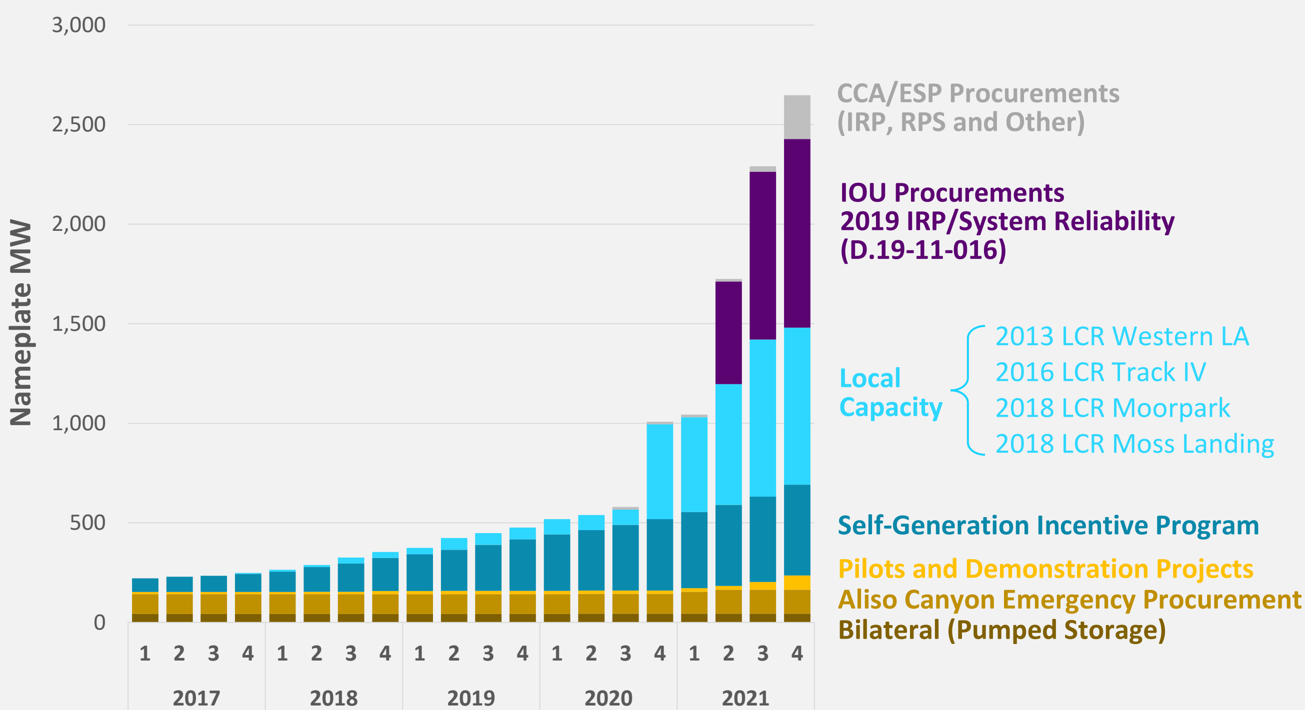


Figure 19: Actual energy storage installations in California by procurement track (2017–2021).

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 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 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.

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 contributing factors and develop 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 additional resources 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 2,000 MW of energy storage.

In June 2021, the CPUC issued its midterm 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 5pm to 10pm. 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.

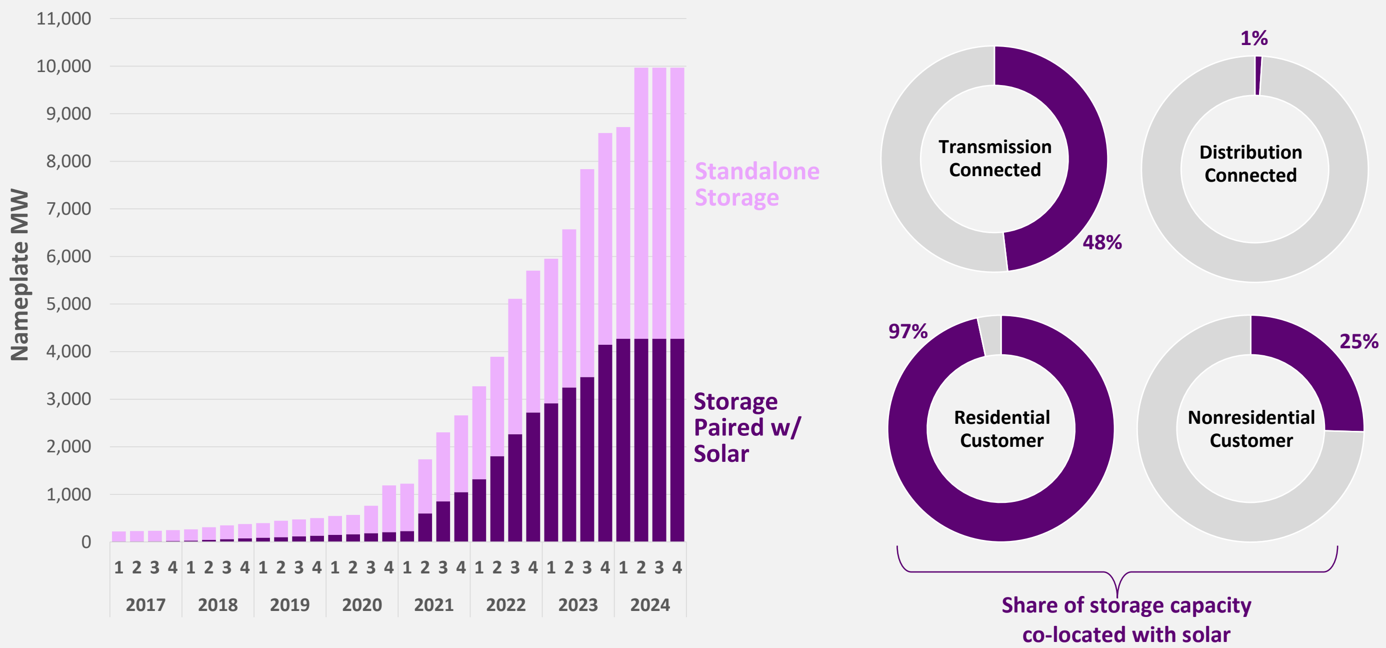


Figure 20: Standalone and co-located storage procurement in California as of summer 2022.

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 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 more than 80% of the storage MW added in California based on 2020-2021 data.

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 of the 1,2 million residential customers who has rooftop PV installed it with energy storage, and fewer than 1,500 of the 30,000 nonresidential customers who has solar also has storage.

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

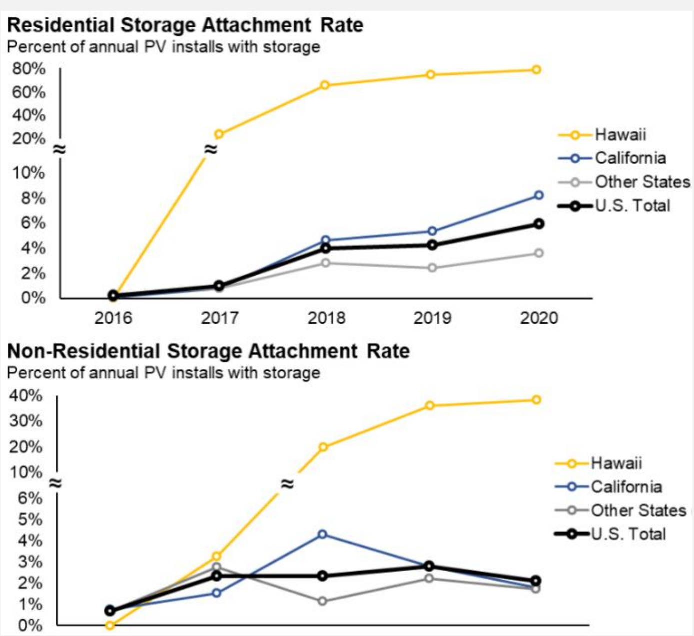


Figure 21: Hawai'i's customer-sited storage attachment rate to solar PV installations over time.

(Barbose et al. 2021)

According to the LBNL study, Hawaii 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 Hawaii that incentivize self-consumption.

Over the past 5 years, Hawaii 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. Key activities are summarized below:

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.

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 currently exploring several potential enhancements to better model and compensate storage resources in the marketplace.

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.

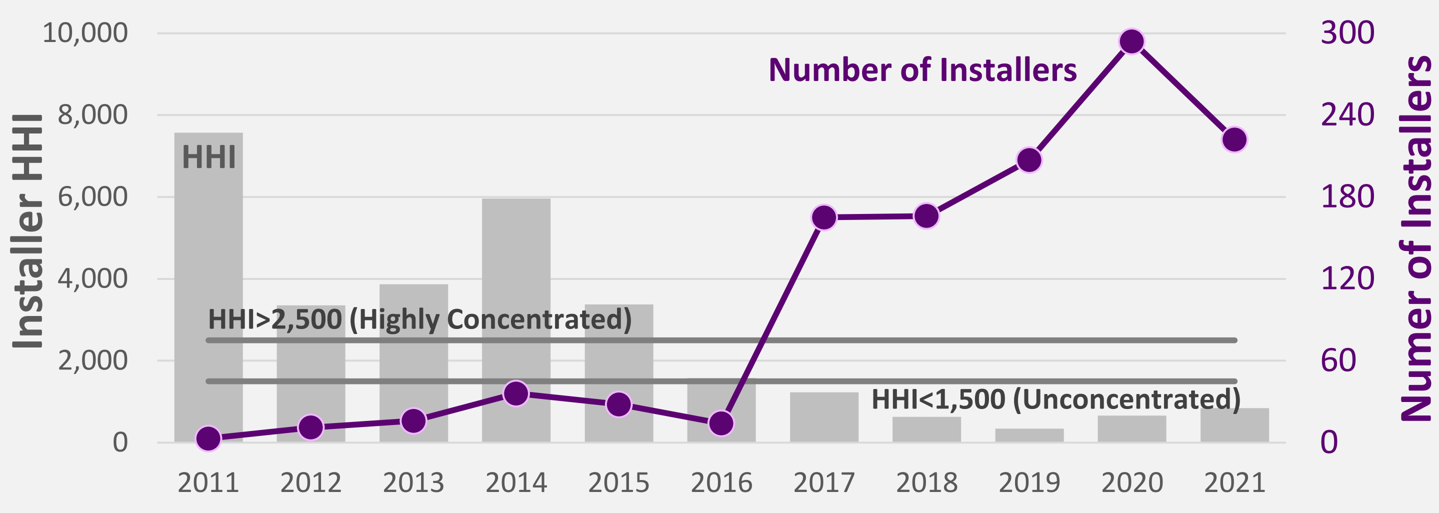


Figure 23: SGIP energy storage installers and market concentration over time.

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 that 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, this capacity grew exponentially and in 2021 represented nearly half of all interconnection requests in the country.

