



Energy Storage Pathways to Meet California's 2030 Greenhouse Gas Goals

by

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Abstract

In California, due to solar resources coming online during the day, renewable generation often exceeds demand, leading to curtailment. However, during peak evening hours, California is forced to rely on GHG emitting thermal power plants. This will make it difficult for the state to meet its aggressive GHG reduction target of 40% below 1990 levels by 2030. AB 1405 and SB 338 are two proposed bills that call for a clean peak standard, where utilities are required to meet a certain percentage of peak hour electricity from clean resources. The purpose of this study is to evaluate the use of utility scale battery storage to achieve the clean peak standard, and aid California's GHG reduction efforts. The study estimated electricity demand and generation profile in 2030, and used an Excel-based optimization model to determine an ideal storage capacity and dispatch strategy. Finally, it investigated the total energy storage cost requirements for different scenarios.

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Executive Summary

The state of California is a leader when it comes to installing new renewable energy capacity and reducing greenhouse gas (GHG) emissions. California currently has aggressive GHG targets to reduce yearly carbon dioxide (CO₂) emissions from the state. One of their goals is to reduce emissions by 40% of 1990 levels by the year 2030. To help aid the state to reach such a goal, Senate Bill 350 was passed in 2015, which called for a new Renewable Portfolio Standard (RPS) of 50% to be conformed in the year 2030.

Over the past decade, the state has been installing more renewable energy technologies each year. As a result, the California's Average Net Load Curve, or affectionately called the "California Duck Curve", has been changing each year. Due to more renewable resources coming online during the day, the 'belly' of the Duck Curve droops lower, creating steeper ramp-down and ramp-up rates during peak evening hours. With increasing renewable energy capacity with more solar and wind, renewable energy generation often exceeds energy demand, thus leading to curtailment of renewable resources. Additionally, during peak evening hours, California is forced to rely on heavy GHG emitting thermal plants with high ramping capabilities. Therefore, having a simple RPS strategy in place to meet GHG reduction targets by 2030 is not effective in reducing carbon emissions.

Currently, two proposed bills AB 1405 and SB 338, call for a Clean Peak Standard. A Clean Peak Standard of 40% would require 40% of all electricity generated during the peak hour window to come from clean resources. As resources, such as solar, dissipate as the sun sets, a way to effectively manage power peaks with clean resources is with utility scale battery storage, specifically with lithium-ion batteries.

The focus of this study is to evaluate the use of utility scale battery storage to achieve a Clean Peak Standard of 40%, and aid California's GHG reduction efforts. In order to investigate a 40% Clean Peak, the study employed a three-stage strategy using Excel-based modeling. In Stage 1, the study estimated 2030 electricity demand, generation profile, and the amount of battery storage required to meet electricity demand during peak hours. In Stage 2, the study used a rule-based Excel modeling to determine an ideal thermal plant dispatch strategy, first without, and then with energy

storage. In Stage 3, the study determined optimal charging and discharging profiles for storage using an Excel Solver-based optimization model.

The analysis of the model determined battery power capacity, energy capacity using a round trip efficiency of 80%, and total energy discharged per year. We found that carbon emissions would be reduced by about 2.3 million tons a year, and that curtailment would be reduced by 35.41%. The study also examined the financials of implementing battery storage through a cost sensitivity analysis. In a range from low to high cost levels for battery storage, annual cost per year has a potential range from about \$970 million to \$4.6 billion a year. Cost of discharge ranges from \$127.52/MWh to \$605.70/MWh. Carbon emission abatement ranges from \$406.59/ton CO₂ to \$1,931.30/ton CO₂.

Key takeaways, recommendations, and conclusions from this study:

- Steeper thermal ramp-up rates during peak hours of electricity generation threaten GHG reduction targets in California.
- A Clean Peak Standard is a feasible pathway to reduce CO₂ emissions.
- High amounts of battery storage will be required during the winter months, (approximately 60,000 MWh).
- There will be low utilization of battery storage with high solar curtailment during the summer months— bring the capacity factor to about 7% a year.
- A policy proposal of a daily fixed CPS is not cost effective:
 - It will cost about \$1 billion per year to have the battery system in place.
 - To abate 1 ton of CO₂, it will cost about \$400/ton CO₂-year.
 - It will cost \$127/MWh for electricity to be discharged.
- The study suggests an annual average CPS instead of a daily CPS, as it may increase utilization of the battery storage system and reduce costs.
- To make a CPS with battery storage more financially feasible, a proposal for a future carbon abatement credit market may need to be instated.

Introduction

At 11:19 AM on March 23, 2017, CAISO notched a record by serving 56.7% of California's electric demand through renewable sources. However, CAISO also warned that curtailments to renewable energy capacity could top 6 – 8 GW in the spring due to a unique bountiful hydro and additional installations of solar (Maloney, 2017a). This is due to the generation profile of solar sources – electricity generation can be higher than what the demand is, leading to potential economic and reliability curtailments. As renewable sources expand, CAISO estimates that renewable curtailment could hit 13 GW by 2024 (Maloney, 2017b). In order to meet its RPS targets, California may need to overbuild renewables and rely on GHG-emitting thermal resources for peaking and ramping needs. This could make it more difficult to achieve California's ambitious GHG emission reduction targets – reducing carbon emissions to be 40% below 1990 levels by 2030 (California EPA Air Resources Board, 2017).

