LONG DURATION ENERGY STORAGE FOR CALIFORNIA'S CLEAN, RELIABLE GRID

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Long Duration Energy Storage for California's Clean, Reliable Grid

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Abbreviations

AAEE	Additional Achievable Energy Efficiency
AAPV	Additional Achievable Photovoltaic
AB	Assembly Bill
AHJ	Authority Having Jurisdiction
BANC	Balancing Authority of Northern California
BESS	Battery Energy Storage Systems
BNEF	Bloomberg New Energy Finance
BTM	Behind-The-Meter
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbines
CEC	California Energy Commission
CESA	California Energy Storage Alliance
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
D.	Decision
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
EAF	Energy Action Fund
ELCC	Effective Load Carrying Capability
ESP	Energy Service Provider
E/P	Energy to Power
GHG	Greenhouse Gas
GW	Gigawatts
GWh	Gigawatt-hour
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
JAR	Joint Agency Report
LADWP	Los Angeles Department of Water & Power
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LCOS	Levelized Cost of Storage
LCRTS	Local Capacity Requirements Technical Study
LDES	Long -Duration Energy Storage
LSE	Load-Serving Entity
MMT	Million Metric Ton
MW	Megawatts
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
NQC	Net Qualifying Capacity
OOS	Out-of-State
O&M	Operations & Maintenance
PG&E	Pacific Gas & Electric
PHS	Pumped Hydro Storage
POC	Protect Our Communities
POU	Publicly-Owned Utility
PRM	Planning Reserve Margin
PSP	Preferred System Portfolio
PV	Photovoltaic
R.	Rulemaking
RA	Resource Adequacy
REC	Renewable Energy Credit
RFO	Request for Offer
RPS	Renewable Portfolio Standard
RSP	Reference System Plan
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TMY	Typical Meteorological Year
TOU	Time-Of-Use
T&D	Transmission and Distribution
WREZ	Western Renewable Energy Zones

Executive Summary

By 2045, California must reliably supply 100 percent renewable energy and zero-carbon resources for electric retail sales to end-use customers; long duration energy storage will be a critical tool to enable this achievement.

In this landmark study, detailed modelling efforts quantify the California grid's system-wide energy portfolio needs for the years 2030 and 2045 respectively, to identify the scale of energy storage required. The study focuses on "long duration" energy storage assets, modeled here as assets with minimum dispatch durations of 5-, 10-, and 100-hours. The research builds upon the knowledge of regulators and stakeholders in California, evaluating additional storage categories under a capacity expansion model with enhanced temporal resolutions.

The results of the study demonstrate an unequivocal and urgent need for significant deployments of energy storage between now and 2045. The specific levels of deployment will be dependent on California's policy choices and the types of long duration energy storage (LDES) that are available. This analysis finds the need for 2 – 11 GW of operational LDES capacity by 2030 to meet or exceed existing carbon policy goals. Furthermore, this report finds that the role of long duration energy storage grows significantly with grid decarbonization and retirement of fossil fueled assets, such that by 2045, California could need between 45 and 55 GW of long duration energy storage- the equivalent of powering over 37 million homes.

This study reveals that 45–55 GW of long duration energy storage will be required to support California's grid by 2045; 2 –11 GW will be required by 2030. This massive grid need reflects a 150x increase (15,000%) in the amount of energy storage deployed in the state over the last decade.

Moreover, this study finds that the addition of long duration storage resources creates multiple diverse benefits across the grid and to California residents. By 2045, long duration energy storage could help to enable the retirement of approximately 10 GW of fossil fueled generation, reduce system capacity costs by $1.5 billion per year, increase renewable energy utilization by 17%, and reduce in-state use of fossil fuels for electricity generation by 25%, relative to a case where the State does not have access to LDES assets.

Given development and procurement timelines, the timing and magnitude of resource deployment implies the need for immediate action. For context, the levels of storage deployment identified in the Base Case of this study are over 150 times the energy storage currently built and operational in California since 2010. Even including planned storage development, it is nearly 12 times all storage currently contracted or in development within California.[1]

For storage to deliver these benefits, this report finds the State must act quickly to reform the procurement and compensation mechanisms that are used to deploy storage and other resources. More specifically, the Integrated Resource Planning ("IRP") proceeding and the Resource Adequacy ("RA") proceeding, both moderated by the California Public Utilities Commission ("CPUC" or "Commission") must be updated to enable this new paradigm.

The CPUC should use the IRP proceeding as a vehicle to establish long-term planning objectives, distinguish deployment priorities, and establish a regular process of resource development. To do this, the CPUC must make the following targeted changes to its existing IRP program:

1. **Adopt a 2045 planning horizon.** The CPUC should use base modeling and procurement activities with clear visibility to 2045 resource needs, and should actively direct procurement towards those targets, focusing on least-regret resources including those with long lead times and high capital costs that will provide significant system benefit.[2]
2. **Prioritize opportunities for LDES to support multiple policy objectives.** The CPUC should employ early LDES procurements to meet multiple policy objectives, such as increasing the resiliency and reliability of locally constrained areas; and accelerating retirement of fossil fuel power plants to improve of air quality, particularly within disadvantaged communities ("DACs").
3. **Establish and enforce clear procurement directives now.** The CPUC must clearly signal the imperative for early action to all load serving entities ("LSEs") through near term procurement targets, portfolio mandates, modifications to individual LSE procurement plans, or other mechanisms to establish and enforce procurement.

The CPUC's RA proceeding is the main vehicle by which the Commission ensures resource availability and establishes the market structures that dictate resource compensation and procurement. Thus, establishing clear market structures within the RA Proceeding will be foundational to enabling a transparent and competitive market for California resource developers and load serving entities. Within the RA proceeding, the CPUC should:

1. **Transition the RA framework from its existing fossil-basis to a zero-carbon grid.** The CPUC should transition to an RA framework that reflects the hours of grid constraint in order to fully value resources that can significantly contribute to reliability despite their energy- or use-limitations.
2. **Base storage reliability contributions on its operational characteristics:** The RA program should be modified to value energy storage as a function of the "size of the

[1] As of October 1, 2020, the California Energy Storage Procurement Tracker developed by the California Energy Storage Alliance (CESA) had identified 288 MW of energy storage online, 2,079 MW in development, and 1,823 MW contracted.

[2] In this report, "least-regret resources" refers to capacity expansions that are both economical and that contribute to local grid reliability needs, or other decarbonization goals considered by the State.

tank" (*i.e.* MWh) and the asset's cycling capabilities. Currently, the CPUC's RA framework only values energy storage based on the asset's maximum power output.

3. **Reform while providing stability:** The CPUC should accompany any revision to the RA framework with limited grandfathering measures for existing and contracted storage resources to maintain market and resource development stability.

The implications of this study are significant for California and beyond, especially other potentially solar-dominated Western states such as Arizona, New Mexico, Nevada, and Utah. As additional US jurisdictions commit to 100% clean energy, it is certain that long duration energy storage will be required to support reliability of all renewably powered clean grids. If California is to achieve its environmental targets in a timely and cost-effective manner, it must establish the regulatory mechanisms that create market certainty, foster competition, and enable a clean, well-planned grid.

Key Results of the Long Duration Energy Storage for California's Clean, Reliable Grid Study show:

- California needs 2-11 GW of long duration energy storage deployed by 2030, escalating significantly to 45-55 GW of long duration energy storage by 2045.
- Long duration energy storage has the potential to deliver value to California's grid by reducing installed capacity costs by $1.5 billion annually by 2045.
- Long duration energy storage can increase renewable utilization by approximately 17% annually.
- Long duration energy storage would reduce reliance on in-state fossil assets by approximately 25%.
- Long duration storage must be enabled through reform of planning, procurement, and compensation mechanisms administered by the California Public Utilities Commission. Thus, the CPUC should consider the following reforms:
    - Modify planning and procurement to consider a longer planning horizon and enforce resource development needs, especially when they can fulfil multiple policy objectives.
    - Transition the fossil-based resource adequacy evaluation to a framework based on future grid needs and storage operational characteristics, while enabling continued utilization of existing and contracted resources.

1. Introduction

This report explores the opportunity for long duration energy storage to help California achieve its electric sector decarbonization goals. To do so, this study utilizes a robust storage modeling approach across a series of scenarios, assessing the incremental value of long duration energy storage ("LDES") applications across an array of weather, cost, and policy cases. This report then provides a series of policy recommendations directly derived from the results of this modeling exercise. Ultimately, this study provides recommendations to reduce policy barriers preventing the development of LDES through the State's long- and short-term reliability proceedings: Integrated Resource Planning ("IRP") and Resource Adequacy ("RA"), respectively.

The paper is structured in four main sections. This first section provides an overview of the grid, policy, and technology context for this report, with a focus on the current state of storage, and should serve as context to better understand the analytical decisions made within this report. The second section focuses on the study methodology; providing an overview of the objectives of the study, the key elements that distinguish this analysis from other efforts undertaken in California, the modeling approach and input assumptions used within this report, and the scenarios and sensitivities considered for analysis. The third section presents a thorough account of the results derived from the Base and Sensitivity Cases; highlighting the relationship between usage of LDES applications and greenhouse gas ("GHG") emission constraints, curtailment, net import usage, and overall system costs. Finally, the fourth section provides a series of policy recommendations grounded on the results of this analysis and its numerical findings.

1.1 California Grid and Policy Context

California has set itself on a path towards an electrical grid with a high share of intermittent renewable generation. According to data collected by the California Energy Commission ("CEC"), renewables (excluding large hydroelectric generators) went from representing 10.7% of the electric mix in 2007 to 36% in 2019.[3] The main drivers of such growth are new installations of solar photovoltaic ("PV") and wind-powered generators, which account for 96% of renewable growth over the 2007-2017 period (56% and 40%, respectively).[4] This trend is expected to continue given the State's policy mandates.

Senate Bill ("SB") 100 commits California to decarbonizing its electric grid by 2045, meaning renewable energy and zero-carbon resources must supply 100% of retail electricity sales and 100% of electricity procured to serve all state agencies by December 31, 2045. SB 100 calls for the decarbonization of 100% of the electricity sold at the retail level in California by December

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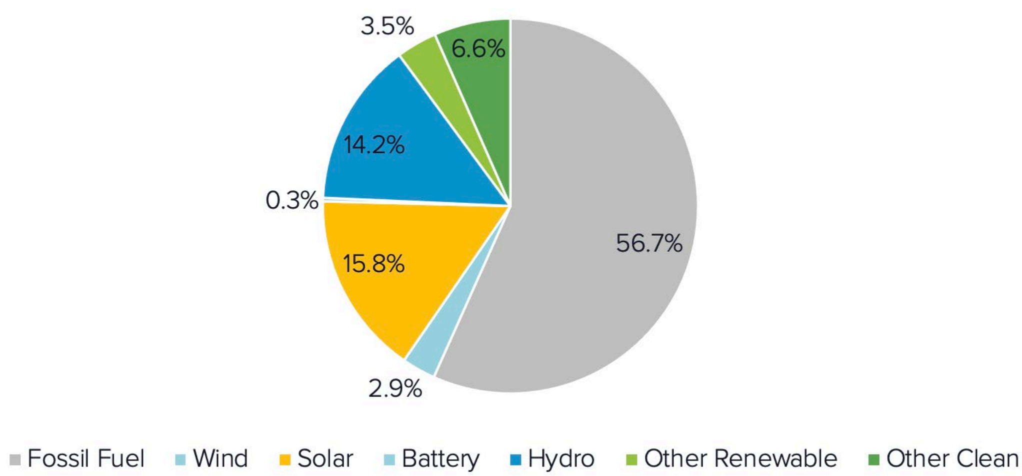
[3] CEC, 2019. "Tracking Progress." https://www.energy.ca.gov/sites/default/files/2019-12/renewable_ada.pdf
[4] Calculation made by the authors using data included in California Energy Commission (CEC). "Electric Generation Capacity & Energy Dataset."
https://www.energy.ca.gov/almanac/electricity_data/Electric_Generation_Capacity.xlsx

31st, 2045.[5] This represents a significant shift from current grid operation, which relies on 56% energy from fossil fuel resources or imports of carbonaceous energy.

Figure 1. CAISO Summer Capacity by Fuel Type, 2019



Source: CAISO, adapted by Strategen Consulting

The bill also requires that the achievement of this policy for California not increase carbon emissions elsewhere in the Western grid and that the achievement not allow resource shuffling. When signed into law, SB 100 modified SB 350, a previous legislative action that extended the renewable generation targets associated with the State's Renewable Portfolio Standard ("RPS"). Thus, with its passage, SB 100 also committed the State to fulfill 60% of all electricity sales with renewable generation by 2030. In addition to these goals, California has other policies that seek to further grow the deployment of distributed generation of intermittent renewable power, such as the Zero Net Energy initiative.[6]

Academic literature and State-directed studies have highlighted the need for energy storage to ensure balanced supply and demand across weather patterns and locational constraints. In California, State agencies, including the CEC, the California Public Utilities Commission's ("CPUC"), the California Independent System Operator ("CAISO") and the California Air Resources Board ("CARB"), have been charting pathways through this transition in the IRP proceeding, the SB 100 Joint Agency Report ("JAR"), and the Local Capacity Requirements Technical Study ("LCRTS").

The results from the most recent IRP proceeding estimate a need for 9.8 GW of incremental energy storage by 2030, with 973 MW of that storage able to support long duration applications. Moreover, the IRP has modeled the 2045 resource needs for directional

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[5] California Legislative Information, 2018. "Senate Bill No. 100."
https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100

[6] As spelled out in the California Energy Efficiency Strategic Plan, the State has ambitious goals for the development of ZNE buildings. These include: (1) all new residential construction will be ZNE by 2020; (2) all new commercial construction will be ZNE by 2030; (3) 50% of commercial buildings will be retrofit to ZNE by 2030; and, (4) 50% of new major renovations of State buildings will be ZNE by 2025.

purposes, signaling a need for an incremental 44.4 GW of energy storage to be added to the grid between 2030 and 2045.

It is worth noting that the IRP only covers CPUC jurisdictional load-serving entities ("LSEs"), thus excluding publicly-owned utilities ("POU") like the Los Angeles Department of Water & Power ("LADWP") and Sacramento Municipal Utility District ("SMUD") that account for approximately 20% of California's energy demand and are under CEC jurisdiction. Due to these limitations, the CPUC, CEC, and CARB have been tasked to complete a statewide report to the Legislature, evaluating the 100 percent zero-carbon electricity policy needed to fulfill SB 100. This study, the JAR, identified the need for approximately 55 GW of energy storage by 2045, with LDES representing about 5 GW of those resources.[7]

All of these efforts recognize the integral nature of storage in enabling such a transition, with the majority finding the need for some form of long duration storage. To support this shift, many studies by state agencies have shown need for storage resources ranging from 6 to 12 hours in duration.[8] Various iterations of the IRP study selected a homogenous portfolio of 6 to 7-hour duration storage and a mixed portfolio of 12-hr and 3-hr storage.[9] Moreover, the CAISO's LCRTS has identified the need for energy storage resources with an average duration of 9 hours in order to effectively decarbonize locally constrained areas.[10]

Yet all of these studies have taken a very narrow view on the potential storage resources that could be deployed in California. For example, the IRP proceeding and the SB 100 JAR consider only lithium-ion batteries, flow batteries, and pumped storage. On the other hand, the CAISO's LCRTS does not consider specific technologies, but seeks to identify the storage characteristics needed to effectively replace all fossil-powered generation in a specific Local Area.

This study takes a more comprehensive view on the potential storage resources that could be deployed in California and focuses on ensuring accurate representation of their potential grid contributions. The specific types of storage solutions considered in this analysis are described in greater detail in sections 1.3 and 2.4, which provide an overview of broad technology classes and more specific performance characteristics, respectively.

With this unique objective in mind, this study did endeavor to align with and calibrate against the ongoing dialogue amongst the state entities charged with planning the future of California's electric grid. As will be discussed further in section 2, the methodology and approach used to assess grid needs was, to the extent possible, aligned with state planning assumptions and with the State's methodology for grid planning analysis.

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[7] CPUC, CEC, and CARB. "SB 100 Joint Agency Report." https://www.energy.ca.gov/sb100
8 California Public Utilities Commission (CPUC), 2020. "Decision 20-03-028."
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF and California Energy Commission (CEC). & "Senate Bill 100 Draft Results Workshop."
https://www.energy.ca.gov/event/workshop/2020-09/senate-bill-100-draft-results-workshop
[9] CPUC, 2020. "2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF
[10] CAISO, 2020. "2021 Local Capacity Technical Study."
http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

1.2 Storage Procurement & Compensation Activity to Date

In 2010, California took a major step in its development of energy storage resources with the passage of Assembly Bill ("AB") 2514, which directed the CPUC to determine appropriate procurement targets for the LSEs under its jurisdiction. As a result of this legislative act, the CPUC issued Decision ("D.") 13-10-040, which established a 1,325 MW target to be met by 2020 by the three largest investor-owned utilities ("IOUs") of the State: Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E"). This goal was the first of its kind in the United States and continues to be one of the most ambitious storage mandates among any US jurisdiction.

Since the passage of AB 2514, California has continued to use legislation to set procurement mandates for energy storage resources. Notably, due to the successful deployment of 221 MW of storage by 2015, the Assembly passed AB 2868 in 2016 which accelerated the deployment of storage by PG&E, SCE, and SDG&E by requiring an additional 500 MW by 2024.[11] In this context, the State's Senate passed SB 801, requiring SCE to deploy 20 MW of energy storage in response to the reliability needs created by the leak at Aliso Canyon natural gas storage facility in 2017. Moreover, SB 801 additionally mandated that LADWP, a POU outside the CPUC's jurisdiction, identify 100 MW of energy storage procurement opportunities.

Almost a decade after the establishment of these initial energy storage procurement mandates, California has seen a boom in the development of energy storage assets. Effective and targeted legislative mandates paired with the economic reality of plummeting energy storage costs enabled the three largest IOUs of the State to comply with the procurement targets of AB 2514, in some instances well before 2020. As of March 2020, PG&E and SCE have indicated to the CPUC that they need no longer hold additional solicitations for energy storage procurement for the purposes of compliance AB 2514. SDG&E, while 7 MW short, is still nonetheless on track to fulfill its requirement by the end of 2020. Given the aforementioned legislative actions and the current market for energy storage, the CPUC reports a total approved procurement of around 1,533.52 MW of energy storage capacity within its jurisdiction.

While the CPUC's data presents a valuable snapshot of approved procurements to date, it does not fully represent the aggressive growth of the market for energy storage across the State. California Energy Storage Alliance ("CESA") tracks requests for offers ("RFOs") from Californian LSEs as well as the development of storage assets prior to CPUC approval.[12] Thus, CESA's California Energy Storage Procurement Tracker offers a picture of emergent storage activity that has not yet passed through the full set of CPUC approval stage gates. As of October 2020, CESA had identified 2,079 MW of energy storage in development and 1,823 MW contracted, for a total of 3,902 MW of storage potentially deployed in California.

In this context of increased energy storage procurement, it is essential to consider the characteristics of these assets. According to CESA's California Energy Storage Procurement

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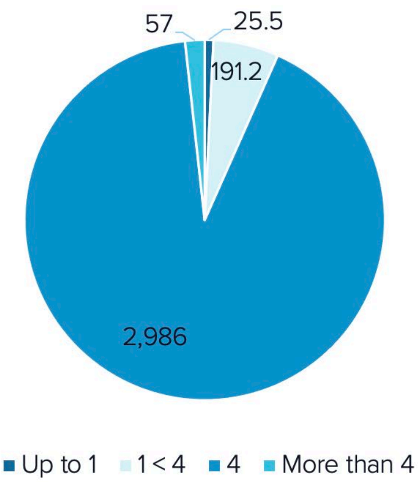
[11] California Legislative Information, 2010. "Assembly Bill No. 2514"
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514
[12] The October update of the CESA Procurement Tracker is included in Appendix B.

Tracker, almost all energy storage assets deployed, in development, or contracted have a duration of four hours or less, as seen in Figure 2.

Figure 2. CA Energy Storage Procurement (MW) by Duration



Source: CESA, adapted by Strategen Consulting

The prevalence of 4-hour duration assets can be attributed to two factors. First, the falling costs of electrochemical storage, particularly assets based on a lithium-ion chemistry, have enabled extremely low-cost deployments of lithium-ion battery storage for durations of four hours or less. Second, one of the most consistent revenue streams for storage assets comes in the form of RA capacity payments. As such, the capacity definition in the RA program has been critical to incent the procurement of four-hour assets.

Currently, the RA program administered by the CPUC calculates the reliability contributions of energy storage based on the maximum power it can continuously discharge for four or more hours.[13] This rule is sometimes referred to as the "four-hour rule". The "four-hour rule" is a heritage construct based on capacity needs in a system heavily dominated by conventional thermal generation. Under this rule, any storage resource that can dispatch at maximum capacity for greater than four hours would receive no additional capacity credits for that increased dispatch capability, and any LSEs that were to contract such a resource would not be able to realize any additional benefits towards their capacity obligations. As a result, LSEs lack incentives to procure resources with durations above four hours.

1.3 Storage Technology Solutions

In the context of the regulatory policy and procurement activity described above, this modeling was undertaken to consider how deployments of longer-duration storage assets could provide grid benefits as California pursues its decarbonization goals. A brief overview of the different types of storage solutions considered in this analysis are outlined below.

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[13] CPUC, 2017. "2018 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings." http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454920

Although some of these solutions may be less commonly commercialized today relative to shorter-duration solutions such as lithium-ion, many of them stem from processes that are well-tested and have existed for years. These solutions represent significant diversity in terms of deployment timelines and cost structures; operational performance characteristics in terms of round-trip efficiency and operating constraints and limitations; and physical requirements or constraints such as asset location or footprint.

Chemical. Chemical methods for long duration storage can include a variety of different battery technologies, as well as chemical storage in the form of hydrogen. As compared to solid-state batteries, such as lithium-ion batteries, flow batteries have liquid electrodes separated by a membrane. Flow batteries have been tested to show little to no degradation over their long lifetime – up to 25 years. Flow batteries can be constructed using a variety of different chemistries, including redox flow, vanadium flow, iron flow, or other chemistries. Sodium sulfur batteries also rely on liquid electrodes in the form of molten salt, and operate at high temperature with high round-trip efficiency, and a 15 year lifecycle.[14] Novel battery chemistries and architectures are continuing to emerge and are allowing for deployment of batteries that have greater storage capabilities and can be produced using more commonly available materials. A different approach to chemical storage is hydrogen energy storage, which creates electricity from passing hydrogen through a fuel cell and can regenerate the hydrogen supply by using electricity to run an electrolyzer. Hydrogen energy storage can be used for both electrical and thermal energy needs; it can be stored for later use as a fuel for combustion or as a non-combustive power source for fuel cells, thus taking advantage of existing natural gas infrastructure.

Mechanical. Mechanical energy storage solutions utilize the movement of materials to store and release energy. While pumped hydro storage ("PHS") is the most common type of mechanical storage on the grid today, it is not the only form of mechanical energy storage in operation and under development. Similarly, while many types of mechanical storage rely on gravity, not all do. Energy can be generated from the movement of air or other gases; water; or even discrete weighted blocks. Both pumped hydro and compressed air energy storage ("CAES") can take advantage of geological formations for high MW capacity. Mechanical storage often has a long operational life; many of the PHS installations in operation today have an average age of 54 years[15] while CAES is estimated to last for about 30 years.[16]

Thermal. Although thermal energy storage types can make use of mechanical or chemical processes, they are considered thermal due to the pronounced use of heat or cold to store energy. For example, liquid air is similar to compressed air, but rather than compressing air to high pressure underground, it uses a cooling process to liquefy and store air in tanks above

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[14] Energy Storage Association, 2020. "Batteries." https://energystorage.org/why-energy-storage/technologies/solid-electrode-batteries/
[15] S&P Global, 2019. https://www.spglobal.com/marketintelligence/en/news-insights/trending/gfjqeFt8GTPYNK4WX57z9g2#:~:text=An%20analysis%20of%20S%26P%20Global,fleet%20age%20of%2050%20years.
[16] Climate Technology Centre & Network. "Compressed Air Energy Storage." https://www.ctc-n.org/technologies/compressed-air-energy-storage-caes

ground and at low pressure.[17] Molten salt is a well-established energy storage technology with commercial deployments in concentrated solar plants since the mid-1990s. Electricity is converted to heat, stored in salt, and reconverted to electric energy using heat engines (turbines and generators).[18] Solutions such as a thermophotovoltaic storage system can store energy as ultra-high temperature heat in solid storage media, such as carbon blocks, then use a solid-state heat engine to convert heat to back to electricity. Many of these types of thermal solutions are notable for their ability to use low-cost and abundantly available materials as the primary thermal storage medium.

The diverse range of technologies capable of providing LDES applications ensures there are multiple pathways to access their benefits. Beyond the potential for increased energy arbitrage and stored energy capability, these technologies can provide a multitude of grid benefits including primary and secondary voltage and frequency response, peaker replacement, transmission and distribution ("T&D") deferral, congestion management, and power quality control. However, for the purposes of this study and the remainder of this report, the discussion will focus primary on the opportunity for long duration storage to provide value at the wholesale level for grid balancing.

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[17] Highview Power, 2020. "Technology." https://www.highviewpower.com/technology/

[18] ScienceDirect. "Molten Salts". https://www.sciencedirect.com/topics/earth-and-planetary-sciences/molten-salts

2. Methodology

This section presents the technical approach undertaken in the study to model the CAISO footprint within California, the broader Western grid, and potential new resources, with a focus on the modeling of long duration storage solutions and their potential role in the California grid. First, the section presents a short overview of the high-level modeling approach used for this study including the intentions and design priorities that were used to inform model development. Next, this section presents a brief description of the modeling tool selected for the study, GridPath, and the customization and development necessary for the evaluation of the benefits of long duration storage. The section goes on to explain some of the modeling choices, including inputs and assumptions, and benchmarking of the model. Finally, the section concludes with a description of the scenarios run for the study.

2.1 Modeling and Analysis of Long Duration Storage to Date

As of 2020, several stakeholders in and out of California have strived to develop the appropriate mathematical models and tools to determine the composition of the future grid given the State's ambitious goals. The CPUC employs the IRP proceeding to identify long-term resource procurement needs and compliance with regulatory and legislative goals and mandates relating to the overall resource composition and electric sector carbon intensity. The IRP proceeding seeks to model the system in the long-term to comply with California's overarching goals regarding renewable energy and GHG emissions, among others, while maintaining grid reliability.[19] The CPUC is mandated to promote a diverse and balanced portfolio of resources that minimizes ratepayer costs.[20]

Within the IRP, the CPUC uses the RESOLVE model to determine the optimal resource portfolio mix in 2030, its planning horizon target year, subject to a set of system and policy constraints. To obtain robust results for the planning year of 2030, the CPUC uses RESOLVE to produce outputs for every year from 2020 to 2024, plus 2026 and 2030.[21] RESOLVE is an optimal investment and operational model designed to inform long-term planning questions in systems with high penetration levels of renewable energy. RESOLVE can solve for the optimal investments in renewable resources, some energy storage technologies, and new gas plants subject to an annual constraint on delivered renewable energy per the State's RPS policy, an annual constraint on greenhouse gas emissions, and capacity adequacy constraints to maintain reliability.[22] RESOLVE co-optimizes new resource investment and dispatch for 37 discrete days over a multi-year horizon in order to identify least-cost portfolios for meeting

[19] California Legislative Information, 1951. "Public Utilities Code."
https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=3.&article=1.#:~:text=454.51.,in%20a%20cost%2Deffective%20manner.
[20] Ibid., Section 454.52
[21] CPUC, 2020. "2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans And Transmission Planning." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF
[22] E3, 2017. "RESOLVE Documentation: CPUC 2017 IRP."
https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/17/RESOLVE_CPUC_IRP_Inputs_Assumptions_2017-07-19_redline.pdf

renewable energy targets and other state policy goals. RESOLVE also incorporates a representation of CAISO-adjacent regions in order to endogenously characterize transmission flows into and out of the main zone of interest – the CAISO footprint.

RESOLVE is an advanced grid planning tool; nevertheless, it has considerable limitations specifically related to the modeling of long duration energy storage. First, RESOLVE analyzes integration needs on a representative sample of 37 days of the year, and not in all 8,760 hours individually. RESOLVE's 37 representative days are not intertemporally linked with each other and are not modeled in chronological order, therefore storage balancing decisions are limited to a horizon of a single day. Thus, RESOLVE selects incremental capacity additions based on a simplification with no intra-hour or multiday optimization of dispatch.[23] This seriously limits the potential grid benefit from energy storage since RESOLVE neither captures contributions from short-duration and highly responsive solutions to address sudden ramping needs; nor considers the ability of long duration energy storage solution to defer electric generation by days at a time.

A second relevant limitation of current application of RESOLVE in the IRP proceeding is that only three types of storage are modeled: lithium-ion batteries, flow batteries and pumped hydro. While RESOLVE only includes these three types of energy storage, it does allow the model to select the capacity and duration of these resources separately, essentially allowing the deployment of these technologies at any duration above its minimal duration. Within the 2019-2020 cycle of the IRP, the minimal duration for lithium-ion and flow batteries was one hour. The minimal duration of pumped hydro storage was set at 12 hours. Implicitly, LDES applications are initially modelled by proxy using pumped hydro, but they could also be included in RESOLVE results if the model assesses that longer duration deployments of the other lithium-ion or flow batteries is economic. Either way, the presumed storage solution set contemplated by RESOLVE is narrow and does not include the full range of potential storage solutions currently available in the market.

2.2 Methodology Design and Approach

When approaching the methodology and design of a tool to model long duration storage, this study prioritized (1) accurately capturing the grid contributions of long duration storage and (2) aligning with the existing tools used by the CPUC for long-term planning. To create comparable results between the IRP's RESOLVE modeling and this study, Strategen chose to base its analysis on a tool that has common roots and similar structure to the RESOLVE model. This allowed the study to establish modeling assumptions consistent with the State's planning assumptions; and identify the portfolio changes that are a result of the incremental modeling modifications.