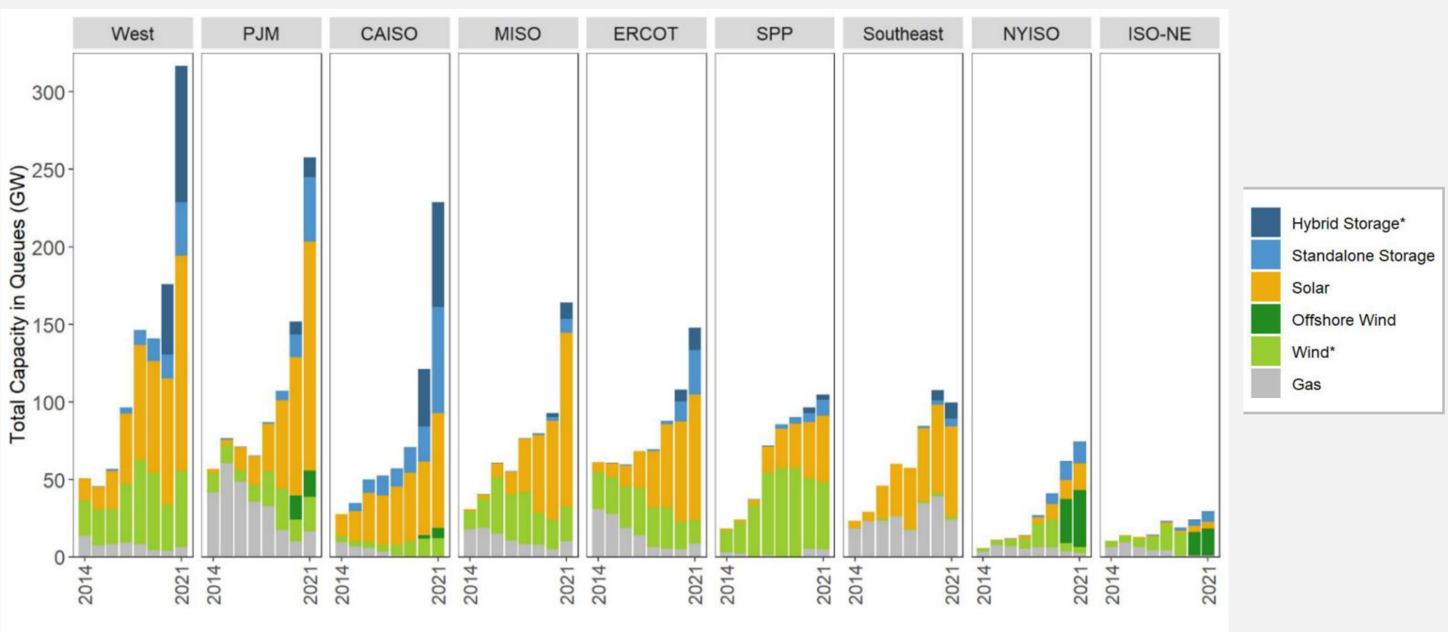


Figure 24: Grid-scale energy storage capacity in interconnection queues over time (2014–2021).

(Rand et al. 2022)

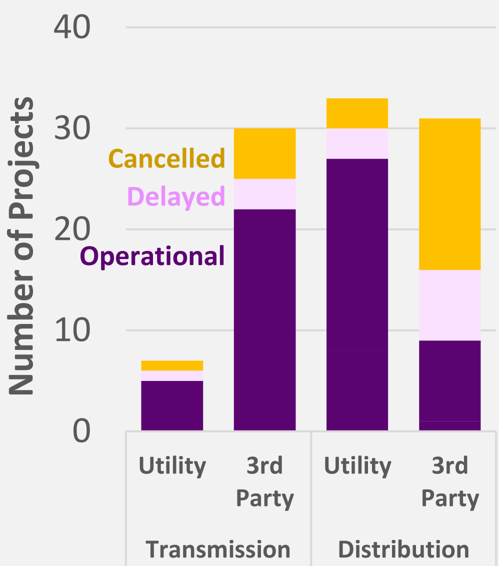


Figure 25: Status of IOU energy storage procurements for start of operations by the end of 2021.

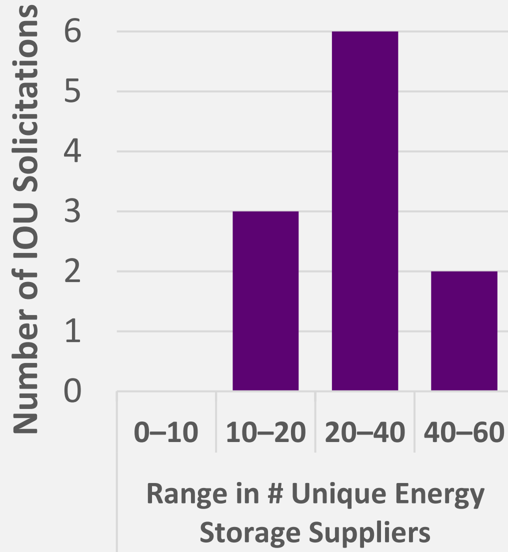


Figure 26: Distribution of IOU solicitations based on the number of unique energy storage suppliers.

Supplier participation in IOU resource solicitations. In **Chapter 1 (Market Evolution)** the Value Propositions section (page 26) 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 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 $73 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 $23 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 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 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 analyzed. 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 1,568 MW/5,169 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.

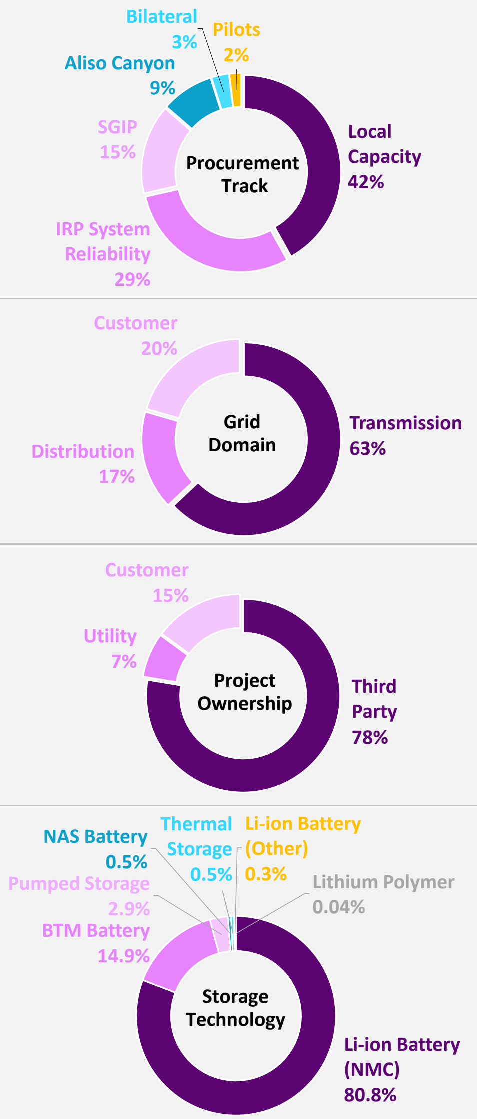
		Nameplate							Procurement	MW IOU	MW
	Count	MW	MWh	LSE	Online	Technology	Owner	CAISO?	Track	AB 2514	Analyzed
Transmission-Sited	**8**	**865**	**3,053**							**460**	**865**
3rd-Party	**6**	**845**	**3,044**							**440**	**845**
Vista Energy Storage	1	40	44	SDG&E	Jun-18	Lithium-Ion (NMC)	Third Party	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	Sep-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	Jun-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-Ion (NMC)	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	Mar-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-Ion (NMC)	Utility	Y	General Rate Case	2.4	no data
Distribution Energy Storage Integration (DESI) 2	1	1.4	3.7	SCE	Dec-18	Lithium-Ion (NMC)	Utility	Y	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	General Rate Case	0.5	0.5
Borrego Springs Unit 2	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	General Rate Case	0.025	0.025
Borrego Springs Unit 3	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	General Rate Case	0.025	0.025
Borrego Springs Unit 4	1	0.025	0.05	SDG&E	Jun-13	Lithium-Based	Utility	N	General Rate Case	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	**22,450**	**387**	**851**							**200**	**205**
SGIP Nonresidential (as of Apr'21)	**1,150**	**242**	**500**							**177**	**205**
SGIP Nonresidential PG&E	320	62	125	PG&E	Various	BTM Battery	Customer	N	SGIP	62	48
SGIP Nonresidential SCE	580	141	291	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)	**21,300**	**145**	**351**							**23**	0
SGIP Residential PG&E	9,800	70	172	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	4,500	30	71	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 >>		**1,568**	**5,169**							**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 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.



Locations of Energy Storage Projects (Transmission- and Distribution-Connected Only)

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 <u>avoided cost</u> of market alternatives to the energy storage resource analyzed.

Benefits and costs focus mostly on <u>ratepayer impacts</u> 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 of this report 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	Snapshot (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 and real-time 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, face significant barriers in energy service, and do 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).

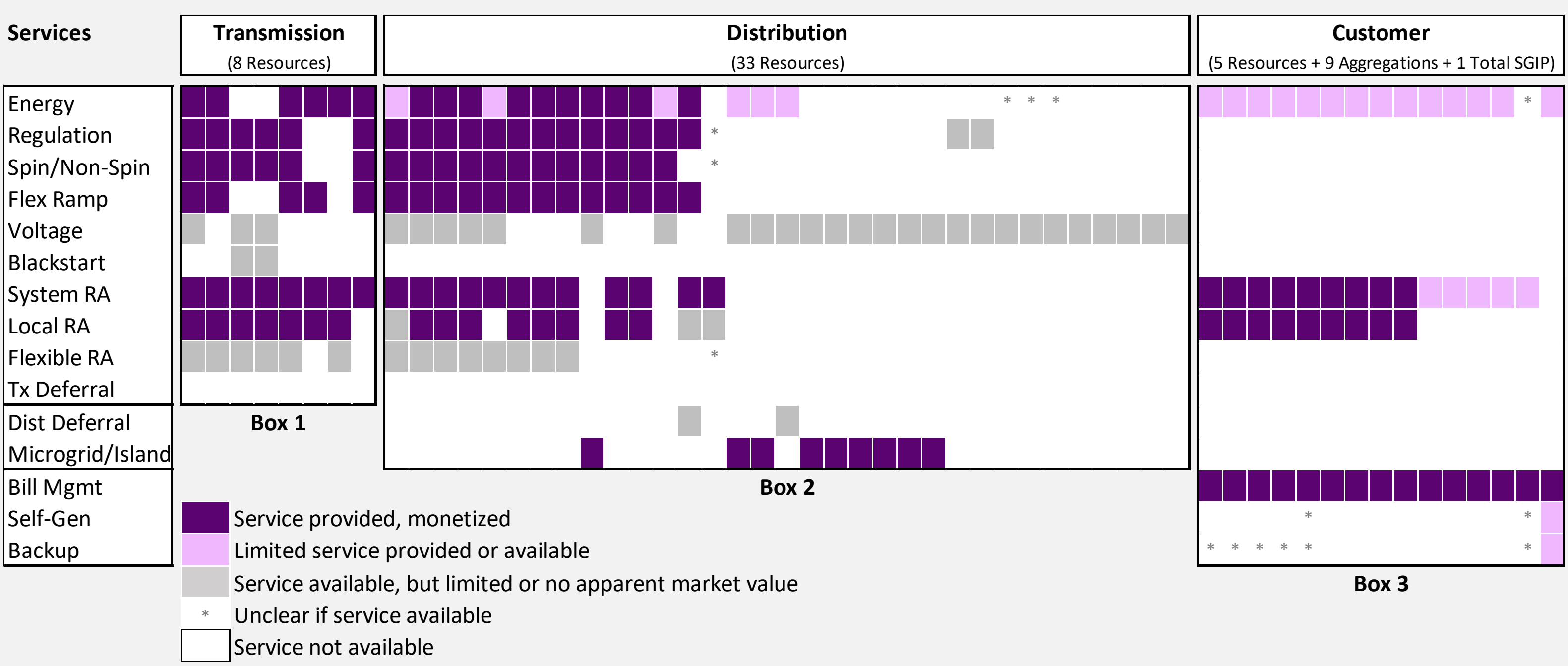


Figure 31: Theoretical versus actual benefit categories (row) by resource or resource group (column).

