ATTACHMENT B: COST-EFFECTIVENESS OF FUTURE PROCUREMENT

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

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

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

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

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Study Approach and Analytical Framework

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

1. **Develop storage cost and performance assumptions:** Select energy storage configurations to be considered in the study and determine their cost and performance characteristics
2. **Develop Base Case outlook for power prices:** Develop 10-year outlook for power prices starting with no energy storage on the system
3. **Simulate storage operations and market value under the Base Case:** Simulate hourly operations of storage under the price forecast developed in Task 2; Estimate net energy market value and RPS benefits from avoided renewable curtailments
4. **Estimate impacts of increased storage penetration:** Quantify how storage charging in low-prices hours and discharging in high-prices hours would impact dispatch of other resources on the system and resulting energy prices; Re-simulate market prices and storage operations at each penetration level to determine extent of market saturation and declining marginal values
5. **Estimate marginal capacity contribution:** Approximate ELCC curves based on marginal impact of storage operations on net peak demand across all 8,760 hours simulated, accounting for shifting and flattening of net peak periods when more storage is installed
6. **Estimate net CONE at various storage duration levels:** Calculate net CONE based on levelized cost minus energy value and RPS benefit, divided by marginal ELCC; Repeat calculations for 4-, 6-, 8-, and 10-hour storage
7. **Determine cost-effectiveness of additional energy storage:** Estimate how much energy storage can be deployed cost effectively by comparing net CONE estimates in Step 6 against each other and alternatives

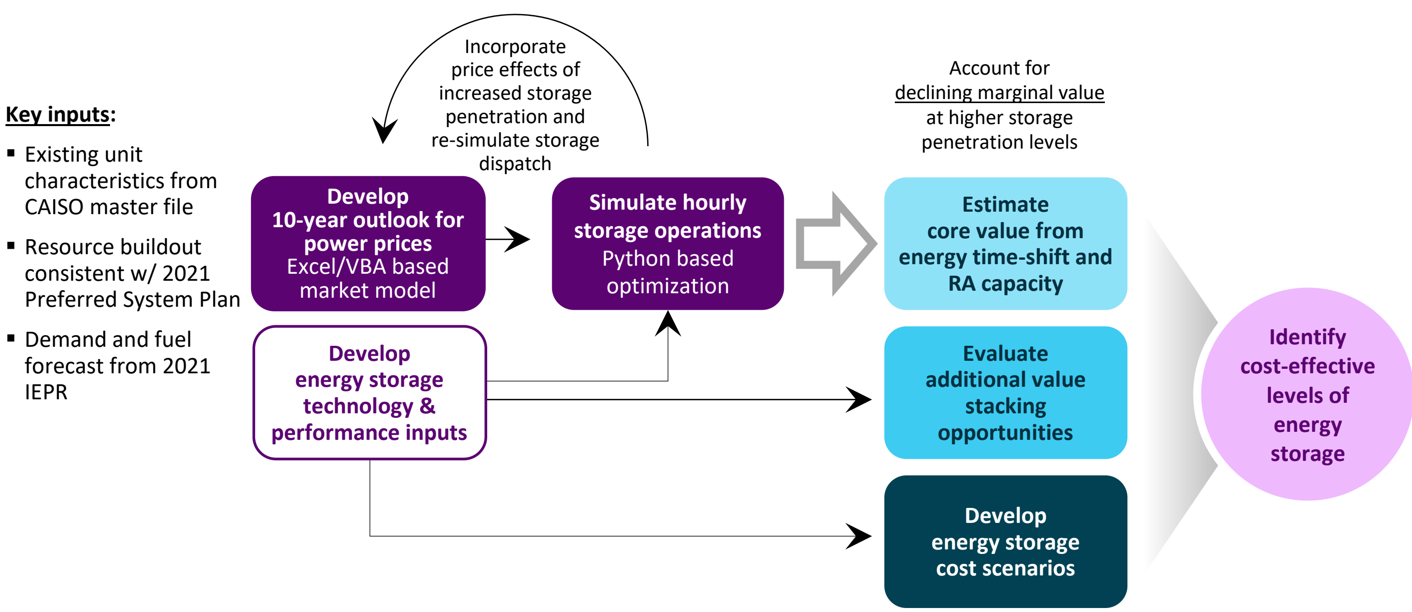


Figure 1: Study flowchart summarizing key tasks and analyses

Storage Technology and Cost Assumptions

Figure 2 below summarizes energy storage configurations and characteristics considered in our study.

While our study approach is technology-neutral, we simulate energy storage operations and analyze value utilizing cost and performance assumptions based on lithium-ion batteries as they are the dominant technology accounting for the large majority of new energy storage capacity procured in California today.

In our analysis, we focus on large utility-scale energy storage projects operating on a stand-alone basis with a primary use case of energy time-shift and resource adequacy at the bulk-grid level. We consider energy storage with 4–10 hours of duration as we expect most of the grid needs over the next 10 years can be addressed by storage systems that can provide up to 10 hours of continuous discharge capability at full output.

We assume 85% round-trip efficiency, which is in line with the actual performance of recently-installed battery projects participating in the CAISO markets. This means for each MWh of energy charged, the storage project will discharge 0.85 MWh of useful energy to be sent to the grid on average after losses and auxiliary use.

Our analysis considers 15 years of economic life during which storage performance is maintained with augmentation. Accordingly, our fixed O&M cost inputs are set to include cost of augmentation needed to counteract performance degradation and keep the energy storage system at rated capacity throughout its economic life.

Focus on stand-alone energy storage operations

Primary use case: Energy time-shift and resource adequacy at bulk-grid level
- Ancillary services are not included due to small market size and need
- T&D deferral has untapped potential to provide locational value, but significant barriers exist for scaling (discussed in main report; outside the scope of this special study)

Storage duration of 4 to 10 hours
- Multi-day and seasonal energy storage will be needed to meet 100% decarbonization goals of California, but we expect bulk grid level needs over the 10-year study horizon can be largely met by energy storage with up to 10 hours of duration

Round-trip efficiency of 85% consistent with our analysis of actual storage installations in California

Economic life of 15 years with augmentation (no degradation)

Figure 2: Energy storage configurations and performance assumptions utilized in the study

Installed cost of 4-hour utility-scale stationary battery storage is currently around $1,500/kW, consistent with our review of the cost data for projects owned by the California IOUs (see Chapter 1 of the report) and other public data (e.g., see reports from NREL and PNNL).

There is very little information on actual installed cost of systems with longer durations. To develop cost estimates for storage with durations of 6–10 hours, we used an approach utilized by NREL which splits the total cost of installations into two components: power- and energy-related costs. Power-related costs may include cost of inverters, power equipment and controls, interconnection, etc. that would typically scale with kW capacity, and they stay the same regardless of duration. On the other hand, energy-related costs (e.g., battery pack) scale with kWh capacity, which means on a $/kW basis it increases proportional to duration level. Currently, energy-related costs including battery pack, EPC, and developer costs add up to approximately $300/kWh for utility-scale stationary battery storage, which accounts for 80% of the total installed cost for 4-hour systems ($300/kWh × 4 hours = $1,200/kW, out of $1,500/kW). We assumed the remaining 20% (equals to $300/kW) is from power-related costs.

Costs of battery storage have declined rapidly over the past decade, with lithium-ion battery pack prices now at >80% below the levels seen in 2010. Going forward, this trend is expected to continue as batteries get cheaper due to the electric vehicle (EV) industry's quest to reduce costs. However, the recent supply chain issues and rising raw material costs create significant uncertainty (at least for the near future). Recognizing this cost uncertainty, we developed three scenarios for the 2032 installed cost assumptions, with energy-related capital cost reductions of 20% to 60% relative to current levels, consistent with the range of projections in the industry.

Figure 3 shows the estimated total installed costs of utility-scale systems with 4–10 hours of duration. Total costs per kWh decrease slightly at higher durations because power-related costs are spread across larger kWh. In $/kW terms, installed costs increase significantly at higher durations because for a fixed level of kW capacity, systems with longer durations require more kWh and energy-related costs account for a relatively large share of total costs.