[23] Although RESOLVE does not include explicit sub-hourly dispatch, intra-hour flexibility needs are identified and dispatched through a "load following" ancillary service requirement. Per CPUC, 2019, "Proposed Inputs and Assumptions: 2019-2020 IRP Planning," "This reserve product ensures that sub-hourly variations from load, wind, and solar forecasts, as well as lumpy blocks of imports/exports/generator commitments, can be addressed in real-time."

Specifically, this study used the GridPath model. GridPath is a versatile grid-analytics platform developed by Blue Marble Analytics LLC. The platform integrates several power-system planning approaches – including production-cost, capacity-expansion, asset-valuation, and reliability modeling – within the same software ecosystem. The modeling team that developed GridPath had several years of experience developing and running RESOLVE and closely reproduced RESOLVE functionality before moving to further development. The analysis uses GridPath's capacity-expansion functionality with the same spatial resolution as the current CPUC's IRP but with an enhanced temporal span and additional storage technology options.

2.2.1 About GridPath

GridPath is an open-source software ecosystem for power-system analytics specifically designed to understand deeply decarbonized grids, and to rapidly and continuously evaluate and plan the evolving electricity system. GridPath has a highly flexible, modular architecture that facilitates the ability to quickly adapt and extend the platform's analytical capabilities including its application to different systems and regions as well as the incorporation of emergent technologies and resources with non-standard characteristics (renewables, storage, demand response, and so on).

GridPath's modular architecture makes it possible to combine modules to create optimization problems with varying features and levels of complexity. Production-cost, capacity-expansion, asset-valuation, and reliability modes are available. Linear, mixed-integer, and non-linear formulations are possible depending on the selected modules. GridPath has a highly flexible temporal and spatial span and resolution. Each generation, storage, and transmission asset in GridPath can be modeled with a user-specified level of detail. The decision for what to simplify and what requires a detailed treatment is left up to the user and can vary depending on the application of interest.

GridPath can simulate the operations of the power system, capturing the capabilities of and constraints on generation, storage, and transmission resources to understand grid integration, flexibility, and resource adequacy needs. The platform can identify cost-effective deployment of conventional and renewable generation as well as storage, transmission, and demand response as well as determine the market performance of an asset or a set of assets. GridPath can optionally capture the effects on operations and the optimal resource portfolio of forecast error, provision of ancillary grid services, interconnection, reliability requirements such as a planning reserve margin or local capacity requirements, and policies such as a renewables portfolio standard (RPS) or a carbon cap.

GridPath is under active development continuously adding new functionality. The codebase is open-source and available on GitHub. For more information about it, visit www.gridpath.io.

2.2.2 GridPath Development for the LDES Study

For this study, GridPath was run as a capacity-expansion model with an enhanced temporal resolution that allowed proper simulation of long duration energy storage. Specifically, each year was modeled as a sequential set of 8,760 hours, making it possible to capture energy time shifting that happens over longer time scales, a feature that is not available in the

RESOLVE model. As a result, this study with the inclusion of LDES technologies proposes a more economic resource portfolio.

Computationally, the increase of the temporal resolution is a significant challenge as it extends the year from a collection of 37 unlinked days with 24 hours each to 8,760 contiguous hours in a year. This computational challenge is counterbalanced by the selection of fewer investment time steps through 2045 so that the model can solve within reasonable run times. Specifically, only two years are modeled for this analysis: 2030 and 2045. Like in RESOLVE, each modeled investment year has an assigned weight, based on the number of years in the entire study period it represents and a discount rate. The model has "perfect foresight", meaning that it can consider future load, costs, and policy constraints in 2030 and 2045, and solves both years in a single optimization. This allows for development of an optimal solution for both study years and avoids technology lock-in that could result from a myopic approach.

As a capacity expansion model, GridPath's objective is to minimize the cost of investment and operations to meet the projected demand under certain technical and policy constraints. Candidate resource options include all resources available in the CPUC's IRP modeling in RESOLVE, as well as a portfolio of long duration energy storage solutions in order to better represent the reality of the energy storage market today and in the future. Constraints include technical limitations of the units and the grid; a need to meet or exceed a 115% planning reserve margin ("PRM"); as well as limits on attributable carbon emissions. Given the problem's magnitude and scope, investment and dispatch decisions were modeled as continuous variables. All of the constraints, as well as the objective function are linear, resulting in a linear problem. Consistent with the CPUC's IRP modeling in RESOLVE, GridPath was not configured to consider any local RA needs nor identify specific locations or interconnection points where generation or storage resources should be located.

2.3 Grid Inputs and Assumptions

For this analysis, system-wide assumptions and inputs were based directly on those used by the CPUC within the 2019-2020 IRP process, where possible. In some instances, the evolution to analysis of full 8,760 temporal resolution required modifications to CPUC assumptions; however, in all cases these assumptions were harmonized with the publicly available datasets developed by and for the CPUC proceedings used to evaluate system-wide reliability needs. This subsection provides a high-level overview of the CPUC modeling assumptions that were foundational to this analysis, as well as a detailed review of the inputs and datasets that were extrapolated from other CPUC proceedings for this effort.

The CAISO was represented with the same spatial resolution as RESOLVE, as a single load zone interconnected with five other zones: three inside California (Balancing Authority of Northern California ("BANC"), Imperial Irrigation District ("IID"), and Los Angeles Department of Water & Power ("LADWP")), two out-of-state zones (the Pacific Northwest and the Southwest), and a proxy "zone" for Northwest hydro resources. This proxy zone is included to allow the model to distinguish the carbon-free Northwestern hydro imports from unspecified, carbon-producing imports. CAISO hourly operations were simulated considering technical constraints for a typical electrical grid (such as load balancing and generation limits). Consistent with the modeling approach used in RESOLVE, a transmission capability was modeled zonally to establishing import and export limits, and reactive power balance was not considered in the modeling.[24]

Since the RESOLVE User Interface (and related spreadsheets) does not contain input data for a full year (8,760 hours), hourly profiles used in the models are based on the following two publicly available datasets:

1. Unified RA and IRP Modeling Dataset[25]
2. 2019-2020 IRP Events and Materials[26]

2.3.1 Demand Assumptions

From these datasets, this report derived 8,760-hour profiles for both generation and load. To inform load inputs and assumptions, this report used load profiles taken from the RESOLVE Reference System Plan ("RSP").[27] The RSP is the result of over a year of modeling and planning efforts at the CPUC's IRP proceeding. The RSP is the optimal portfolio selected by the CPUC, and it is later used as a benchmark for all the individual IRP filings made by CPUC-jurisdictional LSEs. Once LSEs submit their individual IRPs, the CPUC integrates them into a single portfolio, the Preferred System Plan ("PSP"). For the current IRP cycle, 2019-2020, the CPUC has not completed the PSP. As a result, the RSP offers the best comparison available at this time. As such, this report bases its inputs on those included in the development of the RSP, which have been publicly vetted by California's stakeholders. The inputs assumed are the following:

Table 1. Load Profile Assumptions

Data Input	Data Source	Assumption for 2030
Baseline Consumption	CEC 2018 IEPR - Mid Demand	265,707 GWh
Electric Vehicle Adoption	CEC 2018 IEPR - Mid Demand	13,567 GWh
Other Transport	CEC 2018 IEPR - Mid Demand	683 GWh
Building Electrification	None Through 2030	-
Hydrogen	None Through 2030	-
Behind-the-meter PV	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	35,123 GWh
Energy Efficiency	CEC 2018 IEPR – Mid-Mid AAEE	27,940 GWh

[24] Reactive power balance is analyzed in power flow optimizations. This modeling did not include any power flow optimizations.
[25] CPUC, 2020. "Unified RA and IRP Modeling Datasets 2019." https://www.cpuc.ca.gov/General.aspx?id=6442461894
[26] CPUC, 2020. 2019-2020 IRP Events and Materials https://www.cpuc.ca.gov/General.aspx?id=6442459770
[27] For this analysis, the data used was based off the latest publicly available RESOLVE User Interface at the time the analysis began, the 2020-02-07 version available at https://www.cpuc.ca.gov/General.aspx?id=6442464143
See CPUC, 2020. "2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans And Transmission Planning." https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

Existing Shed DR	Mid	1,752 MW
TOU Adjustment	CEC 2018 IEPR	35 GWh
Non-PV Self Generation	CEC 2018 IEPR - Mid Demand	13,565 GWh

The primary source for CAISO load forecast inputs (both peak demand and total energy) in the 2019-2020 Reference System Portfolio is the CEC's 2018 Integrated Energy Policy Report ("IEPR") Demand Forecast Update. The CEC's 2018 Deep Decarbonization in a High Renewable Future report is also used to provide long-term forecasts for the 2045 Framing Studies.[28] Many components of the CEC IEPR demand forecast are broken out so that the distinct hourly profile of each of these factors can be represented explicitly in modeling. The components are referred to in this document as "demand-side modifiers." As a result, the total managed load can be understood as the sum of CEC-forecasted retail sales, per the IEPR Demand Forecast Update, and the demand-side modifiers described in Table 1.

As with the CPUC's IRP modeling in RESOLVE, this report considers the effects of demand-side modifiers in a disaggregated fashion to allow for the evaluation of different sensitivity scenarios. Table 2 shows the additive effect of the demand-side modifiers in 2030 as an illustrative example of how load is calculated from the load modifiers.

Table 2. Derivation of Baseline Consumption from CEC IEPR Demand Forecast (GWh)

Component	Value for 2030
CEC 2018 IEPR Retail Sales	202,653
+ Mid AAEE	+ 27,940
+ Behind-the-meter PV	+ 35,123
+ Behind-the-meter CHP	+ 13,595
+ Other self-generation	+ 681
- TOU rate effects	(35)
- Electric vehicles	(13,567)
- Other transportation electrification	(683)
= **Baseline consumption**	= **265,707**

Consistent with the CPUC's 2019-2020 IRP, this study developed 2045 load profiles using data from the CEC's 2018 Deep Decarbonization in a High Renewable Future report. In this report, the E3's PATHWAYS model provides load forecasts for the three 2045 framing scenarios: High Electrification, High Biofuels and High Hydrogen. Within the IRP, the statewide PATHWAYS load is converted to CAISO load in the 2045 framing scenarios assuming an 81% load share. Strategen based its 2045 load assumptions off the High Biofuels scenario, as it

[28] This information is included into the RESOLVE User Interface version 2020-02-07 within the case used as the RSP, 46MMT_20200207_2045_2GWPRM_NOOTCEXT_RSP_PD." This data was taken directly form that User Interface for this analysis.

was selected by the CPUC as the default scenario in the 2045 framing study because it provides a balanced decarbonization pathway between electrification and low-carbon fuels with relatively low costs and commercially available technologies.

Additional information on the 8,760 baseline load and load modifiers profiles are included in Appendix A.

2.3.2 Carbon Targets and Assumptions

Statewide carbon targets are modeled in GridPath as a GHG constraint on CAISO systemwide emissions. Similar to RESOLVE, the annual emissions of generators within the CAISO are calculated in GridPath as part of the dispatch simulation based on the annual fuel consumed by each generator and an assumed carbon content for the corresponding fuel. Emissions are also attributed to "unspecified" generation[29] that is imported to CAISO based on the deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.428 metric tons per MWh—a rate slightly higher than the emissions rate of a combined cycle gas turbine. Specified imports to CAISO are modeled as if the generator is located within CAISO. The only specified imports in this study are imports from Pacific Northwest hydro generation which have zero emissions.

In this analysis, Strategen employs the same assumptions as the CPUC in its 2019-2020 IRP Cycle. For the IRP, CPUC staff referred to the CARB-established GHG planning target range for the electric sector of 30–53 million metric tons ("MMT") CO_2 statewide by 2030. This range was informed by the 2017 Scoping Plan Update and further supported by CPUC's IRP analysis in developing the 2017-2018 Reference System Plan. As in the previous IRP cycle, the statewide emissions of the electricity sector are be multiplied by 81%, which is the share of ARB's forecasted 2030 allocation of emissions allowances to distribution utilities within the CAISO footprint, to yield a target for CAISO LSEs.

In addition to this alignment of assumptions, Strategen included the same renewable energy credit ("REC") allowance to carry-over as specified in the RSP. In RESOLVE, the CPUC allows the model to comply with emission targets by "banking" RECs. This decision effectively modifies the net carbon constraint in a particular year, since it reflects the carbon constraint net of any RECs that exceeded from previous years. As a result, the Base Case carbon constraints on the two modeled years, 2030 and 2045, were derived as follows:

- For 2030, Strategen assumed a GHG constraint equal to the one observed by the 46 MMT IRP case. This 46 MMT statewide target translates to 32.4 MMT for the CAISO footprint. The level of REC allowances considered by 2030 within the CPUC RSP is equivalent to 5.4 MMT. As a result, the effective carbon constraint for 2030 within this analysis is 32.4 MMT.
- For 2045, Strategen assumed a GHG constraint based on the current interpretation of SB 100 and aligned with the PATHWAYS analysis, which determines how deep decarbonization across all sectors will be in order to establish how much the electricity sector can emit. SB 100 allows T&D losses (which represent about 7.2% of total generation)

[29] "Unspecified" generation includes any generation purchased on the wholesale market outside of California and wheeled into California, and does not include any generating assets that are physically located outside of California but directly interconnecting into the CAISO footprint.

to be supplied by non-zero-carbon resources. Considering this metric and the RESOLVE default PATHWAYS case for 2045, “CEC Pathways High Biofuels”, the effective carbon constraint for 2045 within this analysis is 12.3 MMT.

2.3.3 Renewable Resource Availability

In this report, the representation of in-state and out-of-state (“OOS”) resource potential and availability is derived directly from the assumptions used by the CPUC within the 2019-2020 IRP RESOLVE model. Assumptions on the in-state potential for candidate resources for RESOLVE are derived from the geospatial data developed by Black & Veatch for the CPUC’s RPS Calculator. For input into RESOLVE, the aforementioned geospatial dataset is aggregated into competitive renewable energy zones (“CREZ”). These CREZ are used to represent the different expected deployment costs of several zones within California. In addition to the consideration of in-state zones, RESOLVE also captures the available potential for OOS resources. This data, similarly, relies on Black & Veatch’s assessment of renewable resource potential in a series of Western renewable energy zones (“WREZ”s). The inclusion of these WREZ allows the model to select resources outside California. Access to some of the WREZ is predicated on the requirement of investments in new transmission assets. Unless otherwise stated, modeling assumed no new transmission investments outside of what is already planned in the CPUC’s IRP.

2.3.4 Planning Reserve Margin

In addition to meeting demand during every hour of the year, a capacity expansion model also includes an additional constraint on resource adequacy: the planning reserve margin (“PRM”). The PRM is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon. Thermal resources which have no associated energy limits can contribute their full net qualifying capacity (“NQC”) to PRM, but non-dispatchable or energy limited resources can only partially contribute to the PRM. The capacity contribution of wind and solar resources is a function of the penetration of each of those two resources. For energy storage, a use-limited resource, the contribution to the PRM is a function of both the capacity and the duration of the storage device. The capacity contribution, however, also depends on the rest of the generation fleet, as the duration of the peak changes is based on the generation resources in the system. Thus, when modeling energy storage, it is important to model its capacity contribution as a function of its maximum power output, duration, and the other system resources.

2.4 Storage Modeling Methodology and Inputs

Consistent with RESOLVE’s approach in modeling storage, GridPath selects the optimal power capacity and duration of the energy storage technology endogenously. Parameters that define energy storage resource options include minimum duration, charging efficiency, discharging efficiency, ancillary services provision capability, capacity contribution, cost per MW installed, and cost per MWh installed. Storage systems are balanced (*i.e.* need to return at the same state-of-charge level) on an annual basis.

As with the rest of the generation resources, for energy storage that was already included in the RESOLVE model, this study replicated the inputs & assumptions used by the CPUC in the IRP. In addition to those technologies, this study included a portfolio of long duration energy storage options to better capture the range of long duration energy storage solutions. Additional LDES options are included in the sensitivity runs. The sections below describe in detail the parameters for each of those.

2.4.1 Storage Inputs Based on CPUC Assumptions

The 2019-2020 IRP cycle included behind-the-meter ("BTM") lithium-ion battery storage, wholesale lithium-ion and flow batteries, and pumped hydro. This study includes the above options relying on the same cost and performance assumptions to maintain comparability.

As done within the IRP, to accurately model energy storage systems of differing sizes and durations endogenously, the cost of storage is broken into two components: capacity ($/MW) and duration ($/MWh). The capacity cost refers to all costs that scale with the rated installed power (MW) while the duration costs refers to all costs that scale with the energy of the storage resource (MWh). The two components more accurately reflect how storage costs scale up with different storage components. This breakout is intended to capture the different drivers of storage system costs. For example, a 1 kW battery system would require the same size inverter whether it is a four- or six-hour battery but would require additional cells in the longer duration case. In order to capture the fact that most technologies require a certain scale to be deployed, both the CPUC's IRP modeling and this report incorporate a minimum duration by technology. This allows the model to select a resource at a specific size and duration, and later increase either of those components if it results in a more economical decision than procuring additional assets.

The capital costs of candidate pumped storage resources for the 2019-2020 IRP are based on Lazard's Levelized Cost of Storage 2.0.[30] Pumped storage costs are assumed to remain constant in real terms. Candidate pumped storage resources must have at least 12 hours of duration.

Other energy storage options rely on storage cost assumptions from Lazard's Levelized Cost of Storage 4.0 supplemented by NREL's Solar and Storage Report.[31] Cost assumptions for candidate wholesale storage are derived from Lazard's peaker replacement use case. Candidate BTM battery storage is assumed to be lithium-ion technology, with costs derived from Lazard's commercial use case for lithium-ion. This analysis uses the mid cost option unless specified otherwise. Operation and maintenance ("O&M") costs are included in the power capacity and duration cost components. For example, warranty and augmentation costs are assumed to cover battery cell performance, thus are attributed to the duration category.

[30] Later releases of Lazard do not include pumped storage costs. Lazard, 2016. "Levelized Cost of Storage Analysis 2.0." https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20
[31] Lazard, 2018. "Levelized Cost of Storage Analysis Version 4.0." https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf & Ran Fu et al., NREL, 2018. "2018 U.S. Utility-Scale Photovoltaics Plus-Energy Storage System Costs Benchmark." https://www.nrel.gov/docs/fy19osti/71714.pdf

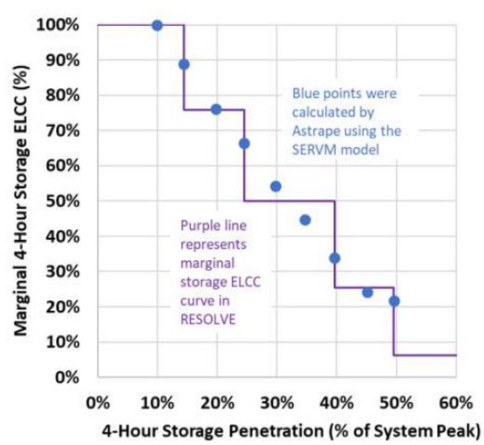
In the CPUC's IRP modeling, the degradation of lithium-ion resources throughout their lifecycle is incorporated via O&M costs. This report follows this methodology as well. Thus, in addition to breaking out capital costs between capacity and duration, different O&M costs are attributed to each of these categories. For example, warranty and augmentation costs are assumed to cover battery cell performance and are therefore attributed to the duration category.

Storage Capacity Contribution

To align with resource adequacy accounting protocols, the CPUC's IRP proceeding assumes a storage resource with four hours of duration counts its full capacity towards the PRM, up to a capacity threshold. After that threshold the capacity contribution of storage declines).

Specifically, the CPUC incorporated a declining storage effective load carrying capability ("ELCC") curve for utility-scale lithium-ion and flow batteries that reduces the capacity value of battery storage at higher battery storage penetrations. The justification for this "de-rated" storage capacity contribution is that storage does not provide equivalent capacity to dispatchable thermal resources at higher storage penetrations due flattening of the net peak, requiring longer duration and/or higher stored energy volumes. The ELCC curve, included below, was developed by Astrape Consulting using (1) the SERVM model; and, (2) the CPUC's SERVM model database populated with the November 2019-vintage proposed 46 MMT Reference System Plan Portfolio. This curve was to calculate the capacity contribution of storage across a wide range of storage capacities. For resources with a duration of less than four hours, the capacity contribution is derated in proportion to the duration relative to a four-hour storage device (e.g. a two hour energy storage resource receives half the capacity credit of a four hour resource).[32]

Figure 3. Battery Storage ELCC Curve Included in the IRP Proceeding (Percentages)



Source: CPUC IRP Proceeding[33]

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[32] This is due to the "Four-hour rule". CAISO, 2020. "Fifth Replacement Electronic Tariff." http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Aug1-2020.pdf & CPUC, 2020. "Decision 20-03-028." Op. cit., p. 41. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

[33] CPUC, 2020. "Inputs & Assumptions: 2019-2020 Integrated Resource Planning." Op. cit., p. 92.

The portfolio used to develop the ELCC curve includes significant BTM and utility-scale solar capacity, which modifies the net load shape and by extension the capacity value of battery storage. Astrape produced battery ELCC curves for 2022 and 2030 resource portfolios; the 2022 ELCC curve is used in RESOLVE for all years because it was deemed as moderately more conservative than the 2030 curve.[34]

There are some documented concerns about the use of the ELCC curve established by Astrape consulting. For example, Astrape's curve does not incorporate an essential dimension for evaluating the ELCC of storage assets: the availability of energy for charging. As the National Renewable Energy Laboratory ("NREL") has shown, the ELCC of storage is positively correlated to the availability of renewable energy.[35] In the particular case of California, the level of solar penetration is key to determine the ELCC of storage assets. NREL's analysis demonstrates that when solar composes a higher portion of the overall resource mix (35% or more), up to 8 GW 4-hour of energy storage could be included without them experiencing significant ELCC derates.[36] Further, this curve is exogenous to the resources selected by the model, such that a change in overall resource mix does not impact the capacity contribution curve.

Despite the limitations of this curve, this curve was used to estimate capacity contributions of resources with 10 or less hours of duration to maintain study alignment with the CPUC's IRP models.

2.4.2 Long Duration Storage Cost and Performance Review

A series of storage industry, regulatory, and academic papers were used to inform appropriate cost and performance assumptions for the modeling of long duration storage resources. These studies are reviewed and summarized below. These studies include reported costs for a collection of longer-duration technologies with some discussion of round-trip efficiency as available.[37]

CPUC (2019).[38] For the 2019-2020 Integrated Resource Planning (2019-2020 IRP) modeling, the CPUC utilized a RESOLVE model to develop the 2019-2020 Reference System Portfolio. The 2019-2020 IRP cycle includes BTM lithium-ion battery storage, wholesale lithium-ion and flow batteries, and pumped hydro. The capital costs of candidate pumped storage resources for the 2019-2020 IRP, which must have at least 12 hours of duration, are based on Lazard's Levelized Cost of Storage ("LCOS")-V2 and have a levelized power cost of $131/kW in 2020

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[34] CPUC, 2020. "Inputs & Assumptions: 2019-2020 Integrated Resource Planning." Op. cit., p. 91.
[35] NREL, 2019. "The Potential for Battery Storage to Provide Peaking Capacity in the United States." https://www.nrel.gov/docs/fy19osti/74184.pdf
[36] Id. 20.
[37] It should be noted that majority of storage price forecasts that are publicly available or available on a subscription basis are based on the presumed use of lithium-ion batteries for storage; few studies attempt to estimate the outlook for non-lithium-ion storage solutions, especially in the time-frames contemplated for this study.
[38] CPUC, 2019. "Inputs & Assumptions: 2019-2020 Integrated Resource Planning." https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP_20191106.pdf

and $109/kW in 2030. Other energy storage options rely on storage cost assumptions from Lazard's LCOS-V4 supplemented by NREL's Solar and Storage Report. For flow batteries, the 2020 power capital cost is $169-267/kW which is projected to decline to $115-202/kW in 2030. The 2019-2020 IRP inputs include low, mid and high-cost options, noting uncertainty regarding future battery costs. Forecasted costs are based on Lazard through 2022 and after 2022, it is assumed the pace of cost reductions slows to zero at a linear rate through 2030.

Comments of the Protect Our Communities Foundation before the CA PUC (2019).[39] Commenting on the development of a 2019-2020 RSP, Protect Our Communities ("POC") presented recommendations for battery cost updates and necessary Sensitivity Cases for the RESOLVE model. The commentary states that even the low end of the model's inputs and assumptions for battery prices continue to be overly high and are not in line with industry analyses; the model's battery capital cost for the energy cost component equals $221/kWh for the low case and $391/kWh for the high case for 2020, but these are above the current market price. Further, the modeling runs are not using the low-end cost but rather the mid-case cost of $265/kWh. Citing the Bloomberg New Energy Finance's 2019 Battery Price Survey, the POC highlighted that there were double-digit price declines for the average cost per kWh for battery packs ($176/kWh in 2018 to $154/kWh in 2019) with a projected 36% reduction in price by 2024 to $100/kWh. The RESOLVE model inputs, based on the Lazard LCOS-V4 and NREL data, assume battery price for the energy cost-component at above $100/kWh in 2030 which are quite different from the Bloomberg New Energy Finance ("BNEF") predictions.

Further, Lazard LCOS-V4 only predicted an annual growth rate for the price of lithium-ion storage at negative 8 percent for 5 years, but the updated LCOS-V5 data demonstrates at least a 26 percent decrease instead of the 8 percent reduction that had been projected by Lazard just one year previously. The POC recommended a new low case price for energy storage of $164/kWh conservatively set between BNEF's $154/kWh and Lazard's $173/kWh. The values presented by the POC indicate how rapidly energy storage prices are changing and how varied predictions from different sources are.

Hydrogen Council (2020).[40] Assuming hydrogen generation from low-cost renewables at $25/MWh with a capacity factor of 50%, the Hydrogen Council reported a cost of $1.70/kg of hydrogen produced. Additionally, the report noted that storing this hydrogen underground would add about another $0.30/kg, so in total the hydrogen costs $2/kg. Using this stored hydrogen to generate power results in costs of $100 to 200 per MWh, the lower end being for a combined cycle gas turbine ("CCGT") turbine at 60 percent utilization, and the higher end is for simple-cycle turbines at 25 percent utilization.

[39] CPUC, 2019. "Opening Comments of Vote Solar, the Large-Scale Solar Association and the Solar Energy Industries Association." https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M323/K227/323227481.PDF
[40] Hydrogen Council, 2020. "Path to Hydrogen Competitiveness: A Cost Perspective." https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

Hydrowires US DOE (2019).[41] Compiled 2018 findings and 2025 predictions for cost are reported for a range of battery energy storage systems ("BESS") and non-BESS technology based on a survey of literature. For all battery technologies, an energy to power ratio ("E/P") of 4 was utilized. The average cost of a redox battery was estimated at $555/kWh in 2018 dropping to $393/kWh in 2025. A cost of $661/kWh was determined for 2018 sodium-sulfur costs dropping to $465/kWh in 2025. For both CAES and PHS, an E/P was selected which covers the higher end of the E/P ratio for plants that are under construction. From available data, the capital cost for PHS was determined to be $2,638/kW for a 16-hour plant, but projections of how this cost will change in the future were not reported because studies differ on whether this will increase or decrease in the next 20- to 40-year time period. The CAES cost was estimated to be $1,669/kW. For an E/P ratio of 10 and an E/P ratio of 40, CAES costs $1,618/kW and $1,720/kW, respectively. This study also reported the round-trip efficiency for several long duration technologies: 75% for a sodium-sulfur battery, 86% for a Lithium-ion battery, 72% for a lead acid battery, 67.5% for a redox flow battery, 80% for PHS, and 52% for CAES.

Imperial College London (2018).[42] For a discharge duration of 8 hours and a system size of 5 GWh/625 MW, a LCOS of $113/MWh for gravity storage, $165/MWh for PHS, $146/MWh for CAES, $257/MWh for Lithium-ion, and $304/MWh for sodium-sulfur was reported. These analyses assume round-trip efficiencies of 80% for both gravity storage and PHS, 42% for CAES, 81% for lithium-ion, and 75% for sodium-sulfur.

IRENA (2019).[43] For hydrogen produced from renewables and fossil fuels, IRENA has reported the average and best case levelized cost of hydrogen ("LCOH") for 2018 and values projected for 2050. Overall, in 2018 the LCOH of hydrogen ranges from around $1-6/kg. In 2050, LCOH estimates decrease to around $1-2.5/kg. For the 2018 range of LCOH, assumptions include an electrolyzer cost of $840/kW, an electrolyzer efficiency of 65%, wind load factors of 34-47%, a wind levelized cost of energy ("LCOE") of $23-55, PV load factors of 18-27%, and a PV LCOE of $18-85. For the 2050 estimate, assumptions include an electrolyzer cost of $370/kW, wind load factors of 45-63%, a wind LCOE of $11-23, PV load factors of 18-27%, and a PV LCOE of $4.5-22. IRENA also cited a study which reported a 45% cycle efficiency for power-to-gas electricity storage.

Lazard (2016).[44] Lazard's LCOS-V2 reports a comparison of the unsubsidized LCOS for a range of long duration technologies. For the transmission system use case (i.e., large-scale energy storage to assist in renewable energy integration) the 2016 range of LCOS is $116-$140/MWh for compressed air, $314-$690/MWh for flow batteries, $152-$198/MWh for pumped

[41] Hydrowires US DOE, 2019. "Energy Storage Technology and Cost Characterization Report." https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf
[42] Imperial College London Consultants, 2018. "Levelized Cost of Storage Gravity Storage." https://625956f1-51c8-4105-8c65-2138877b56e4.filesusr.com/ugd/496e1f_8844f8ef29c1437cb49e939d6a67a005.pdf
[43] IRENA, 2019. "Hydrogen: A Renewable Energy Perspective." https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf
[44] Lazard, 2016. "Levelized Cost of Storage Analysis 2.0." https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20

hydro, $301-$784/MWh for sodium, $262-$438/MWh for zinc, and $227-$280/MWh for thermal. These values are based on an assumed duration of 8 hours. The capital costs are $130-$188/kWh for compressed air, $426-$1,026/kWh for flow batteries, $213-$313/kWh for pumped hydro, $410-$1,200/kWh for sodium, $233-$607/kWh for zinc, and $323-$388/kWh for thermal. The average 5-year capital cost declines (up to 2020) were forecast to be 5% for compressed air, 24% for flow batteries, 5% for pumped hydro, 37% for sodium, 28% for zinc, and 4% for thermal. Lazard reports efficiencies of 80-82% for PHS, 64% for zinc, 75-79% for CAES, 68-73% for flow batteries, and 82% for sodium.