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, 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.

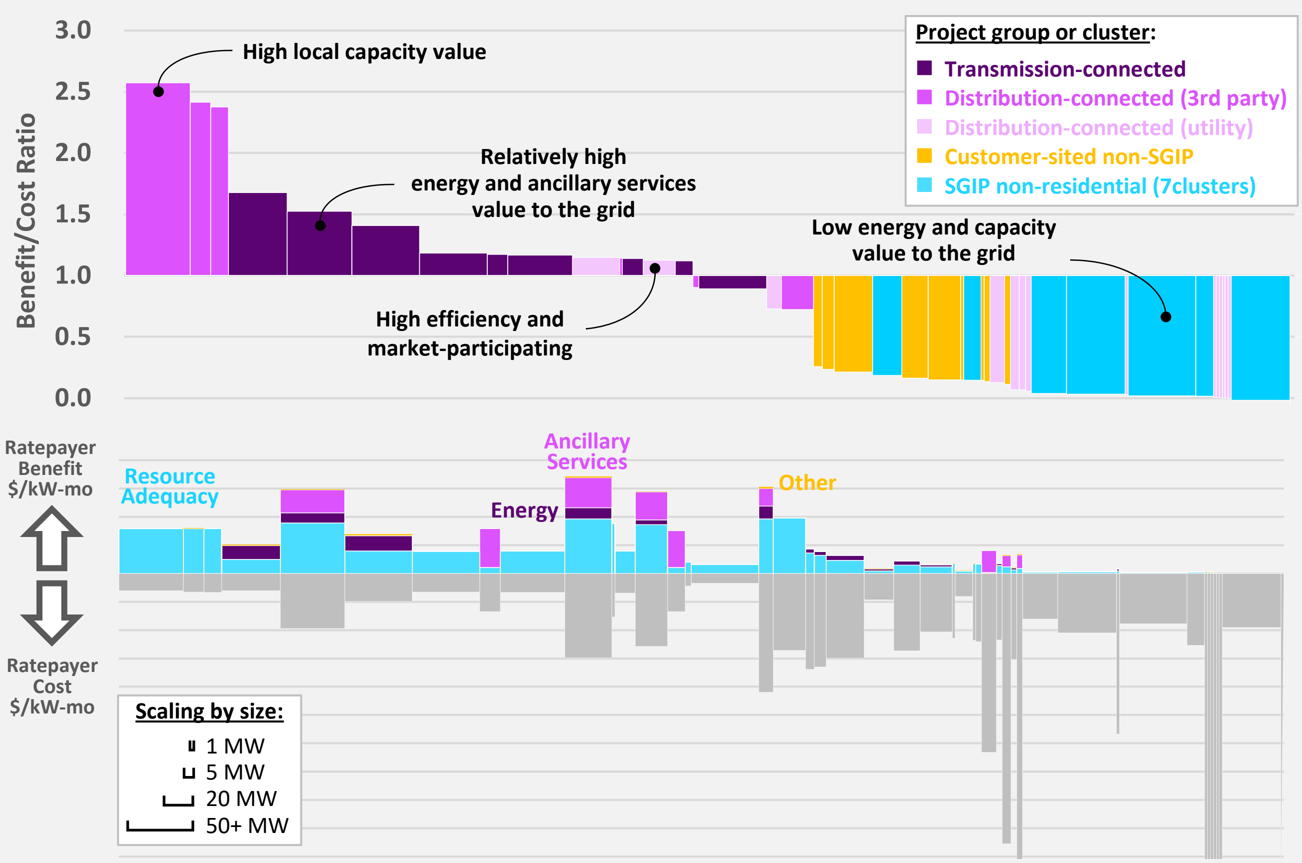


Figure 32: Summary of ratepayer benefit/cost ratio results (top) and underlying components (bottom).

Total dollar impacts. In terms of absolute dollars, the benefit/cost ratios represent a portfolio-wide average of $70 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 $73 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 $17 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/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 $33 million per year by the end of 2021, which includes $22.6 million per year in net benefits produced by market-mature resources, plus $10.7 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 $85 million per year on average over their full amortization period.

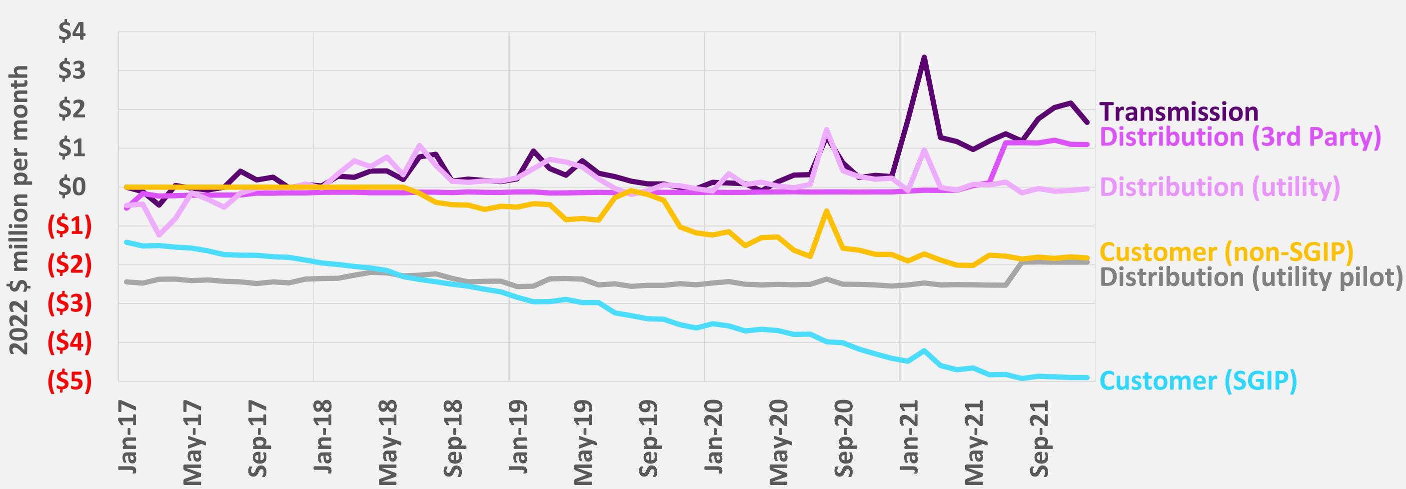


Figure 33: Net ratepayer benefits (costs) over time.

*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.

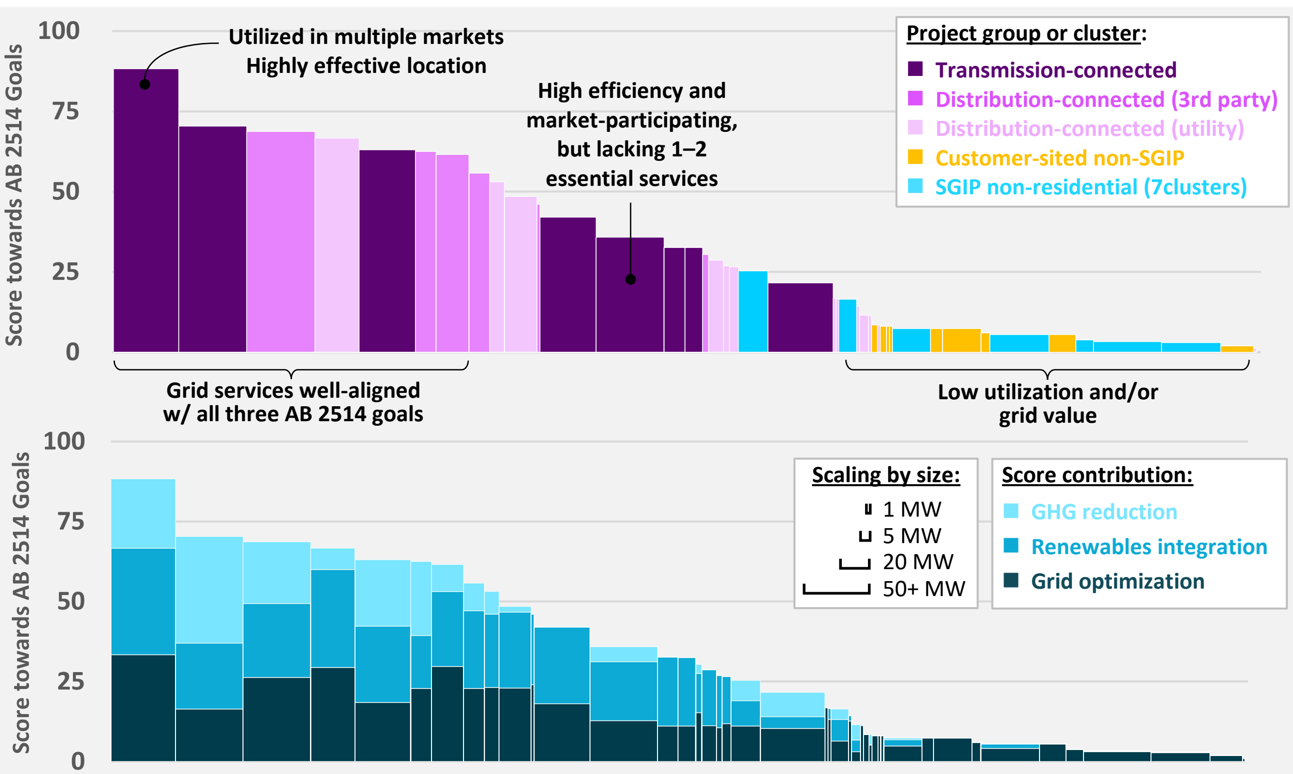


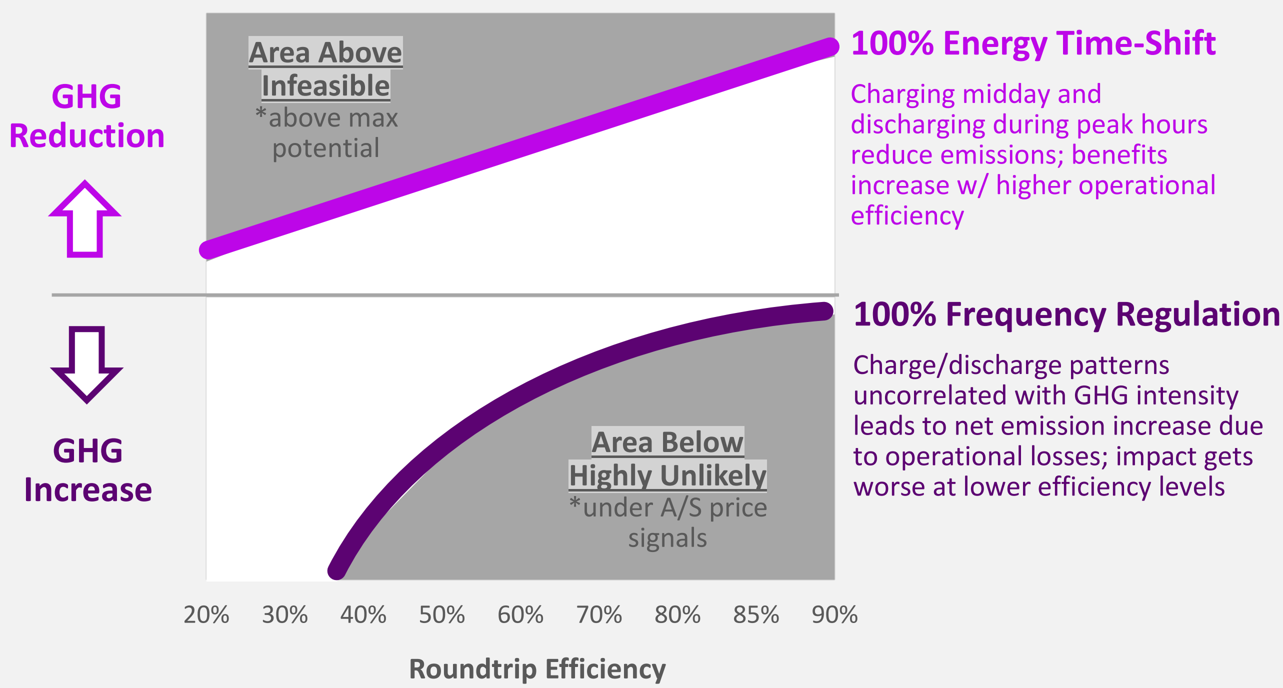
Figure 34: Summary of scoring towards state goals (top) and underlying components (bottom).