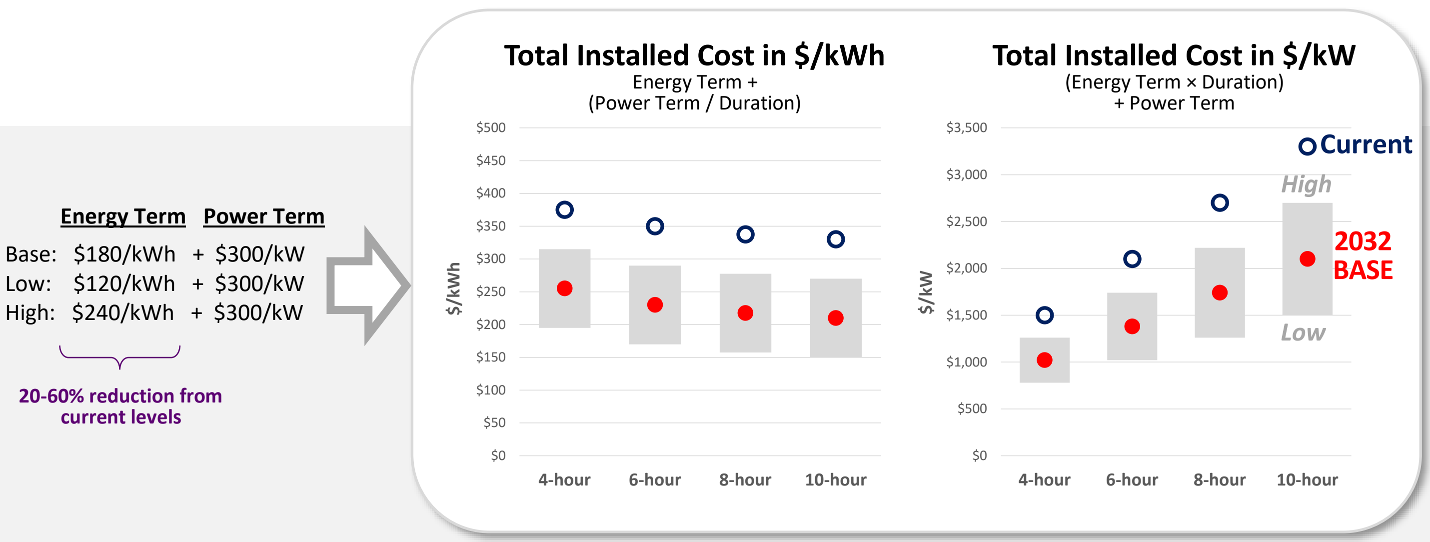


Figure 3: Installed cost assumptions for utility-scale energy storage systems (in 2022 dollars)

Project Life	**15 years** includes augmentation
Federal + State Taxes	**28%**
After-Tax WACC	**7%**
Depreciation Schedule	**5-year MACRS** w/ Inflation Reduction Act
Investment Tax Credit	**30%** w/ Inflation Reduction Act
Inflation Rate	**2.5% per year**
Fixed O&M Cost	**2.5% of installed cost** includes augmentation

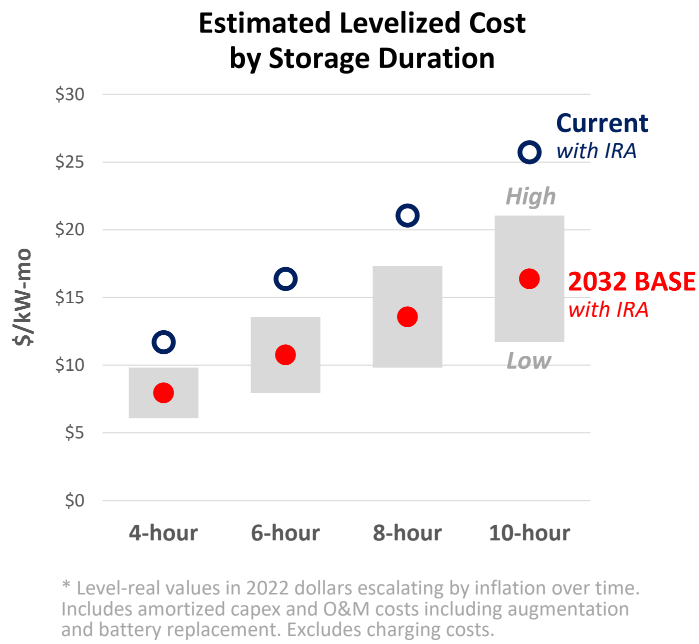


Figure 4: Financial assumptions and estimated levelized cost of storage

Figure 4 above shows our estimated 2032 levelized costs and the underlying financial assumptions. As discussed earlier, we assume 15 years of economic life during which storage capacity will be maintained with augmentation. For consistency, we set fixed O&M cost inputs at a level that includes augmentation costs in addition to other general O&M expenses.

We represent levelized cost values in $/kW-month (2022 dollars) including only capital and O&M costs. We do not include charging costs here because they are already considered when we estimate net energy market value of storage.

The 2032 estimates shown above are with the tax benefits of Inflation Reduction Act (IRA) of 2022, including investment tax credit (ITC) of 30% and treatment as a 5-year property under the modified accelerated cost recovery system (MACRS) rules for depreciation purposes. Figure 5 demonstrates the impact of these new tax benefits on estimated 2032 levelized cost of 4-hour standalone storage. For reference, the storage cost range based on utility contracts approved during the 2020-2021 period is also shown.

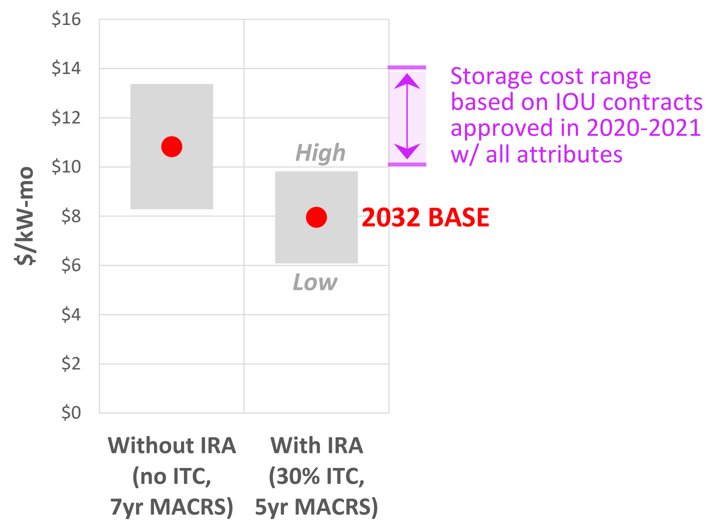


Figure 5: Impact of Inflation Reduction Act (IRA) on estimated 2032 levelized cost of 4-hour storage

Energy Market Model: 2020 Backcast and Model Calibration

We built an Excel/VBA based energy market model that dispatches regional supply against a chronological hourly load to minimize total dispatch cost and estimate system-level marginal energy prices.

Model inputs include unit-specific resource characteristics based on CAISO master file, hourly managed system load, hourly solar and wind generation schedules, monthly energy levels for hydro generation, and daily fuel and GHG prices, and daily aggregate outage profile for thermal plants. Dispatch of large hydro resources assume to follow net load, subject monthly energy inputs and parameters calibrated based on historical data. Hourly import/export schedules modeled based on historical relationship between CAISO net load and net import levels accounting for seasonality and time of day. While unit commitment constraints are not fully included, the model applies a heuristic approach to enforce minimum runtime and ramping limits before final dispatch of resources are determined. Energy storage schedules are determined separately using a Python-based optimization module under a price-taker approach. The two models are run iteratively to ensure prices and storage operations are internally consistent.