Lazard (2020).[45] Lazard's LCOS-V6 provides a general overview of selected long duration storage techniques which include flow, thermal, and mechanical. A LCOS analysis of a 100 MW / 1,000 MWh long duration energy storage system (duration > 6 hours) reported a LCOS of $141-$284/MWh for energy and $494-$997/kW-yr for capacity. These values were based on assumptions of a standalone battery, 20-year project life, and no degradation or augmentation costs. This edition of the Lazard LCOS did not include forward-looking cost estimates.

NREL (2018).[46] NREL discussed the costs of standalone lithium-ion storage and paired solar plus storage resources. The costs for a standalone lithium-ion battery with a duration of 4 hours was reported to be $380/kWh in 2018. The round-trip efficiencies of other storage technology options are also mentioned: 70-80% for PHS, 40-55% for CAES.

Strategic Analysis (2019).[47] The US DOE Hydrogen and Fuel Cells program has funded research in 700 bar Type IV compressed hydrogen storage systems, which can store 5.6 kg of usable hydrogen for onboard automotive applications. In 2015 these systems cost $14.50/kWh and as of 2018 cost $14.19/kWh. The stack has an efficiency of 60%.

Wang (2017).[48] This research article notes that CAES has a scale and cost similar to that of PHS. A range of capital costs is reported for several long duration storage technologies: $600-$1,100/kW for PHS with a storage duration of hours-months, $400-$1,100/kW for CAES with a storage duration of hours-months, $500-$1,250/kW for hydrogen fuel cells with a storage duration of hours-months, and $100-$400/kW for thermal energy storage with a storage duration of minutes-days.

It should be noted that most of these studies discuss current day costs for storage. Some, including Lazard LCOS-V2 (which is used for the CPUC's storage costs) and the Department of Energy include 5-year cost declines, but none provide projections past 2025, several years short of the 2030 or 2045 timeframes contemplated by this report. Notably, the CPUC assumes modest reductions in cost through 2022, and then assumes that cost reductions decelerate through 2030, and cease altogether after 2030, resulting in an overall cost

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[45] Lazard, 2020. "Levelized Cost of Storage Analysis 6.0." https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf
[46] Ran Fu et al., NREL, 2018. "2018 U.S. Utility-Scale Photovoltaics Plus-Energy Storage System Costs Benchmark." https://www.nrel.gov/docs/fy19osti/71714.pdf
[47] Cassidy Houchins and Brian James. Strategic Analysis, 2019. "2019 DOE Hydrogen and Fuel Cells Program Review." https://www.hydrogen.energy.gov/pdfs/review19/st100_james_2019_o.pdf
[48] Jidai Wang et. al., Energies, 2017. "Overview of Compressed Air Energy Storage and Technology Development" https://www.mdpi.com/1996-1073/10/7/991

reduction of 56% from 2020 to 2030 for the power component of lithium-ion batteries and 52% for the energy component.

This outlook on storage cost reductions is in direct contradiction to historic cost declines that have been achieved through technology innovation and scaled deployment. BNEF has reported that the volume weighted average battery pack price fell 85% between 2010-18, reaching an average of $176/kWh.[49] Additionally, an MIT research article highlighted that the cost of solar PV modules has fallen by 99 percent over the last four decades.[50] These studies provide a benchmark for how successful research and development programs, paired with at-scale deployment can achieve significant reductions in market prices.

2.4.3 Modeling of Long Duration Storage

Given the wide array of long duration storage solutions that are currently available on the market or are in development with viable deployment dates prior to 2030, it was determined that a technology-based approach to modeling long duration energy storage would be unnecessarily specific and arbitrary. Instead, long duration energy storage resource options were intended to capture trends of the technology characteristics and can be thought of as generic, technology-neutral resource options. The resource options developed for use in this study are not representative of any single technology, but instead are intended to represent a class of storage solutions that have similar performance capabilities, tradeoffs, and cost profiles.

Determination of specific storage cost assumption was established with a consistent approach, recognizing the inherent uncertainty in long duration storage costs over the study horizon. The uncertainty in cost forecasts for long duration storage stems heavily from the fact that LDES is a maturing technology at the beginning of its learning curve and is thus expected to experience significant cost declines. This forecasting challenge is exacerbated by the 25-year ahead study horizon of this report. Projecting a cost level for each single cost component of an LDES system would be speculative. By combining uncertainties and only projecting a single cost level relative to the already projected cost level of lithium-ion, we manage to capture the important trends and trade-offs of storage technologies and gain insights through their modeling and extensity sensitivity analysis without being overly or unnecessarily specific.

At the highest level, LDES options are assumed to have higher power capacity costs ($/MW), but significantly lower energy capacity costs ($/MWh). Furthermore, round trip efficiency is assumed to decline as the duration of the storage system increases. All of the technologies are assumed capable to provide ancillary services. In addition to the all-inclusive annualized cost and the roundtrip efficiency, storage resources are also characterized with a minimum duration. This minimum duration is meant to capture the scale after which the assumed cost is achievable on a per kWh basis. LDES solutions with minimum duration greater than 10 hours

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[49] Logan Goldie-Scot. BNEF, 2019. “A Behind the Scenes Take on Lithium-ion Battery Prices.” https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/?sf99676771=1
[50] David Chandler. MIT News, 2018. “Explaining the Plummeting Cost of Solar Power.” https://news.mit.edu/2018/explaining-dropping-solar-cost-1120

also receive full capacity credit; while those with shorter duration receive capacity credit in the same fashion as lithium-ion battery storage.

Two primary LDES candidate resources (10- and 100-hour) were modeled in the Base Case as well as in all the sensitivity runs; a portion of the Sensitivity Cases also include additional long duration storage candidate resources. Long duration energy storage solutions were modeled based on cost multipliers relative to the established baseline of lithium-ion as those modeled in CPUC's IRP. The specific cost multipliers are presented in the table below. Table 3 summarizes the input assumptions for the two LDES resource options included in all the runs, as well as for the additional options included in certain sensitivity runs.

Table 3. Cost & Performance Assumptions for Storage Technologies

		Cost Multiplier (Annualized all-inclusive cost)		Round Trip Efficiency	Minimum Duration
		$/MW	$/MWh	%	Hours
CPUC IRP	Lithium Ion	1	1	85%	1
	Flow Battery	8 - 9.6	0.62 - .7	70%	1
	Pumped Storage	10.1 - 12.4	0.39 - .64	81%	12
LDES included in all cases	10+ hr. storage	6	0.25	72%	10
	100+ hr. storage	7.5	0.125	64%	100
LDES included in some Sensitivity Cases	5+ hr. storage	4	0.33	60%	5
	100+ hr. storage - low cost	2	0.05	49%	100

10-hour storage solution

The first long duration energy storage option added to RESOLVE's existing portfolio of resources is a generic technology with a minimum duration of 10 hours, a round trip efficiency of 72%, power capacity cost six times higher than the projected lithium-ion cost, and energy cost equal to one fourth of the lithium-ion cost. This storage solution was included as a resource in all cases unless noted otherwise.

100-hour storage solution

The second long-duration energy storage option represents technologies with discharge duration greater than 100-hours. The cost multiplier for the power capacity component is 7.5 and the multiplier for energy capacity is 0.125 relative to the lithium-ion resource option. Roundtrip efficiency is assumed to be even lower at 64%, assuming a minimum duration of 100 to achieve those economies of scale. This storage solution was included as a resource in all cases unless noted otherwise.

5-hour storage solution

The third long duration energy storage solution considered in the modeling was intended to represent storage solution with discharge duration of 5-hours or more. This resource is assumed to have a 4x multiplier on the capacity component and a 0.33 multiplier on the energy capacity relative to lithium-ion. This resource also had a lower round-trip efficiency at 60%. This resource was not modeled in all cases and is identified when included.

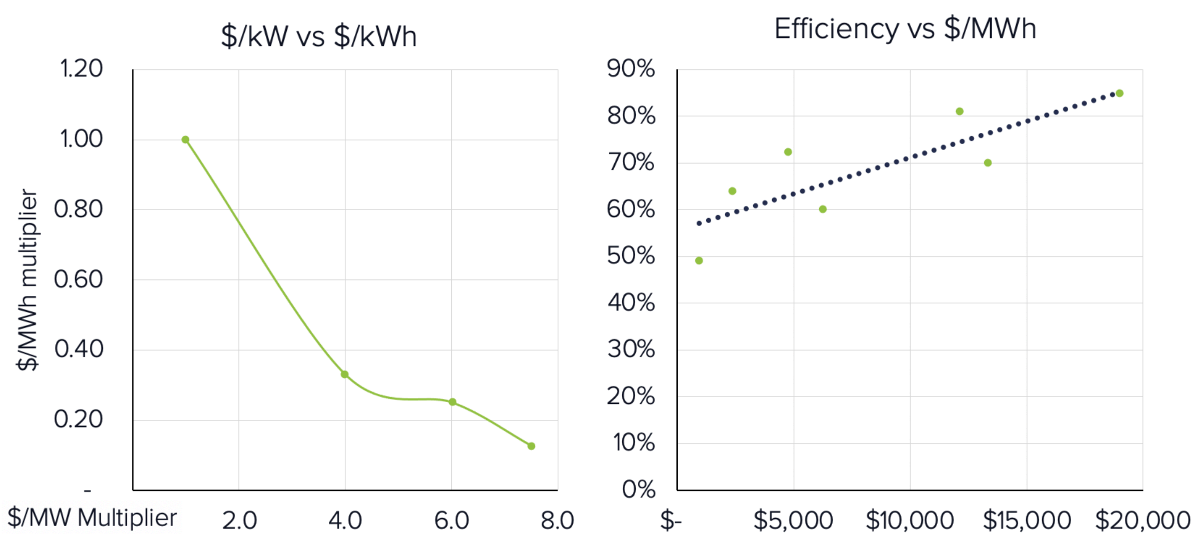
Low-cost 100-hour storage solution

The fourth and final long duration energy storage solution modeled was intended to represent a storage solution with 100-hour dispatch duration with much lower installed cost price points than the 100-hour storage resource modeled as part of the Base Case. This resource is assumed to have a 2x multiplier on the capacity component and a 0.05 multiplier on the energy capacity relative to lithium-ion. This resource also had a lower round-trip efficiency at 49%. This resource was not modeled in all cases and is identified when included.

Storage Portfolio Diversity

Taken collectively, these four resources represent significant diversity across the two different components of installed cost, as well as round-trip efficiency and minimum duration. They are intended to provide sufficient diversity to allow for the model to make trade-offs across the different storage characteristics that are needed for the grid. The below figure highlights some of the cost and performance trade-offs across these resources.

Figure 4. Storage & Performance Cost Trade-offs



Source: Strategen Consulting

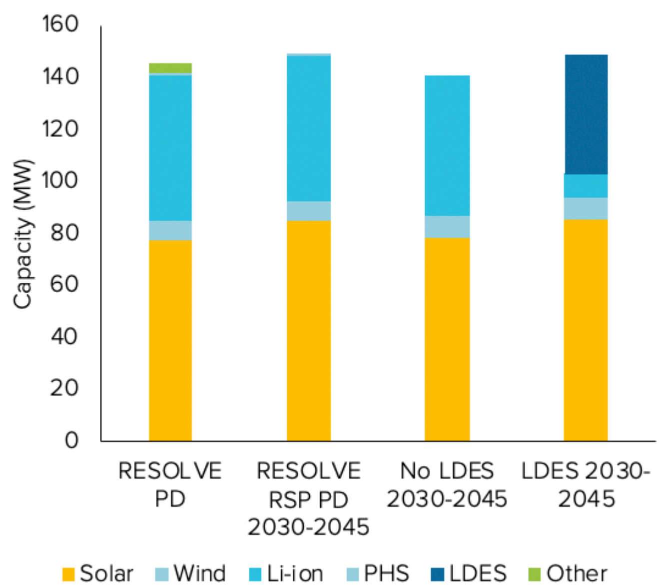
2.5 Benchmarking Analysis

Before running GridPath with the increased temporal resolution and the addition of LDES, Blue Marble performed a benchmarking exercise. This exercise was meant to verify that a differentiation in the results of the study compared to those of the IRP would be due to the increased functionality and storage options instead of any other factor. Indeed, when GridPath was given the same inputs and was configured similarly to RESOLVE, i.e., with 37 days and the same storage resource options, the results closely resembled those of CPUC's IRP.

In addition to the benchmarking run, Blue Marble also conducted a run including the same assumptions and storage options as those of CPUC's IRP, but with the increased time resolution of 8,760 hours. This run did not include the additional LDES resource options. The results again did not deviate significantly from those of the benchmarking case, proving that while the 8,760 resolution is a necessary condition to capture the benefits of LDES, it is not sufficient. In addition to the modeling changes, including LDES in the portfolio of available resources is necessary to model how the technology can deliver benefits to the grid.

Figure 5 below shows the capacity results from RESOLVE's RSP PD and benchmarks these results against a series of simulation runs using GridPath. The GridPath runs include results using GridPath configured as RESOLVE (i.e. 37 days, no LDES options), results using GridPath with the increased time resolution (i.e. 8,760, no LDES), and finally GridPath results with both increased time resolution as well as availability of LDES resource options. This last run replicates CPUC's RSP assumptions, but with a time resolution of 8,760 hours and the availability of LDES as the Base Case of the report, and will be further explored in later sections.

Figure 5. Comparison of Capacity and Total Duration of RESOLVE RSP PD and GridPath LDES and No LDES Cases



Source: Strategen Consulting

2.6 Scenarios Analyzed

2.6.1 Base Case

The first run that was performed was the Base Case. All of the inputs used in GridPath followed closely those of the IRP, with the addition of long duration energy storage options and the increased temporal resolution.

The Base Case was also complemented by a run with the same assumptions, but without including LDES options – referred to as the "No LDES" case. The comparison of the Base Case results with and without LDES are used to derive the incremental system impacts caused by the addition of long duration energy storage.

In addition to the Base Case, the analysis considered different Sensitivity Cases to test for the impacts of weather, policy, and resource availability variations. These are presented in more detail in the next section.

2.6.2 Sensitivity Cases

In addition to the Base Case, the analysis considered different Sensitivity Cases to test for the impacts of weather, policy, and resource availability variations. Generally, Sensitivity Cases demonstrate durable need for long duration storage applications across a wide array of grid and storage technology outcomes. GridPath has thousands of input parameters and constraints that could serve as the basis of a sensitivity analysis. We identified the most important and potentially impactful ones to further explore. These include:

- The state's carbon policy as expressed within the model's carbon constraint
- The weather which shows up in the hourly renewable generation profiles
- The costs of the different energy storage options
- The capacity credit that energy storage technologies receive
- The transmission constraints that limit the level of wind and other out-of-state resources deployed

In addition to the sensitivity runs in which we modified the input to each of the above drivers, we also conducted combined runs in which two or more of these drivers were modified.

Carbon Policy Sensitivity

The state's carbon policy is a significant driver of resource additions, and as such it is important to understand how sensitive the results of the study were under a more stringent carbon policy. We analyzed the Base Case's sensitivity by accelerating the State green-house gas target to net zero-emission by 2045. This scenario (0 MMT) requires unspecified carbonaceous imports and use of fossil fuel generation to be zero by 2045. En route to 0 MMT by 2045, this sensitivity also assumes that 2030 emissions will be capped at 30 MMT, rather than the current CPUC IRP assumption of 46 MMT by 2030.

Low Irradiance Sensitivity

This sensitivity explored how multiple days of low solar irradiance and corresponding reductions in solar generation will affect grid operations and long duration energy storage deployment. To test this sensitivity, renewable generation profiles from 2010 were extracted from the historical SERVM dataset. Across all the historical SERVM weather years, the winter of 2011 saw the lowest contiguous solar generation across the year due to a particularly active storm season in California, and the associated cloud cover sharply reducing solar PV production. Detailed information on the development of the extreme weather year can be found in Appendix A.

Out-of-State Resource Availability

As mentioned previously, the majority of the cases modeled for this analysis do not include incremental transmission development or access to out-of-state renewable resources that would require incremental transmission development. This scenario assumes transmission upgrades that would allow access to out-of-state resources in New Mexico and Wyoming, adding 34 GW of new potential solar resources and 15 GW of new potential wind resources. Transmission upgrade costs factored into this analysis in a manner similar to RESOLVE. New out-of-state resources are attributed an additional transmission cost, representing either the cost to wheel power across adjacent utilities' electric systems (for resources delivered on existing transmission) or the cost of developing a new transmission line (for resources delivered on new transmission). Wheeling costs on the existing system are derived from utilities' Open Access Transmission Tariffs; the cost of new transmission lines is based on assumptions developed for the CPUC's RPS Calculator v.6.2.[51]

Storage Cost & Performance Sensitivities

One of the most significant drivers in the selection of resources in a capacity expansion model is the relative cost of resources. For this reason, modeling included sensitivity runs around the cost of storage resources, especially as it is expected that the technology will experience significant cost declines. Given this uncertainty, it becomes critical to understand the robustness of the results and conclusions when the projected cost of energy storage resources deviates from the base assumption. For this reason, additional sensitivities explore both the performance and cost of energy storage by adding in the incremental long duration storage resources discussed in section 2.4.3, as well as by modifying cost assumptions for lithium-ion storage.

Storage Capacity Credit

In addition to meeting demand during each hour of the year, GridPath includes an additional resource adequacy constraint: the PRM. As explained above, the LDES options modeled in the Base Case receive full capacity credit, while lithium-ion resources follow the ELCC as defined in RESOLVE. To investigate whether the selection of LDES in the model's results was overly attributed to its higher capacity credit, we also included a sensitivity run in which lithium-ion batteries also receive full capacity credit.

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[51] See E3, 2017. "RESOLVE Documentation: CPUC 2017 IRP – Inputs and Assumptions." P. 40. https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentB.RESOLVE_Inputs_Assumptions_2017-09-15.pdf

Table 4. Description of Sensitivity Cases

Name	Description
RSP Benchmark	Replication of the CPUC RSP case with identical assumptions and temporal configurations
8,760 Benchmark	Replication of the CPUC RSP case with identical assumptions and 8,760 optimization horizon
No LDES	46/12 MMT Carbon case with no LDES candidate resources [52]
LDES Base Case	46/12 MMT Carbon case with LDES candidate resources
0 MMT	30/0 MMT Carbon case with LDES deployment
Low Solar	46/12 MMT Carbon case with 1-in-10 weather
0 MMT; Low Solar	30/0 MMT Carbon case with 1-in-10 weather
0 MMT; No LDES	30/0 MMT Carbon case with no LDES deployment
0 MMT; OOS	30/0 MMT Carbon case with additional transmission and out-of-state resources
Li-ion Low Cost	46/12 MMT Carbon case with "low" CPUC assumptions for lithium-ion costs
Li-ion ELCC	46/12 MMT Carbon case with full capacity contribution allowed for lithium-ion
5-hr Storage	46/12 MMT Carbon case with additional 5-hr storage candidate resource
0 MMT; low cost 100-hr	30/0 MMT Carbon case with lower cost 100+ hour storage candidate resource
0 MMT; OOS; low cost 100-hr	30/0 MMT Carbon case with additional transmission and out-of-state resources and lower cost 100+ hour storage candidate resource
100+ hr	46/12 MMT Carbon case with lower cost 100+ hour storage candidate resource

[52] The numbers at the beginning of the description of this case, as well as the ones below it, represent the carbon constraints for 2030 and 2045, respectively.

3. Study Findings and Results

As discussed previously, the objective of this study is to understand the potential role for long duration energy storage on California's electric grid. At the highest level, modeling of different storage options and grid conditions found that the specific types of storage deployed on California grid varied based on grid conditions, storage price points, renewable resources, and other factors. Nevertheless, various forms of longer-duration storage were deployed in all cases. Unsurprisingly, analysis found that deployment of long duration storage accelerated in cases when the State pursued more stringent carbon targets – which was considered in this modeling during the 2030 to 2045 timeframes.

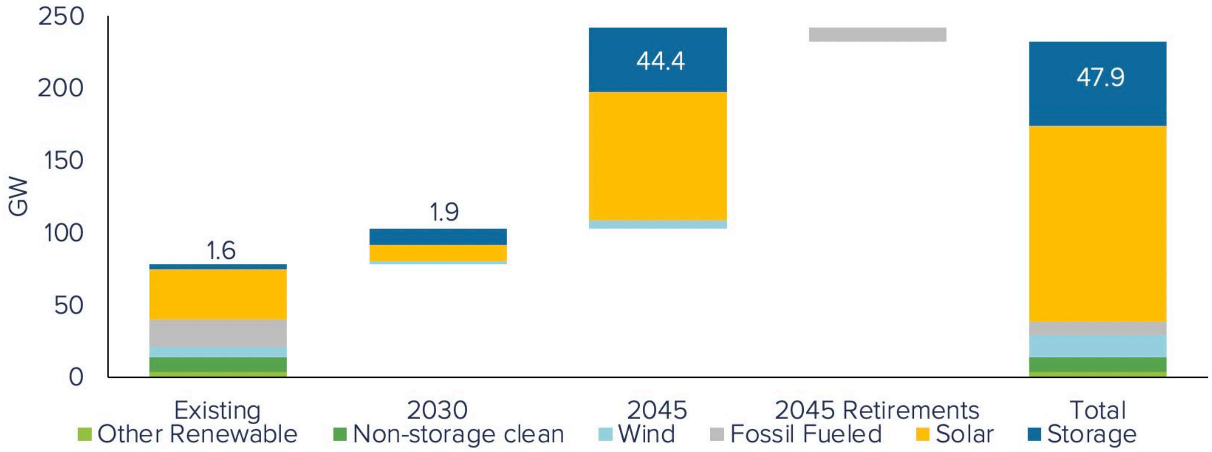
To provide more detail on the role of storage in these different conditions, study findings are broken into four key subsections. The first section explores the findings from the Base Case scenario, with a particular focus on the difference between grid dispatch and operation with and without long duration storage; highlighting the incremental changes enabled by long duration storage selection. The second section provides a deeper look at some of the macro-level trends that drive resource retirement, as well as how these trends impact both long duration storage applications and overall grid performance. The third section describes how these different types of storage operate and dispatch on the grid. The fourth and final section dives into the storage portfolio itself, exploring how different resource availability and cost structures might impact overall portfolio deployment and the composition of the storage portfolio itself.

3.1 Base Case

The objective of the Base Case for this study was to establish a baseline level of long duration energy storage deployment and understand how grid operation in this case differed from other analyses that had not included long duration storage. To be clear, in this instance, the Base Case does not represent a "most likely" case. Instead, it attempts to adhere most closely to the standard modeling and input assumptions used in state-run California regulatory analysis, with the minimum modifications necessary to provide a more realistic assessment of long duration storage.

As described in the previous section on methodology, the Base Case focused on identifying resource deployments and grid operations at two key policy milestones – 2030 and 2045. Figure 6 shows the sequential resource additions needed in 2030 and 2045 relative to the existing portfolio, as well as the cumulative portfolio expected to be online by 2045. Over the next two and a half decades, resource additions in California are expected to come primarily from storage and solar. By 2045, the State maxes out potential deployment of accessible in-state wind resources and will rely heavily on solar to provide the bulk of the clean energy used in the State. Significant quantities of storage – over 55 GW cumulatively, are needed to balance supply and demand, with over 45 GW of needed for long duration storage applications.

Figure 6. Necessary Resource Additions and Expected Cumulative Portfolio, 2045

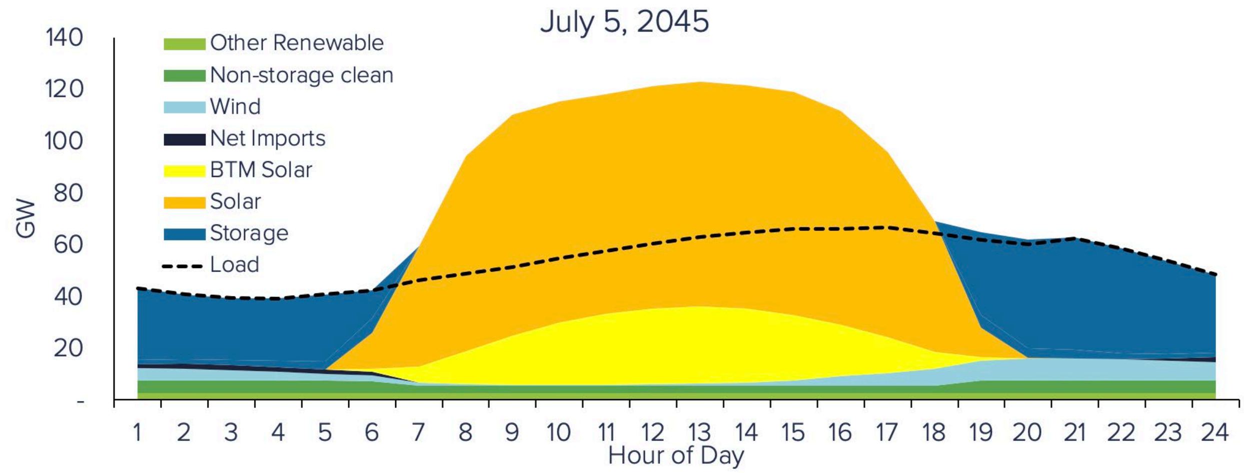


Source: Strategen Consulting

By 2045, energy storage will be the primary balancing and integrating resource on California's grid. Based on the State's estimates of renewable resource availability,[53] solar will become the predominant renewable resource, generating nearly 75% of the energy consumed by Californians. To balance solar generation, storage is needed to absorb mid-day generation for as many as 8 to 12 hours a day. In the evening, storage dispatch ramps up as solar generation dies down, and provides the majority of the State's energy during nighttime hours – dispatching in many cases for 12 hours contiguously. Figure 7 shows energy supply and dispatch on a sample summer day with high solar output.

[53] Renewable resource capabilities are based on assumptions established by the CPUC in their IRP and RPS processes establishing defined Competitive Renewable Energy Zones (CREZ) with set renewable resource capacity potential.

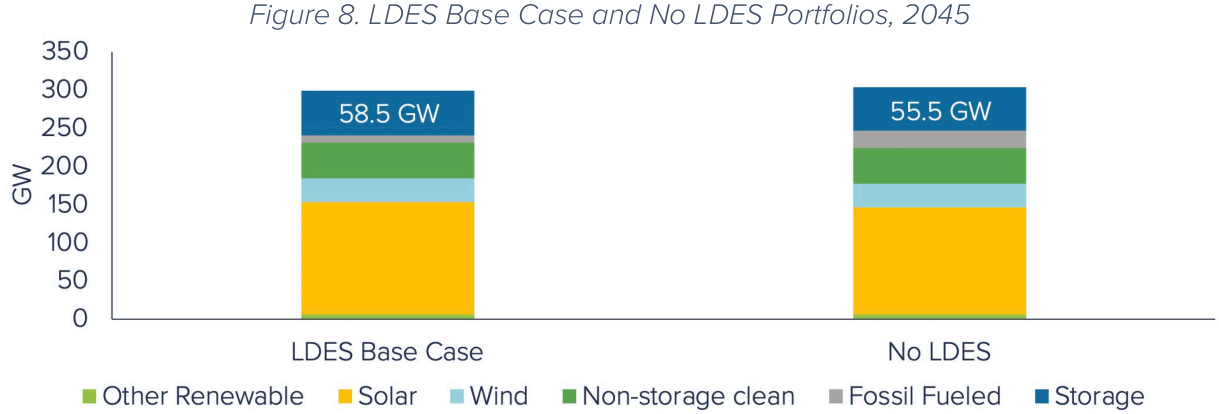
Figure 7. Daily CA Energy Supply, 2045



Source: Strategen Consulting

The overall 2045 portfolios for the cases with and without long duration storage are compared below. The overall renewable mix in both portfolios is very similar; however, the addition of long duration storage significantly impacts the resources that are used to integrate renewables. Notably, the selection of long duration storage enables the retirement of approximately 13 GW of fossil-fueled generation.

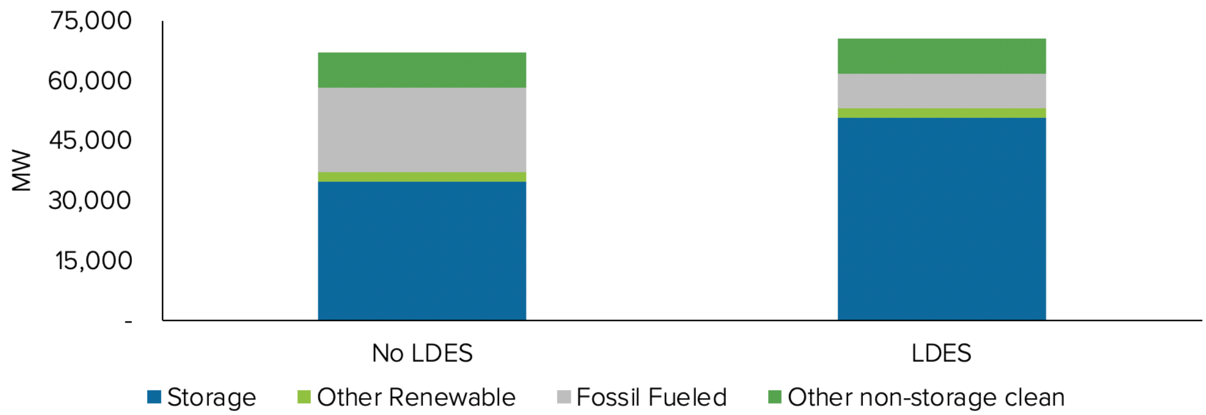
Figure 8. LDES Base Case and No LDES Portfolios, 2045



Source: Strategen Consulting

This incremental retirement occurs for a couple of reasons. First, investment in LDES solutions enables the use of previously generated renewable energy during the night and early morning, significantly reducing the need for natural gas-based generation during those times. Second, long duration storage can provide more capacity per installed MW due to the capacity de-rating of lithium-ion storage discussed in the methodology section. This means that there is reduced need for fossil fueled resources to provide capacity, and that the CAISO 15% planning reserve margin can be met without relying on these fossil assets. For both of these reasons, the fossil capacity is not needed and can be economically retired. As Figure 9 shows, the introduction of long duration storage allows for California's grid to rely much less on both short duration storage and fossil fueled resources to ensure sufficient capacity to meet resource adequacy obligations.