While California already has some of the largest storage projects (Maloney, 2017a), the current RPS does not incentivize faster adoption of Energy Storage Systems (ESS). The MWh model in the standard simply requires load serving entities (LSEs) to supply a certain percentage of total energy through qualifying clean resources. Providing generation capacity during peak hours is a time-specific grid service that is not well matched with the simple MWh model (Huber, 2016). Since renewable generation tapers off during the peak evening hours, LSEs are more likely to meet the peak demand through fossil fuels, thereby, offsetting some of the emissions reductions from renewable resources. Thus, the traditional MWh model lacks the relevant market signals that differentiate between the value of renewable energy based on the time it is produced (Huber, 2016).

California Energy Storage Alliance (CESA) has proposed an advanced RPS (*i.e.*, the Clean Peak Standard) that has the potential to reduce GHG emissions and provide a sustainable path for renewable energy deployment. They propose adding supplemental components to the traditional MWh model, whereby a certain percentage of energy delivered to customers *during peak hours* must be provided by renewable sources (Huber, 2016). However, they have also identified a glaring lack of analysis on the positive impacts of Clean Peak Standards on GHG emissions. Our project will explore energy storage systems as enablers of these standards and evaluate their

impacts on GHG emissions reductions. Our analysis will eventually be used by CESA in its advocacy work at the California Public Utilities Commission (CPUC) and California Legislature.

Objective

The objective of our project is to determine the viability and effectiveness of 'clean peak' concepts as a pathway for GHG emission reductions through energy storage, using an assumed Clean Peak Standard (CPS) of 40% (Figure 1).

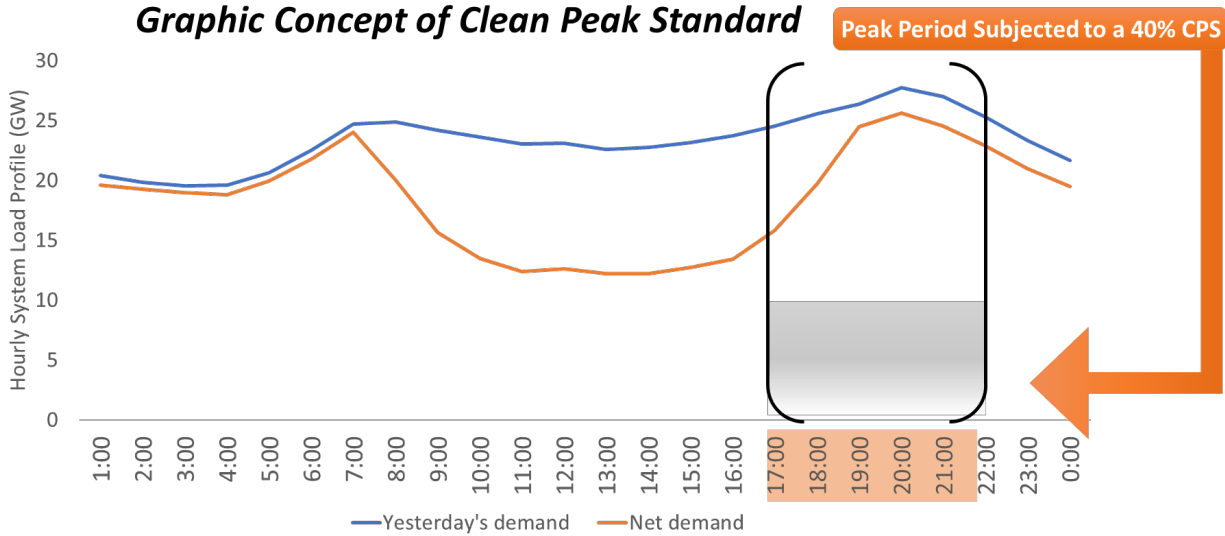


Figure 1. Graphic Concept of Clean Peak Standard

A 40% CPS means that for all the electrical generation during peak hours in 2030, which we have identified to be between 5PM and 10 PM, 40% must come from renewable sources. For the days that do not meet this requirement, as resources like solar dissipate as the sun sets, energy storage, specifically with lithium ion batteries, will be used instead. By using historical hourly generation data from CAISO to interpolate electricity generation in 2030, California Public Utilities Commission 2017 Integrated Resources Plan (IRP), and GHG emissions data from EIA, we evaluated the GHG saving potential of energy storage systems charged during periods of low GHG emissions and deployed at periods of high GHG emissions.

Policy Background

Carbon Policy

One of the first indirect carbon policies in the United States was the Public Utilities Policy Act (PURPA), which was a part of the 1978 National Energy Act. In response to the 1973 United States energy crisis, and to promote more domestic sources of energy, PURPA promoted energy conservation by reducing demand, and encouraged the use for more domestic energy, such as natural gas and renewable energy (The National Museum of American History, 2018). This shift towards the use of natural gas and renewables was one of the first steps to reduce carbon emissions in all 50 states.

California, in 2006, passed AB 32: The California Global Warming Solutions Act of 2006, which was one of the first programs in the US to take a long-term methodology to address climate change, whilst improving the environment and maintaining a healthy economy (California Air Resources Board, 2018). The policy required an 15% reduction in GHG emissions, using GHG levels from 1990 as a baseline, by 2020 (California Air Resources Board, 2018).

In 2013 California launched a cap-and-trade program to assist in their efforts to reduce GHG emissions. The cap-and-trade rule applies to large electric power plants, large industrial plants, and fuel distributors. Currently, about 450 businesses are responsible for about 85% of California's total GHG emissions (California Cap and Trade, 2017). The emissions trading system is expected to reduce GHG emissions from regulated entities by more than 16% by 2020, and by 40% in 2030 (California Cap and Trade, 2017).

Storage Policy

While California already had a 1,325 MW storage mandate by 2024, a natural gas shortage in the LA region caused by the Aliso Canyon leak spurred legislators to enact four bills in 2016 to promote storage (Walton, 2016).