Before simulating 2032 prices, we first created a “2020 backcast” to calibrate the model to track key price patterns including: daily and monthly shapes, price spikes during scarcity conditions, and low prices when there is oversupply. To do this, we populated our model with historical inputs reflecting 2020 day-ahead market conditions and benchmarked the results against actual market outcome. We ran several test cases to identify model refinements needed until results were reasonably close. Figure 6 below summarizes the results of this calibration process.

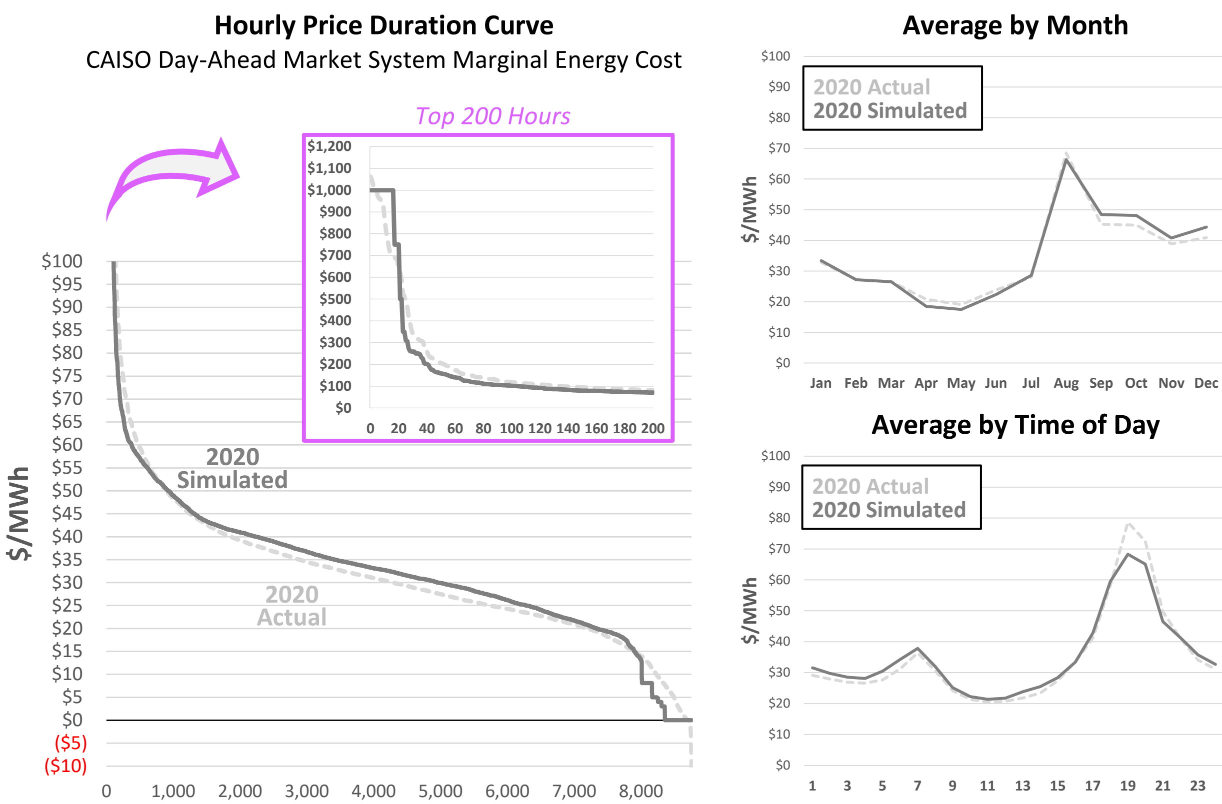


Figure 6: Comparison of simulation results against actual 2020 CAISO energy prices

2032 Modeling Inputs and Assumptions

After the market model is calibrated, we developed inputs to simulate 2032 market conditions. Key model inputs and assumptions are summarized below:

- Unit characteristics for existing resources from CAISO master file as of December 2021
- Hourly load forecast based on CEC 2021 Integrated Energy Policy Report (IEPR) managed load under mid-mid scenario (Mid baseline demand, AAEE Scenario 3, AAFS Scenario 3)
- Resource buildout (except for energy storage levels) based on 2021 Preferred System Plan portfolio adopted by the CPUC, which includes:
  - 5.0 GW onshore wind (3.5 in-state + 1.5 out-of-state)
  - 1.7 GW offshore wind
  - 17.5 GW utility-scale solar
  - 1.2 GW geothermal
  - 0.1 GW biomass
  - 0.4 GW demand response
- Energy storage installations tested at various levels (up to 24 GW)
- Retirement of Diablo Canyon nuclear plant
- Retirement of Alamitos 3-5, Huntington 2, Ormond Beach 1-2, Redondo 5-6, 8 peaking units for OTC compliance
- Hourly renewable generation profiles for existing resources based on 2020 data (pre-curtailment)
- Hourly renewable generation profiles for new resources from CPUC Unified RA and IRP Modeling Datasets used to develop 2021 Preferred System Plan
- Monthly energy for small hydro resources at historical 2015-2021 average (data from CAISO)
- Monthly energy for large hydro resources at historical 2002-2021 average (data from EIA-923)
- Gas price forecast based on CEC Natural Gas Burner Tip Prices (September 2021) adjusted for transportation adder and other rate differences based on historical fuel price indices from CAISO OASIS website
- GHG price set to $32/ton (in 2022 dollars) which reflects the estimated 2032 price floor for the California cap-and-trade program
- Hourly import/export schedules modeled based on historical relationship between CAISO net load and net import levels accounting for seasonality and time of day
- CAISO net export limit set to 5,000 MW consistent with CPUC IRP modeling assumptions used to develop 2021 Preferred System Plan

Figure 7: Summary of 2032 model inputs and assumptions

Simulation Results and Estimated Storage Value

We started with a simulation of 2032 base case with no storage to create a reference against which we can measure cumulative impacts of adding storage. This base case highlights major changes from today's market conditions and some of the significant challenges that the system would have in absence of energy storage.

Figure 8 below shows the resulting system-level energy prices, relative to 2020 levels. Charts on the left shows hourly prices sorted from highest to lowest and the chart on the right shows average daily price patterns.

These simulation results confirm that there would be a large increase in supply-constrained hours after Diablo Canyon and OTC retirements if system had no energy storage installed. We estimated there would be around 100 scarcity hours during which market prices would be at ~$1,000/MWh. This is five times higher relative to 2020 which was an extreme year with severe heat waves and multiple grid emergency events.

At the same time, massive solar buildout needed for to meet the state's clean energy and decarbonization goals increase oversupply in the middle of the day. With over 50 GW of installed solar capacity by 2032 (utility-scale + BTM) system will have significant amount of excess renewable generation above what can be exported, and that excess generation would need to be curtailed if it cannot be stored for later consumption. Accordingly, we estimate energy prices to drop to $0 (assumed floor) in most days between 9am and 3pm.