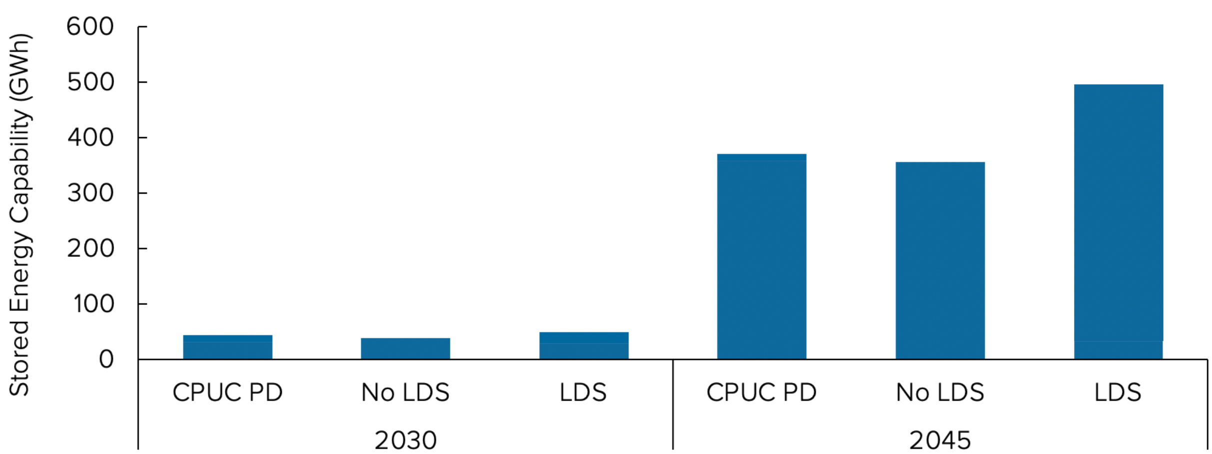
Figure 9. Resource Adequacy Contribution



Source: Strategen Consulting

Another notable difference in the numbers shown in Figure 9 is the shift from a homogenous portfolio of shorter duration storage to a mixed portfolio with both long and short duration storage. The installed capacity numbers shown in Figure 9 are not able to capture a more foundational shift that can be seen in the overall MWh capability deployed. While shorter duration storage continues to be deployed on the grid to provide balancing services, in the context of a larger blended portfolio, it makes up a much smaller portion of the storage MWh capability.

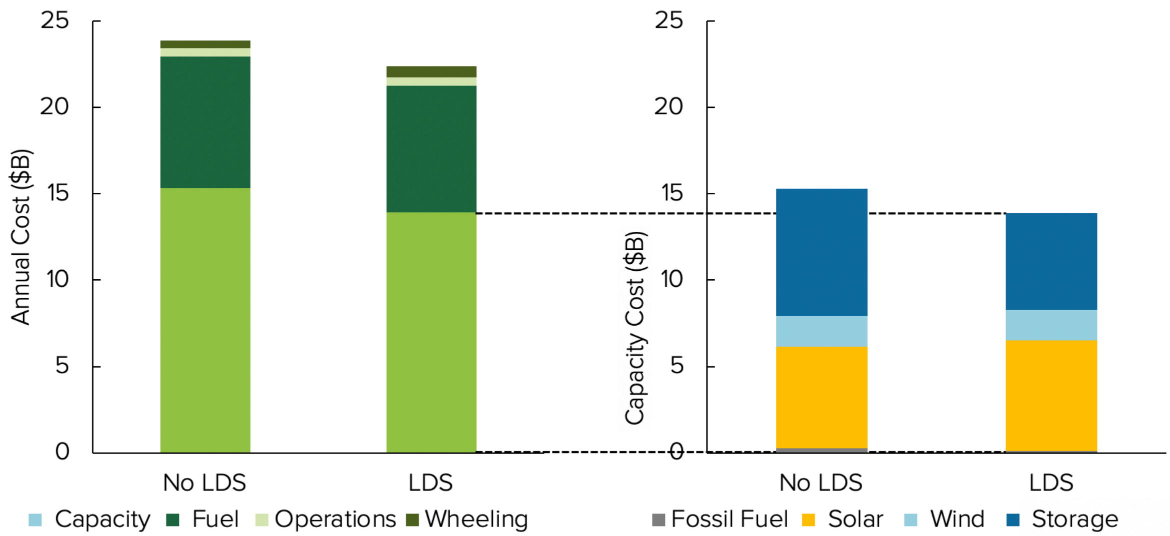
Figure 10. Total CAISO Stored Energy Capability in 2030 and 2045



Source: Strategen Consulting

This shift in MWh capability from short-duration to long duration storage is driven by the cost trade-offs highlighted in the previous section – it is as much as four times less expensive to add a MWh of 10-hour storage relative to a MWh of lithium-ion. These cost trade-offs are the biggest driver for $1.5 billion / year reduction in system costs by 2045, relative to the case without long duration storage.

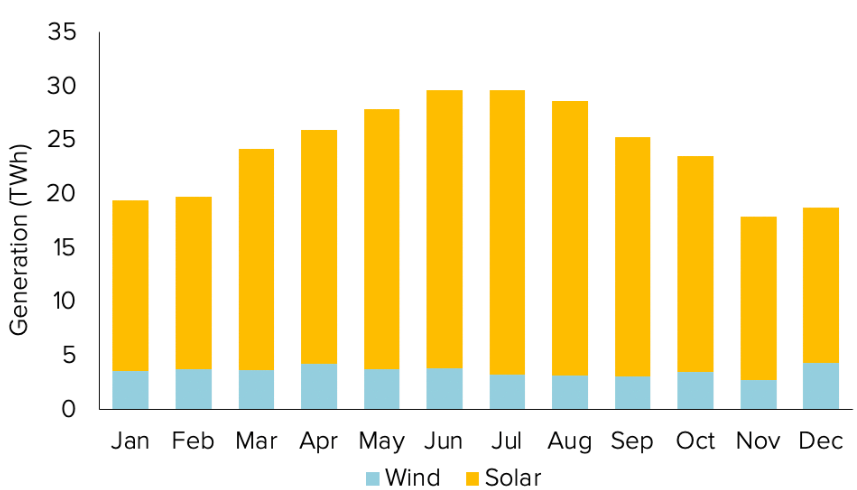
Figure 11. Total System Cost for LDES and No LDES Case, 2045



Source: Strategen Consulting

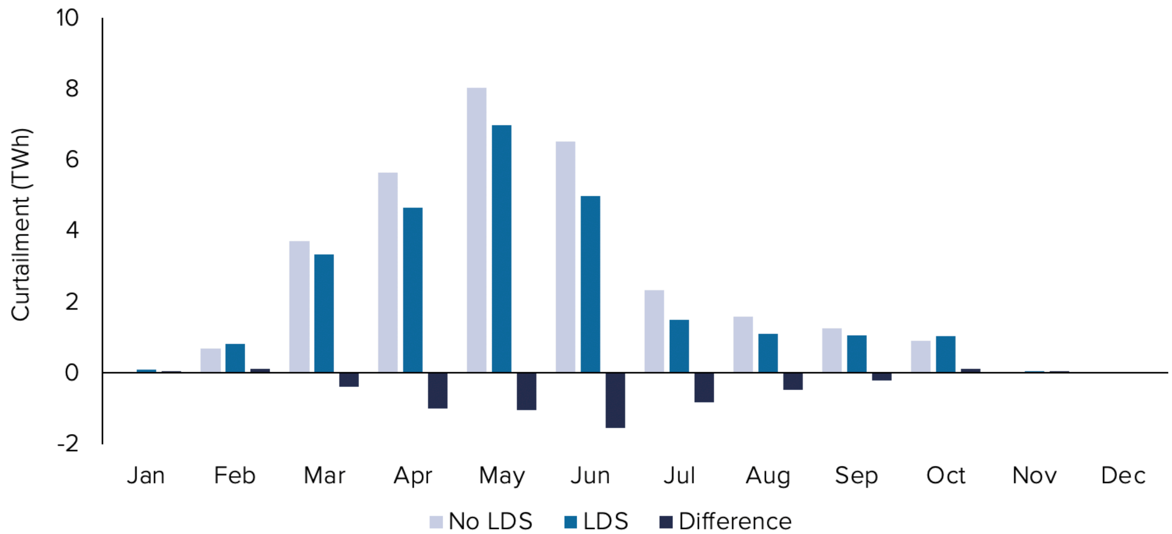
The increase storage energy capability also helps to support higher utilization of in-state renewable energy. The nearly 40% increase in MWh energy storage capability reduces annual curtailment by around 17% across the 2045 modeling year relative to a case without long duration energy storage. As shown in Figure 13, this curtailment reduction occurs primarily during the spring and summer months of peak renewable generation.

Figure 12. Monthly Renewable Generation in LDES Base Case, 2045



Source: Strategen Consulting

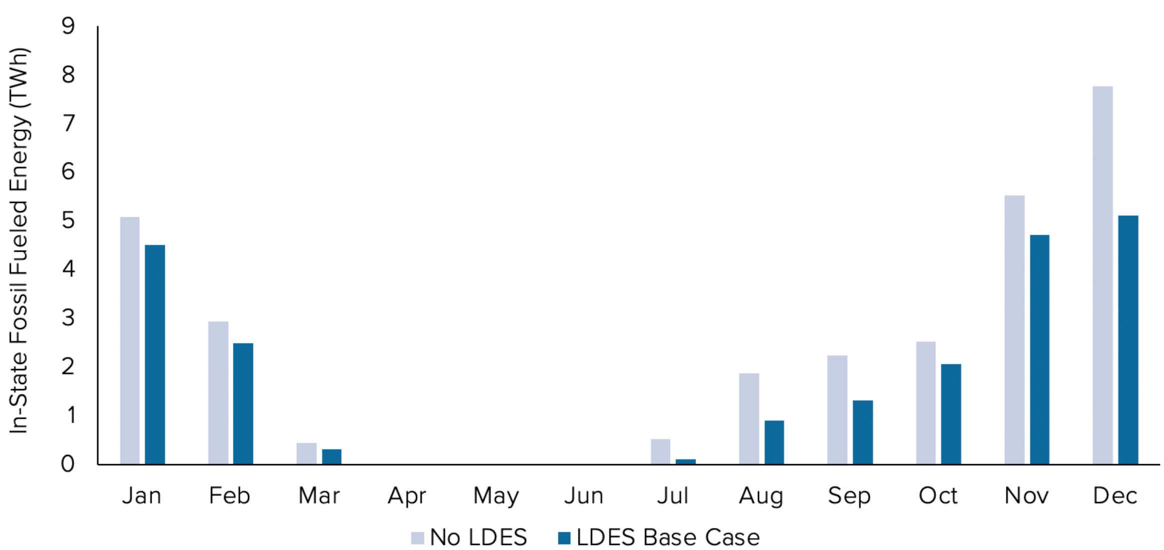
Figure 13. Monthly Curtailment in LDES Base Case & No LDES Case, 2045



Source: Strategen Consulting

A combination of increased renewable energy capture and availability paired with the increased operational flexibility provided by longer-duration storage assets allows for approximately 25% reduction of in-state fossil fuel resource usage. As shown in Figure 14, this reduction occurs in all months.

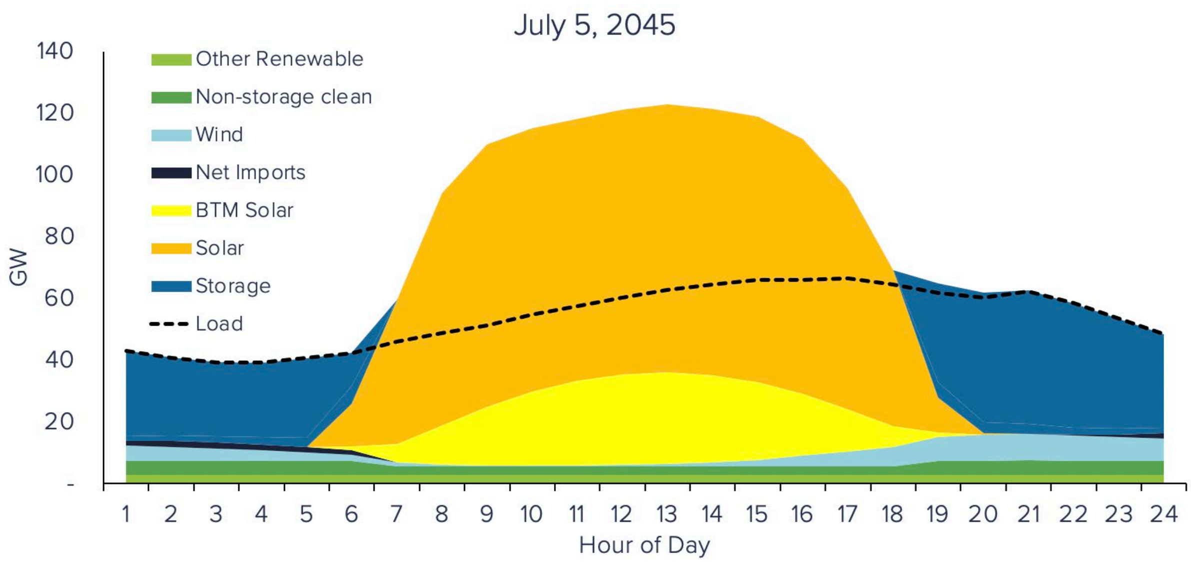
Figure 14. Reduction in In-State Fossil Fueled Energy with LDES



Source: Strategen Consulting

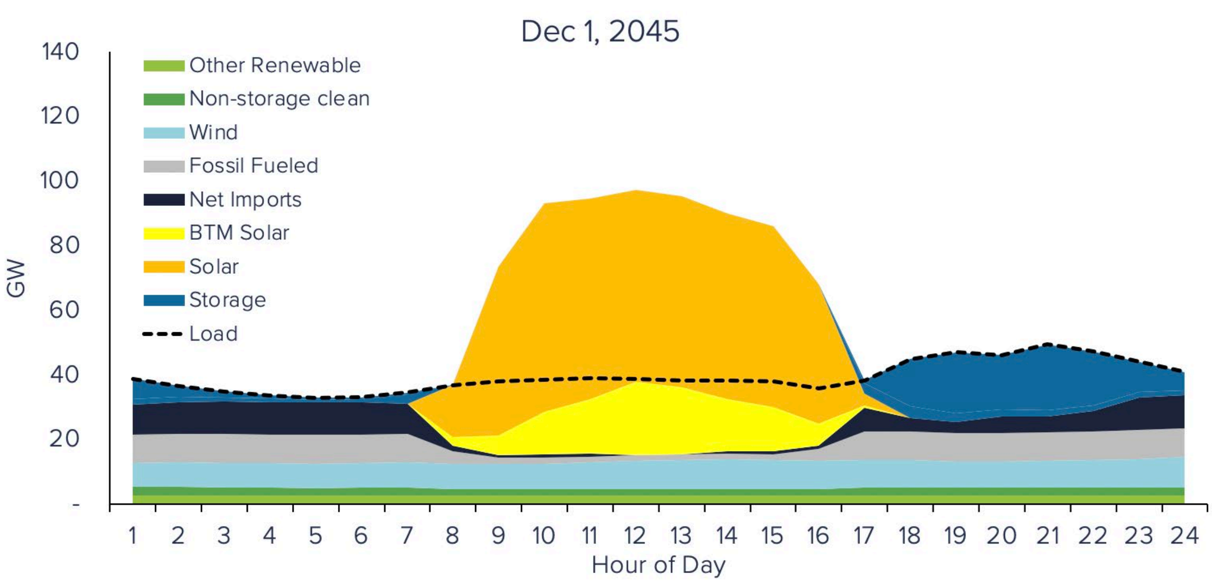
Interestingly, this dispatch pattern, which shows highest use of fossil resources during the winter, is the opposite of current dispatch patterns of peak demand during summer months. The cause of this change can be seen by comparing a dispatch during a sample day in the summer against another in the winter. Figures 15 and 16 show sample days in July and December, respectively, to highlight the impact reduced solar output in winter months, which reduces the opportunity for storage charging. The specific impacts to storage operation are discussed in greater detail in sections 3.3 and 3.4.

Figure 15. Daily Dispatch Pattern in Sample Summer Day, 2045



Source: Strategen

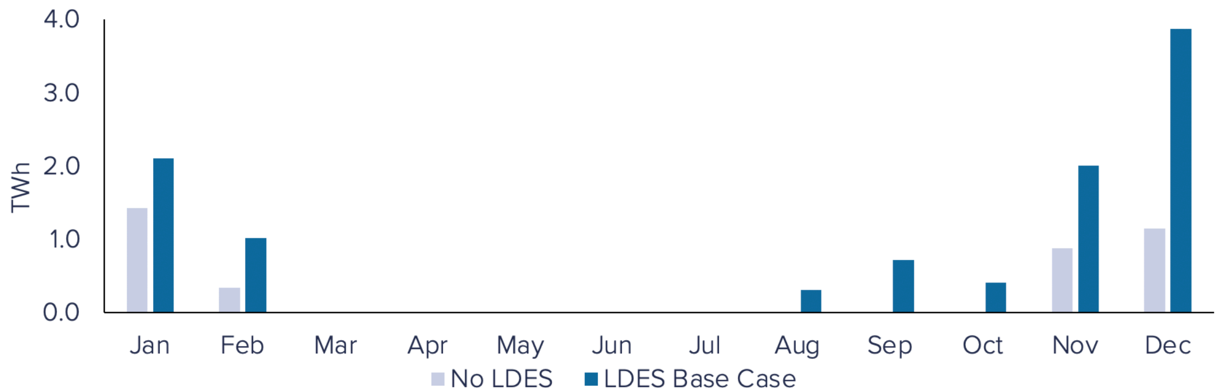
Figure 16. Daily Dispatch Pattern in Sample Winter Day, 2045



Source: Strategen

The in-state emissions reduction shown above is offset by an increased reliance on imports. This is caused by the carbon counting rules established by CARB – namely that both direct use of in-state fossil fuel resources and "unspecified" power imports both contribute toward the electric sector carbon cap.[54] By 2045, the statewide carbon target is the biggest driving factor for resource additions and system dispatch, thus the model optimization will precisely meet, but not exceed, carbon targets to minimize overall system cost. In this case, this means taking advantage of (relatively) low-cost imports during times of peak system need rather than building incremental resources to meet that need. Imports provide 10 TWh of energy annually in the LDES Base Case.

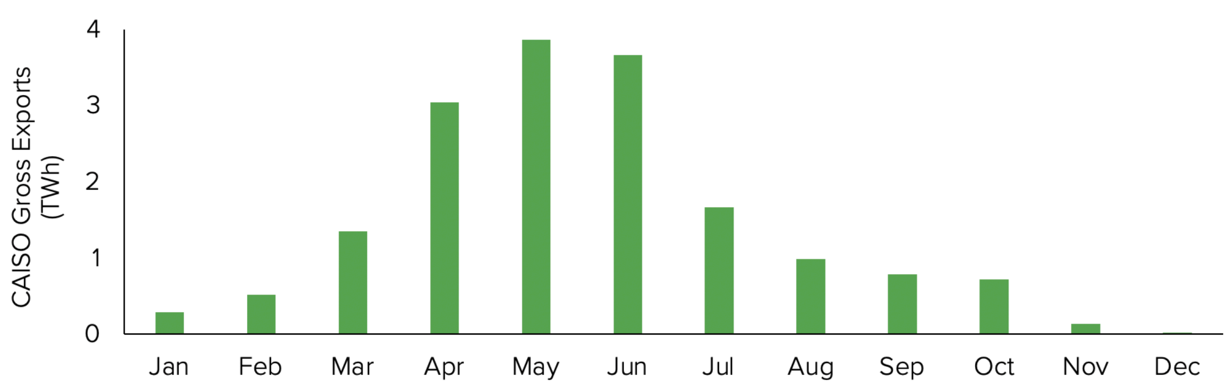
Figure 17. Out-of- State Imports, 2045



Source: Strategen

Despite the reliance on out-of-state imports to balance renewable generation during peak demand months, by 2045 CASIO is forecast to be a net exporter of energy. CAISO exports are expected to peak with renewable generation in the spring and summer; with nearly 17 TWh per year flowing out of CAISO into the surrounding region, exceeding imports by nearly 7 TWh.

Figure 18. CAISO Gross Exports, 2045



Source: Strategen

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[54] California Air Resources Board (CARB), 2019. "California Greenhouse Gas Emissions for 2000 to 2017." https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2016/ghg_inventory_trends_00-16.pdf

The next section, which explores Sensitivity Cases including tighter carbon targets, describes how California's grid compensates when carbon counting rules prevent use of out-of-state imports to balance demand and resource availability.

3.2 Sensitivity Cases: Macro Trends

While the Base Case described above paints a clear and compelling vision for how long duration storage can support a deeply decarbonized Californian electric sector, it represents a singular and specific pathway for California policy and grid development to unfold. These Sensitivity Cases are intended to explore different paths that California's grid might take, and to understand how the role of long duration storage evolves in those different futures.

The sensitivities discussed in this section explore how macro-level trends, such as policy changes or weather variation, could impact grid evolution. As it became clear that pursuit of a completely decarbonized grid created the most significant changes to resource deployment, a set of these sensitivities narrow in on what it might take to build a zero-carbon grid, and how long duration storage would be called upon in that grid. Table 5 shows the Sensitivity Cases discussed in this section.

Table 5. Sensitivity Descriptions for RESOLVE Model

Name	Description
No LDES	46/12 MMT Carbon case with no LDES candidate resources
LDES Base Case	46/12 MMT Carbon case with LDES candidate resources
Low Solar	46/12 MMT Carbon case with 1-in-10 weather
0 MMT	30/0 MMT Carbon case with LDES deployment
0 MMT; Low Solar	30/0 MMT Carbon case with 1-in-10 weather
0 MMT; No LDES	30/0 MMT Carbon case with no LDES deployment
0 MMT; Wind	30/0 MMT Carbon case with additional transmission and out-of-state resources

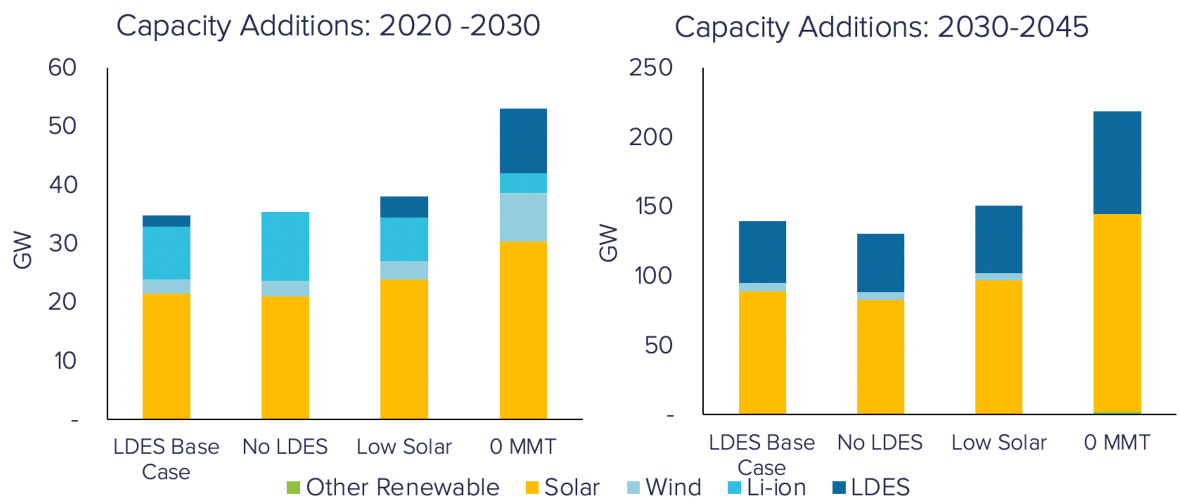
3.2.1 Capacity Additions

Across all sensitivities, modeling found that demanding grid conditions, such as reduced carbon constraints or reduced solar generation, increased overall resource deployment, including storage deployment. Figure 19 compares California resource additions in 2030 and 2045 across four cases that place increasing demand on the electric grid.

More specifically, Sensitivity Cases also demonstrate that LDES needs increase substantially, from 46 to 55 GW, when a more restrictive GHG target is adopted. Furthermore, given the dominance of solar generation in California's future grid, Sensitivity Cases show that planning on the expectation of periods of low solar irradiance would increase the LDES requirement from 46 GW in the Base Case to about 49 GW.

Notably, even in cases when California is not able to access and deploy long duration storage (the "No LDES" case), the State is deploying similar levels of overall storage capacity. In the "No LDES" case, even lithium-ion storage is deployed at durations of 7 to 8 hrs. The 0 MMT case presents the greatest challenges to the grid, evidenced by the addition of approximately 20-25% more capacity, mainly solar and storage. It should be noted that across all of these cases, the model accesses all available in-state wind capacity (approximately 30 GW of total capacity, or about 8 GW more than currently in operation today) while remaining renewable capacity is provided by solar.

Figure 19. Capacity Additions for Scenarios with Increasing Demand on Electric Grid

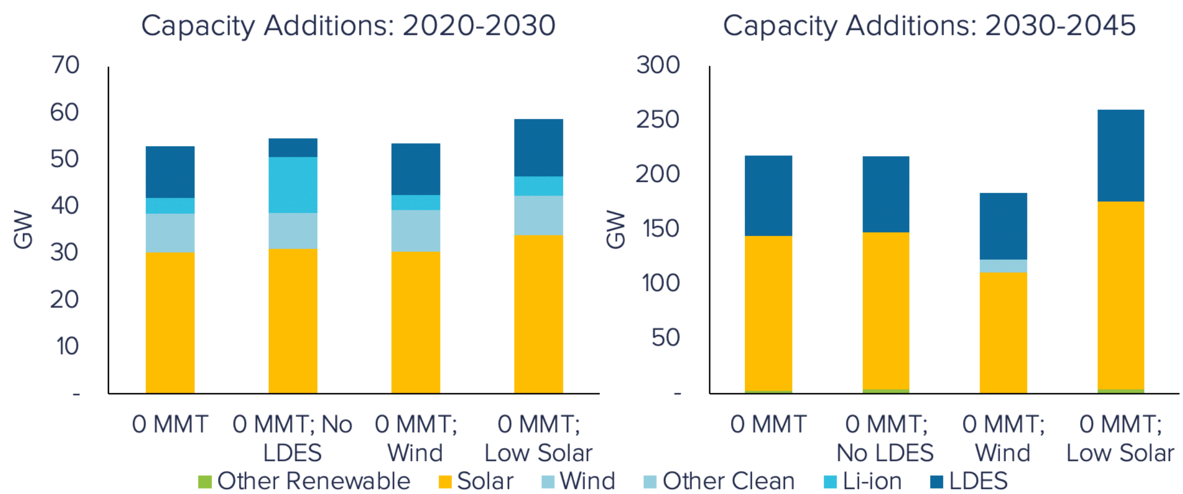


Source: Strategen

A second set of scenarios explored the different ways that California might achieve a 0 MMT electric sector, shown in Figure 20. Across the board, these cases saw accelerated deployment of long duration energy storage in 2030, paired with incremental deployments of lithium-ion storage in 2045. All cases shown in Figures 19 and 20 saw between 45 and 60 GW of cumulative long duration storage deployments by 2045. In addition, the 0 MMT cases also included the selection of 20-30 GW of lithium-ion storage. In all cases where the State achieves a zero-carbon electric sector, long duration storage plays a significant role in system balancing and in overall system resourcing.

Interestingly, in the case where none of the incremental long duration storage solutions were included as candidate resources ("No LDES"), the model deployed the maximum long duration storage available based on CPUC assumptions, in the form of pumped hydro. This result demonstrates the need for incremental energy storage capability that persists regardless of the candidate resources available. In the case where the model was allowed to access additional transmission zones to help meet California's renewable energy needs, results show a significant increase in overall wind capacity (approximately 42 GW, relative to the 30 GW cap on wind resource in California), which helped to produce a reduction in both solar and storage installed capacities. However, the introduction of additional wind capacity in no way obviated the need for storage – this case continued to find a need for around 70 GW of storage by 2045.

Figure 20. Capacity Additions for a Zero Emissions Electric Sector in CA



Source: Strategen

The case where the model was asked to meet a 0 MMT carbon target and was simultaneously presented with renewable generation reflective of a year with prolonged periods of low solar irradiance ("0 MMT; Low Solar") presented the greatest challenge for sufficient resourcing. This case saw a 20% increase in solar deployment and a 14% increase in storage deployment relative to the 0 MMT case with typical meteorological year ("TMY") weather.

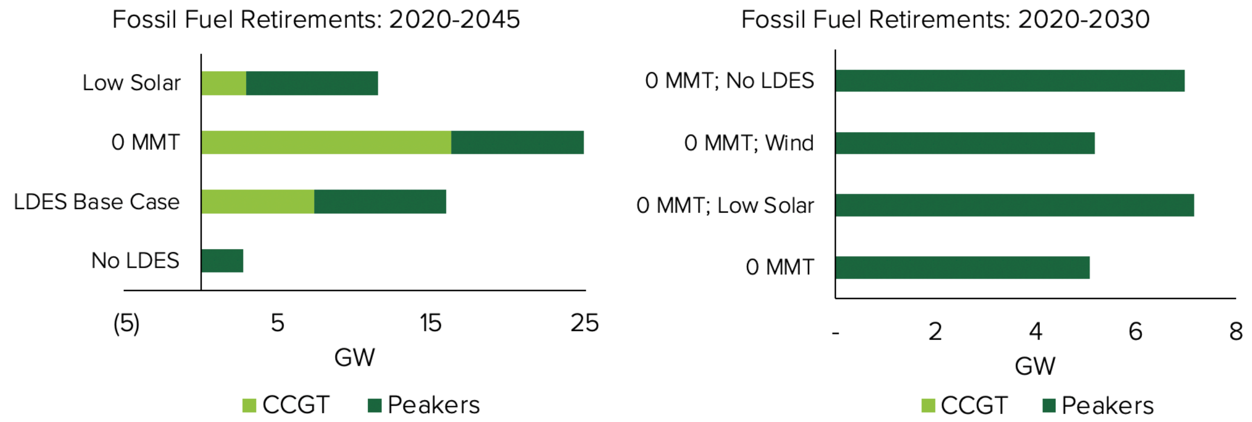
3.2.2 System Impacts

To track broader system impacts of these resource additions, this section compares total system costs, fossil fuel capacity retirements, and renewable curtailment across the sensitivities discussed above.