AB 33 directs the CPUC to consider large-scale storage to mitigate renewable over-generation and steep evening load ramp-ups. AB 2868 allows the three major utilities to develop 500 MW of

storage (divided equally among them), over and above the original 1,325 MW mandate. AB 1637 aims to double the Self-Generation Incentive Program, which would be a boost to behind-the-meter energy storage systems. Finally, AB 2861 requires the CPUC to resolve interconnection disputes within 60 days, helping energy storage systems to come online more smoothly.

The California utilities have already started acting – San Diego Gas & Electric proposed a 150 MWh battery system following the Aliso Canyon gas leak. Southern California Edison unveiled plans to retrofit an existing gas plant with 80 MWh of batteries. Pacific Gas & Electric is also not far behind and announced that it would retire the Diablo Canyon nuclear plant, and replace it with zero-carbon resources, including energy storage.

Renewable Portfolio Standard (RPS) and Clean Peak Standard (CPS)

California’s RPS program was established in 2002 with SB 1078 and enhanced and expanded upon in 2006 under SB 107 and in 2011 under SB 2 (California Energy Commission, 2018). The California Public Utilities Commission and the California Energy Commission jointly implement the RPS program with in the state. In the efforts to reduce GHG emissions, the RPS program requires all investor-owned utility companies and any electric service providers to increase procurement from renewable resources to 33% of all procurement by 2020 (California Public Utilities Commission, 2018). More recently, SB 350 was passed in 2015, which called for a new RPS of 50% by the year 2030.

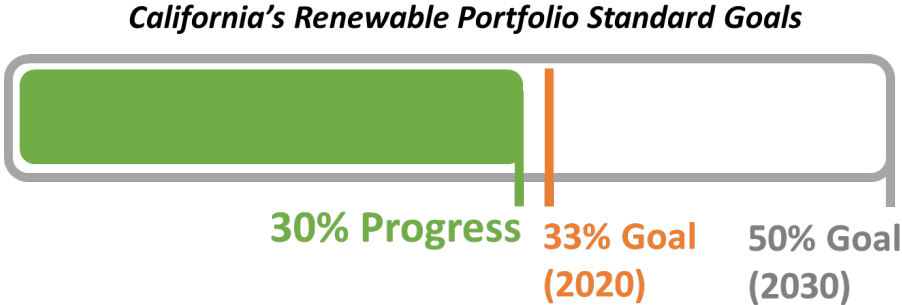


Figure 2. California's Renewable Portfolio Standard Goals

Source: California Energy Commission (2017)

In 2013, California became the first state to set an energy storage mandate that directed the three investor-owned utilities to procure and deploy 1.325 GW of energy storage systems by 2020 (Walton, 2017). New bills have been introduced to the California Assembly and Senate that encourage and support for more clean energy resources that help peak-shaving, reliability and minimize the need for electricity generation from fossil fuels (Spector, 2016). SB 338, signed on October 11, 2017, requires the Public Utilities Commission (PUC) to implement a process for every load-serving unit to report an integrated resource plan and schedule updates to verify that all load-serving units are on their way to meet the state's greenhouse gas emissions reduction targets. GHG targets for California require that at least 50% of its electricity that is procured needs to come from qualifying renewable resources by December 31, 2030 (California Legislative Information, 2018). The law also requires that all local publicly owned electric utilities, that have an annual electrical demand that is more than 700 GWh, on or before January 1, 2019, must implement an integrated resources plan and methodology for revising the plan at least once every 5 years. This safeguards that the utility is on track to fulfill the state's GHG reduction targets by December 31, 2030. Overall, this bill compels utilities to evaluate how storage, energy efficiency, and distributed energy resources can meet peak power needs while reducing the need for new generation and transmission (Bade, 2017).

Currently, 29 states have adopted mandatory or voluntary RPS, which accounts for 55% of energy coming from renewable sources. Similar to the Residential Utility Consumer Office in Arizona, CESA proposes to evolve the RPS model by adding time-based price signals for electricity generation (Spector, 2016). The model also includes energy storage for solar and wind projects to make it possible for them to satisfy the CPS (Spector, 2016). It will not only enable delivery of clean energy at times of greatest need but avoid GHG-intensive investments in peaking capacity. Another bill, AB-1405, lays the foundations of the CPS. This bill requires the CPUC to identify by December 31, 2018, the percentage of "clean peak resources" – renewables and storage – being used by the utilities to meet peak hour demand. Each utility would have to meet escalating clean peak targets every three years starting in 2020 and reaching 40% in 2029. Thus, by 2029, each California utility would be required to procure 40% of all electricity served during peak hours from clean resources. Further, the utilities would be required to meet the minimum target at least fifteen days every month. While other components of the bill such as enforcement, measurement standards and non-compliance penalties are still being ironed out, the bill is a huge boost to

expanding renewable energy storage systems to meet peak hour loads. Further, it will reduce dependence on costly and polluting "peaker" plants and aid the state to reach their GHG reduction targets.

Overview of CAISO

Duck curve

As renewable capacity further expands in California, California Independent System Operator (CAISO) will have to cope with more volatile generation while maintaining the grid stability. The net load, that is, the difference between total load and volatile renewable generation, is a good indicator to evaluate the influence on the power grid from on-site solar and wind generation.

In 2013, CAISO depicted some historical daily net load curves, and then projected the future daily net load curves of the following continuous years with more renewable capacity connected into the grid. The duck-shape net load curve has a duck belly generated from renewable peak in the midday and a neck resulted from peak demand starting in the late afternoon to early evening. Hence, the net load curve is also called "Duck Curve". The range of net load within a day is further enlarged due to the mismatch between renewable peak and demand peak.