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 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 benefits, it is essential for 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.



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

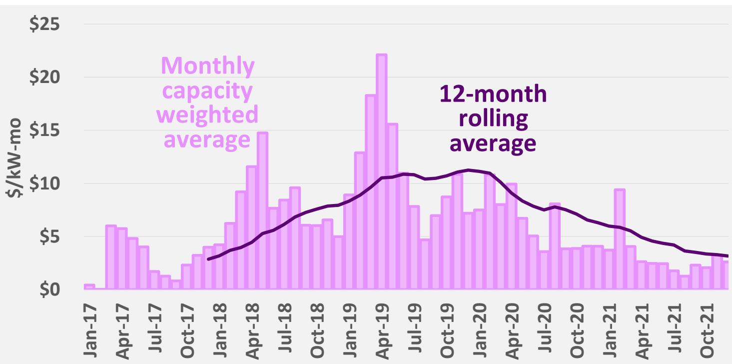
The market for frequency regulation (regulation) service is managed and administered by the CAISO. Regulation provides operating flexibility to fine-tune the grid's frequency through rapid injections to and withdrawals from the grid. Energy storage is unique in its ability to provide up to 2 MW of regulation 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 19 CAISO-participating resources that provided regulation during 2017–2021 with a total capacity of 743 MW/2,497 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.

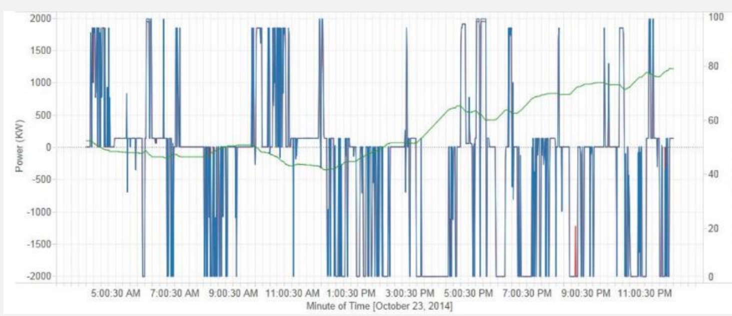
However, the regulation use case does not offer scalable benefits to customers or towards the state's clean energy goals for three reasons: (1) it is limited by its total market size of 400–700 MW, (2) it does not move renewable energy in bulk from one time period to another or reduce GHG emissions, 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).

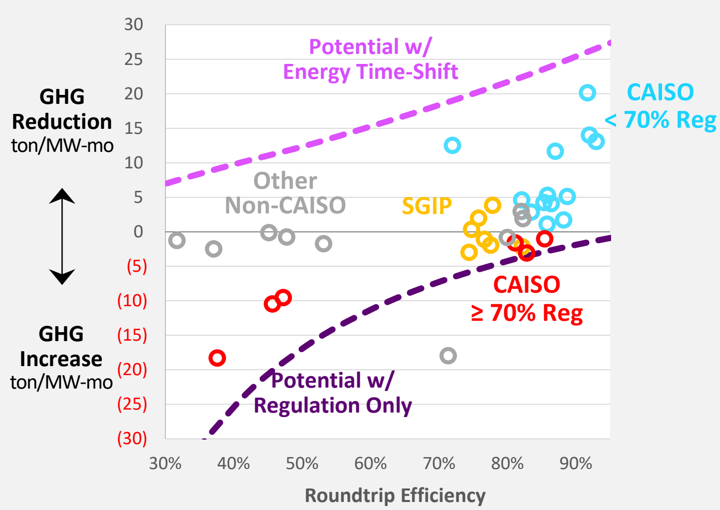
This use case as a standalone service is not consistent with the energy time shift use case to move renewable generation from times of excess to times of deficiency.



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 250 MW at the beginning of 2020 to about 2,500 MW by the end of 2021. 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.

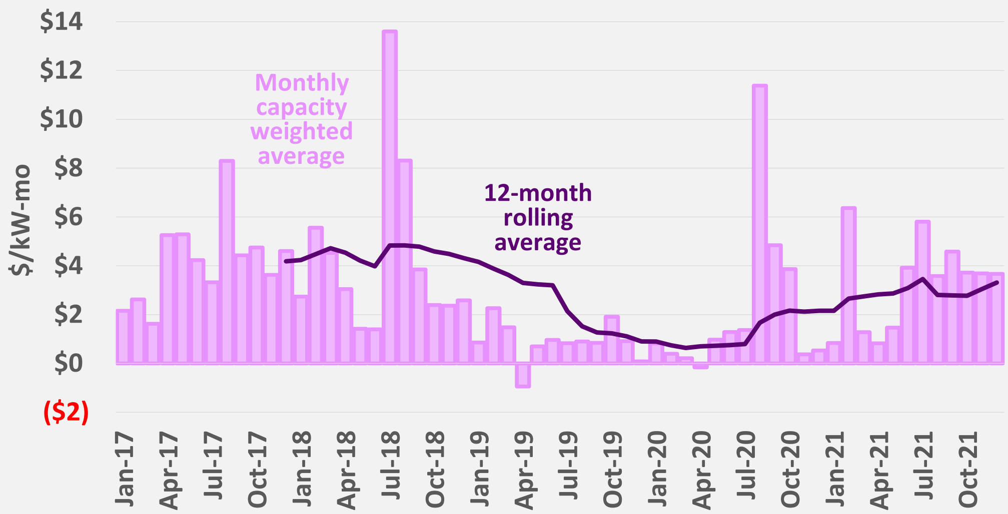


Figure 36: Average CAISO energy market revenues across the storage fleet.

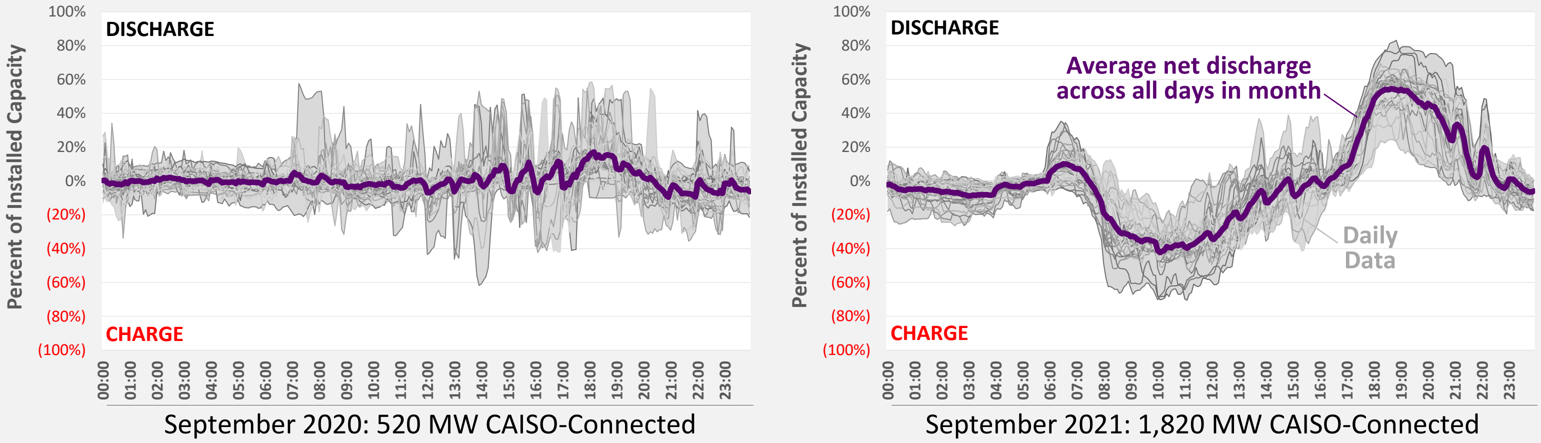


Figure 37: CAISO aggregate battery output in September 2020 versus September 2021.

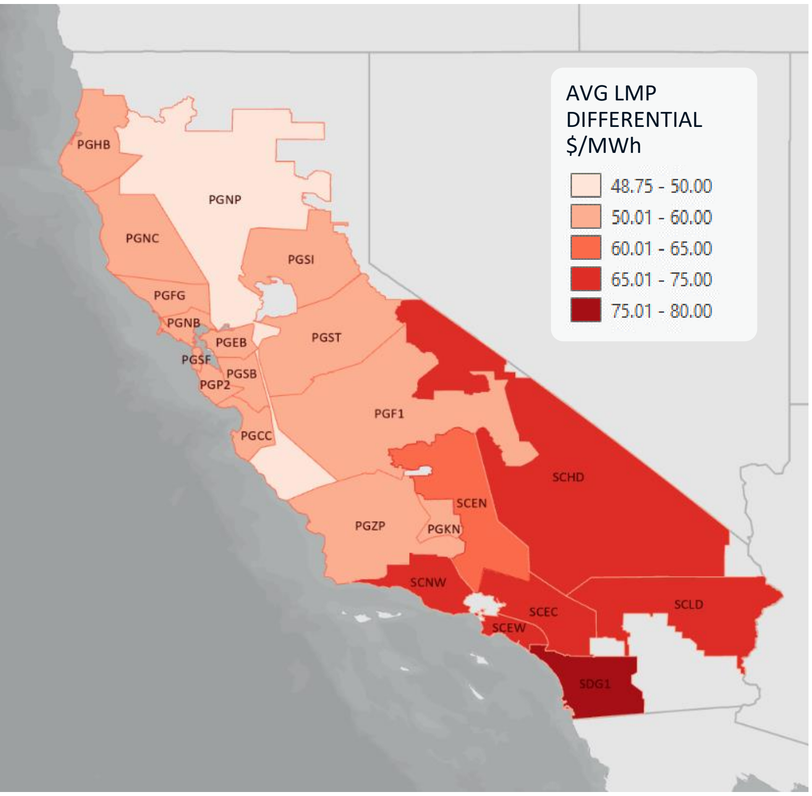


Figure 38: Average differential between real-time LMPs in top 4 and bottom 4 hours during 2018–2021