Fossil Fuel Retirements

Due to the strict 0 MMT carbon target by 2045, all zero carbon cases retire the full existing portfolio of 25 GW of fossil assets. Nonetheless, all of these cases have an in-line carbon cap of 30 MMT in 2030, which helps to accelerate retirement of fossil peaking assets by 2030, as shown in the below chart. The cases with a 46 MMT carbon cap in 2030 and a 12 MMT carbon cap in 2045 do not see any fossil retirements by 2030, but by 2045 the model starts to retire some portion of the CCGT and peaker fleet. Figure 21 shows how long duration storage helps to enable accelerated retirement of both of these asset classes relative to the case without long duration storage. As discussed in the previous section reviewing Base Case results, these findings are enabled in part by the increased capacity contributions from long duration storage.

Figure 21. LDES Enables Fossil Fuel Retirements

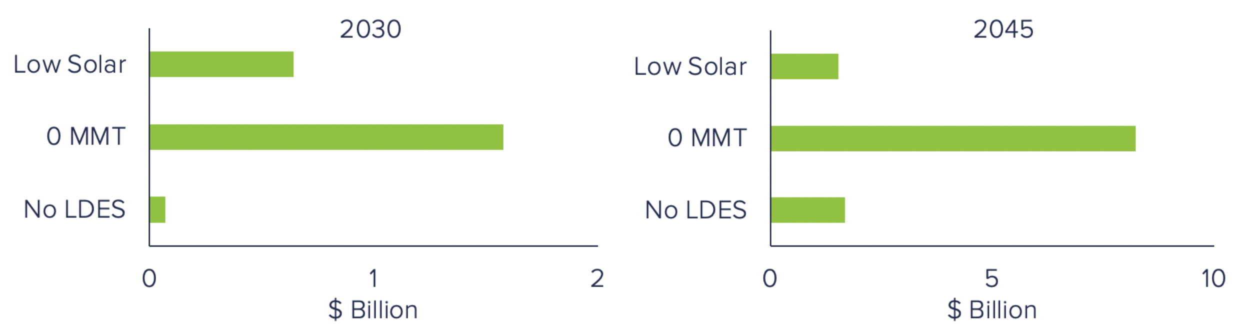


Source: Strategen

System Costs

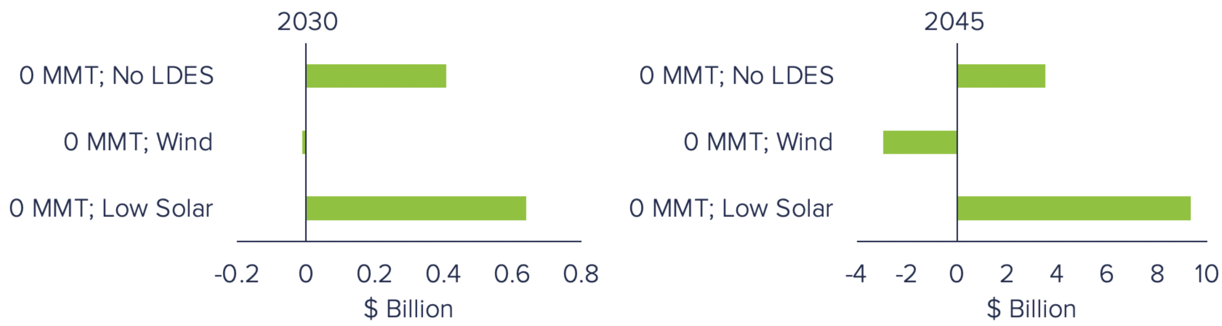
As discussed in the review of findings from the Base Case, the addition of long duration storage helps to reduce overall system costs by around $1.5 billion per year by 2045, primarily in the form of reduced system capacity costs. While modeling showed that more challenging grid conditions, such as tighter carbon targets or reduced solar generation, increased costs, it also showed that deployment of long duration storage was one of the most impactful solutions to help manage those costs. Especially if the State were to pursue tighter carbon targets, access to long duration storage solutions could save CAISO customers as much as $4 billion per year.

Figure 22. Annual System Cost Impacts for Scenarios with Increasing Demand on the Electric Grid



Source: Strategen

Figure 23. Annual System Cost Impacts for a Zero Emissions Electric Sector in CA



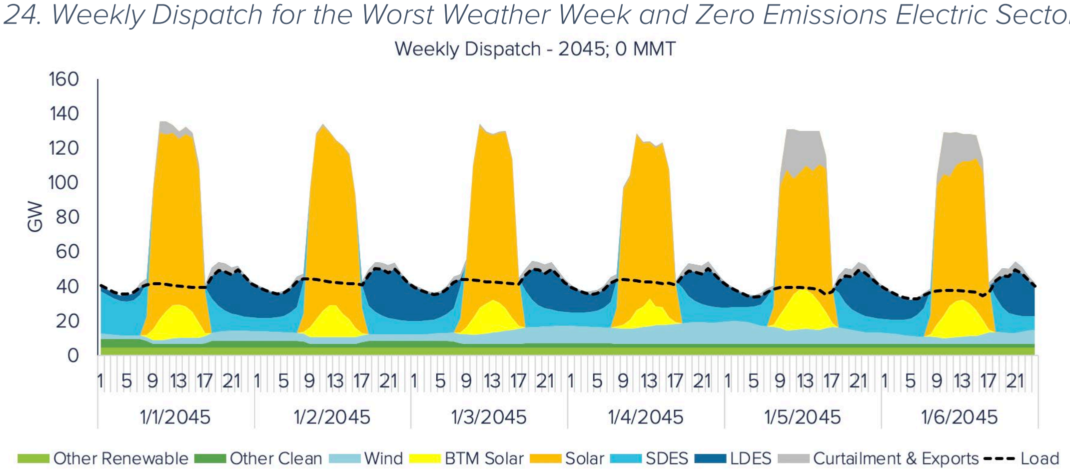
Source: Strategen

3.2.3 Weather Driven Variation

The Base Case results showed how reduced renewable resource availability in the winter months impacted solar generation, storage charging, and dispatch availability in the evening hours. This trend continues in the Sensitivity Cases and can be seen in its most extreme form in the cases focusing on low solar irradiance.

As California pushes to a strict 0 MMT carbon target, the grid is no longer able to rely on unspecified imports or fossil fueled generation to supplement renewables during days of low solar generation. Instead, storage is selected to fill those gaps. Figure 24 shows system dispatch during the week of lowest solar generation. Peak solar output is just under 140 GW, around 65% of total installed solar capacity of 175 GW. Shorter duration storage, which has higher round trip efficiency, charges and discharges at its maximum capacity every day. Long duration storage is called upon to flexibly dispatch and meet remaining demand. During the times when renewable generation is limited, recharging higher efficiency short-duration storage is a greater priority, and oftentimes long duration energy storage cannot fully recharge due to limited solar generation. During this time, long duration storage is forced to call on its larger "tank" of energy to ensure that grid supply can meet demand.

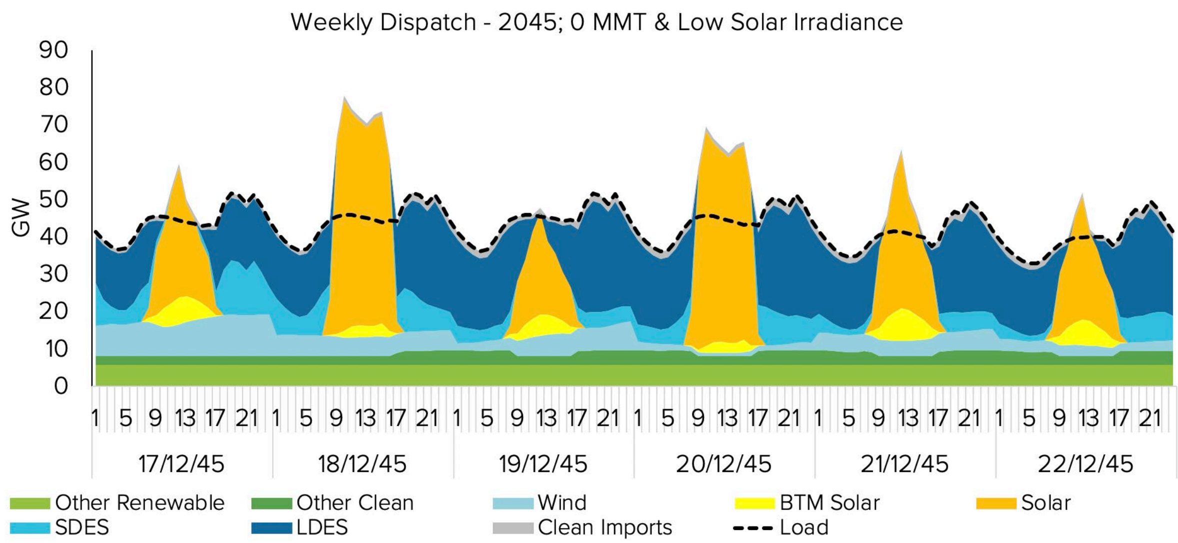
Figure 24. Weekly Dispatch for the Worst Weather Week and Zero Emissions Electric Sector, 2045



Source: Strategen

This phenomenon is more evident in the scenario exploring the impact of low solar irradiance combined with a strict 0 MMT carbon target. As a reminder, this case considers annual solar output that represents approximately a 1-in-10 low solar output year. This means that during the week of the year with lowest solar generation, max solar output is about 30% of total installed system capacity of 208 GW. As in the previous scenario, solar energy is used during the day to charge short-duration storage, but in this case solar output is so low that during many days, even short-duration storage is not able to fully recharge or may not be able to recharge at all. Long duration storage does not charge at all during this period, and instead must draw on stored reserves to help meet night and evening energy needs. Over the course of the week, shorter duration storage output declines, from 150 GWh of continuous output to 50 GWh. In its place, long duration energy storage ramps up output over the course of the week.

Figure 25. Weekly Dispatch for Low Solar Irradiance and Zero Emissions Electric Sector, 2045



Source: Strategen

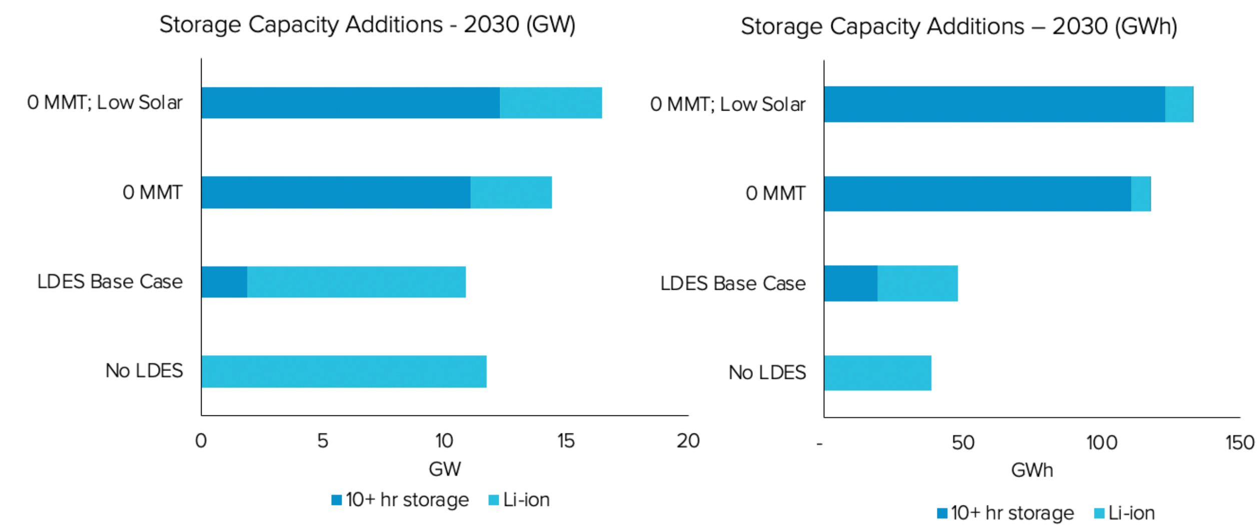
3.3 Storage Portfolio and Operational Performance

As storage grows to encompass a larger portion of the grid resources used to integrate renewables, it plays a wider array of roles to support system balancing and meeting peak demand. This section provides more detail on the specific make-up of the storage portfolio, and explores the different ways that storage is called upon to perform and dispatch in these new roles.

3.3.1 Storage Portfolio Composition

In 2030, most of the Sensitivity Cases find that lithium-ion storage continues to compose the majority of the installed capacity in the storage portfolio. Despite this fact, long duration storage could make up nearly half of the stored energy capability of the portfolio due to its longer storage duration and higher MWh storage energy capability. Long duration storage continues to take over a larger portion of the overall storage portfolio as carbon targets restrict use of fossil fuel resources and imports, pushing for a more significant deployment of long duration storage to hit a 30 MMT carbon target in 2030.

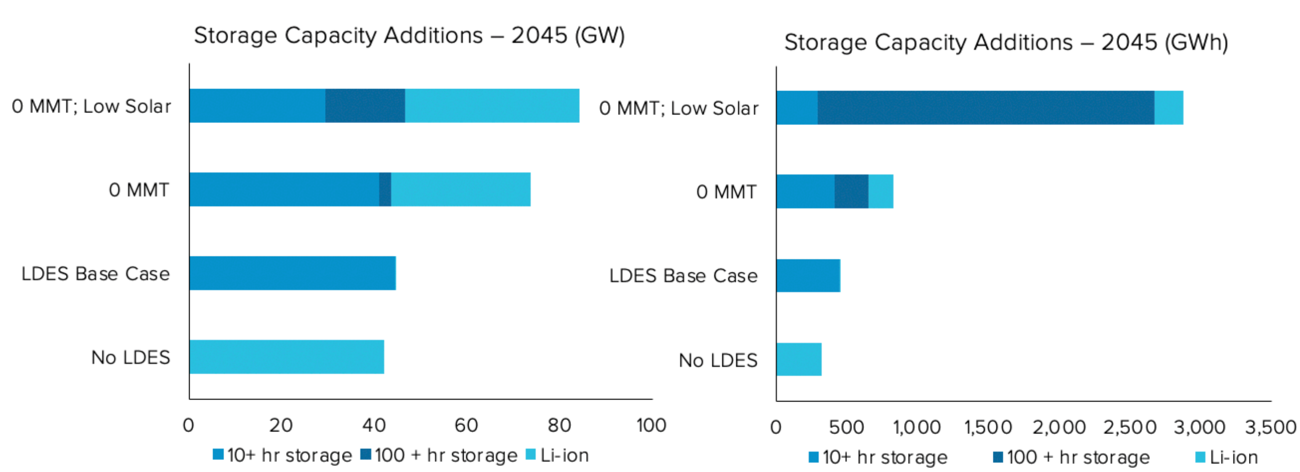
Figure 26. Storage Portfolio: 2030



Source: Strategen

When California is able to access long duration storage at scale, it composes the majority of the storage deployed on the grid between 2030 and 2045, with over 40 GW deployed across all policy-compliant cases. Notably, even when long duration storage solutions are not included as candidate resources, over 40 GW of storage is deployed across the State. However, it tends to be shorter duration resources, reducing the State's overall stored energy capability.

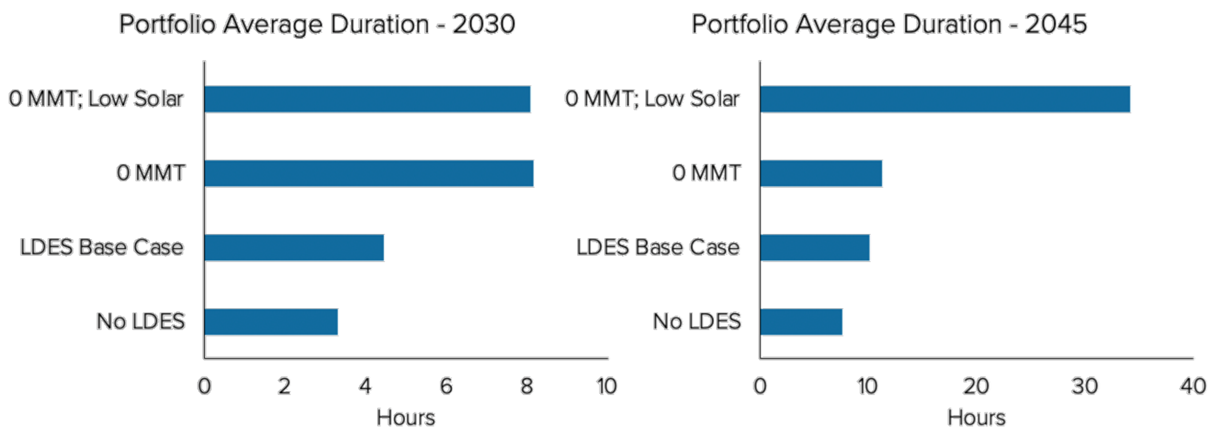
Figure 27. Storage Portfolio: 2045



Source: Strategen

This is most evident when considering the average storage portfolio duration. The sensitivity without access to long duration storage shows consistently lower portfolio duration in both 2030 and 2045.

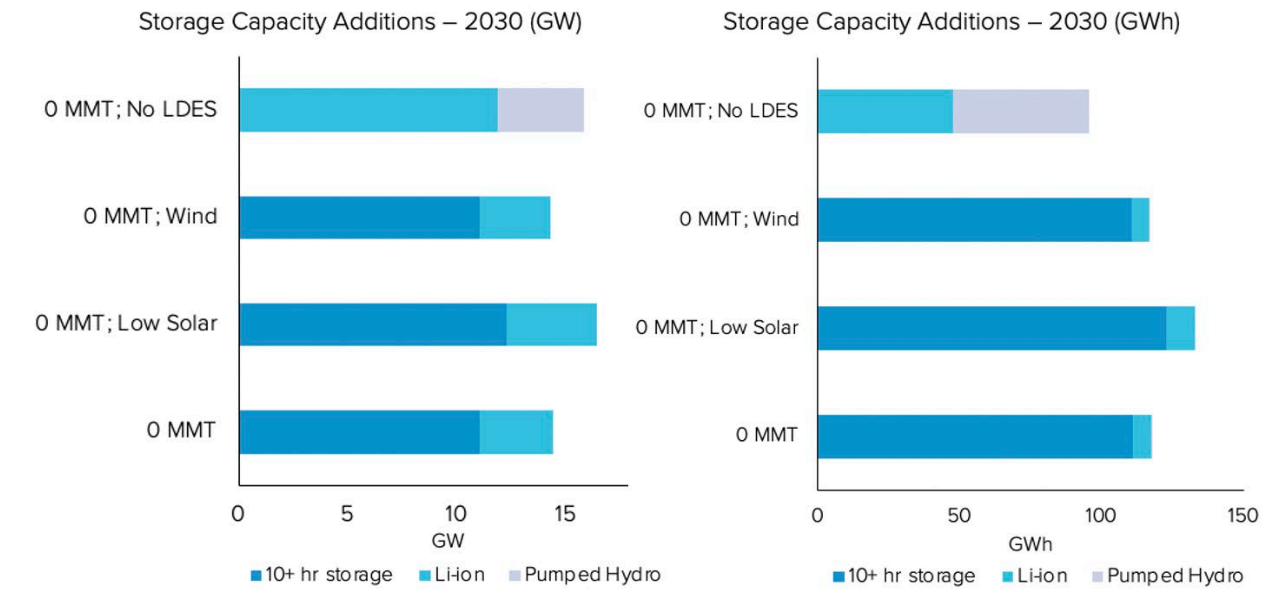
Figure 28. Storage Portfolio Average Duration in 2030 and 2045



Source: Strategen

Tighter carbon targets in 2030 push a higher percentage of the storage portfolio towards long duration storage. As a reminder, these cases also see a 50% or more increase in installed solar capacity, and many of these cases see accelerated retirement of fossil assets. In these cases, long duration storage supports both energy and capacity needs. It is also notable that even in the case where California is not able to access new long duration storage candidate resources, the model adds long duration storage in the form of new pumped hydro, which contributes around half of the overall stored energy capability by 2030.

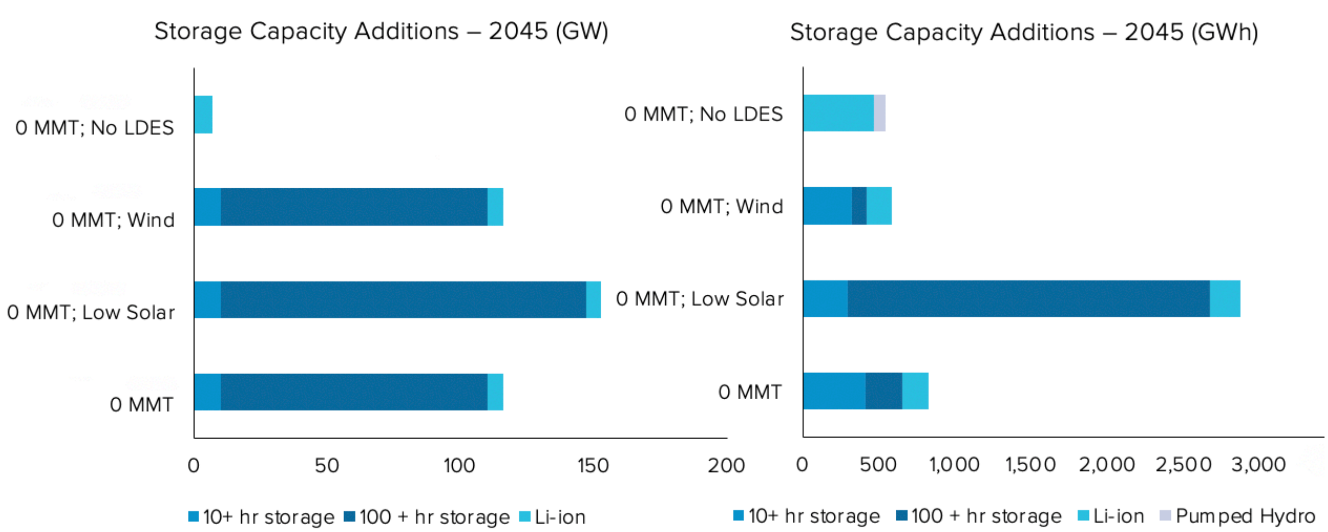
Figure 29. Storage Portfolio: 2030, 30 MMT



Source: Strategen

Although storage additions are relatively similar in 2030 across the cases with access to LDES, more significant divergence across cases is seen in the transition from 30 MMT in 2030 to 0 MMT in 2045. All cases with the option to add 100-hour duration storage do add some to the portfolio by 2045. The case with the greatest challenges for the grid – the 0 MMT case with low solar – adds a significant amount of 100-hr storage, such that it makes up around 80% of the overall stored energy capability on the grid.

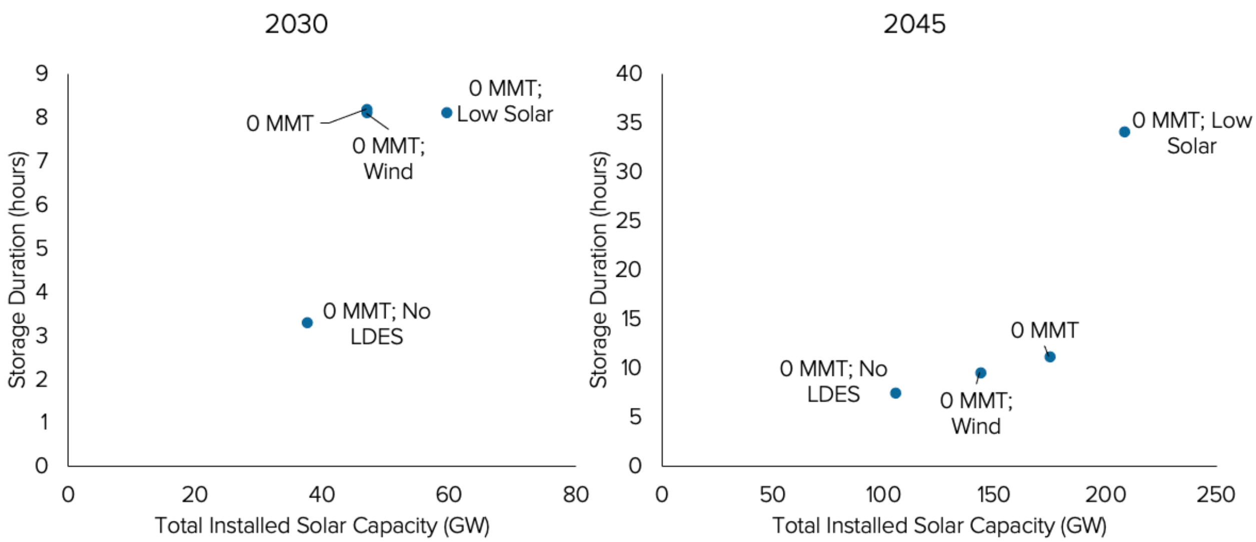
Figure 30. Storage Portfolio: 2045, 0 MMT



Source: Strategen

It is also notable that although the overall GW capacity of storage remains similar across all cases – around 70 GW – the stored energy capability varies significantly, and correlates strongly with the level of renewable variation that storage is asked to integrate, as shown in Figure 31.

Figure 31. Correlation Between Stored Energy Capability and Installed Storage



Source: Strategen

3.3.2 Storage Portfolio Performance

As the grid transitions away from fossil fueled resources, storage is asked to step into the roles that fossil fueled resources fill today. Historically, the fleet of fossil fueled resources was composed of different types of fossil assets that can be called upon for different grid needs – less flexible but more efficient steam turbines to provide much of the baseload energy; combined cycle resources to provide flexible and dynamic power for longer dispatch; and simple cycle peakers help to meet peak need and other shorter duration grid balancing services. Similar to today's fossil fleet, which is composed of a diversity of resources, a robust portfolio of storage must also have different resources that can be dispatched to meet different grid needs and conditions.

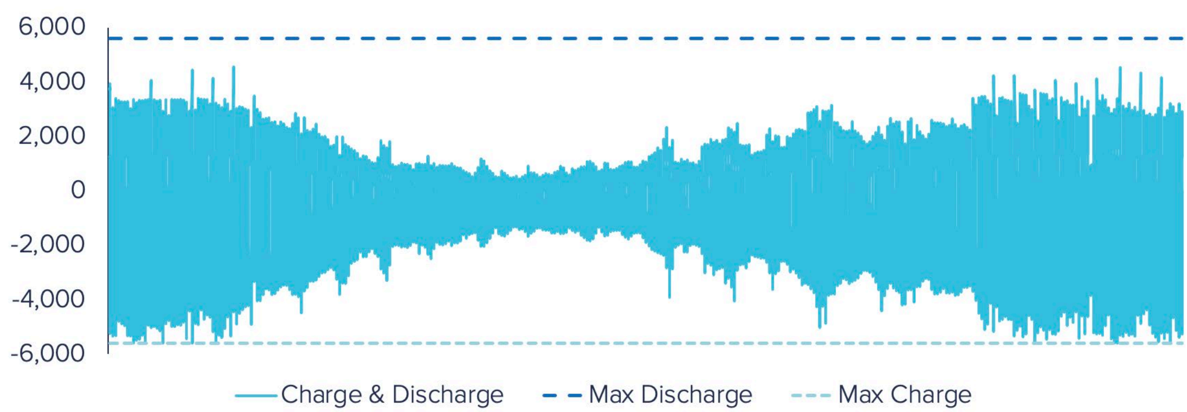
From 2020 through 2030, storage is deployed to provide additional system capacity and meet reliability needs as well as to help manage system carbon emissions. However, from 2030 through 2045, storage deployment is primarily driven by a need to reduce fossil fueled power generation in support of attaining of carbon goals, rather than by the need for additional system capacity. In all cases, the State has significant demand for MWh of storage capability to facilitate energy shifting, which was a key driver of storage deployment. This deployment of long duration energy storage enabled accelerated retirement of fossil fuel generators and created opportunity for LDES to provide grid balancing and flexibility services that have historically fallen to fossil fueled resources. Despite this growing need for long duration applications, all storage resources continue to be needed by the grid, including for shorter duration applications, and are dispatched to help support reliable service.

Lithium-Ion Storage

Of all of the storage resources modeled in this analysis, lithium-ion has the highest round-trip efficiency (85%), one of the most flexible deployment models (1-hour minimum duration), and relatively low cost for the addition of new capacity. With these characteristics in mind, we see lithium-ion deployed to 3 specific use cases.

First, lithium-ion is deployed before 2030 as a short duration (2-3 hours) storage asset to help meet system capacity and PRM needs. Second, in the cases with higher solar deployment, lithium-ion is deployed after 2030 as a longer-duration asset (5-7 hours) that can absorb peak solar generation during the midday hours. In this second case, lithium-ion installation sizes are determined primarily by charging needs, as opposed to discharging needs. This is clearly seen in the below graph, Figure 32, which shows annual charging and discharging activity for lithium-ion batteries. As shown below, lithium-ion batteries more frequently max out their charging capability – which is heavily dictated by timing of solar generation – than their discharge capability – which is generally dictated by load demands.