The more generation is from solar or wind, the larger range of net load will the region go through in a day. This implies a steeper ramping requirement during the evening peak hours, which is mainly reached by the thermal peaking plants with faster ramping capability. A heavier belly and a higher neck are observed from the net load curves of 2011 to 2017 (Figure 3), indicating the California duck is coming. California duck has become a critical issue in the CAISO power system.

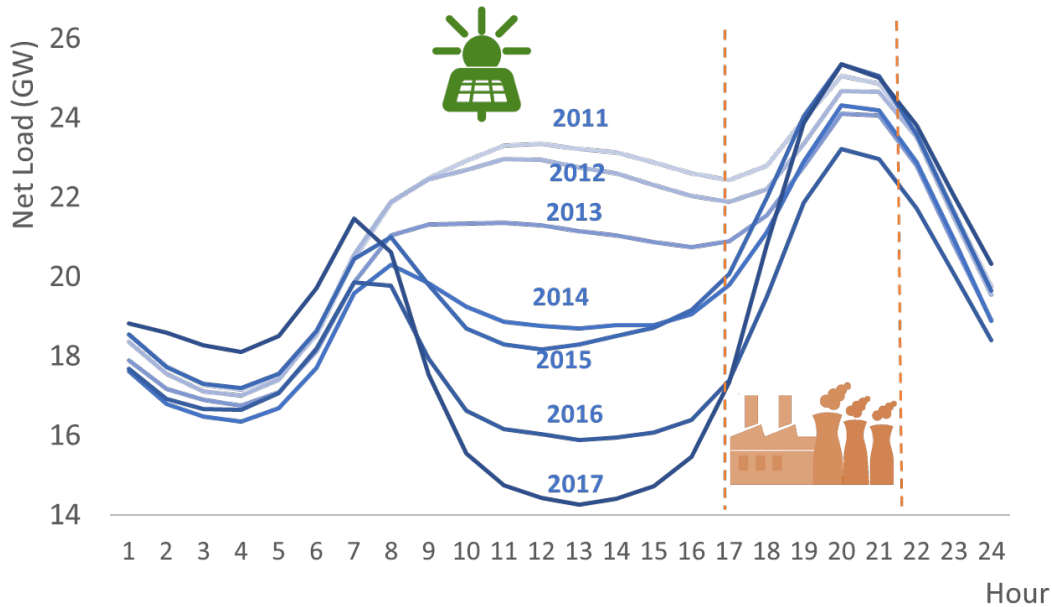


Figure 3. Average Net Load Curve in March (2011-2017, CAISO)

Data source: CAISO

The 2030 target of 50% RPS (SB350) predicts a future with larger renewable capacity and more volatile generation. To meet 50% RPS by 2030, the duck curve will face an even heavier belly, that is, a higher ramping requirement from the non-renewable generation. Several operating risks are also emerging such as short and steep ramps during the peak hours, oversupply during the non-peak hours, decreased frequency response, and price uncertainty (California Independent System Operator, 2016). Therefore, more adjustments in the system will be expected to tackle with the short sharp changes of net load in the late afternoon brought from midday solar surfeits and steep evening ramps.

As more renewable generation comes online, it will be difficult to meet the steeper ramps only through thermal generation along with GHG emissions. More idle and inefficient plants are required to be dispatched during the peak hours to catch the steep ramps, possibly leading to more backup thermal peaking plants construction and higher GHG emissions from the grid. This could make it more difficult to achieve California's ambitious GHG emission reduction targets 40% below 1990 levels by 2030 (California EPA Air Resources Board, 2017). Additionally, CAISO estimates that renewable curtailment could hit 13 GW by 2024 (Maloney, 2017b). If being stored

and shifted to later use, curtailment will provide a great amount of energy during peak hours. Hence, to ensure the greenness of peaking and ramping needs, the emerging energy storage is a clean solution by charging the curtailment from oversupplied renewable generation and discharging to assist the fast ramps.

GHG Emission Target

California has several GHG reduction targets in relation to different scopes and sectors. The transportation and electrical sectors both have separate GHG reduction goals. California as a state as a cumulative GHG reduction goal for various years, such as 2020, 2030, and 2050. This study focuses on California's 2030 GHG reduction target of being 40% below 1990 levels by 2030. That is a reduction of about 185 million tonnes of carbon dioxide by 2030 (Figure 4).