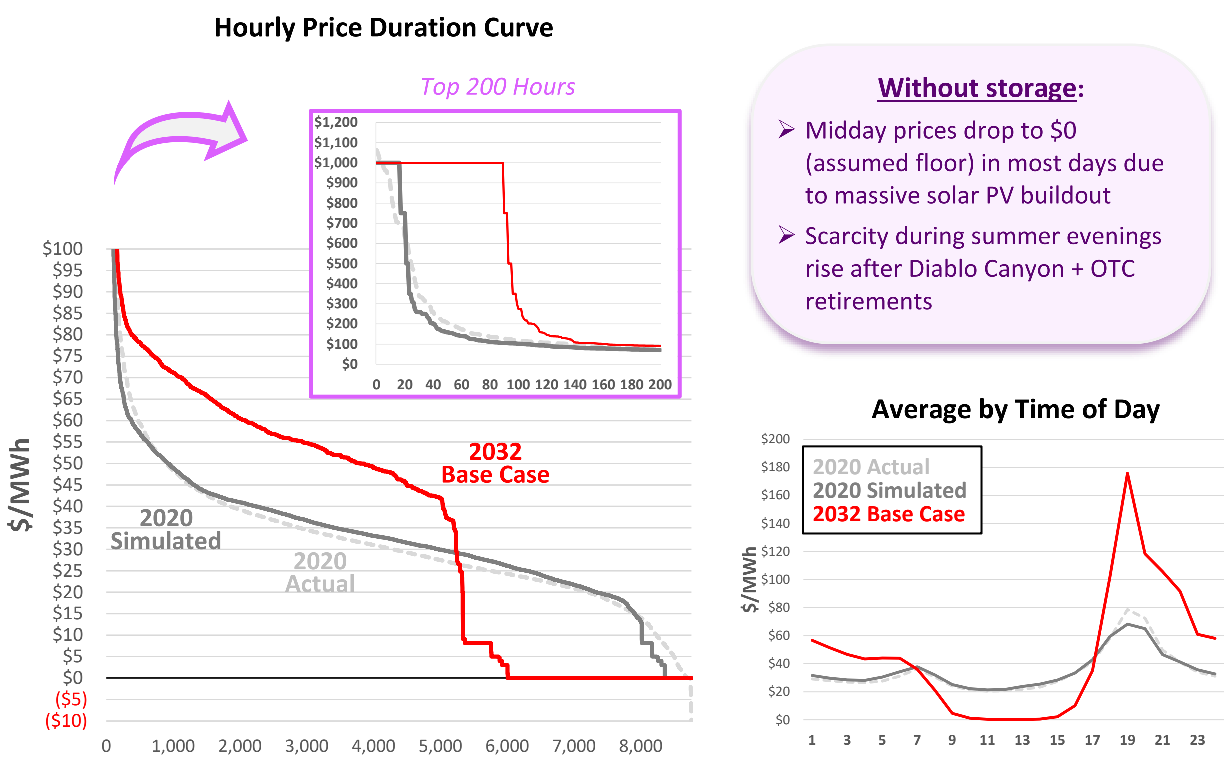


Figure 8: Simulated 2032 price patterns without energy storage

We then re-simulated the 2032 market conditions with various levels of energy storage. As described earlier, we determine energy storage schedules using a Python-based optimization module under a price-taker approach. We run the energy market model and storage dispatch module iteratively to ensure prices and storage operations are internally consistent. We add energy storage in small increments (100 MW) to avoid convergence problems.

Figure 9 below shows the impact of energy storage on market prices. Although we tested energy storage buildout at highly granular levels ranging from 0 to 24 GW in 100 MW increments, we show here only results for 2.5 GW, 5 GW and 10 GW of storage to illustrate the overall direction and magnitude of changes on price patterns:

- The initial 2.5 GW of storage added to the system significantly reduces the evening price spikes and number of scarcity events. But it has little impact on renewable oversupply in the middle of the day and prices stay at floor in most days.
- Increasing storage capacity to 5 GW further reduces evening prices and scarcity events, while also starting to lift midday prices.
- At 10 GW storage penetration, most of the simulated scarcity events go away (under normalized load, without extreme events) and daily prices get relatively flat as the spread between midday and evening peak prices are reduced due to storage operations.
- Accordingly, flattening prices reduce intraday energy arbitrage opportunities and results in declining energy value for marginal energy storage resources added to the grid (discussed next).

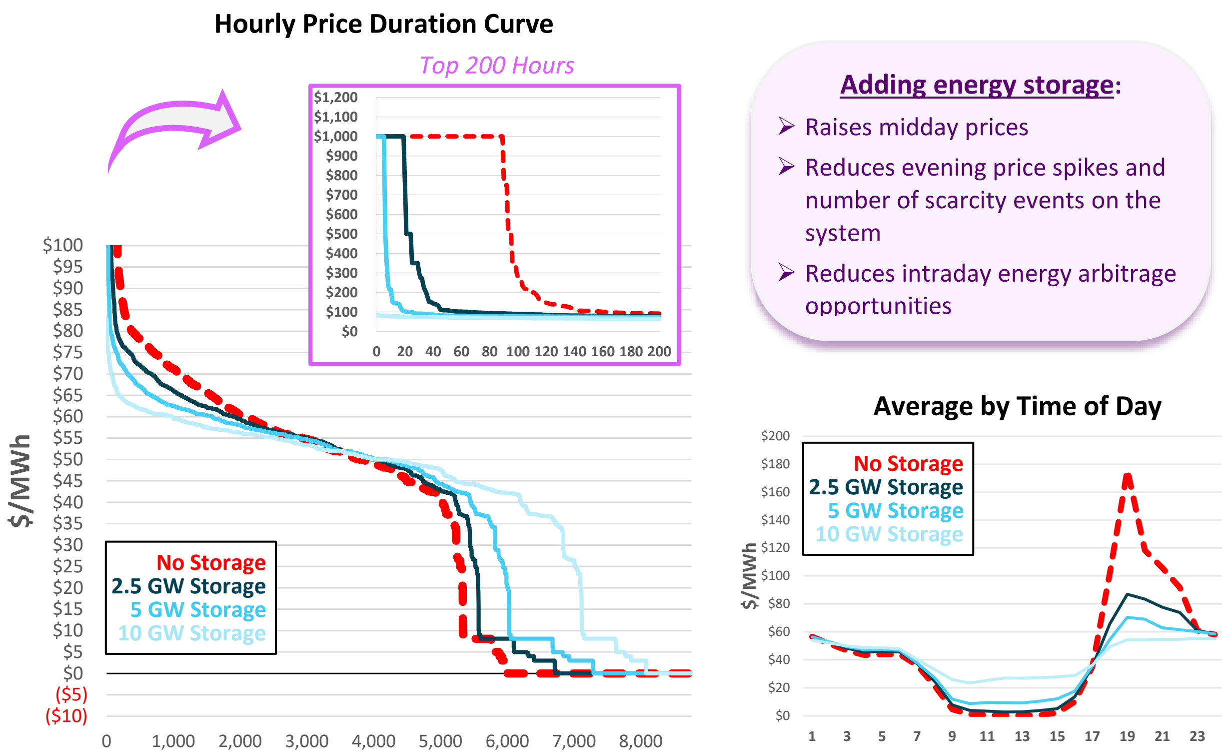


Figure 9: Simulated 2032 price patterns with various levels of energy storage

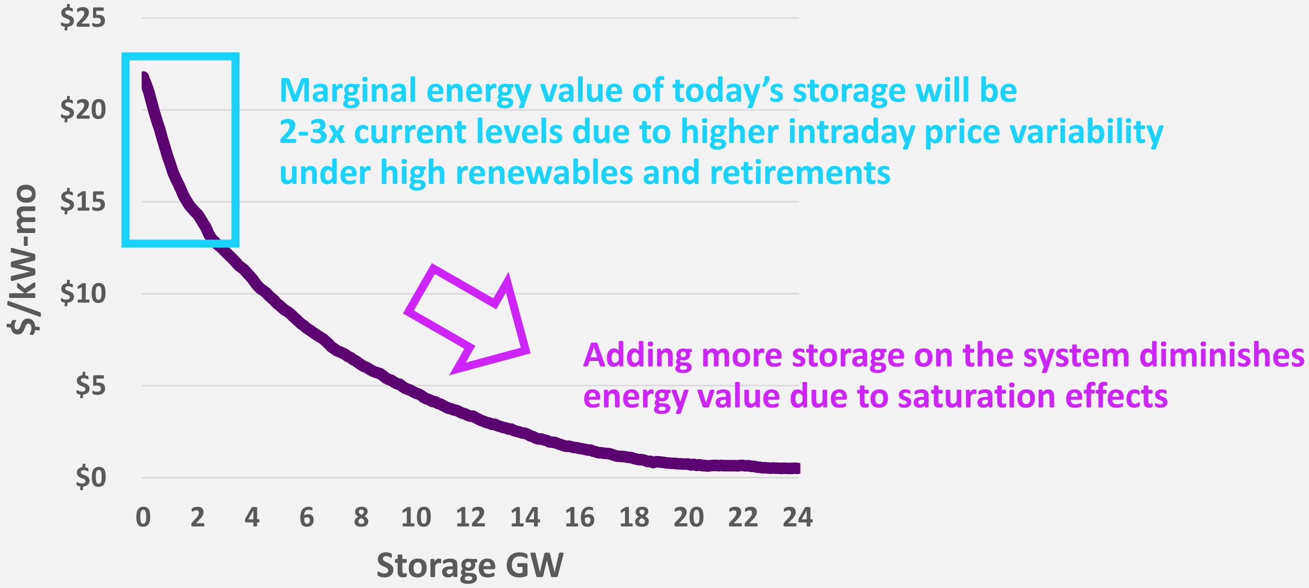


Figure 10: Estimated marginal energy value for 4-hour storage in 2032 (in 2022 dollars)

Marginal energy value reflects the energy value of the last storage MW added to the system, net of any charging costs. During the 2017–2021 period, intraday price differentials yielded energy value potential of $4–6 per kW-month for 4-hour storage participating in the CAISO energy market without ancillary services focus. We estimate that value would be 2–3 times higher in a 2032 electric system and renewable buildout consistent with the 2021 Preferred System Plan.