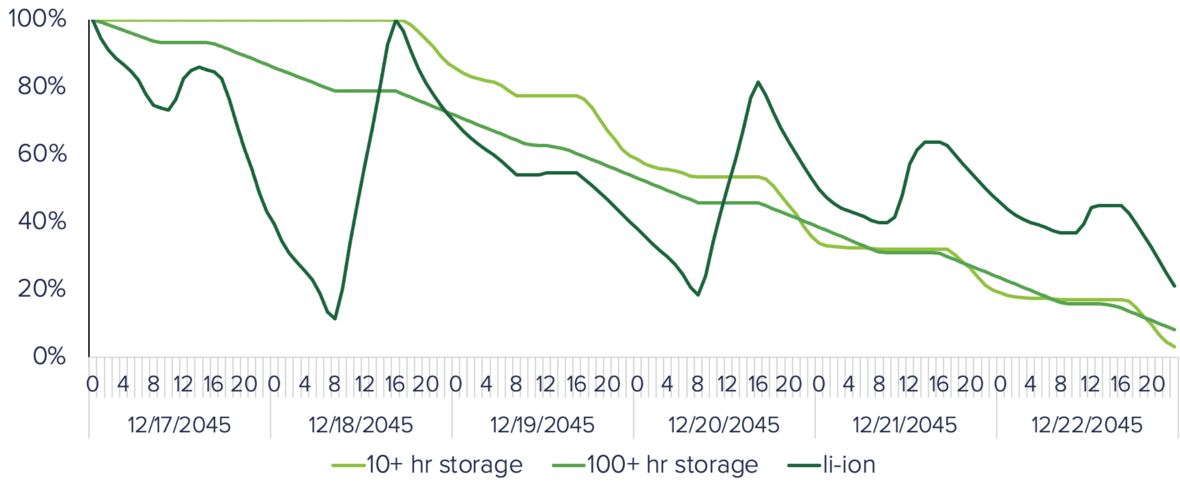
Figure 32: Li-Ion Annual Charge & Discharge Activity



Source: Strategen

Finally, lithium-ion is called upon during instances of reduced solar generation to maximize the energy capture and use from limited mid-day solar resources. When solar generation is limited due to low solar irradiance, lithium-ion's high round trip efficiency enables optimal usage of the energy that is generated, and lithium-ion is first in line to charge during these periods. The below chart shows charging activity for all lithium-ion, 10-hr, and 100-hr storage during a week of low solar generation in the 0 MMT Low Solar case. Notably, lithium-ion in the only storage that is charged at all during this period, while the other two types of storage are merely on managed discharge over the duration of the week.

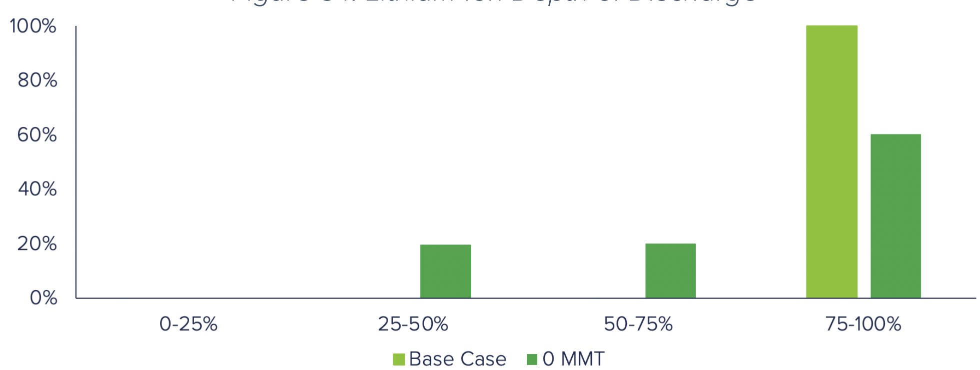
Figure 33: Storage State of Charge During Worst Weather Week



Source: Strategen

An important caveat to note on these analyses is that the model does not directly take lithium-ion battery degradation into account in terms of operational performance. As discussed in the methodology, lithium-ion degradation is included in both O&M and installed capacity costs, but is not assumed to impact the ability of lithium-ion assets to fully charge and discharge. Lithium-ion batteries are known to degrade under maximal cycling operations[55], and many of the use cases described above do call for lithium-ion to charge and discharge at or near its maximum capacity. The below chart shows the daily depth discharge of lithium-ion storage in both the LDES and 0 MMT base case. In both cases, lithium-ion batteries are asked to provide full or near full discharge cycle for most days of the year. It should also be noted that lithium-ion batteries in the 0 MMT case have an overall deployment duration of just under 6 hours, versus around 3.5-hour duration in the base case.

Figure 34: Lithium-Ion Depth of Discharge



Source: Strategen

[55] Yuliya Preger et. al., Journal of the Electrochemical Society, 2020. "Degradation of Commercial Lithium-Ion Cells as a Function of Chemistry and Cycling Conditions," https://iopscience.iop.org/article/10.1149/1945-7111/abae37

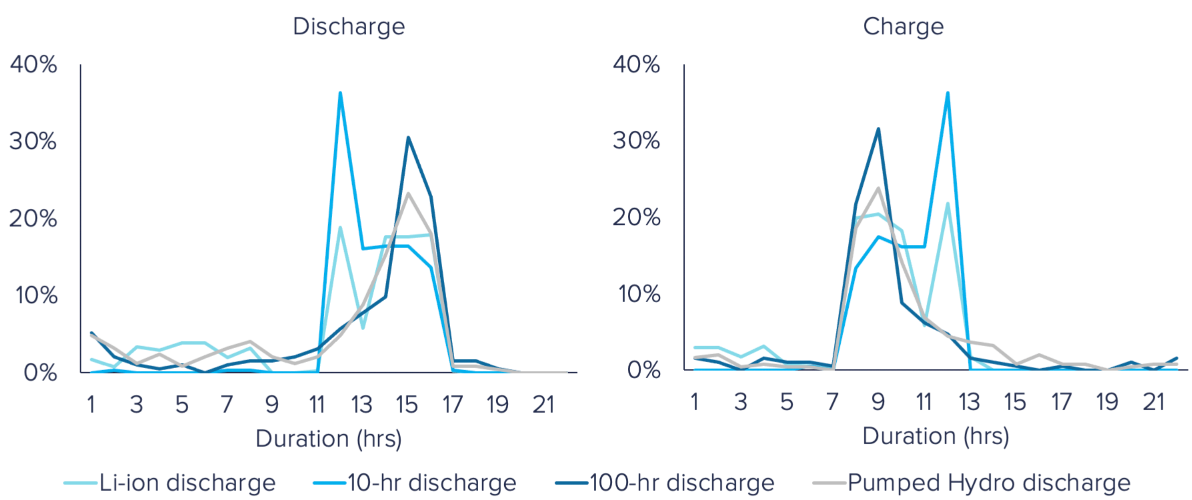
As stated in the methodology section, it was not the intent of this study to re-litigate the assumptions established by the CPUC for candidate resources used for the IRP analysis. With this being said, it is clear that lithium-ion performance under the circumstances and use cases defined above will have significant impacts on the overall storage needs in California.

10-hour storage

The diurnal cycling of storage is the largest application of storage from 2030 through 2045 and is primarily met by 10-hour storage. This storage is assumed to have mid-level cycling efficiency (72%) and relatively low costs for additional storage energy capability. This asset is the preferred resource for managing diurnal shifting of solar for three reasons.

First, the cost structures assumed for this storage solution mean that a 10-hr storage asset costs about 50% what it would cost for equivalent duration from lithium-ion batteries, giving 10-hr storage a significant advantage in terms of installed capacity costs. Second, as California pushes towards higher renewable and clean energy targets, it begins to see a significant growth of excess renewable energy, which may either be absorbed by storage, exported, or curtailed. The increase in zero-marginal cost energy and the increase in excess energy mean that the lower round trip efficiency of 10-hour storage is less of an overall cost to the grid. Finally, the duration is a good match for the durations needed for system-wide diurnal cycling needs. The below dispatch chart shows how daily charge and discharge cycles follow the overall duration of solar generation – with an 8-hour charge cycle aligning to winter solar generation and a 12-hour charge cycle aligning to summer solar generation. The discharge range of 12 to 16 represents the other half of the 24-hour cycle.

Figure 35. Daily Charge and Discharge: 2045, 0 MMT



Source: Strategen

This storage resource becomes the workhorse of California's grid, composing a significant percentage of overall storage deployment in all cases. It is important to note that this resource is deployed by the model in 10-hour durations in all cases, despite a resource modeling structure that allow for modular additions of longer storage capability.[56] That is, the model has the option to deploy this solution with durations longer than a 10 hours but chooses only to deploy it as a 10 hour asset. This indicates that (1) the model definitively would not prefer this asset at longer durations, given the efficiency and price points modeled and that (2) it is possible that the model might have selected lower durations, if it were an option.

As discussed in the introduction, there are a wealth of storage solutions that can meet duration deployments in this range, and additional modeling would be needed to draw any more specific inferences on storage duration. It should also be noted (and will be discussed further) that the model selects an overall storage portfolio composition that will complement itself, and so the make-up of the remainder of the storage portfolio may have significant impact on the specific design selections for the storage that is asked to fill this specific use case. Regardless of these caveats, modeling shows unequivocal need for around 40 GW of storage that can support 8 to 12-hour diurnal cycling.

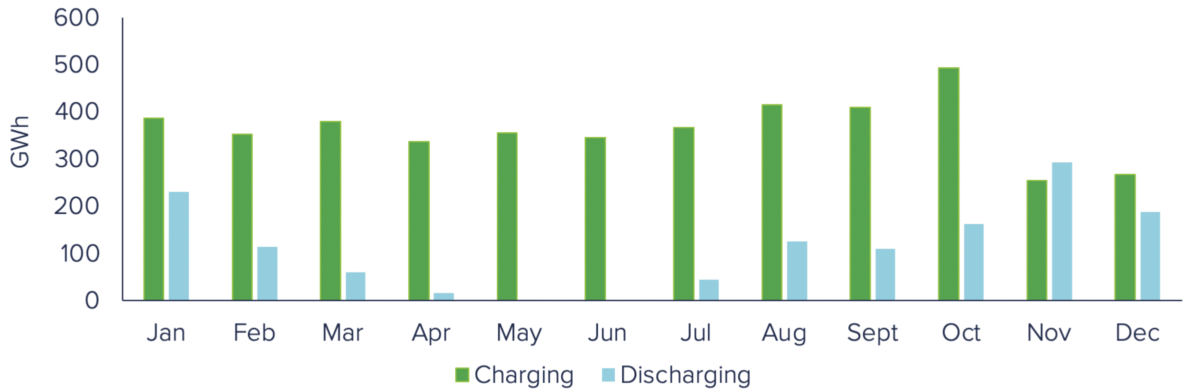
100-hour storage

Storage with 100-hour minimum duration provides capabilities for seasonal shifting of energy in a fashion that cannot be replaced by either lithium-ion or 10-hour storage. It is not selected in the cases with a 12 MMT carbon target, but shows up in every case with a 0 MMT carbon target, implying that access to resources with these types of capabilities will be critical for jurisdictions looking to achieve a true zero-carbon electric sector.

As a reminder, in the 12 MMT case, California is still able to access imports and fossil fueled resources to meet energy demand during the days with lowest renewable energy generation. In the 0 MMT cases, the grid is not able to call upon carbonaceous energy in this fashion, and 100-hour storage is called upon in its place. Broadly speaking, 100-hour duration storage charges methodically throughout the year from excess renewable energy, and then discharges in spurts during times of low solar generation. The below two charts show the charge and discharge behavior of 100-hour storage across an annual time horizon, and then during multiple days of low solar generation. As might be expected, these days of low solar occur most frequently during the fall and winter months, although as shown in the monthly chart, 100-hour storage is still called on during months of highest solar generation, including April and July.

[56] Reference Methodology section 2.4 discussing storage modeling methodology

Figure 36. Monthly Dispatch – 100+ Hour Storage

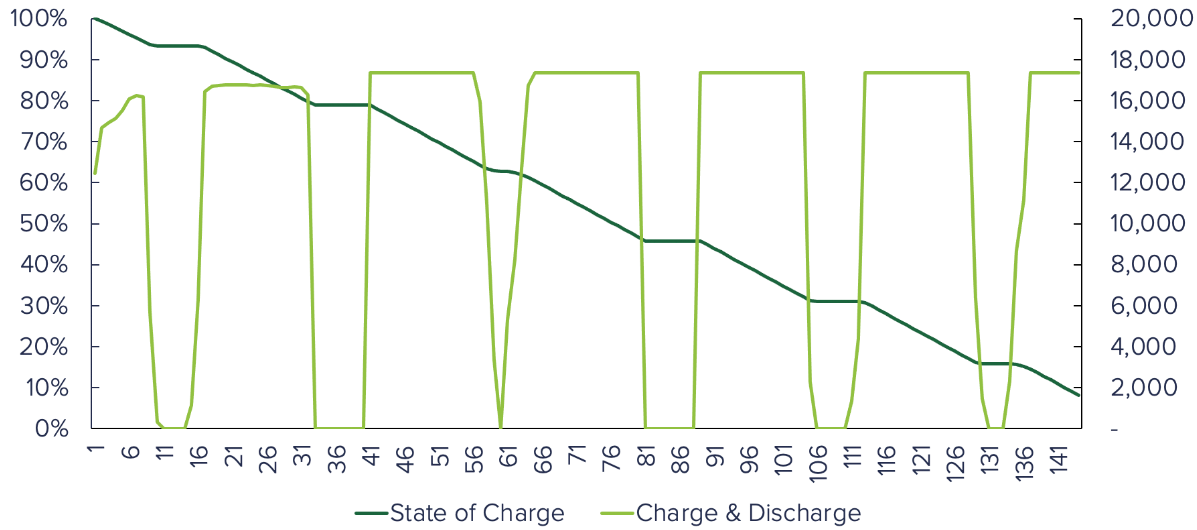


Source: Strategen

An important caveat on the circumstances under which 100-hour storage is deployed: although the model selects no 100-hour storage in the 12 MMT case, and does select it in the 0 MMT case, it is unclear where along the carbon reduction curve the model would select 100-hour storage. For example, 100-hour storage might be selected for an 11 MMT case, or it might not be selected until a 5 MMT case. Presumably, once 100-hour storage had been selected, it would also be included for all stricter carbon targets (*i.e.*, selection of 100-hr storage for an 11 MMT case would imply its selection for a 10 MMT case, a 9 MMT case and so on).

It is also important to note that although carbon targets and the way that they reduce access to imports and fossil generation appear to be a primary driver for adoption of 100-hour storage, other constraining grid conditions drive the level of deployment. For example, deployment levels for 100-hour storage decrease when access to new out-of-state renewable resources is introduced and increases significantly when solar irradiance and generation are reduced. In the case where California must meet a 0 MMT target amidst reduced solar generation, deployment of 100-hr storage capacity increases by 7x, relative to resource needs for a typical meteorological weather year. In this case, 100-hour storage is deployed at longer durations (approximately 135 hrs in duration), indicating that the system has a need for even longer duration storage than 100-hours and that this is the preferred asset to provide that duration.

Figure 37: 100+ Hour storage – Low Solar Days



Source: Strategen

As shown in Figure 37, 100-hour storage goes from 100% state of charge to close to 0% over the course of 6 days of low solar production. During these days, 100-hour storage dispatches reliably at its highest rated capacity output of just over 17 GW, and uses close to the full stored energy capability.

3.4 Sensitivity Cases: Storage Portfolio Evaluation

As demonstrated in the review of long duration storage cost assumptions, there is significant variation in perspectives on the current state of long duration storage solutions, as well as how storage solutions will evolve over the next decade. The sensitivities discussed in this section are intended to explore how different evolutions of storage solutions might impact optimal storage deployment in California. These sensitivities incorporate different storage resources, or different performance and price points for storage resources. The first subsection focuses on different assumptions for lithium-ion storage, while the second subsection focuses on different assumptions for the portfolio of long duration candidate resources.

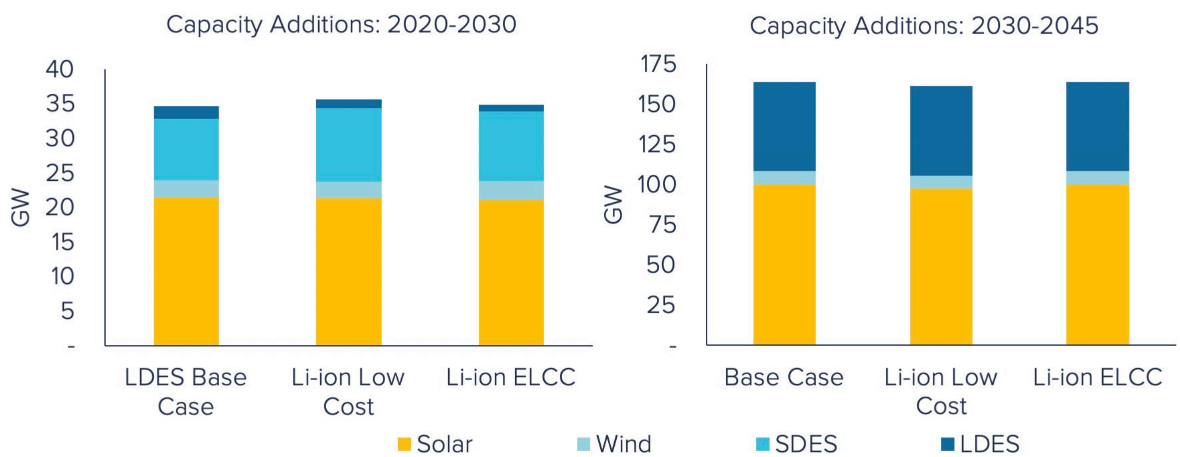
It should be noted that the optimal deployment levels selected by the model are dependent on the specific cost and performance assumptions of the different resources, as well as their relative difference to one another. The variations seen in the following sensitivities reinforce the extent to which the specific numerical results are dependent on the specific numerical assumptions used for modeling. However, the durability of high-level results also demonstrates that the underlying grid needs identified here persist despite different economic trade-offs offered to the model. That is to say, the need for assets with daily cycling capability, the need for 100+ hour storage in zero carbon cases, and so on must be met; cost and performance trade-offs will merely dictate which type of storage might be most cost effective to meet those needs.

3.4.1 Lithium-ion Cost and Policy Sensitivity

The two scenarios focused on lithium-ion storage solutions were intended to explore how improved cost or performance forecasts for lithium-ion storage might impact the role of other storage solutions in meeting grid needs.

Both of these cases demonstrate increased deployment of lithium-ion storage relative to the Base Case, but do not materially diminish the need or opportunity for long duration storage, especially in the second half of the study period. Notably, reduced costs for lithium-ion have a greater impact on lithium-ion storage deployment from 2030 – 2045, while lithium-ion capacity value has a more significant impact during early years. This is consistent with findings from the Base Case, which show that both capacity and carbon targets are drivers of resource deployment from 2020 through 2030, but from 2030 onwards, carbon targets are the largest driver of resource development. It is also notable that the overall level of storage deployment across these cases is similar, indicating that these changes do not materially impact the overall system-level need for storage, but only changes the "optimal" level of deployment based on installed cost trade-offs.

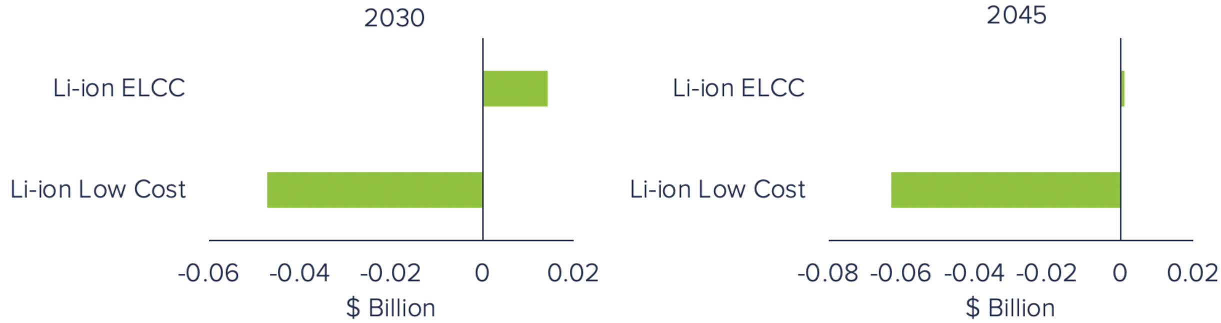
Figure 38. Lithium-ion Value Sensitivities



Source: Strategen

The increased benefits attributed to lithium-ion storage in these cases have relatively minimal impacts on overall system costs and are less than the system cost impacts of not deploying long duration storage.

Figure 39. Annual System Cost Impacts Lithium-ion Value Sensitivities



Source: Strategen

3.4.2 Long Duration Storage Evolution

In addition to the sensitivities focused on lithium-ion storage, four sensitivities were run to evaluate opportunities for different long duration storage candidate resources. The first of those sensitivities was focused on a storage candidate resource with a minimum duration of 5 hours; the second set of sensitives was focused on an alternate 100+ hour duration storage with different cost and performance trade-offs. Both of these candidate resources had lower round trip efficiency than other candidate resources, but were successfully selected in one or more Sensitivity Cases, indicating that high round trip efficiency is not strictly necessary for storage to provide unique value to the grid and to be most efficient at meeting specific grid use cases.

5-hour storage

As a reminder, the existing set of candidate resources used for the Base Cases described above had minimum durations of 1, 10, 12, and 100 hours. This resource was intended to provide a viable alternate option for a storage deployments between 5-10 hours of duration that might not have been captured by the portfolio of candidate resources offered in the Base Case. The Sensitivity Case used to evaluate the opportunity for this 5-hour storage resource is identical to the 12 MMT base case with the exception of the introduction of this resource, and so can be used to understand the incremental changes that are caused from its introduction.

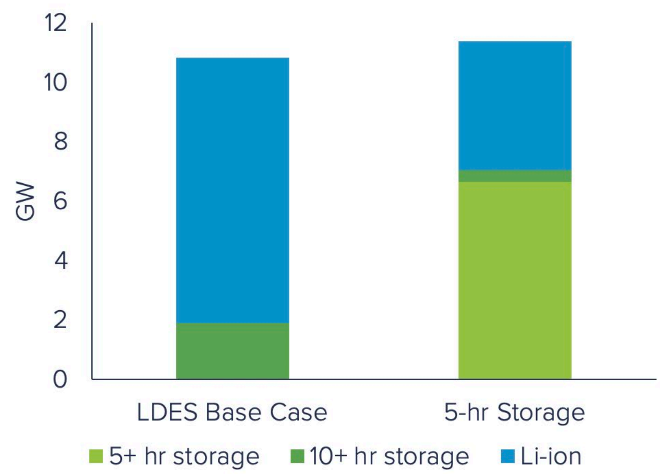
The 5-hour storage candidate resource modeled in this case has a couple of notable characteristics that define its role in the overall storage portfolio. First, it has relatively low installation costs compared to other long duration storage candidate solutions that were introduced to this study, especially at lower durations. The below table shows how the installed costs of this asset compare to lithium-ion and the 10-hour storage solution at different durations. Second, it has relatively low round-trip efficiency relative to both lithium-ion and 10-hour storage and so would be less effective for energy capture and usage during times of limited solar output. Finally, given lower deployment duration of this asset, 5-hr storage was modeled subject to the same capacity contribution de-rates as lithium-ion.

Table 6. Installed Cost Comparison

	Cost for 5-hr storage	Cost for 10-hr storage
	$/kw-yr.	$/kw-yr.
Lithium Ion	$121.96	$233.16
5+ hr. storage	$79.74	$116.44
10+ hr. storage	$92.59	$120.46

The addition of 5-hour storage causes shifting across the portfolio, decreasing deployment of both lithium-ion and 10-hour storage across both study timeframes, though most significantly impacts deployment levels in the 2020 to 2030 timeframe.

Figure 40: Storage Portfolio Changes from 5-hr Storage



Source: Strategen

The introduction of 5-hour storage produces a couple of interesting changes in the 2030 storage portfolio. First, it causes small reductions in the overall duration and stored energy capability of the storage portfolio but increases installed capacity. More specifically, there is a 7% decrease in stored energy capability (GWh) and a 5% increase in installed capacity. The implication here is that the specific storage duration configurations that were selected for 2030 in the LDES Base Case may not be an artifact of actual grid need for storage capability, but could instead be the byproduct of the minimum deployment duration of the 10-hour storage resources. Thus, the introduction of a 5-hr duration storage asset allows for a more custom fit of the storage portfolio duration; but does not represent a significant change from the overall stored energy or capacity selected by the model.

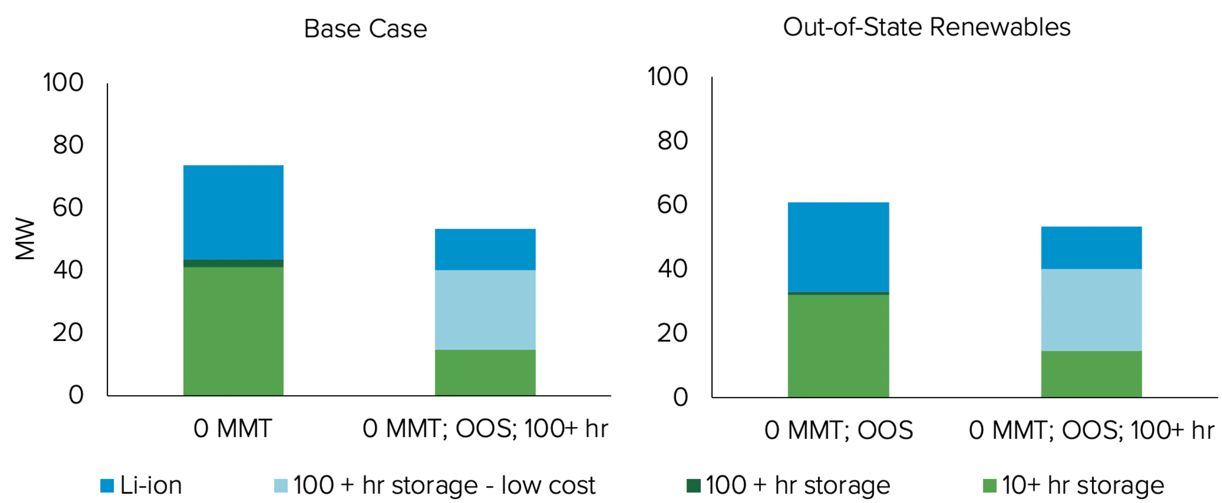
Second, it reduced both the overall quantity and the duration of lithium-ion selected for the portfolio, causing a nearly 50% reduction in installed capacity and a 75% reduction in stored energy capability. Finally, it also causes an 80% reduction in the capacity and stored energy capability from 10-hour storage. This implies that a resource with comparable installed costs may be able to meet some of the lithium-ion use cases in 2030; it further implies round trip efficiency may not be a barrier to storage deployment, even as early as 2030. It should be noted that renewable deployments for both wind and solar increase by about 33% and 11% respectively to compensate for the reduced roundtrip efficiency.

Low Cost 100-hour storage

The other three Sensitivity Cases were focused on the addition of an alternate storage candidate resource with a minimum duration of 100 hours, but with different cost and performance configurations. More specifically, this 100-hour resource had much lower installed cost, but also lower round trip efficiency. The intention of this case was to understand how different price points and design trade-offs might impact optimal resource deployment levels. This candidate resource was included in three different sensitivities described above – the LDES Base Case with a 12 MMT carbon target, and two of the different 0 MMT cases. Consistent with the other Sensitivity Cases, neither of the 100-hour storage candidate resources were selected in the 12 MMT carbon case and will not be discussed further in this section. Also consistent with the other Sensitivity Cases, neither of the 100-hour storage candidate resources were selected until after 2030.

These Sensitivity Cases were based off of the 0 MMT base case and the 0 MMT case with access to OOS resources. In both of these sensitivities, the low cost 100-hour storage was deployed at a much higher rate than the 100-hour storage used for the original cases. For example, between the two 0 MMT base cases, low-cost 100-hr storage was deployed at close to 10 times the rate of high-cost 100-hr storage; in the 0 MMT OOS case, low-cost 100-hr storage was deployed at 25 times the rate of high-cost 100-hr storage.

Figure 41: Storage Portfolio Changes from Low Cost 100-hr storage



Source: Strategen

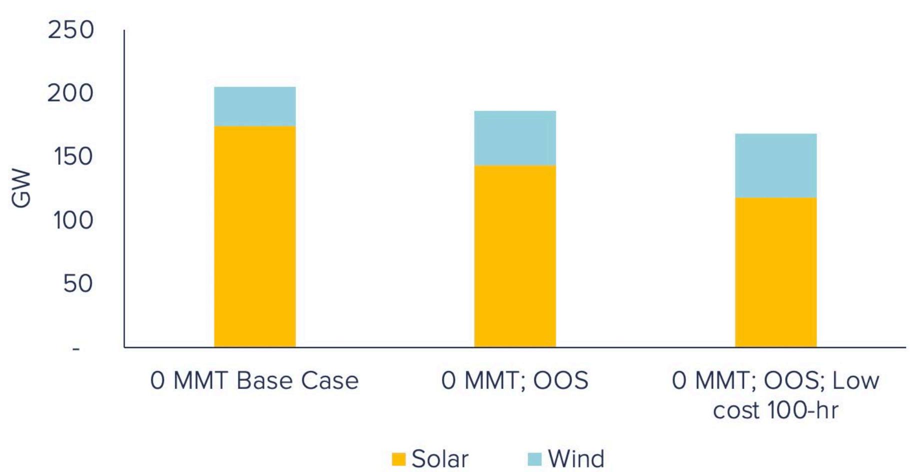
This is an unequivocal indicator that the installed cost, not the efficiency, is the biggest hurdle to deployment of 100-hour storage. If 100-hour storage is able to achieve the price points identified in this report by 2030, it could represent a significant portion of both the capacity and storage energy capability on the grid by 2045.

As might be expected, for the 0 MMT cases, the increased capacity and stored energy from the low-cost 100-hr storage resource displace a significant amount of 10-hour storage, reducing installed capacity by around 57% in the 0 MMT sensitivity. However, in this sensitivity there is almost no impact on deployment of lithium-ion storage, which increases both capacity and stored energy by around 8-9%. Another point of note is that there is almost no impact on the total installed capacity of the storage portfolio, although the overall stored energy capability and average storage portfolio duration increase significantly, caused by the greater storage energy capability and storage duration of the low-cost 100-hr storage resource.