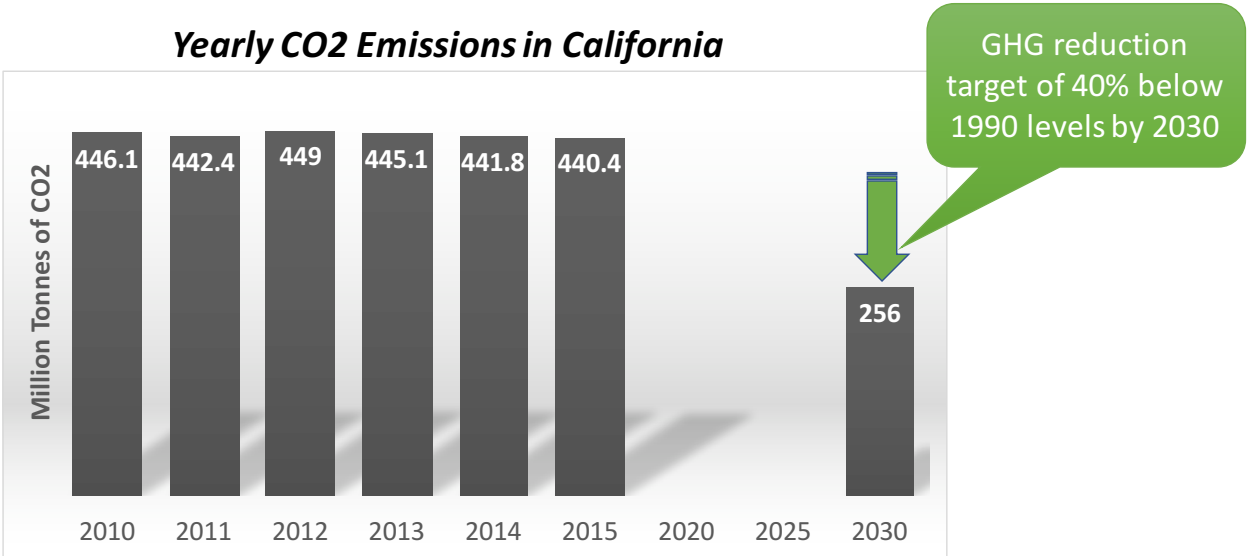


Figure 4. Yearly CO₂ Emissions in California

Source: California Air Resource Board

To help California reach the statewide 40% GHG reduction goal from 1990 levels by 2030, CAISO set up a feasible goal— to emit no more than 42 MMT GHG in statewide electric sector in 2030 (CAISO Integrated Resource Plan 2017). CAISO intends to ensure the effectiveness of GHG reduction as well as the system reliability at the least cost. Consistent with statewide 40% reduction goal from 1990 levels, the 42 MMT target by 2030 substantially indicates a 50% decrease in

electric sector emissions from 2015 levels, and 80% decrease from 1990 levels. This target will reasonably avoid the system and financial risks brought from too aggressive reduction in the near term on the path to ambitious 2050 goals — total statewide 90% GHG emission reduction of 1990 levels.

Moreover, imported generation might be projected to decline due to much lower GHG intensity of in-state generation. In 2015, the GHG intensity of in-state electricity generation in California was around 0.24 tonne CO₂ equivalent per MWh, 25% lower than that of imported electricity generation from other states, 0.32 tonne CO₂ equivalent per MWh (California Air Resources Board, 2017).

Despite a foreseeable lower-carbon generation profile in 2030, CO₂ emission from peak-hour generation is still a big concern. A new operating standard such as CPS requirement becomes essential for CAISO market to guarantee the clean dispatch brought by energy storage. With battery storage discharging during peak hours to meet CPS, it shall effectively reduce the carbon dioxide emission generated from fast-ramping thermal plants during evening peak hours. This new standard will better assist CAISO to control future in-state emission below 42 MMT by 2030.

Research Methodology

Data Source

To inform our analysis, we used data from CAISO Integrated Resource Plan (IRP), California Energy Commission (CEC), and Energy Information Administration (EIA). We analyzed the data from EIA and CAISO to understand the current electricity generation profile in California. Then, we took IRP information as our main assumptions in this study to estimate demand in 2030 and used CEC data to scale solar and wind in 2030 to implement the corresponding capacity projections. Besides determining hourly generation from different power plants and renewable resources, we also used the IRP data to calculate hourly emissions of the thermal resources in 2030 using the given heat rates.

CPUC 2017 IRP

To determine the viability of CPS and energy storage as a pathway for meeting California’s 2030 GHG reduction goals, we first identified the proposed generation mix and the total system load in 2030. We used the latest 2017 IRP (California Public Utilities Commission, 2017a) released by CPUC for thermal, large hydro, and other renewable (non-solar and non-wind) resource mix, and CPUC Reference System Plan (California Public Utilities Commission, 2017b) for solar and wind resource mix. Further, we determined the heat rate, ramp rates, and capacities of various kinds of thermal power plants from the IRP. Finally, as in the IRP, we assumed that large hydro and other renewables see no increase or decrease in installed capacities.

We found that system load is projected to increase by ~10% by 2030. Grid-connected solar will increase by 9 GW to a total installed capacity of more than 20 GW. Behind-the-meter solar will reach 16 GW, for a total solar installed capacity of 36 GW. Wind will increase by 1.1 GW, while thermal capacity will fall by 7 GW to about 35 GW. Finally, large hydro and other renewables capacities will see no change. Our findings are summarized below.

Table 1. System Load Projection (CPUC, 2017a)

<i>System Load</i>	<i>2017 Baseline (GWh)</i>	<i>2030 Projection (GWh)</i>
Electric retail sales	237,605	261,760

Table 2. Overall Resource Mix (CPUC, 2017a)

<i>Resource Type</i>	<i>2017 Baseline capacity (MW)</i>	<i>2030 Default scenario capacity (MW)</i>
In-front-of-meter (IFOM) Solar	11,172	20,172
Behind-the-meter (BTM) Solar	6,000	16,000
Wind	6,269	7,369
Thermal	41,686	34,679
Large Hydro	7,844	7,844

Table 3. Thermal Resources Characteristics (CPUC, 2017a)

<i>Thermal Plant Type</i>	<i>Installed Capacity (MW)</i>	<i>Heat Rate at max power (BTU/kWh)</i>	<i>Heat Rate at min power (BTU/kWh)</i>	<i>Cumulative Ramp Rate (MW/hour)</i>
CCGT Type 1	17,916*	6,865	7,280	11,466
CCGT Type 2	2,974	7,381	7,996	1,606
Peaker Type 1	7,838	9,308	12,904	29,628
Peaker Type 2	2,729	12,110	15,182	9,224
Steam Turbine	652	9,663	17,117	665
Reciprocating Engine	263	9,151	10,893	3,932

*installed capacity includes CCGT1 generation resources from the Los Angeles balancing region

CAISO 2017 Hourly Generation by Source

To interpolate the future generation profile of 2030, we used hourly generation mix of 2017 as a base case to scale up by generation source. The data has a resolution of 24 hours and 365 days, and it was downloaded from CAISO published database.