As shown in Figure 10 however, when the bulk-grid level energy storage penetration goes up, marginal value of adding the next MW declines. The storage portfolio provides significant value as a whole, but flattening of marginal energy prices increasingly signal market saturation and no more need for new entry for energy. The CPUC-adopted 2021 Preferred System Plan identifies a total need for 13.6 GW of battery storage by 2032, mostly with 4-hour duration. At that level, our estimated marginal energy value drops below $2/kW-month, which suggests that further development will likely require a combination of higher capacity payments, technology carve-outs and/or other storage incentives.

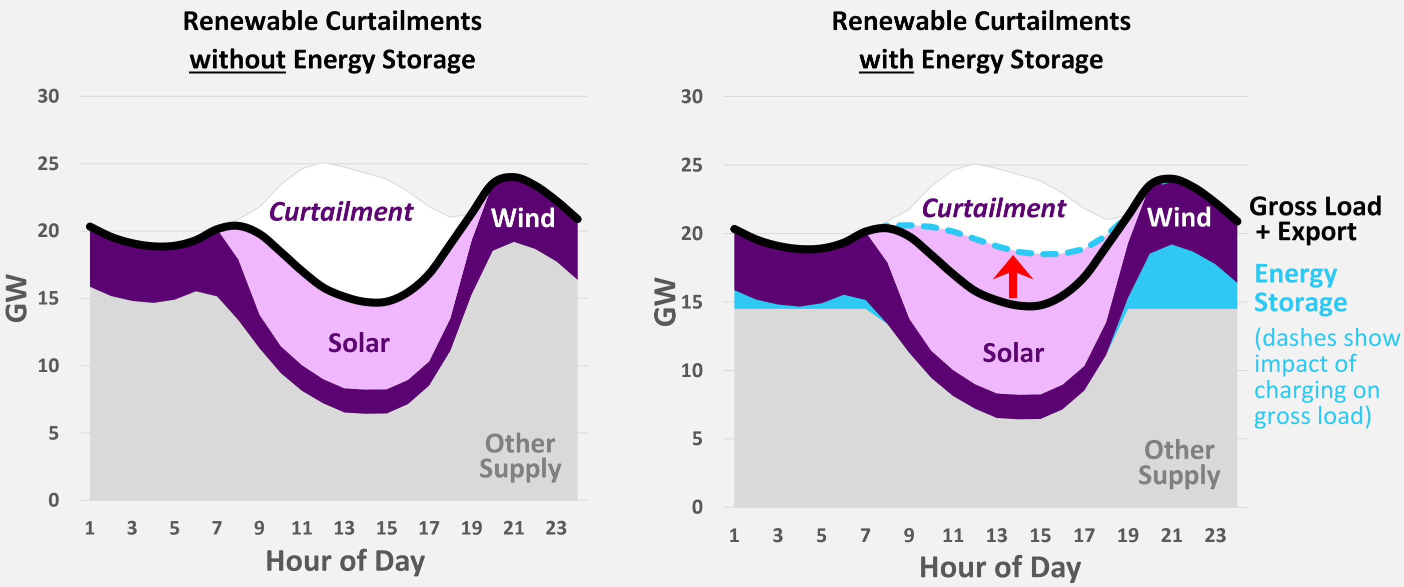


Figure 11: Illustration of energy storage impact on renewable curtailments

Energy storage can reduce renewable curtailments by mitigating oversupply conditions, which will get increasingly more challenging as California continues to decarbonize its electric system. As illustrated in Figure 11 above, charging of storage when the system has oversupply can reduce the excess renewable energy that would otherwise get curtailed.

Avoided renewable curtailments reduce the need (and cost) to procure additional resources to meet RPS and other clean energy targets. To estimate benefits, we first determine the impact on renewable curtailments based on net charge of marginal energy storage resources during simulated hours with system-level curtailments. The maximum potential benefit of 4-hour storage is around 120 MWh of monthly curtailment reduction per MW of storage capacity assuming 1 cycle/day and 4+ curtailment hours every day. Our estimated impact under 2032 base case with no storage is very close to this potential, but marginal benefits decline rapidly as more energy storage is added to the system.

We monetize RPS benefits based on renewable energy credit (REC) value adjusted for curtailments. We start with $15/MWh, which is consistent with the RPS adders in CPUC's Power Charge Indifference Adjustment (PCIA) estimates. This value reflects in average incremental cost of RPS-eligible resources based on recent transactions. We further adjust this value for marginal curtailments in our 2032 market simulations. For example, if a renewable resource needs $15/MWh of REC payments for each potential MWh that could be generated, but 50% of it gets curtailed on the margin, then effective marginal RPS cost would be equal to $15 ÷ 50% = $30/MWh.

Figure 12 below shows estimated impact on renewable curtailments and marginal benefits of 4-hour storage at different penetration levels.

Benefits of initial storage installations are relatively high because at low storage penetration levels, system would have more extreme oversupply and frequent curtailment events, and intraday energy time-shift more effectively addresses these challenges. When more storage gets installed, marginal benefit of adding the next storage MW declines because renewable oversupply is already partially mitigated and there are fewer curtailment events left to be addressed.