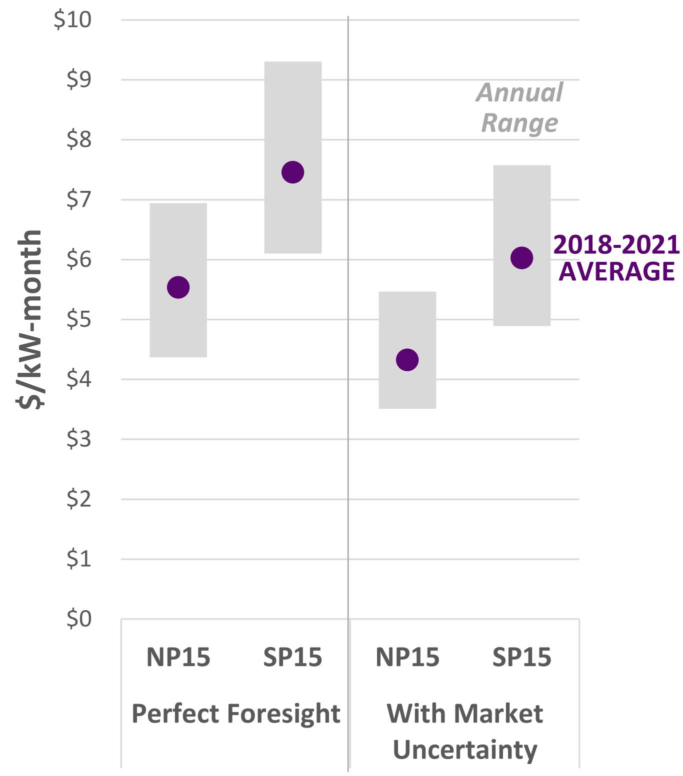


Figure 39: Estimated energy value potential for 4-hour storage in California under historical LMPs

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 simulated storage operations, where we first determine the next day's hourly schedule using day-ahead LMPs, then evaluate 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 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 2,210 MW/8,846 MWh of online storage capacity had been procured through resource adequacy procurement tracks, 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;
- 1,301 MW/5,267 MWh transmission-connected resources procured to meet system-level capacity needs.

In the period 2019–2021 demand for 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 in 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 issued a set of decisions which enabled exceedance of the 3,300 MW requirement for summer 2021 reliability, created a path for emergency procurement of energy storage 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 help to advance development of capacity to meet the earlier decisions or to find temporary nearer-term solutions.

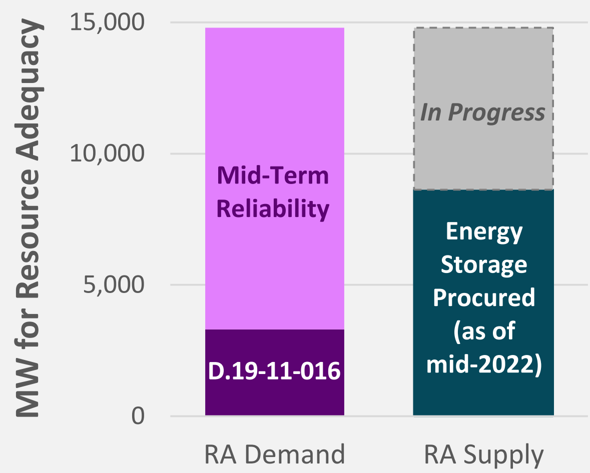


Figure 40: Demand and supply for 2021–2026 resource adequacy procurements.

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 1,900 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 Resource Adequacy Program 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 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 not participating in the CAISO marketplace;
- 4MW/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);
- 212 MW/435 MWh of 674 non-residential installations under SGIP, nearly all enrolled under program years prior to 2020; and
- 79 MW/182 MWh of almost 28,000 residential installations under SGIP, enrolled under program years prior to 2020 and 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 674 resources into 7 clusters based on each installation's interval-level operating behavior during the historical period.

Non-residential use cases (clusters): 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).

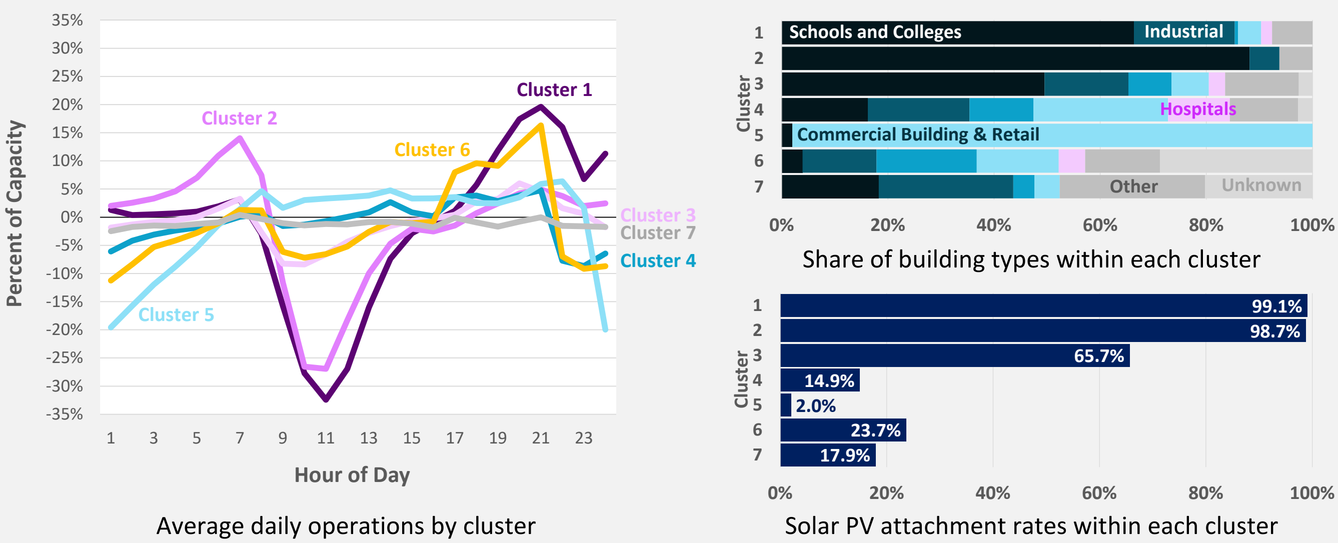


Figure 41: Observed characteristics of non-residential installations under SGIP (674 installations in 7 clusters).

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 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.

SGIP evaluation studies found that residential installations produce at least twice energy value of non-residential installations (Verdant, 2021). 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.

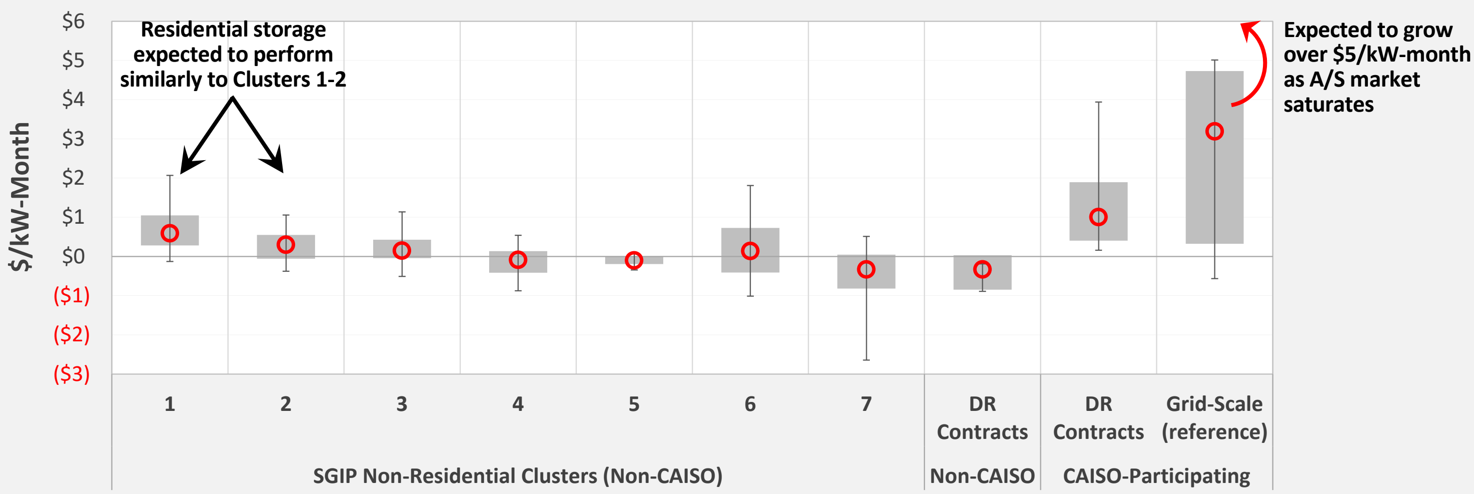


Figure 42: Average energy value produced by customer-sited energy storage.

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.

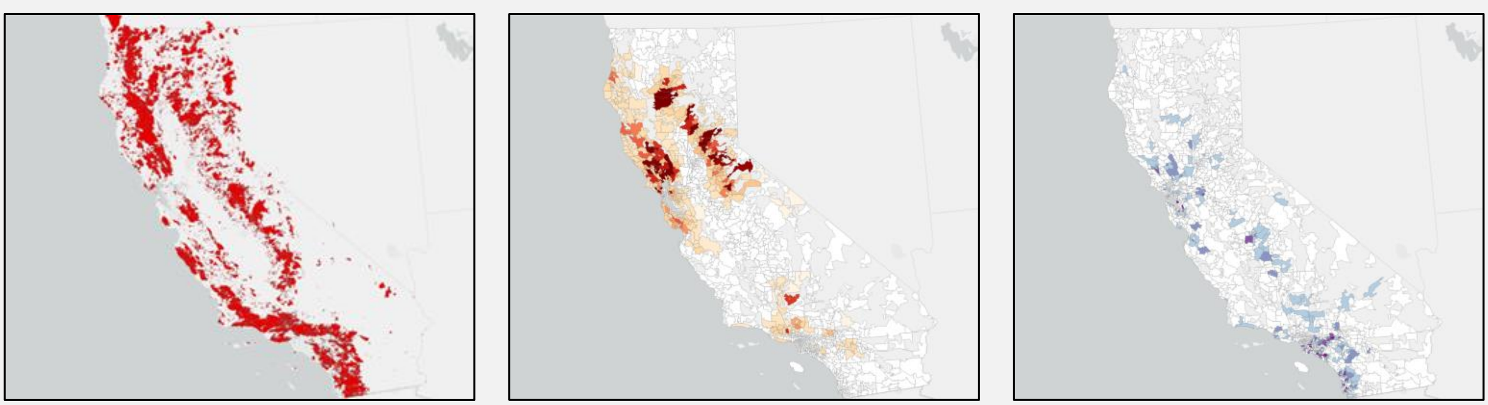
Unfortunately, wildfire risks in the West have accelerated rapidly, revealing a complex relationship to electricity service and a strong dynamic of wildfire risks both to and from the grid. The IOUs have relied upon sustained day-long or multi-day outages to reduce ignition risks in the areas and times 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.