Current generation mix of CAISO market is diverse (Figure 5). In 2017, thermal power was slightly dominant in the generation portfolio, occupying 28% of the total generation. Imported generation came second with a share of 26%. Renewable generation accounted for 24% of the total generation. Specifically, solar and wind resources represented 11% and 7% of the generation sources. The remaining generation was powered by large hydro (14%) and nuclear (8%).

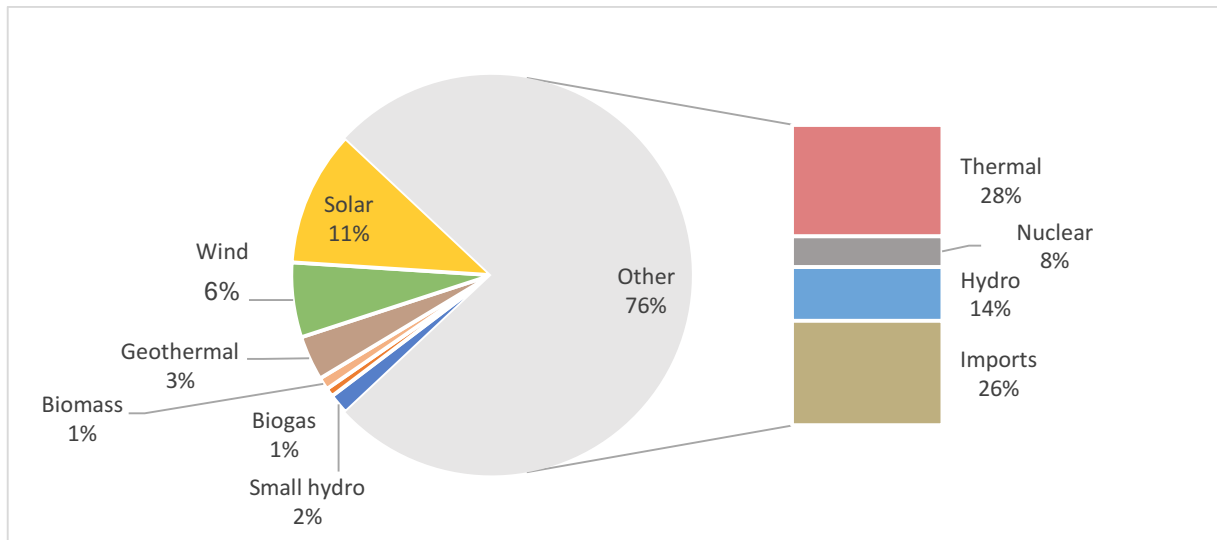


Figure 5. CAISO Generation Mix in 2017

Data source: CAISO

Hourly generation mix varied greatly throughout the day due to volatile renewable generation (Figure 6, Figure 7). In 2017, on average, wind and solar resources reached peak generation around midday, usually between 10 am to 3 pm, and were responsible for more than 30% of the total generation. With renewable generation declining in the late afternoon, thermal and imported generation started to take over. Thermal plants generated over 20% in a given day, and this percentage climbed up to around 35% between 5 to 10 pm. Due to lower total load and the stable imports, imported generation became dominant after midnight and until early morning of the next day, sharing a proportion of over 30%. Though only contributing a small amount, generation from other source types was relatively stable throughout 24 hours, including small hydro, biomass, biogas, geothermal, etc.

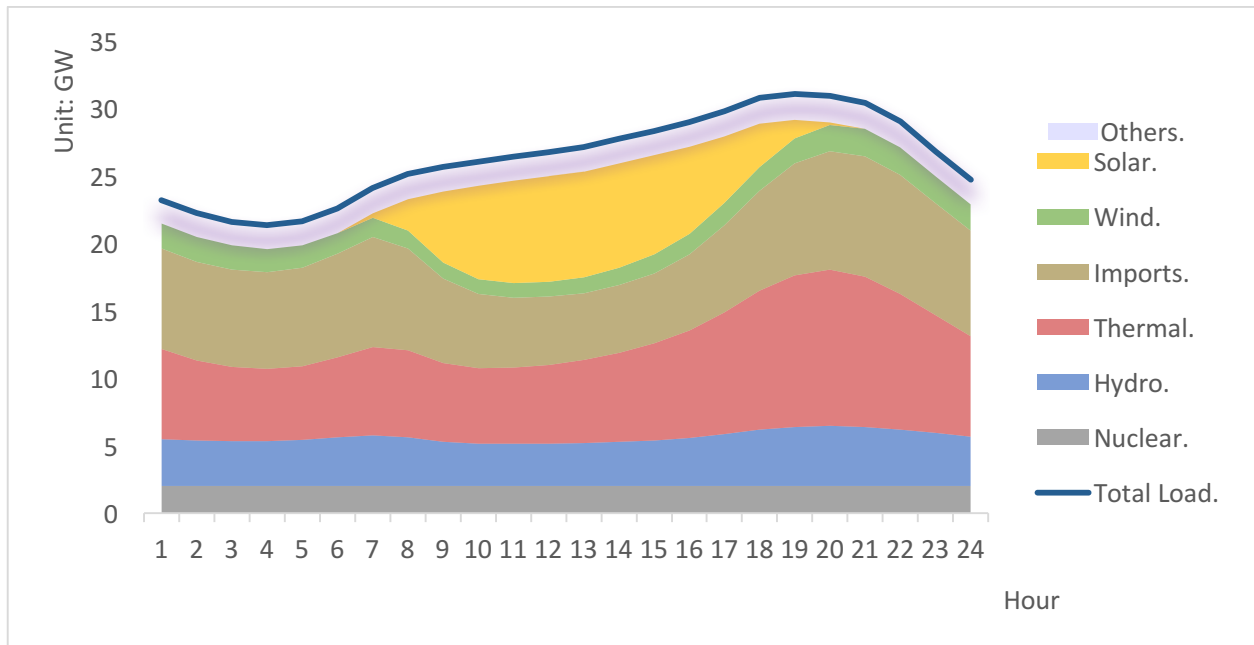


Figure 6. CAISO Hourly Generation Mix of Average Day in 2017 by Generation Source Type (Unit: Gigawatt)