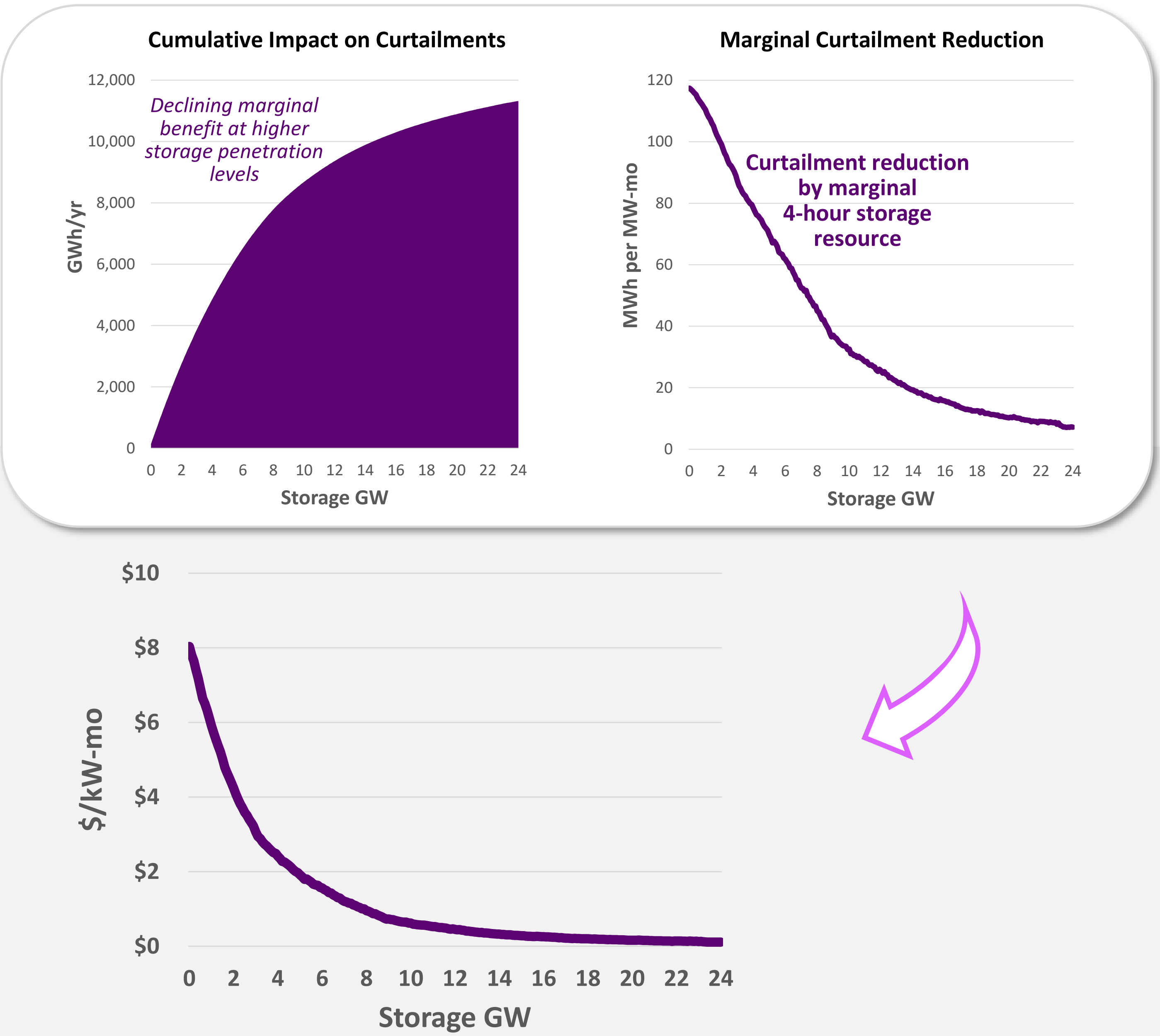


Figure 12: Estimated marginal renewable curtailment benefits for 4-hour storage in 2032 (in 2022 dollars)

Most of the recent energy storage procurements in California are driven by the emerging system reliability and resource adequacy (RA) needs. We expect this trend to continue as the state decarbonizes its electric system.

The ability of an energy storage resource to address reliability and resource adequacy needs depends on its instantaneous capacity (MW) as well as its energy capacity (MWh). A 1 MW/4 MWh storage resource has 4 hours of duration, which means it can provide up to 4 hours of continuous discharge capability at full output. For reliability events lasting longer than 4 hours, its instantaneous capacity would need to be de-rated accordingly. The overall capacity contribution would be a function of possible durations of reliability needs, relative to the duration of storage.

CPUC's initial "4-hour rule" required storage resources to have at least 4 hours of duration to qualify for full capacity credit. More recently, this has shifted to a probabilistic "ELCC-based approach" to recognize value of storage duration, dynamic interactions between renewables and storage, and saturation effects of storage. For the purposes of this study, we estimate capacity credit of storage based on its impact on CAISO's net peak demand. We optimize storage dispatch to maximize capacity credit (primary objective) and respond to energy price signals to increase market revenue (secondary objective). Our analysis relies on weather normalized load forecast and assumes energy storage has perfect foresight of system conditions. Possibility of extreme reliability events and real-time uncertainty is not modeled and may reduce capacity contribution of storage resources below estimated levels. While this deserves additional attention in future studies, we believe that the approximation implemented here sufficiently captures the key factors needed to identify value opportunities, including relative value of energy storage duration, renewable-storage interactions, and saturation effects.

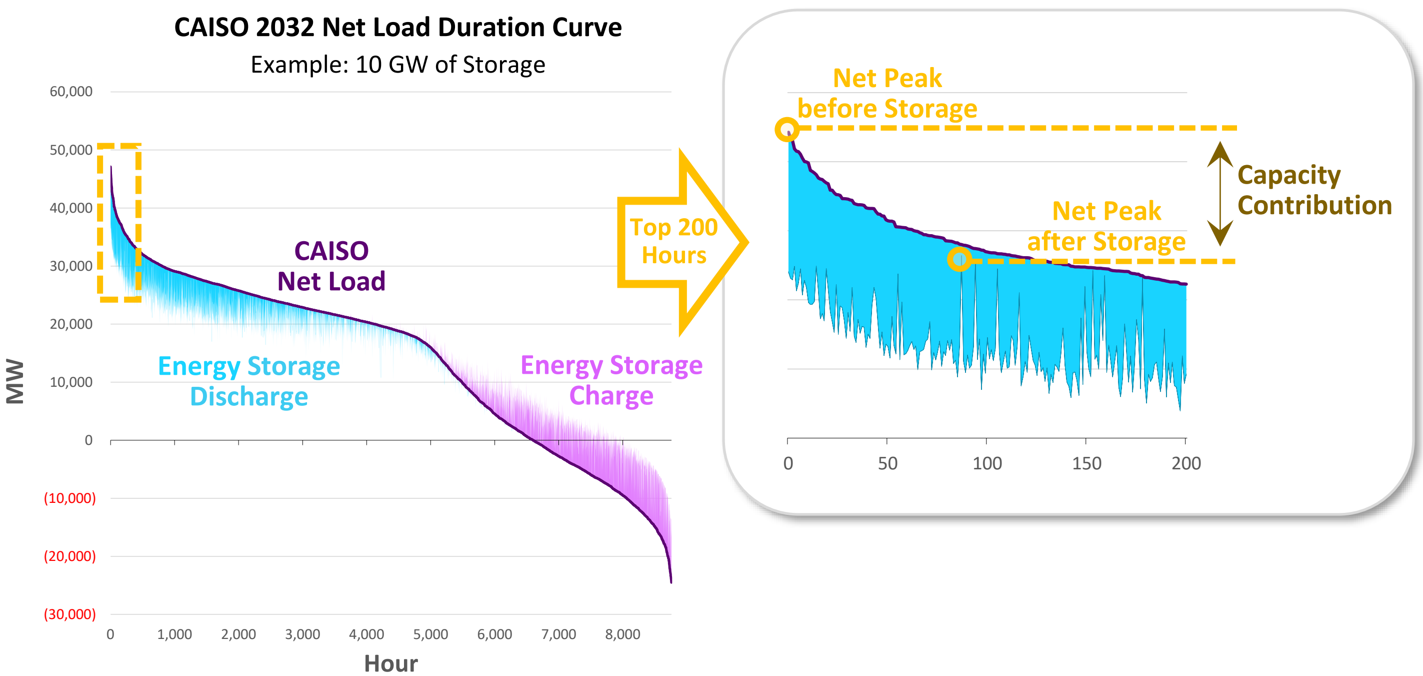


Figure 13: Illustration of energy storage capacity value based on impact on net peak demand