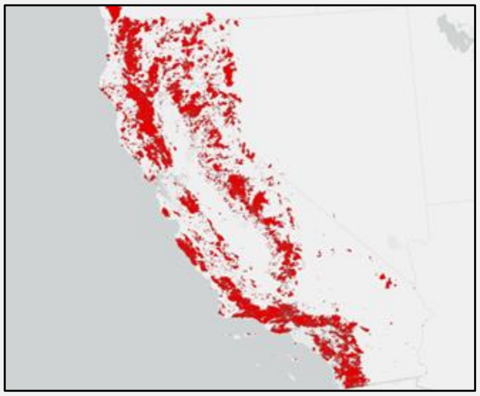
In 2017–2021 outage mitigation value for non-residential SGIP installations was largely an untapped potential. Historical wildfire perimeters and PSPS areas compared to the distribution of non-residential storage shows low spatial correlation (Figure 43). Only 20% of non-residential storage installations 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 $10/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.

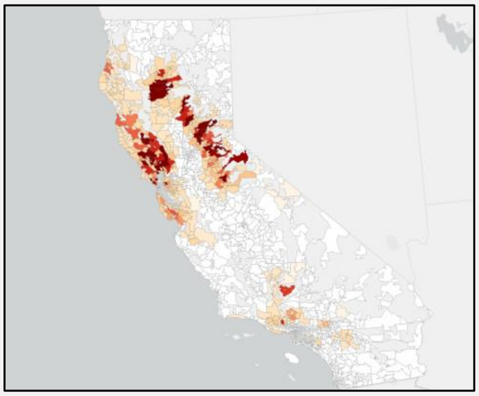


Historical fire perimeters | Relative PSPS severity in total customer-hours | Distribution of SGIP non-residential installations in kWh capacity

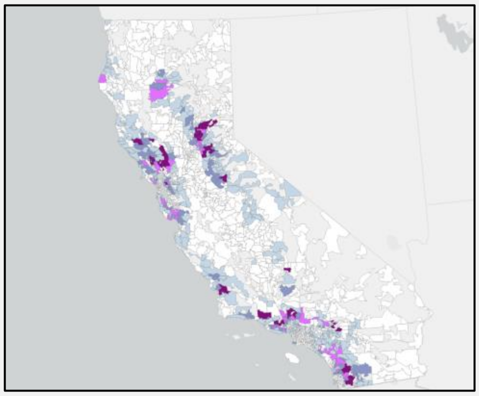
Figure 43: Comparison of SGIP non-residential installations to wildfire threat areas.



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.

<u>SGIP Equity Resiliency budget</u>: 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

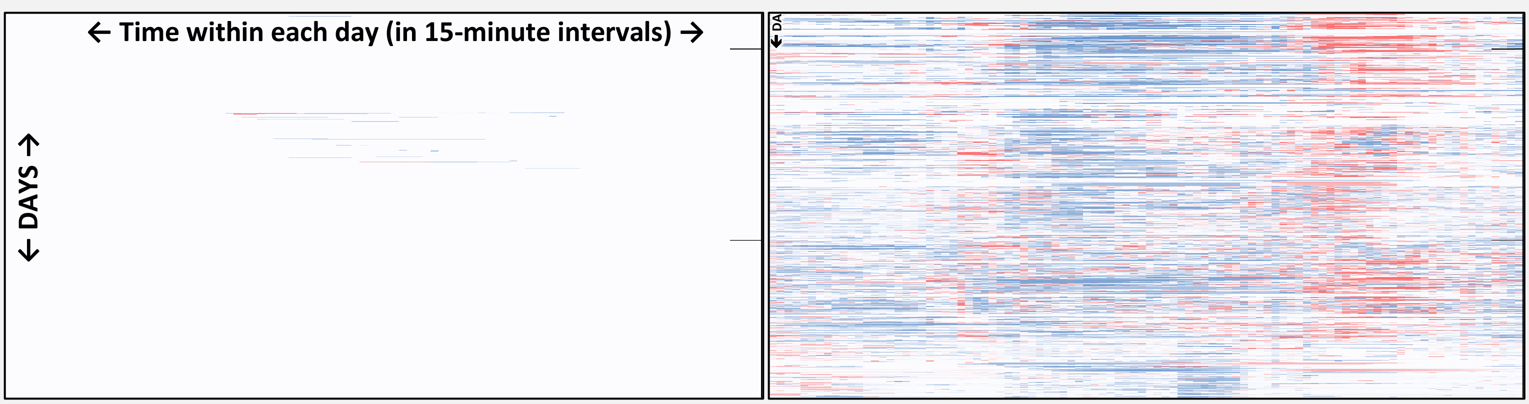
IOU-owned distribution-connected resources developed for microgrid and other distribution-related services provided very little value overall and contributed to GHG emissions increases. This highlights the drawback of standby losses when transmission-level grid services are not integrated into the energy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

A 12 MW/28 MWh subset of early pilot and demonstration projects were 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 15-minute operations of an IOU-owned distribution-connected resource built for microgrid purposes (left) to an IOU-owned distribution-connected resource participating in the CAISO marketplace (right) for the entire calendar years 2019 and 2020. 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 either 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.

These resources do not help to decrease GHG emissions. Instead, they increase 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.



Standalone Microgrid Use Case

CAISO-Participating

Figure 45: Heatplot of energy storage charge (blue) and discharge (red) in 15-minute intervals.

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 agencies 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 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 overall and contributed to 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 $830 million to $1.35 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–$1.55 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 6 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 the CAISO initiatives, opened the door for energy storage to provide energy and an array of ancillary services in the CAISO's 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 ability of energy storage to provide energy, ancillary, and RA capacity services matured 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 areas: (1) in the energy time shift use case in the CAISO marketplace, and (2) in the system RA capacity use case in the utility and other LSE's procurements.

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

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 $830 million to $1.35 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 time shift value of energy storage grows as more variable renewable generation is added to the system. By 2045, we expect the potential energy time shift value to grow far beyond the 2032 levels and for more of the energy storage portfolio to contribute to that set of services.

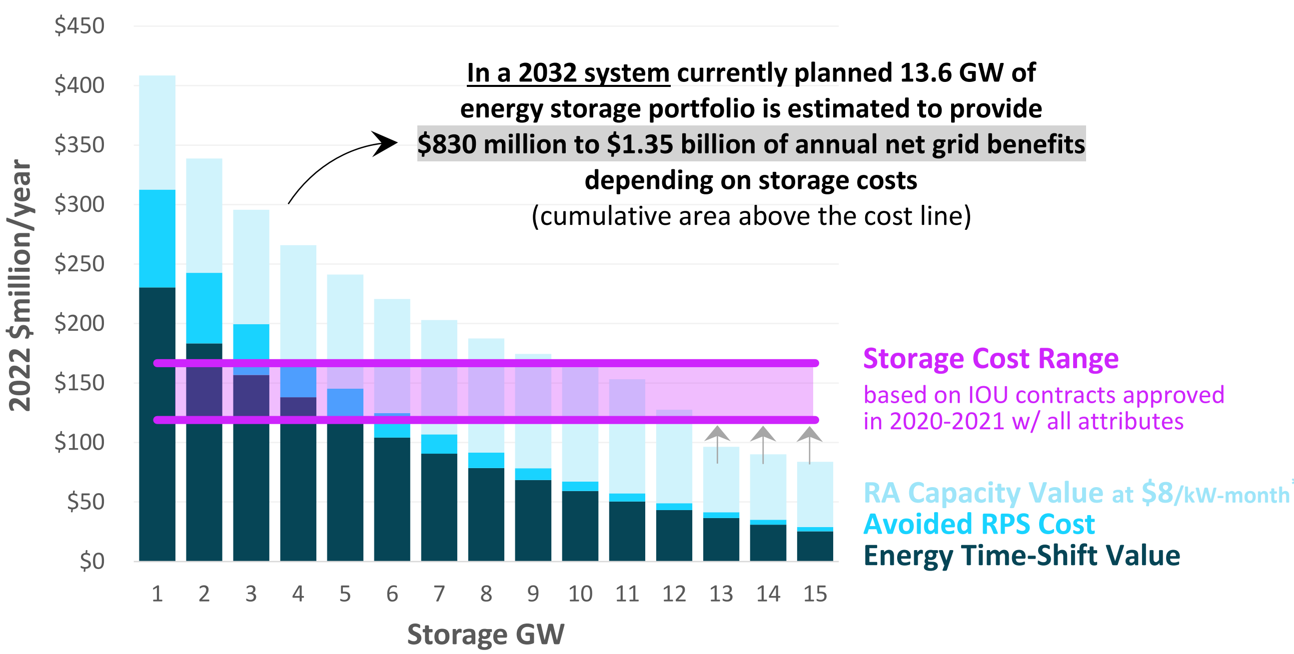


Figure 46: Incremental energy, renewables integration, RA capacity value of 4-hour storage in 2032 (2022 $).

* 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 time shift 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.

Future role of the ancillary services use case. Ancillary services are unquestionably 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. Furthermore, 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, in itself, is not a high-yield method 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 needs.

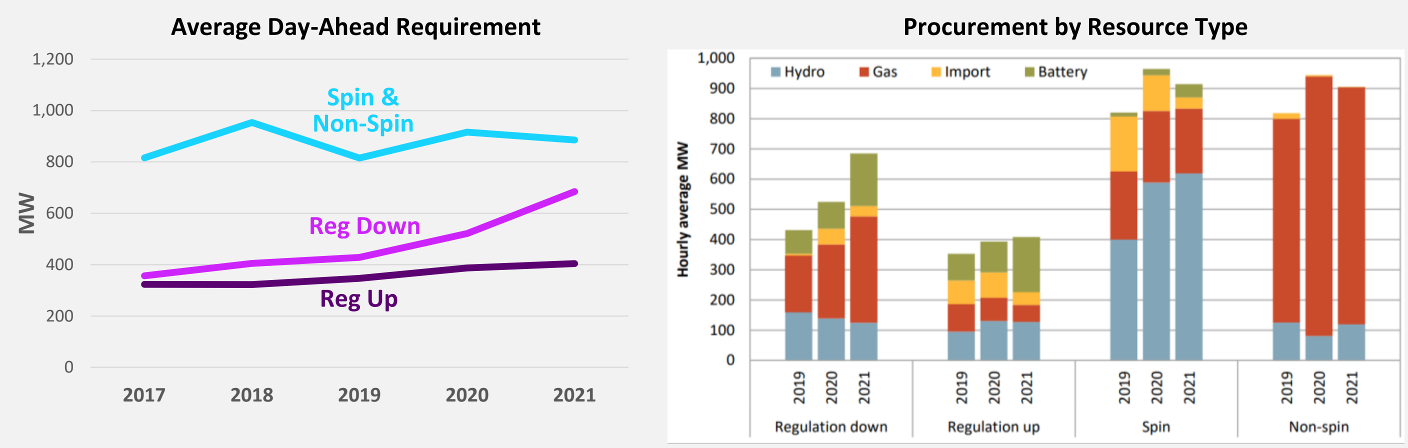


Figure 47: CAISO ancillary services markets size and supply.

(CAISO OASIS n.d.; CAISO DMM 2022)

Future value of energy time shift. 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 is expected to diminish its own 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 to $2.5/kW-month.