The 0 MMT OOS sensitivities shows some similar impacts to the storage portfolio, with a 54% reduction in 10-hour storage. However, this case differs from the 0 MMT OOS case in that it also sees a 52% reduction in lithium-ion storage, both capacity and stored energy, and an associated reduction in total installed storage capacity. As discussed in the previous section, much of the lithium-ion capacity additions in 2030-2045 were driven by need to absorb peak solar output, which is significantly reduced in the 0 MMT OOS sensitivity due to a decline in installed solar capacity.

As a reminder, the 0 MMT OOS sensitivity has a 12 GW (39%) increase in wind capacity and a 31 GW (18%) reduction in solar capacity relative to the 0 MMT, enabled by out of state renewables. This trend continues in the 0 MMT OOS sensitivity with low-cost 100-hr storage, which has an 17% increase in wind and 18% decrease in solar relative to the case with high-cost 100-hr storage, and an 63% increase and 32% decrease relative to the 0 MMT base case.

Figure 42: Renewable Capacity Comparison



Source: Strategen

The indication from this case is that 100-hour storage pairs very well with wind resources, which tend to have more seasonal variability than solar. In fact, in this particular case, 100-hour storage pairs so well with wind that access to low cost 100-hour storage singlehandedly drove increased adoption of wind resources.

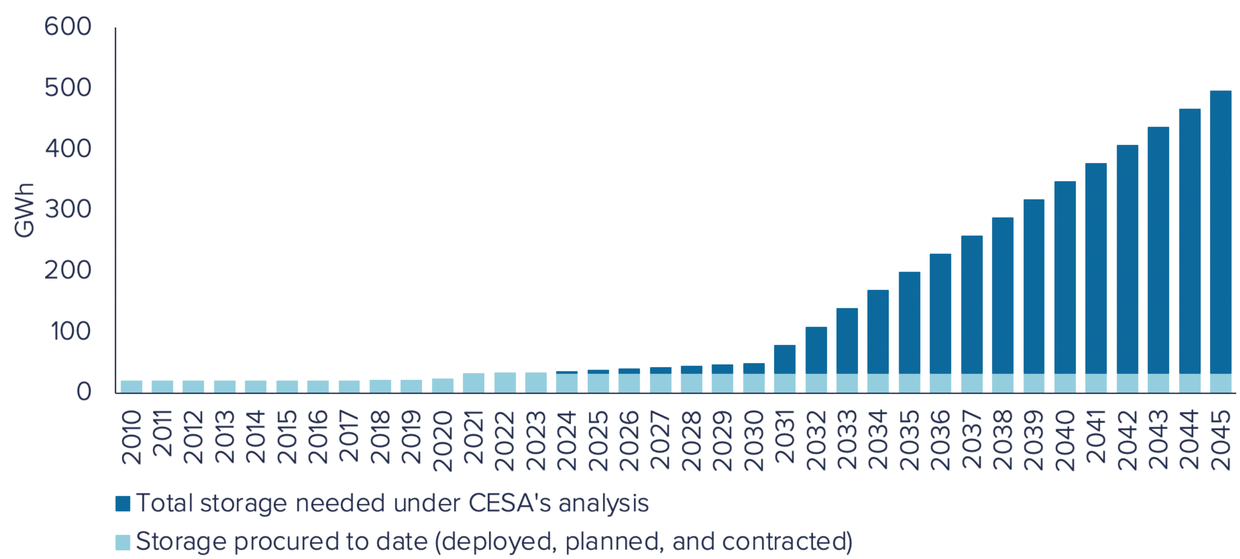
4. Policy Recommendations

The intent of this section is to outline the key learnings from this study that are relevant to inform policy development, and to identify a set of policy actions that should be taken to remove existing barriers to long duration storage deployment.

4.1 Key Findings for Policy Action

The previous section identifies two storage deployment findings that are key to informed policymaking. First, a very rapid acceleration of storage deployment will be needed after 2030, which implies that appropriately scaled procurement activities must occur between 2021-2025 to enable a scaled, competitive market of long duration storage projects available to deliver 3 GW of new projects per year no later than 2030. Figure 43 below shows an estimation of storage deployment over the next two and half decades compared to existing and contracted storage. This forecast of storage additions is based on linear allocation of storage across each study period, necessitating contracting and procurement well in advance. From 2030 onwards, California would need to bring online nearly 3 GW of storage, every year. This represents annual storage additions nearly *twice* what the CPUC has approved *in total over the past decade*.

Figure 43. Energy Storage Deployment Needs (GWh)



Source: Strategen

Second, by 2045, grid needs are heavily defined by stored energy capability, *a.k.a.* storage 'duration'. While the peak storage output (in MW) remains relevant to meeting daily energy, reliable electric service in California will be most substantially driven by the amount of stored energy that the State is able to access during times of greatest grid stress.

Combined, these two findings represent a need to evolve both the procurement and compensation structures that the State uses to ensure sufficient resource deployment. By adopting an informed and forward-looking policymaking approach, the State can minimize customer costs, maximize grid performance, and adopt a least-regrets approach to the State's clean energy transition.

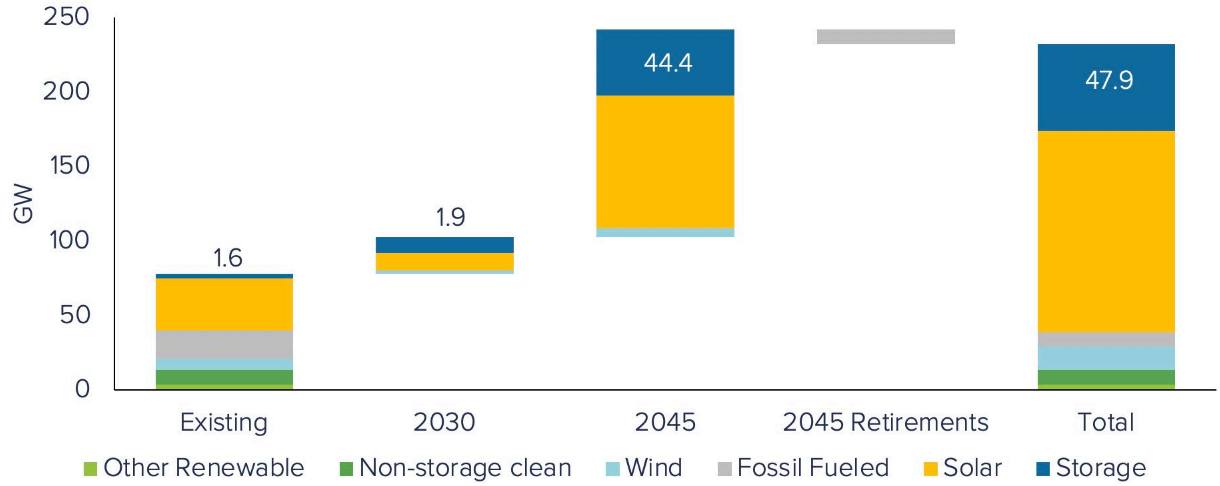
In sum, this report's results highlight two needs for policy action. First, there is a need for increased planning and coordination on the procurement of storage resources given the results of this and other similar studies. Second, it is necessary to reevaluate the current market incentives and program rules to ensure there is regulatory certainty on revenue streams to enable investment in appropriately designed energy storage resources. Fortunately, California has established processes and rules that allow it to enact these changes in an effective manner. In the following section, the report focuses on the policy changes that are essential for this transformation, as well as the guiding principles behind the actionable policy recommendations.

4.1.1 Storage Deployment Pace

As noted in previous sections, this report finds that LDES procurement will be necessary by 2030 and indispensable by 2045, and that significant procurement activities need to occur before 2025 to ensure that California has a sufficient pipeline of LDES projects to meet future grid needs. The deployment of resources capable of providing LDES applications would bring significant economic, environmental, and reliability benefits. Nevertheless, the realization of these benefits is contingent upon the timely deployment of LDES.

In this context, it is fundamental to first consider the scale of the deployment necessary given this report's results. The Base Case results, for example, highlight a need for 44.4 GW of LDES resources by 2045. This figure, while monumental, is comparable to the 2045 storage projections derived from the IRP proceeding and the SB 100 JAR, which estimate a need for approximately 44 and 55 GW of energy storage, respectively. As such, the totality of California's energy storage procurement activity to-date, which amounts to approximately 4 GW according to CESA's California Energy Storage Procurement Tracker, represents approximately 7-9% of the storage required by 2045.

Figure 44. Necessary Resource Additions and Expected Cumulative Portfolio (Base Case, 2045)



Source: Strategen

The figures derived from the Base Case represent over 150 times the current level of storage resources online today. If the deployment of these resources were to be done in a linear fashion by integrating a fraction of the total 2045 need every year from 2030 onwards, the deployment rate would need to be almost 3 GW per year. Essentially, starting in 2030, California would need to complete procurement over two times the totality of the AB 2514 storage mandate, every single year. Given this procurement need, it is worth noting that there are significant milestones that any project seeking interconnection to the CAISO footprint must achieve before initiating operations. The path to operation for storage resources is not immediate; first, new resources must obtain approval and permitting from the authority having jurisdiction ("AHJ"), a process that can take up to six months, even in an expedited track.[57] Once projects have been approved, developers must secure financing and make necessary equipment orders, a process that typically lasts a year.[58] When both financing and equipment have been obtained, developers can finally start the siting and construction processes, which could last anywhere between 12 to 18 months. Including testing and other interconnection requirements, a resource's path from the drawing table to commercial operation can take between three to five years.

Given the magnitude of these deployments and the timescales in which they can be accomplished, the State must establish a storage procurement and deployment pace that will be able to actuate these needs in a regular, dependable manner. These procurements must be prepared to scale and must be near term. More importantly, these processes must be stable and continued, scaling at a pace consistent with the evolving grid needs. This, paired with the development of new technologies and the anticipated decreases in energy storage prices, would create conditions similar to California's experience with the RPS, a recurring procurement mechanism which primes market participants to accelerate technological research, leading to innovation and cost reductions.

[57] This estimate assumes the AHJ is the CPUC and the approval was sought through a Tier 3 advice letter.
[58]

4.1.2 Storage Valuation and Compensation Mechanisms

At-scale deployment of new storage is reliant on the creation and preservation of revenue streams for these resources. Currently, storage penetration in California remains modest relative to the estimates of this report and other analyses such as the IRP and the SB 100 JAR. Since storage assets make up a small fraction of the current capacity fleet, storage resources that have been procured or brought online today have been forced into valuation structures and market rules that have been historically designed for conventional, thermal generators. As a result, current programs such as the RA framework do not compensate the full suite of products and services that storage assets can provide for the grid, particularly storage assets suited for LDES applications.

An important example of this situation can be found within this report's results. As stated in Section 3, this study finds that storage assets suited for LDES applications will provide continuous discharge for approximately 12 hours during the periods of high solar irradiance and normal grid conditions. Storage discharge with far longer durations spanning multiple days could be needed during atypical weather events that reduce solar output. While this usage of storage assets would reduce curtailment significantly (~ 17%) and reduce the usage of fossil-fueled generation, the ability of storage resources to provide such dispatch is not currently compensated within the RA program. Thus, revising RA counting rules to create certainty around the value of different storage assets in meeting different grid needs would increase the prospects of investment in these resources and provide incentives to deploy energy storage technologies that are suited to meet these needs in a cost-effective manner.

4.2 Actionable Policy Recommendations

This section focuses on recommendations for the coordination of regulatory, modeling, and planning proceedings and initiatives across the State. In addition, this section provides actionable recommendations for the two policies that are best suited to address the challenges related to timely deployment and fair valuation of storage assets capable of providing LDES applications: the IRP and RA proceedings overseen by the CPUC.

4.2.1 Overarching Recommendations

The following recommendations encompass coordination opportunities between the various planning and modeling proceedings, initiatives, and venues within the Californian regulatory space.

The State should fully integrate the RA and IRP modeling

The IRP process must be able to plan for both system and local reliability needs, with collaboration from relevant stakeholders, mainly the LSEs and the CAISO. This modification would be highly beneficial for the planning of the future grid. By creating synergies between both proceedings, the CPUC could provide further certainty to stakeholders and systematically improve the modelling work done for both short- and long-term planning.

The CPUC should use tighter GHG restrictions for 2030 in their IRP modeling processes

The IRP's GHG constraint for 2030, which currently limits emissions to a 46 MMT statewide target, must be revised to create a realistic and well-informed reduction trend that can be used in current modelling tools, ensuring SB 100 compliance. The creation of a viable GHG reduction trend will primarily fall upon the main government agencies in charge of administering and regulating California's electrical sector. However, since this trend is highly dependent on resource costs, input from other stakeholders such as developers and LSEs would be highly beneficial. This could be done as a working group series, a method commonly employed by the CPUC to generate proposals that are backed by relevant stakeholders. As the coordinating venue for SB 100 compliance, the JAR is uniquely positioned to determine the GHG reduction trends needed. For this purpose, alignment between the IRP proceeding and the SB 100 JAR is essential. Thus, load and GHG emission projections should be conducted as part of the JAR in order to inform GHG targets within the IRP proceeding.

The State should identify resources that overlap with the Local RA requirements and the IRP Preferred Scenario to inform "least-regret" procurements, especially when those resources overlap with locational needs in DACs

As it was mentioned in this analysis, both the IRP and RA proceedings have put forth some effort modelling the needs and emission impacts particular to disadvantaged communities ("DACs"). Since there are overlaps in their assessments, the State should use this information to mandate the procurement of resources that will be helpful to accomplish both short- and long-term goals. In this context, "least-regret" procurements refer to capacity expansions that are both economical and that contribute to local grid reliability needs, or other decarbonization goals considered by the State. In this case, solar PV and energy storage developments within locally constrained areas are a good example. The CPUC's RESOLVE model, the JAR, and this report have shown that solar PV and energy storage are set to expand considerably in the State. With this in mind, it would be both economical and viable to begin procurements in some areas in order to begin to curb GHG emissions and take advantage of current tax incentives.

Table 7. Overview of Policy Recommendations

State's Policy Gaps	Implications	Will Require
Consideration of 2045 targets within planning processes	Difficulties meeting the necessary procurement to maintain reliability	Explicitly model 2045 goals and conditions within the IRP proceeding in coordination with the SB 100 JAR
Current planning targets for 2030 do not align with the State's 2045 goals	California could be short on procurement given 2045 goals, increasing reliability concerns	Adopt more constraining 2030 GHG targets to prime the market for accelerated procurement in the 2030-2045 timeframe

The valuation of energy storage is focused on a resource's maximum output over four hours	Valuable characteristics of storage assets are overlooked	RA proceeding should value the reliability contributions of storage based on both duration and cycling
Lack of coordination between IRP and other policy goals	Inability to effectively identify and procure resources that could advance more than one policy goal	Identify resources needed to accelerate decarbonization of DACs and Local Areas, define storage assets that can meet those needs and have been selected within IRP as "least-regret" resources
Lack of a continuous process that directs procurement of needed capacity	Increased reliability risks, lack of market signals to buyers and sellers regarding needed assets	Utilize the IRP procurement track to direct procurement at a constant pace

4.2.2 Recommendations for the IRP Proceeding

The IRP proceeding is employed by the CPUC to plan for the long-term procurement needs in compliance with regulatory and legislative environmental goals and resource deployment mandates. Since its first cycle, the IRP has formalized a Procurement Track within its current proceeding, Rulemaking ("R.") 20-05-003. This Procurement Track seeks to address near-term reliability needs by directing procurement to CPUC-jurisdictional LSEs in accordance with the results derived from its Modeling Track. It is worth noting that the institutionalization of the Procurement Track follows the issuance of D. 19-11-016 in November 2019, which directed the procurement of 3,300 MW of incremental System RA to cure for deficiencies in compliance years 2021 to 2023. Consequently, the IRP proceeding is the current vehicle for the targeted procurement of assets essential to system reliability within CPUC-jurisdictional LSEs, which represent approximately 80% of California's load and 91% of the load in the CAISO footprint.[59] In view of the scale of energy storage deployment required according to this study and other similar analyses, the IRP is well-suited to serve as a venue for charting a course of procurement that emphasizes near-term reliability while planning for and advancing the procurement of least-regret resources. To do so, the IRP proceeding would need to modify its focus from one solely dedicated on the fulfillment of 2030 goals, to one that considers the overarching results of its Modeling Track and sets longer-term procurement targets as a vehicle for SB 100 compliance and targeted decarbonization.

The IRP proceeding is reframed as an explicit vehicle for the fulfillment of SB 100

[59] California Independent System Operator (CAISO), 2020. "Preliminary Root Cause Analysis Mid-August 2020 Heat Storm." Op. cit., p.2.

More emphasis must be placed on the 2045 modeling results, which are currently serving solely an advisory purpose. Currently, the IRP process focuses on near-term reliability needs and the fulfillment of 2030 targets. This framing has resulted in the IRP becoming the venue to address the replacement of the capacity currently provided by the Diablo Canyon nuclear power plant, which is set to retire in 2024. While the procurement of incremental capacity needed to sustain near-term reliability is indeed essential; the limited planning horizon has hindered the ability of the IRP proceeding to effectively ensure the deployment of the resources identified as necessary per this rulemaking's Modeling Track.

Consequently, the State should extend the IRP planning and procurement horizon to 2045, the "deadline" for SB 100 compliance. This modification would provide further certainty to buyers and sellers of energy storage technologies on the development of the market, as well as the deployment trends expected in the coming years. By extending this horizon, California would be able to transition the IRP proceeding from one focused on curing near-term deficiencies to one properly equipped to guide the State towards decarbonization. As the results of this analysis suggest, the State will need to install approximately 150 GW of incremental capacity in the next 25 years, essentially tripling the current installed capacity. This monumental deployment challenge cannot be underestimated and must be addressed. As such, the CPUC should base modeling and procurement activities with clear visibility to 2045 resource needs.

The CPUC should issue of targeted procurement to accelerate the decarbonization of specific areas within its jurisdiction

The CPUC should continue engaging with its jurisdictional LSEs to identify procurement pathways for resources that may imply long lead-times or high capital costs. Creating opportunities for collective procurement and establishing clear cost-allocation mechanisms is imperative to ensure the State can enact a smooth transition away from fossil-based energy, and towards a system based primarily around intermittent energy resources and energy storage assets. Moreover, the CPUC should conduct regular procurement. This can be modeled off the CPUC's experience with the RPS program, which directed IOUs to procure renewable resources to meet the State's goal of renewable generation. Regular and continued procurement directives will stimulate the market, priming it for research and development that could lead to cost reductions

The CPUC should utilize IRP-directed procurement as a means to achieve multiple policy goals. This issue is of special importance in the context of DACs, which have been recognized by the CPUC as areas that experience a disproportionate rate of environmental burdens stemming in part from the electric sector. According to the CPUC, DACs have a disproportionate share of fossil-fueled power plants: 39% of conventional generators are located within DACs while only 25% of the population live in DACs.[60] This focus on DACs is in fact part of the IRP's mandate; California Public Utilities Code, Section 454.52 states that the IRP process should "minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code."[61] It is worth noting that the prevalence of these generators within DACs is highly correlated with the fact that DACs have been historically underserved, and as a result, they often lack the infrastructure necessary to obtain electricity from sources other than local generators. Thus, there is substantial overlap between areas defined as locally constrained and DACs. Given this correlation, it is noteworthy to consider the efforts of the CAISO to estimate the storage characteristics needed to replace GHG-emitting generation in the Local Areas within its footprint. In the LCRTS, the ISO identifies that storage assets with an average duration of nine hours would be necessary to decarbonize most Local Areas.[62] This study, in conjunction with the State's commitment to reduce local pollution burdens in DACs, and the need for the deployment and demonstration of storage assets capable of fulfilling LDES applications, provides an initial roadmap to the acceleration of the replacement of conventional generation in a targeted, managed fashion.

The CPUC, along with the CEC and the CAISO, should identify priority areas for early, targeted procurement. The CPUC should target procurement directives to support existing local grid needs and to accelerate the retirement of fossil-fueled generation, particularly within DACs. As it has been stated previously in this report, DACs have a disproportionate share of fossil-powered assets due to systematic underinvestment in said areas, transmission limitations, and other environmental justice issues. Due to this historic disservice, DACs are fertile ground for policy and technological innovation. Using the information derived from the CAISO's LCRTS, the CPUC and CEC could establish procurement directives and pilot programs to enable the development of the storage required to accelerate decarbonization within DACs.

There are multiple benefits associated to this policy action. First, through targeted investment, California could help DACs to leapfrog towards decarbonization, strengthening vulnerable load pockets. Second, this approach would increase the familiarity of stakeholders with innovative technologies and applications. By starting the procurement of these resources in areas that are commonly serviced by local resources, California agencies and the CAISO would be afforded time to evaluate the

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[60] CPUC, 2019. "Proposed Preferred System Portfolio for IRP 2017-18: System Analysis and Production Cost Modeling Results."
https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Attachment%20A_Proposed%20Preferred%20System%20Portfolio%20for%20IRP%202018_final.pdf
[61] California Code, Public Utilities Code - PUC § 454.52.
https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=454.52.&lawCode=PUC
[62] CAISO, 2020. "2021 Local Capacity Technical Study."
http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

policy changes required to enable statewide transformation, such as increased market optimization runs or horizons, dispatch processes, and resource accounting rules.

4.2.3 Recommendations for the RA Proceeding

The RA proceeding is the second venue that can be used to address the regulatory hurdles faced by LDES. The CPUC adopted a RA policy framework in 2004 to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all LSEs within the CPUC's jurisdiction, including IOUs, energy service providers ("ESPs"), and community choice aggregators ("CCAs"). The RA program guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that it is available to the CAISO when and where it is needed. The CPUC's RA program now contains three distinct requirements: System RA requirements, Local RA requirements, and Flexible RA requirements. Consequently, the RA program lies at the heart of the tension between the deployment of incremental capacity and the revenue streams available to these assets. Therefore, in order to incent investment in said resources, it is necessary to modify current market rules to value the grid benefits provided by assets capable of meeting LDES needs.

Currently, the RA program values the reliability contributions of energy storage at the maximum power it can continuously discharge for four or more hours.[63] This rule is sometimes referred to as the "four-hour rule". This construct is a result of the peak load perceived in a system heavily dominated by conventional thermal generation. Nevertheless, as this study and others demonstrate, variable renewable generation and energy storage resources will make up the vast majority of the installed capacity within California by 2045 given the ambitious environmental targets of the State. As a result, the provision of storage discharge for periods in excess of four hours will be fundamental to maintain system reliability. This, in turn, should not detract from the value of the storage resources with durations equal to or less than four hours. As this study shows, a diverse suite of storage resources is required to meet the reliability needs of the grid. In this sense, the storage resources that are currently operational or are in development provide and will continue to provide essential services to the grid and, as such, must be afforded regulatory certainty to ensure their timely deployment.

Base storage reliability contributions on its operational characteristics

This could be achieved in several ways, from instituting an ELCC approach to modifying the current "four-hour rule" to reflect durations that are necessary to support system and local grid reliability with high levels of renewables and fewer fossil fueled resources. This report's results, however, find that the energy capacity (*i.e.* the MWh) value of the storage asset and the timing of grid needs are increasingly important in a context of high renewable penetration. Therefore, the evaluation of storage resources using solely a power (MW) metric might not be adequate to represent the reliability contributions of these assets in the future. As a result, the RA program must reform the current compensation of storage contributions to account for (1) the energy contribution

[63] CAISO, 2020. "Fifth Replacement Electronic Tariff." http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-for-SchedulingCoordinatorsintheCaliforniaISOBalancingAuthorityArea-asof-Aug1-2020.pdf & CPUC, 2020. "Decision 20-03-028." Op. cit., p. 41. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

of the storage asset given its MWh value; (2) the ability of the storage's resource to provide energy during the hours of grid need; and (3) resources that are capable of balancing grid needs over atypical weather events, which are likely to create reliability risks at high levels of renewables. This should not only capture the nameplate duration of the storage asset, but also its cycling capabilities.

Any reform to the RA proceeding should provide regulatory stability to energy storage resources currently operating or being developed

This report's results demonstrate that, in all cases analyzed, a mix of short- and long duration resources is necessary to maintain system reliability, particularly in the coming decade. In order to ensure these resources come online, stability regarding revenue streams is necessary for investors to calculate offers and operational targets. Thus, any reform to the RA structure should be accompanied by a clear transition plan that provides assurance to buyers and sellers of energy storage alike.

Conclusion

This report identifies a need for between 2-11 GW of energy storage by 2030, and between 44-55 GW by 2045. With an analytic framework that improves upon the limitations of other models previously used in the State, this report shows an unequivocal need for significant deployments of energy storage in order to enable a clean, reliable, and cost effective low-carbon, high-solar grid.

In particular, this report shows that the role of LDES grows significantly with grid decarbonization and retirement of fossil fueled assets, creating benefits across the grid. Namely, the procurement of LDES assets could help to enable the retirement of approximately 10 GW of fossil fueled generation, reduce system capacity costs by $1.5 billion per year, increase renewable energy utilization by 17%, and reduce in-state use of fossil fuels for electricity generation by 25%, relative to a case where the State does not have access to LDES assets.

Furthermore, this report's Sensitivity Cases clearly demonstrate the pivotal role of storage, in all its forms, should the State plan for more constraining GHG targets and more adverse weather conditions. Sensitivity Cases indicate that a 0 MMT GHG target by 2045 paired with a planning assumption of particularly low solar irradiance would trigger a 14% increase in the amount of storage deployed relative to the Base Case. When paired with increased solar adoption (20% more than the Base Case), this would not only result in a cleaner grid but also one that could save ratepayers up to $4 billion per year relative to a case where California is unable to harness the benefits of LDES options.

The 2045 findings imply the need to deploy over 150 times the amount of storage that has been developed over the last decade. As a result, this report offers a series of recommendations to ensure California can realize the procurement needed despite its extraordinary magnitude. These recommendations focus on the IRP and RA proceedings at the CPUC.

First, it is clear that the scale of resource deployment needed requires immediate action. Thus, it is necessary to establish a regular procurement schedule within the IRP proceeding in order to prepare for and accomplish long-term planning objectives. Moreover, there is an opportunity to reframe the IRP as an explicit vehicle for the fulfillment of SB 100, extending its planning horizon and prioritizing procurement directives that allow for the fulfillment of several policy targets simultaneously.

Second, it is essential to align the incentives in the RA program with the composition and nature of the future grid: one heavily reliant on intermittent renewable generation and storage-enabled energy arbitrage. To do so, this report recommends the CPUC transition to an RA framework that focuses on the hours of grid stress in order to fully value resources that can significantly contribute to reliability despite their energy- or use-limitations. Furthermore, this report notes that all types of energy storage will be instrumental to achieve decarbonization while maintaining a reliable supply of electricity. To value these contributions fairly, the RA program should be modified include the value energy storage as a function of the "size of the tank" (*i.e.* MWh) and the asset's cycling capabilities, rather than focusing on only one criterion, the asset's maximum power output over four hours.

This study provides insights and recommendations regarding the future of California's electric grid; nevertheless, the implications of this study extend beyond California's borders, showing a path that could likely be followed by other solar-dominated Western states such as Arizona, New Mexico, Nevada, and Utah. Given the rise of RPS-like goals and programs across the US, it is certain that long duration energy storage will be essential to incrementally integrating renewable assets while supporting reliability.

In sum, this report indicates that near-term reform of California's planning and procurement processes is necessary to meet the goals established by SB 100 in a timely and cost-effective manner. Moreover, the report clearly demonstrates that storage assets with different characteristics will be necessary to decarbonize the electric sector. As such, if California is to achieve its environmental targets in a reliable, timely and cost-effective manner, it must establish the regulatory mechanisms that create market certainty, foster competition, and enable a clean, well-planned grid.

Appendix A: Model Documentation: Methodology & Data

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Blue Marble Analytics

Blue Marble Analytics Disclaimer

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Introduction

A number of studies have investigated scenarios for meeting California's energy and climate goals. Notably, the CPUC in its IRP and LTPP proceedings conducts extensive analysis of electric procurement to ensure safe, reliable, and cost-effective electricity supply that also meets California's economy-wide greenhouse gas emissions reductions targets. The CEC has also funded studies to investigate deep decarbonization scenarios for the California economy and grid. The RESOLVE capacity-expansion modeling done in the CPUC's IRP proceeding and in CEC-500-2018-012 ("Deep Decarbonization in a High Renewables Future" study) uses only 37 representative days per year, with storage balancing decisions made on each day independently from those on other days. This approach has inherent limitations in valuing storage technologies with durations of around 12 hours or more, as the 37 days are not linked – storage balancing decisions are made on each day independently – while long duration storage technologies may derive value from shifting energy over multiple days, weeks, or even months and seasons. Therefore, this modeling approach cannot capture the role that long duration storage may play on a deeply decarbonized grid, not only underestimating its value but also affecting the results for the optimal deployment of other technologies, which may depend on the availability of long duration storage, as a different supply mix may be more cost-effective if the full value of long duration storage were to be fully incorporated.

We improve on the current modeling approaches by using GridPath's capacity-expansion functionality with an enhanced temporal span relative to prior studies. We benchmark GridPath with the same temporal setup as RESOLVE's but then implement a model temporal structure that can allow us to better reflect the capabilities and value of long duration storage resources: instead of using sample days, we run GridPath in capacity-expansion mode with 8,760 sequential hours per year, making it possible to capture energy shifts that happen over longer time scales than a day. After benchmarking to the RESOLVE results, we use only the 2030 and 2045 investment periods, omitting the prior years included in the IRP, in order to reduce computational complexity.

2019-2020 CPUC IRP

We use the public data available from the 2019-2020 cycle of the California Public Utilities Commission (CPUC) Integrated Resource Planning (IRP) proceeding (available on the CPUC website here). These data were developed as inputs to the Renewable Energy Solutions (RESOLVE) model to create the Reference System Plan (RSP). In particular, we use the data inputs to the RESOLVE 46MMT_20200207_2045_2GWPRM_NOOTCEXT_RSP_PD case. We attempt to adhere to the RESOLVE Reference System Plan modeling – both in terms of functionality and input data – as closely as possible.