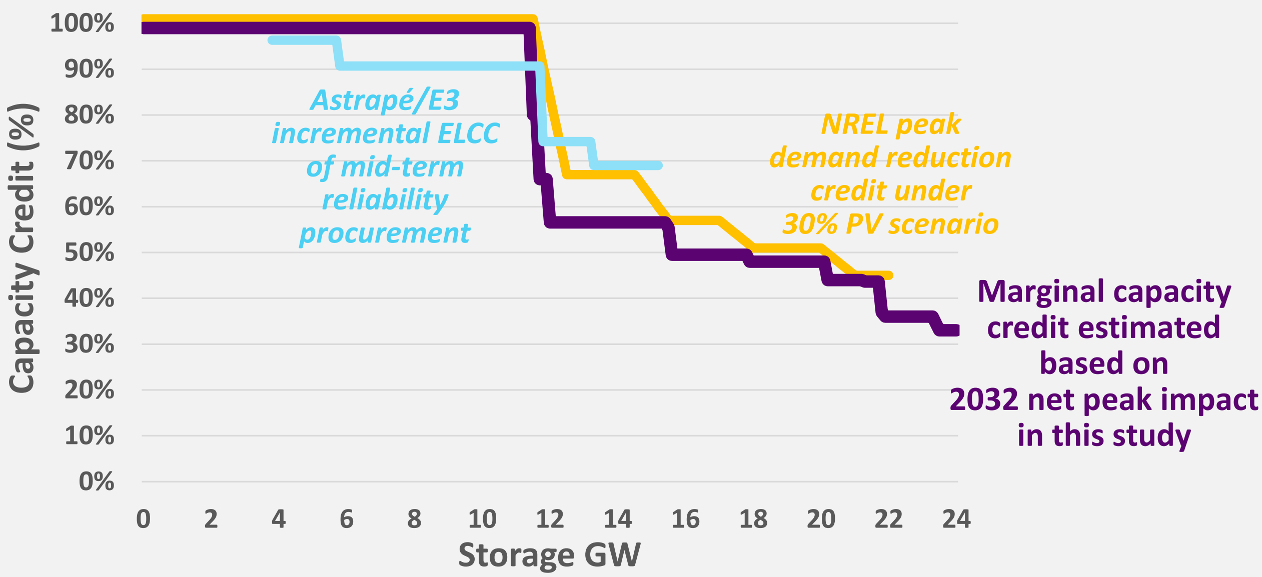


Figure 14: Estimated capacity credit for 4-hour energy storage in California

Figure 14 above shows our estimated capacity credits for 4-hour storage at different penetration levels and benchmarks against other studies analyzing capacity value of energy storage in California. The marginal capacity credit remains high initially, but drops significantly after storage installations reach a certain level. This "tipping point" depends on how much solar is on the system. Adding solar reduces the duration of grid reliability needs and thus enables more storage at higher capacity credit levels, moving the tipping point. The chart also shows results from Astrapé/E3 study (2021) used to determine incremental ELCC values for Mid-Term Reliability Procurement and NREL study (2018) evaluating the potential of storage to provide peaking capacity in California under increased solar PV penetration. While final metrics are not directly comparable, they show similar patterns on tipping point for 4-hour storage at around 12 GW of cumulative installed capacity.

The sudden drop of marginal capacity credit or ELCC value of storage is driven by the shape of net load in California. At high solar penetrations, net load is peakier with a relatively short window of capacity need in the evening. But when storage installations reach a certain level and flatten the evening net peak demand, getting the next MW of capacity requires a much longer duration, which reduces the capacity value of storage.

Figure 15 shows results for energy storage with durations up to 10 hours.

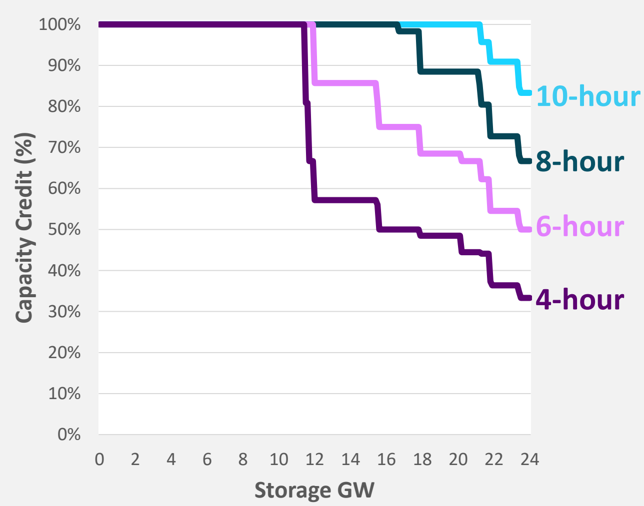


Figure 15: Estimated capacity credit by duration

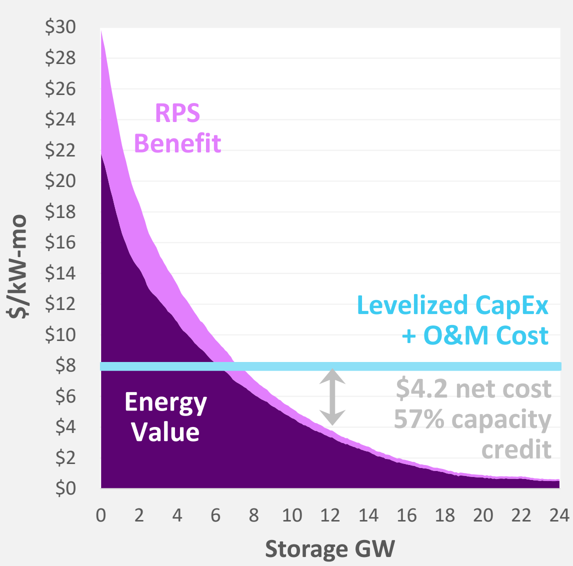
*Values for marginal additions in a system where bulk of the storage portfolio has 4-hour duration.

Estimated Net Cost of New Entry

California's ambitious GHG emission reduction targets combined with expected plant retirements, and climate change impacts on electric supply and demand create a significant need for new clean capacity resources on the system. For example, the CPUC's recent decision (D. 21-06-035) required procurement of at least 11.5 GW of additional net qualifying capacity (NQC) between 2023 and 2026. Energy storage is expected to meet a large share of this need.

A key metric to help with the evaluation of economic potential for energy storage is its net cost of new entry (net CONE) value at various storage penetration levels in California. Net CONE is the amount of capacity revenue that a resource would need to support its initial investment costs that are not covered by other types of benefits. In Figure 16 below, we show the calculations of net CONE of energy storage based on levelized capital and O&M costs *minus* non-capacity benefits (energy and RPS), normalized for the ELCC or capacity credit of the resource. The example illustrates how declining marginal capacity credit and other value streams can put upward pressure on net CONE for energy storage, even with anticipated cost reductions.

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



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 per kW-month**

Figure 16: Calculation of marginal net cost of new entry (net CONE) for energy storage

Figure 17 below shows the estimated net CONE of marginal storage resources built in a 2032 system, illustrating effects of storage cost assumptions (left) and duration (right).

Initial storage installations have a zero net CONE because estimated energy and RPS benefits in 2032 would be sufficient to recover costs if storage penetration remained low. Net CONE gradually increases at higher penetrations as estimated energy and RPS benefits decline, with big jumps when storage capacity credit drops.

Overall, 4-hour storage is more cost effective initially (as expected) but the gap with longer duration storage configurations closes as more storage is installed. We see crossover points after capacity credit of 4-hour storage plummets at around 12 GW. But the difference in net CONE levels remains relatively low until storage penetration exceeds 20 GW.

Altogether, these results suggest that further development of energy storage in California will require a combination of higher capacity payments, technology carve-outs and/or other incentives. Locational opportunities and additional value stacking (not analyzed) can further increase benefits and accordingly reduce net CONE of storage. The path for cost-effective long-duration storage (up to 8–10 hours) is in sight, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC or capacity credit modeling assumptions.

Given inherent uncertainties with future RA capacity needs and resource contributions, procurement efforts may have to pivot quickly and adjust target portfolios based on unexpected changes and new information. Battery storage systems and site designs are highly modular and adding duration at existing sites can have a streamlined interconnection process that can be completed more quickly and at a lower cost.