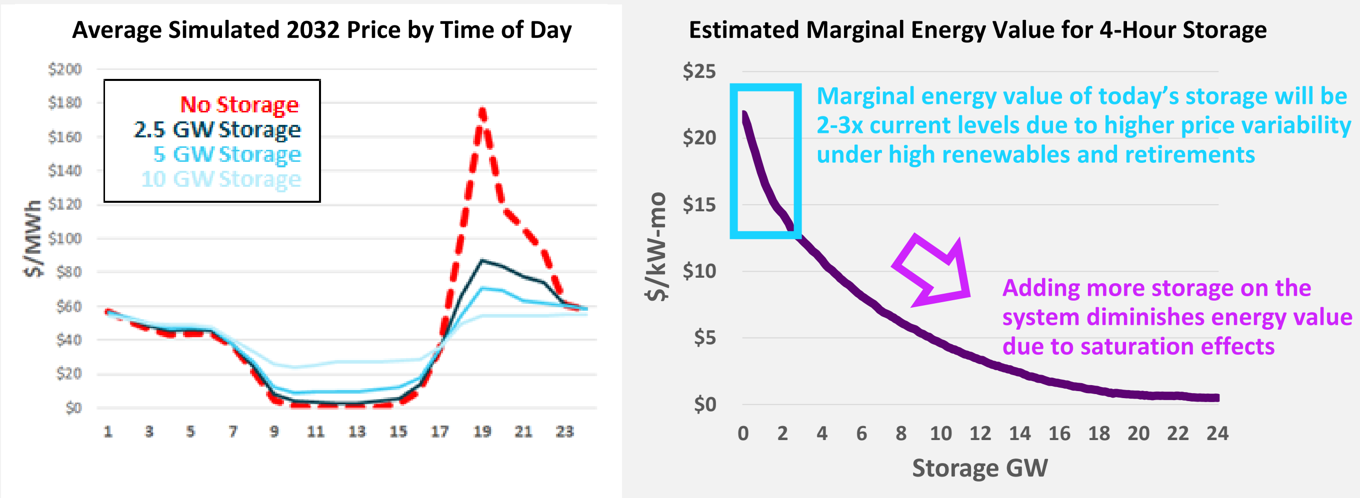


Figure 48: Simulated 2032 energy prices and storage energy value (2022 $).

Future value of RPS benefits. 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 time shift 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.

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 California to 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</u>.

As the California's grid transformation continues, **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**. 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.

Decreasing and uncertain marginal capacity credit. 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.

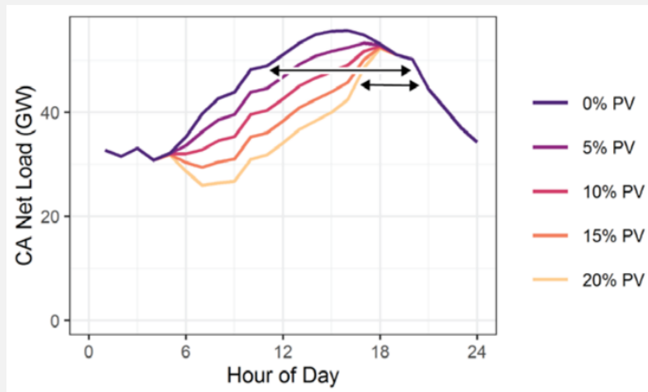


Figure 49: Effect of solar on net peak duration (Blair et al. 2022)

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, which will published by December 31, 2022.

To adapt to the rapidly changing energy landscape in California, CPUC's Resource Adequacy (RA) program 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.

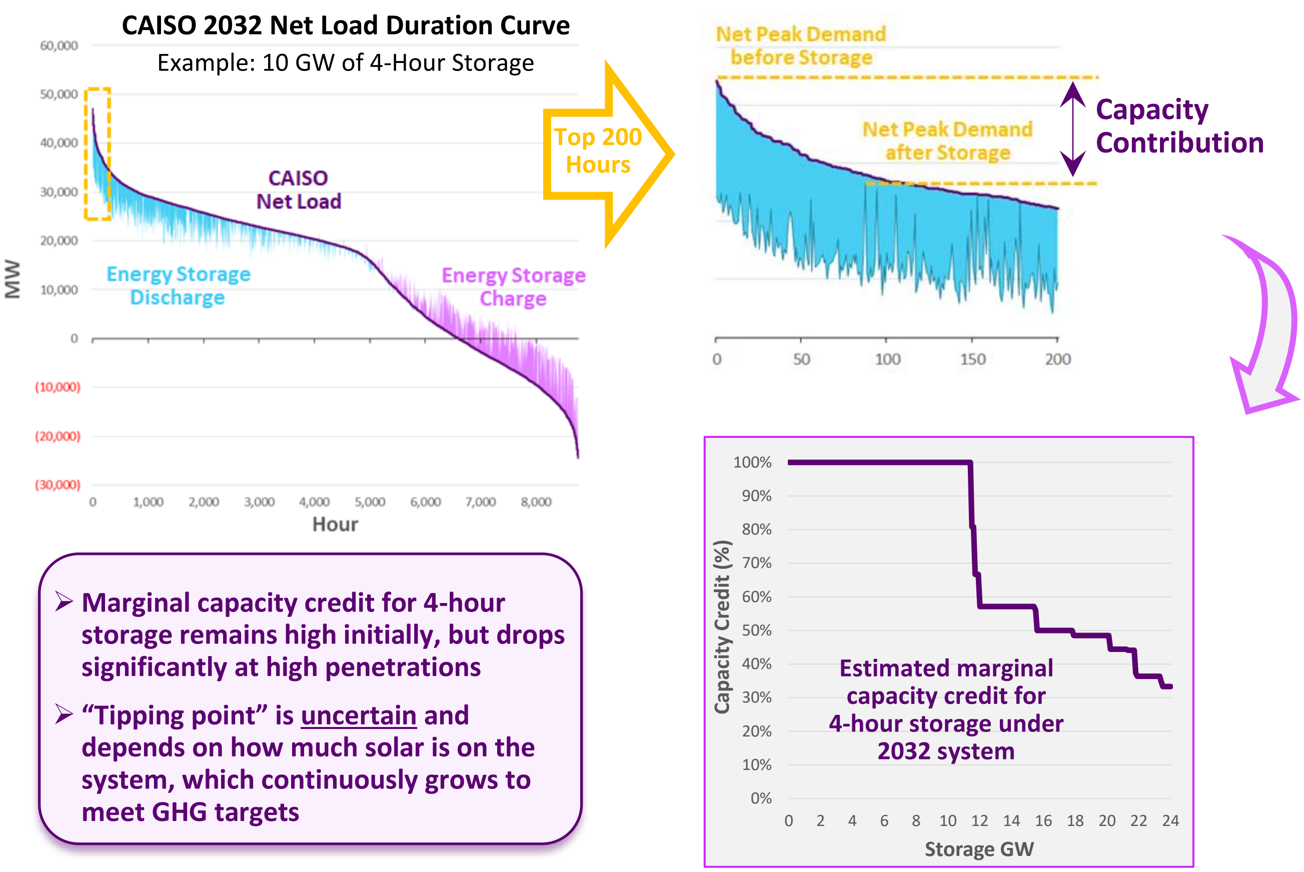
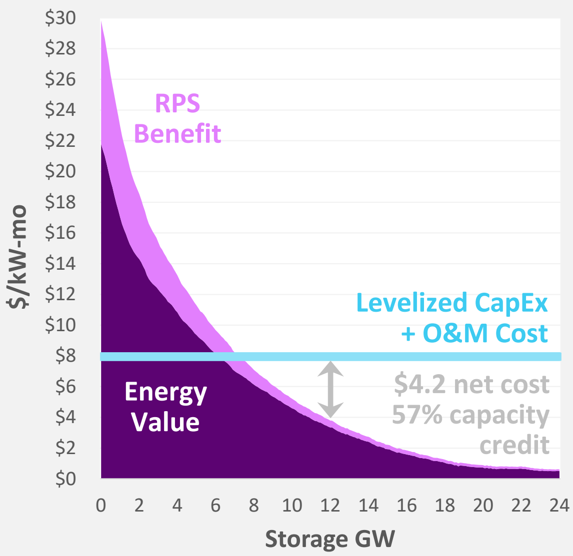


Figure 50: Illustration of declining marginal capacity credit for 4-hour storage at high penetration levels

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.



$$\text{Energy Storage Net CONE} = \frac{(\text{Levelized CapEx} + \text{Levelized O\&M Cost}) - (\text{Levelized Energy Value} + \text{Levelized RPS Benefit})}{\text{ELCC or Capacity Credit of Energy Storage}}$$

Example for marginal storage at 12 GW:

- Levelized Cost (Capex + O&M) = $8/kW-month
- Marginal Energy Value = $3.3/kW-month
- Marginal RPS Benefit = $0.5/kW-month
- Marginal Capacity Credit = 57%
- Net CONE = ($8 – ($3.3 + $0.5)) ÷ 57% = **$7.3/kW-month**

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

Need for long(er) duration energy storage. 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 to the 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 high clean energy future. However, meeting 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 20 GW or more.

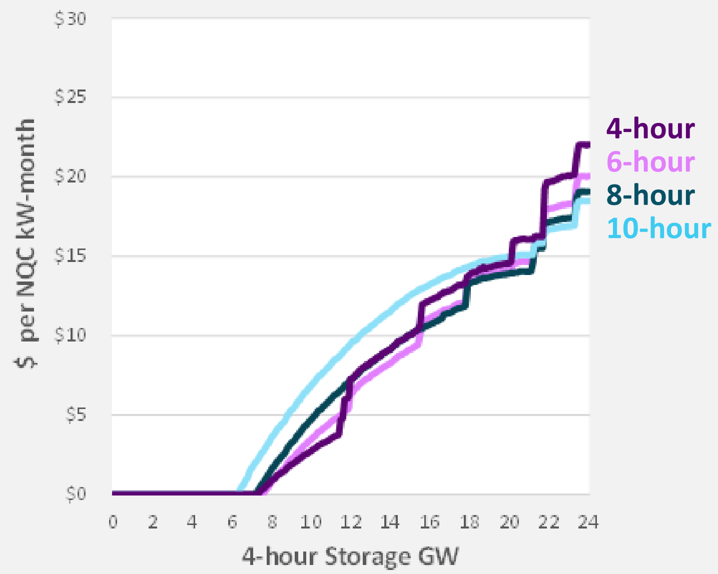


Figure 52: Estimated 2032 net CONE of storage by duration (in 2022 $)

*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 Midterm Reliability 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. These results will be updated by the end of 2022 for contracts executed after November 30, 2022, and 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 $15/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 $30 million per year.

Real option value for adding duration. 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.

Impacts of climate change and extreme system events. We see an increasing need to reflect future climate trends and extremes in the state's resource planning and ELCC models. 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 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.

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, launched in 2022, aims to build a resilience planning framework and re-parameterize the state's planning model inputs and assumptions in order to 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 61 MW at the start of 2017 to at least 582 MW by the end of 2021, largely driven by 468 MW of SGIP-funded installations (Figure 53).

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).

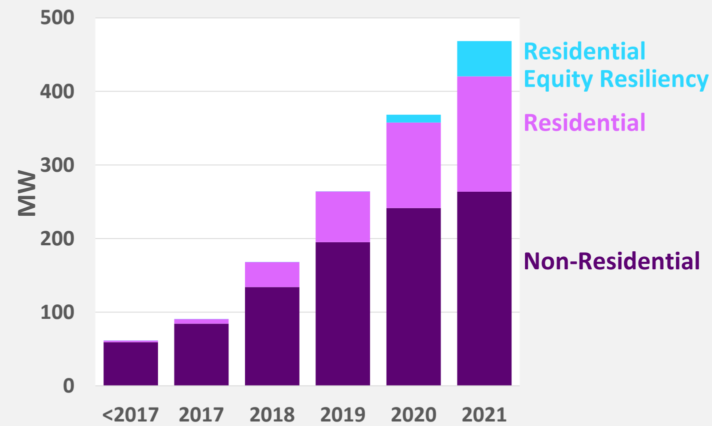


Figure 53: SGIP-funded installed storage capacity over time.