Data source: CAISO

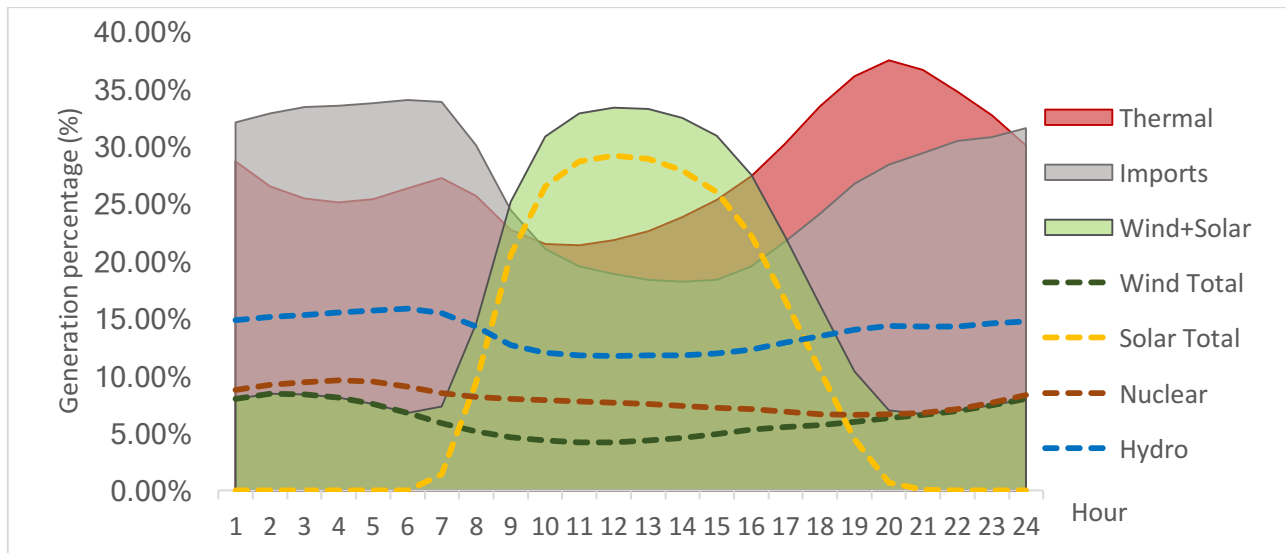


Figure 7. CAISO Hourly Generation Share Change of Average Day in 2017 by Generation Source Type (Unit: %)

Data source: CAISO

In California, the peak hours of net load usually occurred in the late afternoon. As renewables expand and total load increases, the net load duck curve will have a deeper belly year by year, requiring even steeper ramps during 5 pm – 10 pm. In 2017, the total average ramping requirement during peak hours in spring reached up to twice of the netload amount at 5 PM. Regardless of the seasons, the net load peak hours are quite similar throughout the year. Hence, as observed from CAISO historic net load curves from 2011 to 2017, we defined peak hours to be between 5 pm – 10 pm for this study.

Despite renewable energy generating the most electricity during the daytime, a considerable amount of renewable was also curtailed due to oversupply. In fact, only a small amount of curtailment was observed in summer months of 2016 and 2017, usually from May to August (Figure 8). Besides, much more renewable curtailment occurred in spring, especially from February to April, and most curtailment was originated from solar power. In the spring of 2017, solar generation was curtailed four to five times more than wind generation on average (Figure 9). Additionally, renewable curtailment is also projected to become larger in the future, which can potentially provide a clean source for energy storage charging.