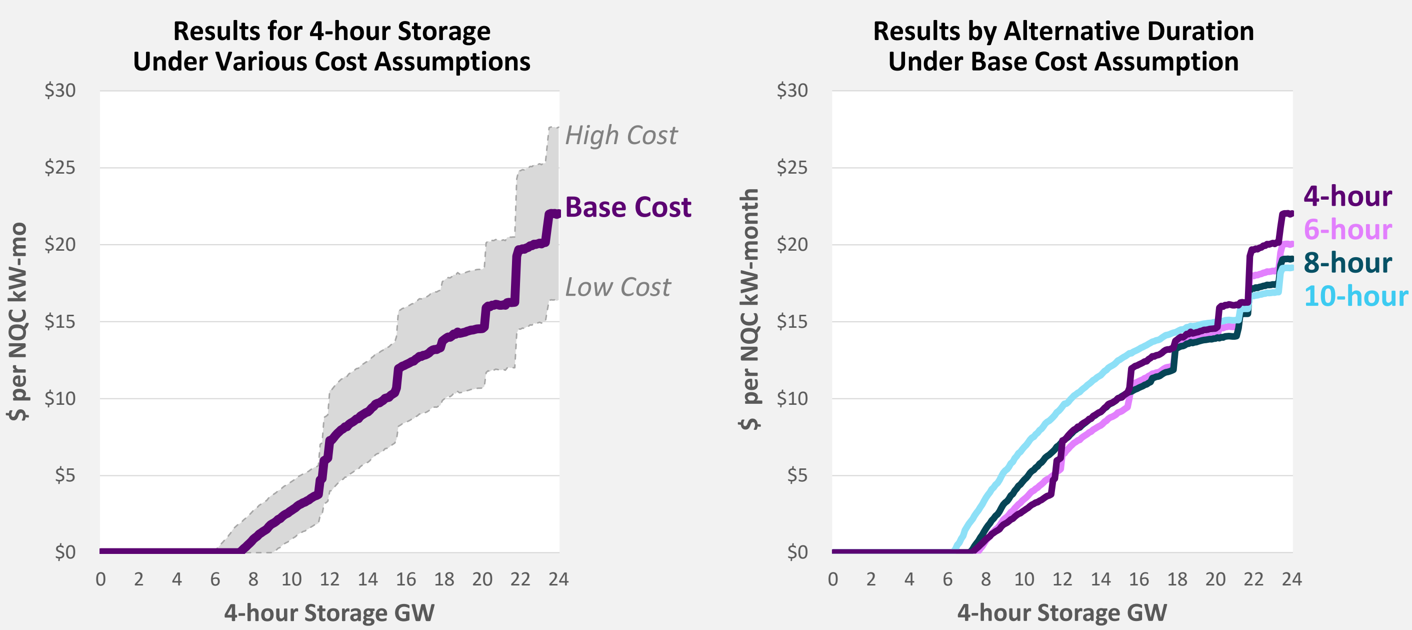


Figure 17: Estimated 2032 net CONE for storage (in 2022 dollars)

*Values are for marginal resource additions in a system where bulk of the storage portfolio has 4-hour duration.

Net Benefits of the Planned Storage Portfolio

Figure 18 shows estimated net benefits of the currently planned 13.6 GW of storage portfolio identified in the 2021 Preferred System Plan.

We calculate energy time-shift value and RPS benefits of storage based on the analysis described earlier in this attachment. For RA capacity, we assume marginal value would initially be at $8 per NQC kW-month, which is in line with the top 10% of historical RA contract prices for 2021 delivery. At higher penetrations, we assume RA prices will rise to net CONE of storage to incentivize new investments needed for reliability. This is conservative because without storage other much more costly alternatives would be needed to meet the reliability targets and the related cost savings would be higher than the RA capacity value shown here.

A large portion of the planned 13.6 GW storage buildout is already procured by the California LSEs. So, when evaluating net benefits of this portfolio as a whole, using current storage cost levels is more appropriate than the 2032 cost forecast developed for the marginal net CONE analysis presented earlier. The cost of storage based on utility contracts approved during the 2020-2021 period is within the range of $10–$14 per kW-month, which translates to an average of $120–$170 million/year for each GW of storage built. Under this cost range, we estimate a 4-hour energy storage fleet of 13.6 GW to potentially yield $830 million to $1.35 billion per year in net grid benefits, which corresponds to the cumulative area above the cost line in the figure.

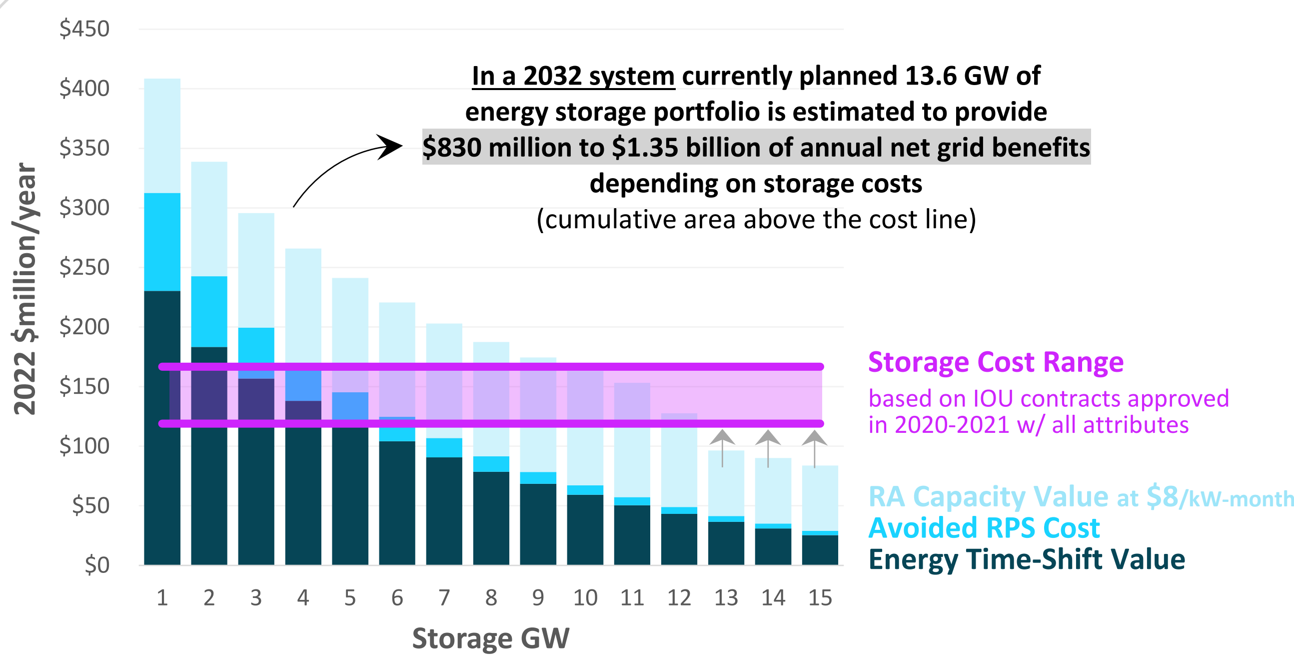


Figure 18: Incremental energy, renewables integration, RA capacity value of 4-hour storage in 2032 (2022 $).

Key Observations

Below is the summary of the key findings and observations based on results of this study:

- With the effects of increased renewables and upcoming retirements, **energy time-shift value of today's storage will be at least 2–3x higher by 2032 relative to current levels**.

- **As more storage is added, energy value and renewable curtailment reduction benefits will decline rapidly**. Marginal value is estimated to drop below $3/kW-month when energy storage buildout reaches 13.6 GW by 2032 as included in the recently adopted 2021 Preferred System Plan portfolio.

- This value decline coincides with an ELCC "tipping point" where **capacity contribution of 4-hour storage is estimated to plummet at 10–15 GW level**. Accordingly, capacity prices will need to rise significantly to enable future development of storage resources.

- **"Crossover point" for cost-effective long-duration storage (8–10 hour) is in sight** over the next 5 to 10 years, but exact timing and magnitude of the need is highly uncertain and sensitive to ELCC modeling assumptions.

- CPUC's shift from the "4-hour rule" to a probabilistic ELCC-based approach is a significant improvement to recognize value of storage duration, portfolio interactions between renewables and storage, and market saturation effects. But implementation is not yet fully tested, and **more stakeholder input and transparency are needed to understand key differences in ELCC results across durations (or lack thereof)** and make sure they signal the need for long-duration storage when the need arises.

- **Creating a "real option" to add more duration to battery projects at the initial design and procurement phase could support a timely and cost-effective transition for longer duration**. Storage system and site designs are highly modular and adding duration at existing sites can have a streamline interconnection process that can be completed more quickly and at a lower cost. Actual developers are taking advantage in this modularity in their market participation and development strategies.