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 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.

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 has been achieved, but these signals are still in an initial pilot phase with impacts that are not yet fully understood.</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 <u>AND</u> 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 2021 CPUC proposed decision to make adjustments to the net energy metering tariff that, among other impacts, would better incentivize energy storage attachments to solar PV installations. That proposed decision received strong stakeholder reactions both for and against it, and the proceeding is still open at the time of this report. 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 (Rulemaking 22-07-005).

In terms of wholesale market integration, in 2020 CAISO expanded its Proxy Demand Resource model to include a Load Shifting Resource (PDR-LSR) option. This further opens the door for market participation of customer-sited energy storage and its bi-directional operating capabilities. Earlier in 2015–2016 CAISO developed enhancements to its performance evaluation methodology for behind-the-meter resources to address some of the measurement and verification challenges. Both efforts are examples within a broader set of CAISO 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.

Urgency is evident in the need for grid signals for customers that preclude achieving widespread advanced rate design and/or wholesale market integration—rather than steps along the way—as the practical solution. 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 roughly 4 GW of installed capacity by 2032. Under status quo, if current operations and use case remain unchanged, thousands of MW built at the customer-side 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.

<u>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.</u>

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. 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 per 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 per 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 allow the demand charge management use case to continue to be funded under the program, and prioritize 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.

With the target now in place, when might we see the shift from emissions increases to 5 kg per kWh emissions reductions from non-residential installations funded by SGIP? In operational data through September 2021, we still observe no effects of this GHG reduction rule. This is likely due to lags driven by exemptions for legacy projects and program enrollment timelines. If impacts can be observed in 2022 operational data, then they would be reported in the annual SGIP impact evaluation study published in 2024. Following the course of history, if the SGIP impact evaluation study published in 2024 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 status quo 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.

<u>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.</u>

Scale of untapped potential for grid benefits. 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 time-shift 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 $118–$285 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 <u>new</u> 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:

- **<u>Bring stronger grid signals to customers overall</u>** 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:

- **<u>Elevate assessment of effectiveness of GHG signals in SGIP</u>**, 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.

- **<u>Strengthen grid signals in SGIP</u>** through a course-correction to align program goals and performance requirements to produce significantly more energy and RA capacity value.
    - 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 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.

- **<u>Incorporate more flexibility in IOU contracts for customer aggregations</u>** 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 with market transformation not yet achieved.

We also observe in **Chapter 2 (Realized Benefits and Challenges)** that the 3rd-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 has 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, 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 3rd-party-owned resources procured for local RA capacity service yield a 2.5 ratepayer benefit/cost ratio compared to a 1.5 benefit/cost ratio for the next-best transmission-connected resources. Two other utility-owned resource 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 system support services and do not include services to the transmission grid. These resources are severely under-utilized and operate well below their potential to help meet state goals, both from a ratepayer and a societal perspective.

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.

Need 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.

Challenge of peaker replacements. 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. Energy storage installed across all domains has proven capable to serve local capacity needs through several local RA capacity procurement tracks. These procurements helped to 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 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). Exactly how much 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, and (c) whether or not solar PV can be developed at a reasonable cost within the local capacity-constrained area.

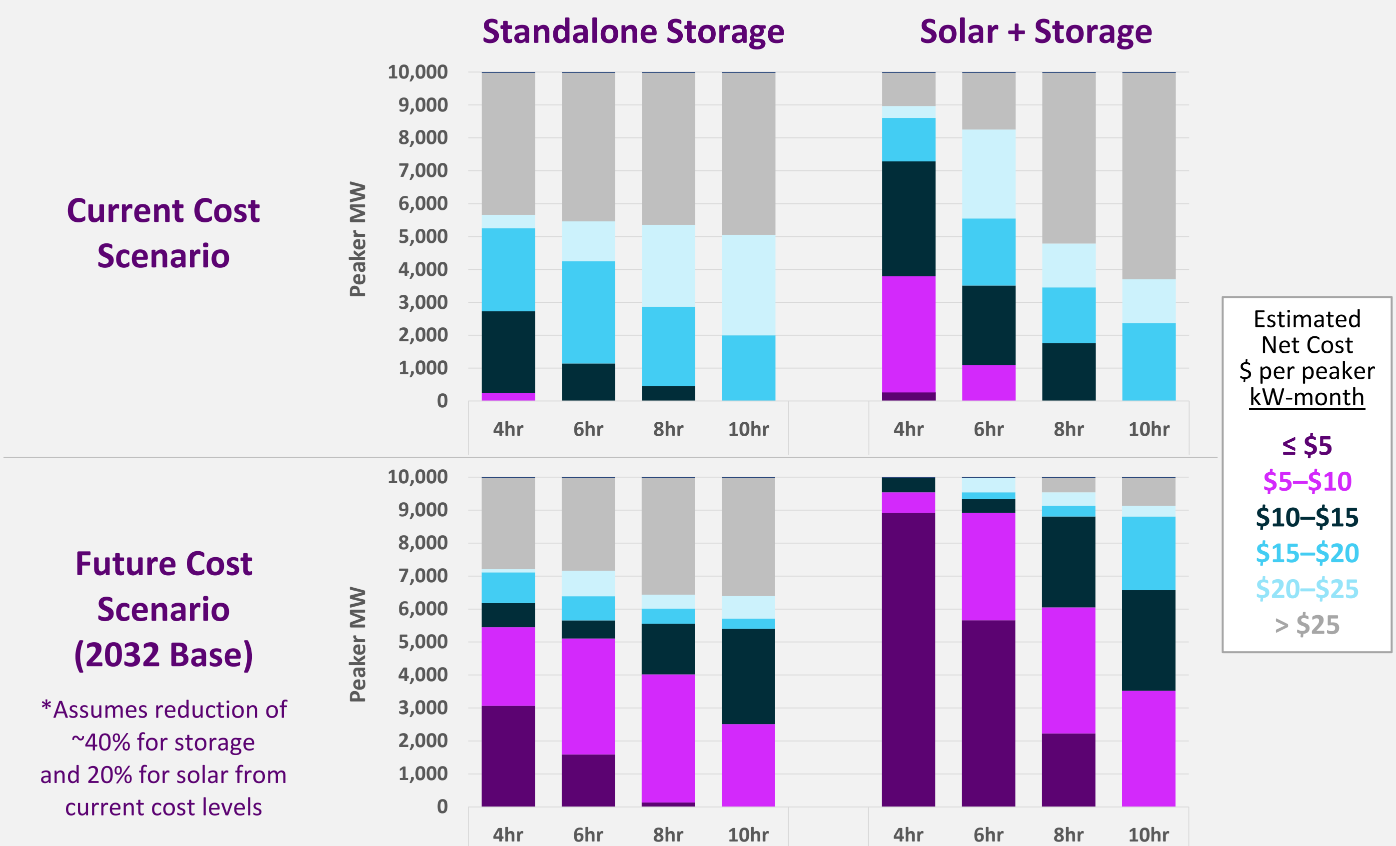


Figure 54: Distribution of peaker replacement net costs with no limitations on grid interconnection (2022 $).

* 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 for study details and discussion of alternative storage configurations analyzed.

Third-party developers of distribution-connected resources may be able to offer creative and low-cost solutions to achieving cost-effective peaker replacements by distributing interconnections across the local grid, while also offering downstream benefits of outage mitigation and distribution system support.

More generally, 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.

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:

- **Accelerate market transformation** including improvements to 3rd 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.
- **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, require all utility-owned installations and contracted third-party distribution deferral projects to seek participation in the CAISO marketplace.

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 a more viable use case for outage mitigation.

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.

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.

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

Need for planning and solutions at the customer and community level. 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.

Need to define 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.

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.

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 (Rulemaking 19-09-009), have made significant advancements in exploring the meaning of resilience and in developing a foundational "4 Pillar Methodology" for approaching resilience evaluation and valuation. Next steps for application of the 4 Pillar Methodology are to develop a definition of resilience and specific resilience evaluation metrics—ideally for use across a wide range of resource planning activities.

A stronger resilience 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, the depth of potential benefits to ratepayers of customer-sited energy storage depends crucially on the value proposition to individual customers.

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 square [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.

	[1] **Ratepayer B/C Ratio < 1.0**	[2] **Ratepayer B/C Ratio > 1.0**
[A] **Individual Customer B/C Ratio < 1.0**	[1A] *Example investments:* Most earlier SGIP projects *Example policy drivers:* Innovation, market transformation	[2A] *Example investments:* Grid-scale storage *Example policy drivers:* Ratepayer + societal benefits
[B] **Individual Customer B/C Ratio > 1.0**	[1B] *Example investments:* *Projects funded by* SGIP Equity Resiliency budget *Example policy drivers:* Equity, overcome financing hurdles	[2B] *Example investments:* Small subset of customer-sited storage projects *Example policy drivers:* Ratepayer + societal benefits

Figure 55: 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]).

Projects that fall under square [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 square [1B] to square [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 square [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 (square [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 square [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.

Need to capture rapidly changing and future 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 under the CEC and resource planners across the state are studying the IPCC climate projections closely to better understand future extreme conditions and human vulnerabilities. SGIP and other initiatives related to resilience planning will need to be updated periodically with new information on wildfire risk and other climate-related vulnerabilities.

Recommendations. Considering all of these 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**, 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 Division 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 and the state's planned installations represented 50% of all planned capacity in the country.

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 around the country repeatedly show 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> 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 1,900 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 acting 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.

System reliability. System reliability implications of safety events 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 and 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 windspeeds on high wildfire threat days.

VBB's system and site design took advantage of 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 at least a year. The event occurred in September 2021 and the facility came back online in late June 2022. Unfortunately, an almost year-long fallout 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, Hawai'i 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 on the local permitting process. The speed at which California is developing energy storage puts pressure on local authorities and the local review and permitting process. Many challenges are becoming apparent to achieve timely permitting across all local agencies 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 agencies still shoulder much of the burden. The CEC is well positioned to support local agencies 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.

(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 agencies 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.
- **Explore the safety-reliability link:** 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**: 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) 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 between 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 the CPUC does not have complete or reliable access to even the most basic 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.

Templates for data management.

Several existing practices may help improve access to the most essential energy storage data:

- 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 installation, 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.
- 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 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 some untapped potential in distributed resources. As described earlier, we estimate that the 13.6 GW planned transmission-connected energy storage portfolio has the potential to yield $830 million to $1.35 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 time-shift 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 $118–$285 million/year in net grid benefits. This would bring the total storage portfolio-wide 2032 net grid benefits to a range of $1 to $1.55 billion per year in 2022 dollars, as summarized in Figure 58 below.

		High Storage Cost Scenario	*Low Storage Cost Scenario*
Estimated 2032 Net Grid Benefits of 13.6 GW Planned Transmission-Connected Energy Storage Portfolio	[1]	**$830 million**	**$1.35 billion**
Additional Net Grid Benefits from Better Utilization of Future Customer-Sited Storage			
30% replacement	[2a]	$118 million	$171 million
50% replacement	[2b]	$197 million	$285 million
Total Estimated 2032 Net Grid Benefit of Storage			
30% replacement	[1]+[2a]	$1.00 billion	$1.47 billion
50% replacement	[1]+[2b]	$1.12 billion	$1.55 billion

Total 2032 Net Storage Benefit Range $1–$1.55 billion/year
(in 2022 dollars)

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

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 (which may require more complex modeling), and incorporation of future state agency and stakeholder data and analytical innovations to refine our future outlook.

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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