Load Zones

We model the CAISO as a single zone interconnected with five other zones: three within California (BANC, IID, and LADWP), two external zones (the Pacific Northwest and the Southwest), and a proxy "zone" for Northwest hydro resources. The transmission topology and transfer limits are the same as in RESOLVE. Hurdle rates are applied on transmission line flows. We also include a constraint on simultaneous flows across groups of lines, including on exports from CAISO that are the same as in RESOLVE.

Temporal Setup

We model seven investment periods like in the RESOLVE RSP case: 2020, 2021, 2022, 2024, 2026, 2030, and 2045. Both GridPath and RESOLVE can also make retirement decisions for CCGT and peaker gas plants in the CAISO at those times. To represent each period, 37 independent days are used, weighted to represent load and resource availability conditions over a full calendar year. Operational decisions are made at an hourly resolution on each day. The 37 days used in RESOLVE have been selected from the historical meteorological record and assigned weights to reflect the distribution of load, renewable resource availability, and hydro conditions. Like in RESOLVE, each modeled investment year has an assigned weight, based on the fraction of the entire study period it represents and a discount rate.

Load Profiles

We use load profiles taken directly from the RESOLVE RSP case with the following assumptions:

Baseline Consumption	CEC 2018 IEPR - Mid Demand
Electric Vehicle Adoption	CEC 2018 IEPR - Mid Demand
Other Transport	CEC 2018 IEPR - Mid Demand
Building Electrification	None Through 2030
Hydrogen	None Through 2030
Behind-the-meter PV	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV
Energy Efficiency	CEC 2018 IEPR - Mid Mid AAEE
Existing Shed DR	Mid
TOU Adjustment	CEC 2018 IEPR
Non-PV Self Generation	CEC 2018 IEPR - Mid Demand
BTM CHP	CEC 2018 IEPR - Mid Demand

Generation and Storage Portfolio and Operating Characteristics

We use the "planned" generator and storage portfolio from the RSP case. Like RESOLVE, we input aggregated 'fleets' of generators for the following resource categories: CHP, CAISO_ST, and CAISO_Reciprocating_Engine, CAISO_CCGT1, CAISO_CCGT2, CAISO_Peaker1, and CAISO_Peaker2 with their associated operating characteristics including heat rates at minimum and maximum load, ramp rates, and minimum up and down time.

New Resource Options

We provide the same new resource options to GridPath as used in the RSP including their costs and deployment potentials.

- The model can pick from a range of renewable resources that represent aggregations of individual sites, grouped to several geographic areas that each include several Competitive Renewable Energy Zones (CREZs). Like RESOLVE, we model the transmission zones each California renewable resource is in along with the zone's existing transmission capability, i.e. the amount of new resource capacity that can be added while receiving full capacity deliverability status (FCDS). Beyond that, the model can choose to install resources either as energy-only – up to a certain capacity limit – or to incur an additional transmission cost for full deliverability.
- Solar deployment is limited to 2000 MW per year in 2020, 2021, 2022, and 2023.
- Candidate natural gas resources include advanced CCGTs, aero CTs, and reciprocating engines.
- The model can also pick storage resources. Like in RESOLVE, the duration of storage is endogenously determined based on the storage technology's power and energy cost structure. Pumped storage is not allowed to be built before 2026 and is limited to 4000 MW thereafter. Lithium-ion or flow battery storage are other options available to the model. Each is modeled in a few different tiers that have different capacity contributions; the final tier has unlimited potential.

System Operating Reserves

We model several reserve types for the CAISO load zone including frequency response, regulation up, regulation down, load following up, load following down, and spinning reserves. The frequency response requirement is 770 MW, half of which must be provided by thermal or storage resources while the rest can be provided by hydro. The spinning reserves requirement is 3 percent of hourly load, and the regulation up/down and load-following up/down requirements are the same as in the RSP inputs. These reserve products can be provided by thermal generation, limited by their 10-minute ramp rate, and by hydro and storage resources limited by their available headroom or footroom. Battery and pumped hydro resources must also have sufficient energy available in storage or room left in the "reservoir" to store energy. Like RESOLVE, we also allow CAISO wind and solar resources to provide load-following down (i.e. resources incur curtailment within the hour when providing downward reserves). We model this explicitly for each resource rather than in aggregate. The contribution of variable resources to load-following down is limited to 50% of the available footroom.

Planning Reserve Margin

Like the RSP, we include a resource adequacy constraint in the CAISO requiring sufficient capacity to meet a 15 percent planning reserve margin (PRM). The requirement is reduced by the CAISO import capability after adjustment for the CAISO share of Hoover and Palo Verde, which are modeled as if located inside the CAISO. CAISO conventional thermal and hydro resources contribute a fraction of their capacity based on the CAISO Net Qualifying Capacity list. Baseload renewable resources (geothermal, biomass, and small hydro) are assumed to contribute their full capacity to the PRM. We also include the contribution of variable renewable resources like wind and solar via a piecewise linear ELCC surface developed in the IRP. The ELCC surface expresses the total capacity contribution of the portfolio of wind and solar resources as a function of the penetration of each of those two resources. Energy storage with at least four hours of duration receives full capacity credit based on its power rating; storage with shorter duration can contribute an amount of capacity derated proportionately relative to a 4-hour resource (e.g., a 2-hour device will contribute 2/4 or half of its power capacity).

Renewable Portfolio Standard and Carbon Cap Policies

We include constraints enforcing the Renewable Portfolio Standard (RPS) based on SB100 in each modeled year.

We model a constraint on greenhouse gas emissions produced within or imported into the CAISO. The constraint is based on California statewide caps of 46 MMT, adjusted for specified imports. The assumed carbon intensity of unspecified imports is 0.428 metric tons per MWh.

Fuel Prices

We use the fuel price forecast from the RSP inputs. These are based on the 'Mid' forecast with a carbon price adder fuel used in California.

Other Zones

For the five other zones modeled, we use the load profiles, resource mixes, and curtailment costs assumed in the RSP inputs.

8,760 Profiles

Data Sources

Since the RESOLVE User Interface (or related spreadsheets) does not contain input data for a full (8,760 hours) year, hourly profiles used in GridPath are based on the following two public datasets:

1. Unified RA and IRP Modeling Dataset: available on the CPUC website here.
2. 2019-2020 IPRP Events and Materials, available on the CPUC website here.

The Unified RA and IRP Modeling Dataset contains the following key hourly input data:

- SERVM Solar Profiles
    - 1998-2017 weather, normalize to installed cap of 100 MW
    - 32 sites, not exactly matching RESOLVE and no mapping provided

    - 3 configurations: fixed tilt, single-axis tracking and dual-axis tracking
    - capacity factors seem on the lower side compared to RESOLVE capacity factors
- SERVM Wind Profiles
    - 1998-2017 weather, normalized to installed cap of 100 MW
    - 16 sites, not exactly matching RESOLVE and no mapping provided
    - capacity factors tend to be much lower than RESOLVE capacity factors
- SERVM Baseline Load Profiles:
    - Available for all zones, by BA (PGE_Valley, PGE_Bay, SDGE, TEPC, PSE, etc.)
    - 1998-2017 weather year normalized profiles
    - 7 versions available, starting on each day of the week
    - In SERVM, loads are scaled up to hit a peak load and annual energy forecast using the stretching algorithm provided in the Input & Assumptions document. Peak and annual forecast for each BA is provided for 2019-2030.
- SERVM Load Modifier Shapes (TOU, EE, EV)
    - Available for all CAISO BAs (PGE, SDGE, etc.)
    - Only 1 weather year available (unclear which one).
    - Different profiles available for forecast years 2019-2030, with each of them properly aligned with the actual weekdays of the forecast year.
    - Profiles are normalized to peak and need to be multiplied by the “capmax” forecast (from the load modifiers forecast spreadsheet) to get the actual profile.

The 2019-2020 IPRP Events and Materials contains the following key input data:

- Clean System Power Calculator (CSP) Renewable Profiles
    - 2007 weather year only
    - 14 wind profiles, 8 solar profiles, not exactly matching RESOLVE (less profiles) but some mapping is provided
    - Capacity factors are much more aligned with RESOLVE capacity factors
- Clean System Power Calculator (CSP) Load Profiles
    - CAISO only, but both baseline and load modifier (EE, EV, BTM PV, building electrification, other transportation electrification profiles are available)
    - 2007 weather year only
    - Different profiles available for forecast years 2020, 2022, 2026, 2030, with each of them properly aligned with the actual weekdays of the forecast year.
    - Profiles are normalized to annual demand

Load Profiles

The main goal is to extract the right weather year data from the SERVM dataset, aggregate the loads to match the RESOLVE/GridPath spatial resolution (zones), and scale the loads to match the RESOLVE/GridPath load forecast. The steps to get there are described below:

- Baseline:
    - start with SERVM baseline shapes
    - for each BA, for each forecast year (2020, 2021, 2022, 2023, 2024, 2026, 2030), figure out the start day of the forecast year, grab the 2007 weather year profile with that start day, stretch to meet forecasted peak load and annual load of the relevant forecast year

- aggregate BA shape by RESOLVE zone and normalize shape
- intermediate result: baseline load shape for each year and each RESOLVE zone, normalized to annual energy
- take the baseline "net energy for load" forecast from the RESOLVE UI for each RESOLVE zone and modeling year, and multiply the appropriate normalized shape with this number.
  - for 2045, use the 2030 normalized shape but multiply with the 2045 forecast
- final result: baseline load profile for each year and each RESOLVE zone
  - note: for CAISO we will add load modifiers as well, see below

- Load modifiers:
  - start with SERVM load modifier shapes
    - exception: there are no load modifier shapes for building electrification and other transportation electrification. Use CSP shapes instead (which in turn are based on the month-hour shapes in the RESOLVE UI)
  - for each load modifier for each CAISO BA, for each forecast year (2019-2030), take the appropriate profile, multiply it with the “capmax” from the load modifier forecast spreadsheet
    - note: the building electrification and other transportation electrification shapes don’t vary by forecast year since there is only one year available in the CSP spreadsheet. They also don’t distinguish weekdays vs. weekends.
  - aggregate BA shapes to one CAISO RESOLVE zone shape, and normalize shape
    - note: we don’t normalize TOU shape
  - intermediate result: shapes for all CAISO load modifiers for each year, normalized to annual energy
  - take the “net energy for load” forecasts from the RESOLVE UI for each CAISO load modifier and modeling year, and multiply the appropriate normalized shape with this number.
    - for 2045, use the 2030 normalized shape but multiply with the 2045 forecast
    - note: TOU is not scaled and is used “as is”.
  - final result: profile for each year and each CAISO load modifier
- Total:
  - Add the CAISO load modifier profiles to the CAISO baseline for each modeling year to get the final CAISO total load shape.

Renewable Profiles

The main goal is to extract the renewable shapes from the CSP dataset, match the CSP profiles to RESOLVE/GridPath resources, and rescale the profiles to match the RESOLVE/GridPath capacity factors. The steps to get there are described below:

- Renewable profiles come from the “Renewable Profiles” tab of the CSP calculator spreadsheet and are normalized per MW of installed capacity.
  - We initially considered using the SERVM dataset instead but did not pursue this because the capacity factors of many resources, especially the wind resources, were very different from similar RESOLVE capacity factors, and no mapping is provided between SERVM resources/units and RESOLVE resources (see figure below).
- BTM PV profiles found in the “Demand Profiles” tab of the CSP calculator spreadsheet were normalized to GWh, not to installed capacity. To convert to shape normalized to installed

capacity simply divide the shape by the maximum output value found in any hour. This assumes that there is an hour in the year where all PV is outputting at max capacity. It will result in a certain assumed capacity factor.

- We can then scale the profile linearly (and clip at 100%) to make sure it matches the capacity factor in RESOLVE.
- To remove near zero values, we round to the nearest 5 decimals
- The mapping from RESOLVE resource to profile name is done using the clarifications in the CSP calculator spreadsheet, using the profile with the best matching cap factor fit in case there are multiple options. For DG PV, we take the 2030 BTM PV profile, as the 2020-2022-2026 shapes are all pretty much the same (there are some very slight differences).
- For some RESOLVE resources we couldn't find any appropriate profile in the mapping, so instead we used some of the SERVM shapes that were provided in the 2019 unified dataset (slicing out just the 2007 weather year):
    - Arizona_Solar -> Solar_1Axis_AZ_LaPaz_None
    - Baja_California_Wind -> Solar_1Axis_CA_Imperial_Ocotillo
    - Idaho_Wind -> Wind_ID_Lincoln_Paul
    - NW_Solar_for_Other -> Solar_1Axis_OR__Medford
        - Note: solar the cap factors were significantly lower in the SERVM shapes. We could have grabbed dual axis shapes to get higher cap factors but we felt like that would distort the profiles too much and most solar farms have single axis tracking. Instead, our scaling mechanism (multiply and cap by 1) reflects scaling up the ILR, which might be the reason for the low cap factors in the first place.

As shown below, SERVM capacity factors do not match well with RESOLVE, and CSP capacity factors match a lot better.

Figure 45: SERVM Capacity Factors

RESOLVE candidate resources

RESOLVE resource	CF
Carrizo_Solar	31%
Central_Valley_North_Los_Banos_Solar	29%
Distributed_Solar	21%
Greater_Imperial_Solar	31%
Inyokern_North_Kramer_Solar	32%
Kern_Greater_Carrizo_Solar	31%
Kramer_Inyokern_Ex_Solar	32%
North_Victor_Solar	32%
Northern_California_Ex_Solar	28%
Riverside_Palm_Springs_Solar	31%
Sacramento_River_Solar	28%
SCADSNV_Solar	31%
Solano_Solar	29%
Southern_California_Desert_Ex_Solar	31%
Southern_Nevada_Solar	31%
Tehachapi_Ex_Solar	32%
Tehachapi_Solar	32%
Westlands_Ex_Solar	31%
Westlands_Solar	31%
Arizona_Solar	31%
Northern_California_Ex_Wind	29%
Solano_Wind	30%
NW_Ext_Tx_Wind	30%
Baja_California_Wind	36%
New_Mexico_Wind	44%
Wyoming_Wind	44%

SERVM available profiles*

SERVM profile name	CF
Solar_1Axis_CA__Chico	22%
Solar_1Axis_CA__Fresno	24%
Solar_1Axis_CA__LosAngeles	24%
Solar_1Axis_CA__Monterey	21%
Solar_1Axis_CA__Oakland	22%
Solar_1Axis_CA__Sacramento	23%
Solar_1Axis_CA__SanDiego	22%
Solar_1Axis_CA__SantaRosa	22%
Solar_1Axis_CA_Imperial_Calipatria	25%
Solar_1Axis_CA_Imperial_Ocotillo	27%
Solar_1Axis_CA_Kern_Bakersfield	24%
Solar_1Axis_CA_Kern_LostHills	25%
Solar_1Axis_CA_Kern_Rosamond	27%
Solar_1Axis_CA_Kings_Stratford	24%
Solar_1Axis_CA_LosAngeles_Lancaster	27%
Solar_1Axis_CA_Madera_Madera	24%
Solar_1Axis_CA_Placer_Roseville	23%
Solar_1Axis_CA_Riverside_Riverside	25%
Solar_1Axis_CA_SanBernardino_AppleValley	27%
Solar_1Axis_AZ_LaPaz_None	26%
Solar_1Axis_NV_Clark_Henderson	25%
Wind_CA_Solano_RioVista	30%
Wind_WA_Benton_Paterson	9%
Wind_CA_Kern_Mojave	26%
Wind_CA_Riverside_ThousandPalms	7%
Wind_NM_Socorro_Alamo	12%
Wind_WY_82083_RockRiver	28%
Wind_WY_Johnson_Mayoworth	27%

SERVM and RESOLVE renewable capacity factors are not well aligned. Some SERVM wind capacity factors in particular are unrealistically low

***Dual-axis tracking profiles omitted as they are rarely used in industry**

Figure 46: CSP Capacity Factors

RESOLVE candidate resources

RESOLVE resource	CF
Carrizo_Solar	31%
Central_Valley_North_Los_Banos_Solar	29%
Distributed_Solar	21%
Greater_Imperial_Solar	31%
Inyokern_North_Kramer_Solar	32%
Kern_Greater_Carrizo_Solar	31%
Kramer_Inyokern_Ex_Solar	32%
North_Victor_Solar	32%
Northern_California_Ex_Solar	28%
Riverside_Palm_Springs_Solar	31%
Sacramento_River_Solar	28%
SCADSNV_Solar	31%
Solano_Solar	29%
Southern_California_Desert_Ex_Solar	31%
Southern_Nevada_Solar	31%
Tehachapi_Ex_Solar	32%
Tehachapi_Solar	32%
Westlands_Ex_Solar	31%
Westlands_Solar	31%
Arizona_Solar	31%
Northern_California_Ex_Wind	29%
Solano_Wind	30%
NW_Ext_Tx_Wind	30%
Baja_California_Wind	36%
New_Mexico_Wind	44%
Wyoming_Wind	44%

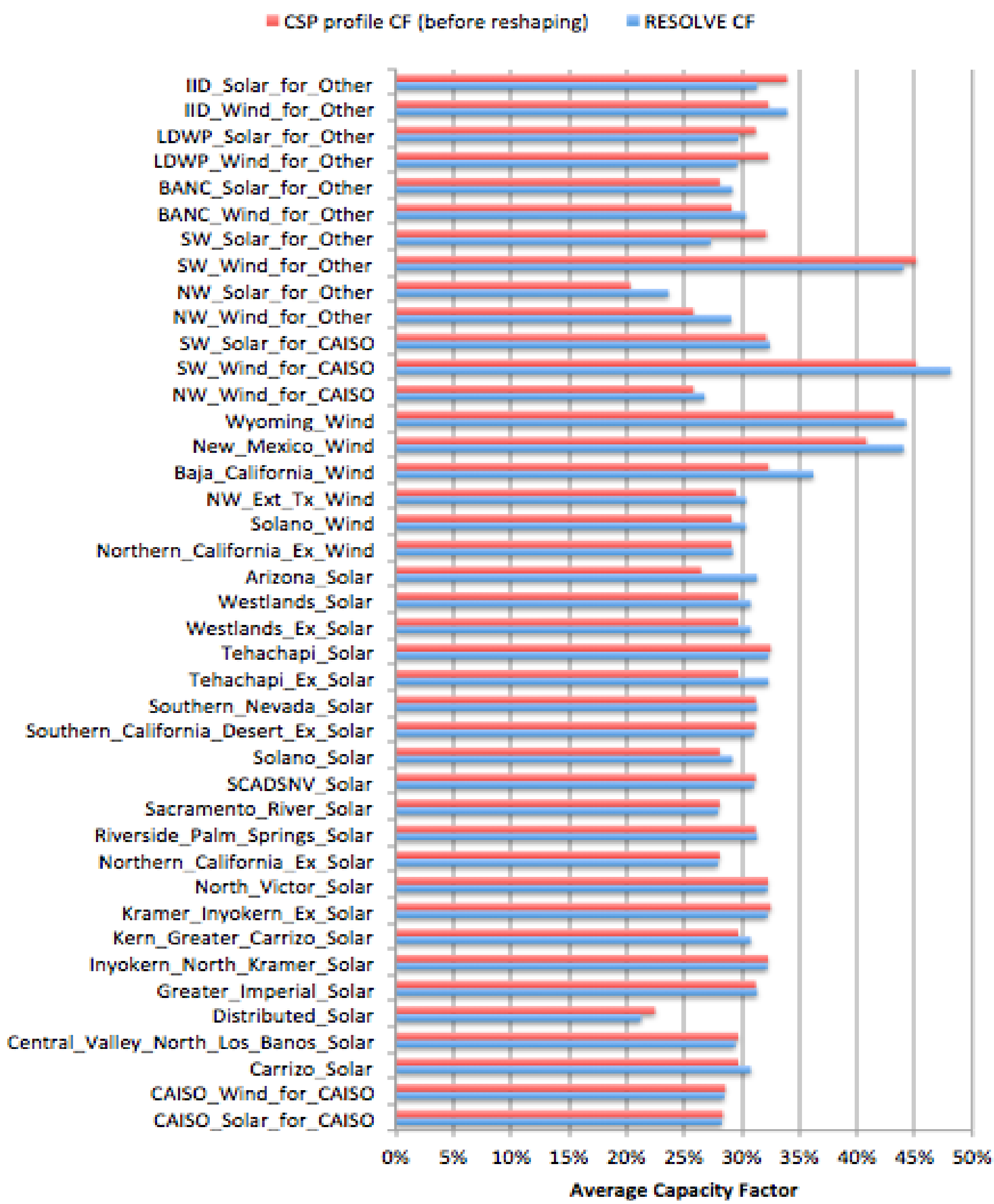
CSP available profiles

CSP profile name	CF
Existing CAISO Solar	28%
Existing SW Solar	32%
Existing IID Solar	34%
Southern_PGE_Solar	30%
Southern_CA_Desert_Southern_NV_Solar	31%
Greater_Kramer_Solar	32%
Sacramento_River_Solar	28%
Tehachapi_Solar	33%
Existing CAISO Wind	29%
Existing SW Wind	45%
Existing NW Wind	26%
Southern_PGE_Wind	31%
Southern_CA_Desert_Southern_NV_Wind	32%
Greater_Kramer_Wind	31%
Sacramento_River_Wind	29%
Tehachapi_Wind	34%
Wyoming_Wind	43%
New_Mexico_Wind	41%
NW_Ext_Tx_Wind	29%
SW_Ext_Tx_Wind	33%
Humboldt_Bay_Offshore_Wind	50%
Diablo_Canyon_Offshore_Wind	47%

CSP and RESOLVE renewable capacity factors are much better aligned. Resource mapping is also easier (see CSP* spreadsheet)

As can be seen in the figure below, after mapping RESOLVE resources to appropriate CSP profiles, capacity factors match closely. Note that before input to GridPath, CSP shapes are linearly scaled to exactly match RESOLVE capacity factors

Figure 47: RESOLVE versus CSP capacity Factors



Hydro Budgets

- Hydro data comes from "1998 to 2017 Hydro Inputs_Rev1" spreadsheet that is part of the unified I&A dataset
  - Has min/max/budget for each BA for each weather year 1998-2017
- Aggregate hydro min/max/budget data across RESOLVE zones, using the BA-to-RESOLVEzone mapping for each weather year
- Slice out just 2007 hydro budgets for each RESOLVE zone and re-scale so the annual budget matches the weighted average RESOLVE hydro budget.
  - Use the same scalar to re-scale the min and max values
  - Note: this makes sure we are working with exactly the same hydro budgets as the RESOLVE 37 days, which represent an average hydro year through a combination of low/mid/high years. However, 2007 actually has lower than average hydro conditions in CA so this might not be entirely weather consistent with the other renewable and load data
- Divide the 2007 min/max/budget by the RESOLVE installed capacity to get normalized input values

Load Following and Regulation Up/Down

- Start with RESOLVE 2030 input loads for CAISO and normalized RE shapes
- Start with hourly (8,760) 2030 (weather year 2007) GridPath input loads and normalized 2007 renewable profiles (note: these shapes come from CSP spreadsheet, RESOLVE mapping, and re-scaling).
- Using the 2030 renewable portfolio of 46MMT_20200207_2045_2GWPRM_NOOTCEXT_RSP_PD, scale up RE shapes and get net load both for RESOLVE and Gridpath.
- Go through each GridPath day (365), find RESOLVE day that has closest net load, and grab the LF and regulation requirements from that day.
- Loop over all modeling years and use the same slope-intercept approach to get the actual requirements in each year.

Extreme Weather Year

- Find an "extreme year" year within the 1998-2017 SERVM dataset
  - Assuming a typical 2030 RESOLVE portfolio, scale up SERVM load and renewable profiles (assuming a certain mapping of SERVM to RESOLVE resource) to get a net load profile for 1998-2017
  - Look at running averages of net load and renewable production over 1-21 days and identify years with low running averages over long durations.
  - Determined that low renewable output is the main driver of high net loads in California's solar-heavy system where high renewable output in the summer coincides with high loads
  - Determined that 2010 has a very low renewable output in December and parts of January. This was driven by a particularly active winter in California with lots of winter storms battering California, and the associated cloud cover sharply reducing solar PV production.
- Variable Profiles

- Create day map between reference year (2007) and extreme year (2010) for load, wind, and solar
    - Algorithm finds day with smallest mean squared error
    - E.g. Jan 1 in 2010 is most similar to Jan 8 in 2007; Jan 2 in 2010 is most similar to Jan 3 in 2007 etc.
- Create a synthetic variable profile for the extreme year using the day map
    - Algorithm goes through each day in the extreme year and grabs the appropriate day in the reference year using the day map
    - This means some 2007 days will be repeated (e.g. the ones with high net loads) whereas others won't make it in the extreme year

- Load Profiles
    - Same steps as reference year (2007), but now for the extreme year (2010)
- Hydro
    - Same steps as reference year (2007), but now for the extreme year (2010)
- Reserves
    - Same steps as reference year (2007), but now for the extreme year (2010)

Appendix B: CESA Storage Procurement Tracker

About CESA and the California Energy Storage Procurement Tracker

The California Energy Storage Alliance (CESA) is a 501c(6) membership-based advocacy group committed to advancing the role of energy storage in the electric power sector through policy development, education, outreach, and research. As part of our efforts, CESA tracks the procurement of energy storage assets within California to provide vital information on the state of the market and the progress the State has made towards its decarbonization and reliability goals. The California Energy Storage Procurement Tracker is updated monthly to reflect the latest trends on utility-scale and behind-the-meter (BTM) procurement, as well as customer-sited installations supported by the Self-Generation Incentive Program (SGIP). In this document, "procurement" refers to the bilateral contracting Project-specific information is available for members only. Contact Grace Pratt (gpratt@storagealliance.org) to join today.

When using this data, please cite this source as follows: California Energy Storage Alliance (CESA), CESA's California Energy Storage Procurement Tracker, October 1, 2020.

Data Sources & Disclaimer

The information presented in this document has been compiled from publicly available sources in order to estimate the current state of energy storage market in California, focusing on storage assets that have been procured since 2010. These figures have been gathered by meticulously reviewing documents published by the California Public Utilities Commission (CPUC), developers, and load-serving entities (LSEs) such as investor-owned utilities (IOUs) and community choice aggregators (CCAs). Given the disaggregated nature of procurement reporting in California, this data is limited by the availability of complete information and should be used for informational purposes only.

Key Trends & Takeaways

- As of October 1, 2020, there are 4,189 MW of energy storage online, in development, or contracted.
  - Online (project is interconnected and operational): 287 MW.
  - In development (project is undergoing construction or interconnection): 2,079 MW.
  - Contracted (project has been contracted but has not begun construction or still requires regulatory approval): 1,823 MW.
- Li-ion batteries account for bulk of energy storage procurements, amounting to over 3,500 MW.
- As of October 1, 2020, more than two-thirds of energy storage procurements are within the transmission domain (as opposed to distribution or customer domains).
- As of October 1, 2020, SGIP has enabled the deployment of 250 MW of customer-sited electrochemical storage.
- SGIP has enabled the deployment of 10 MW of electrochemical storage in the first 10 months of 2020.

Summary Charts & Table

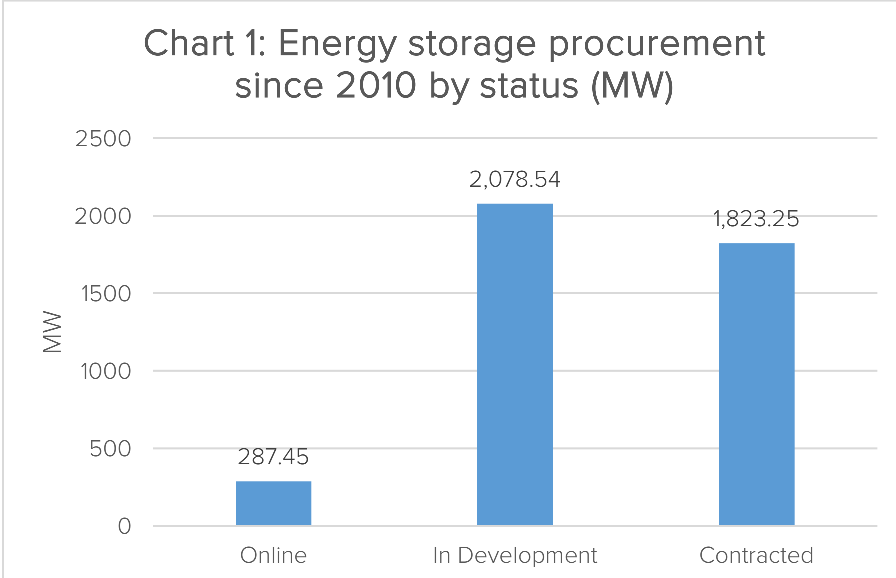


Table 1. Energy storage capacity procured by LSE since 2010 (MW)	
LSE	MW
Southern California Edison	1,290.39
Pacific Gas & Electric	1,135.19
Clean Power Alliance	468.00
Los Angeles Department of Water & Power	411.01
San Diego Gas & Electric	317.16
East Bay Community Energy	153.75
Silicon Valley Clean Energy & Monterey Bay Community Power	105.00
California Choice Energy Authority	15.00
San Jose Clean Energy	10.00
Riverside Public Utilities	7.85
Sonoma Clean Power	5.00
Redding Electric Utility	3.60
Glendale Water & Power	3.50
City of Santa Clara Utilities	3.25
City of Anaheim Public Utilities	3.15
Sacramento Municipal Utilities District	0.87
Pasadena Water & Power	0.74
Moreno Valley Utilities	0.08
Lancaster Choice Energy	0.03
Colton Public Utilities	0.02
Alameda Municipal Power	0.01
Burbank Water & Power	0.00
Imperial Irrigation District	0.00

Table 2. Energy storage capacity procurement by technology type since 2010 (MW)	
Technology	MW
Li-ion battery	3,601.76
Pumped hydro storage	40.00
Zn-air battery	10.00
NaS battery	7.00
LiFePO4 battery	2.00
VRF flow battery	2.00
Flow battery	0.50
Flywheel	0.01
Metal halide battery	0.00

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