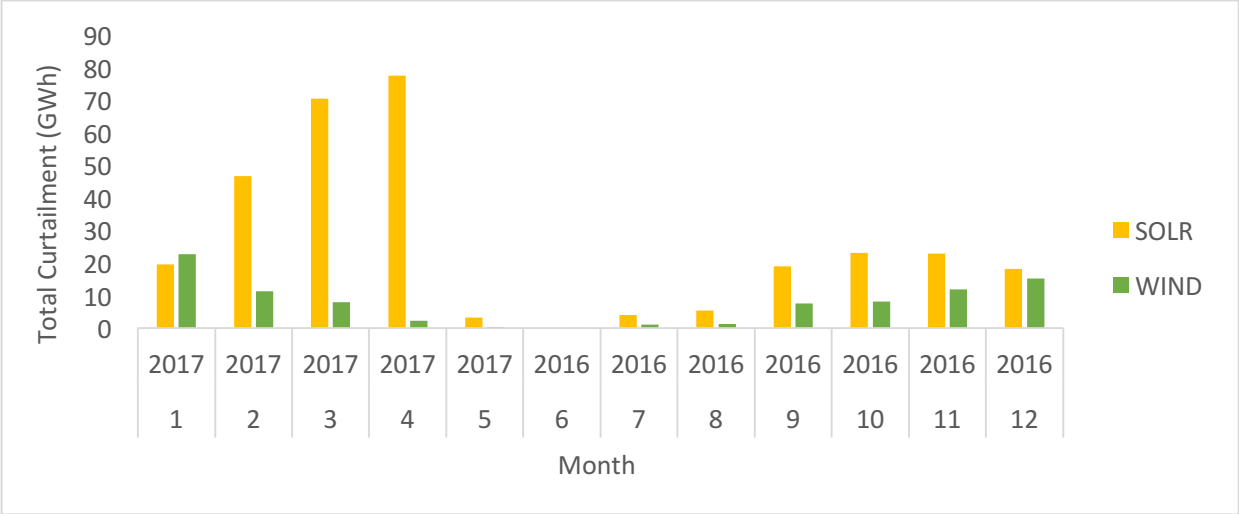


Figure 8 California Renewable Curtailment by Month (June 2016-May 2017)

Data source: CAISO

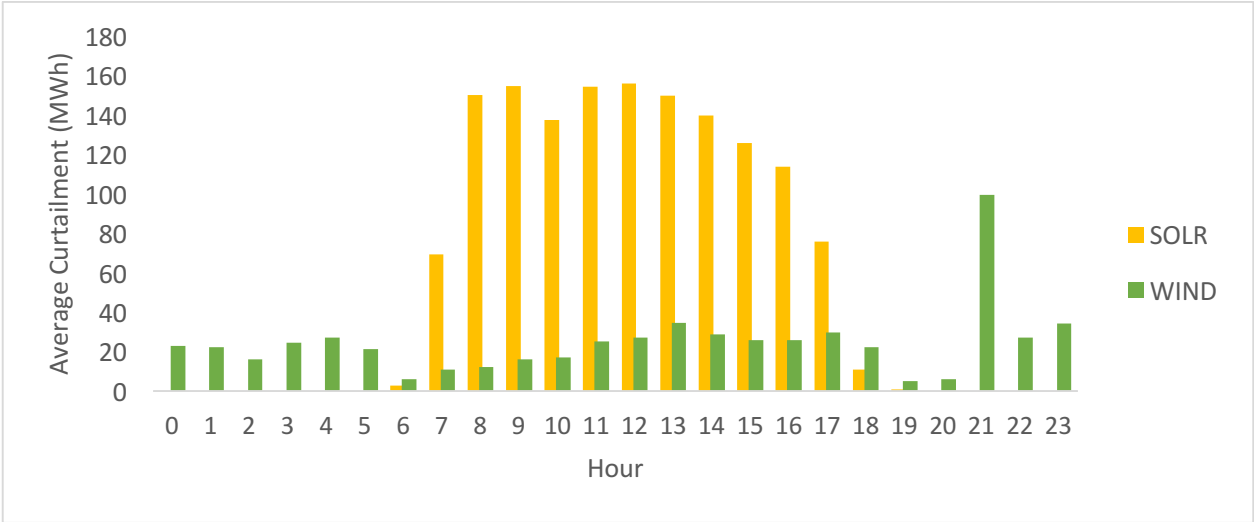


Figure 9 California Hourly Renewable Curtailment of Average Day in Spring (2017)

Data source: CAISO

Methodology Design

Introduction of Modeling Methodology

We established a model composed of three stages to evaluate the effectiveness of carbon emission reduction brought from 40% CPS when dispatching energy storage during peak hours (Figure 10). In this model, the result output of each stage was an input to the next stage. Hence, the stages and corresponding results were closely related in the model.

- **Stage 1** - “*2030 future extrapolator*” was to extrapolate the future hourly generation mix in 2030 from the current generation profile in 2017, including the hourly generation performance of thermal power, solar, wind, imports, nuclear, biomass, etc. Stage 1 assumed that the generation between hours in 2030 will fluctuate the same as that in 2017, and hourly generations of solar, wind, and thermal of 2030 were scaled using capacity increase coefficient with a baseline of 2017.
- **Stage 2** - “*rule-based thermal dispatch*” was to calculate CAISO’s total carbon emission from in-state thermal peaking power plants by optimizing thermal dispatch following certain rules and constraints. It assumed all thermal peaking plants were ready to be turned on or off at any given time. We also assumed that the conventional thermal power system to be investigated consists of CAISO balancing area and Los Angeles Department of Water and Power (LADWP) external zone at a default setting of 2030 in terms of baseload and thermal power plant capacity. The expected results were hourly total carbon emission and hourly average carbon emission rate from thermal peaking power plants.
- **Stage 3** - “*optimal storage dispatch*” was to optimize energy storage monthly charging and discharging strategy with an objective function to minimize total carbon emission, that is, to maximize the total carbon emission avoided by energy storage applications. Stage 3 assumed that ramping capacity of energy storage is very rapid and that there is no minimum charging or discharging period required in battery storage system. Due to CPS, energy storage was also assumed to be dispatched as a priority. The optimal storage dispatch profile was largely determined by the hourly average carbon emission

rate from the peaking plants without energy storage. Hence, energy storage hourly charging and discharging profiles were the expected results.

From the three-stage model, we generated two thermal dispatch profiles from two different situations - without or with energy storage dispatched in the market (Figure 10).

- Assuming a CAISO system without energy storage in 2030, we obtained a first-order thermal dispatch profile by running stage 1 and stage 2.
- For a CAISO system with energy storage dispatched, more steps were required to calculate the daily energy storage discharging requirement to reach 40% CPS. After obtaining an optimal energy storage dispatch profile for low-carbon charging and discharging from stage 3, we re-ran stage 2 of the model and generated a second-order thermal dispatch profile using the adjusted hourly thermal peaking plants load requirement.

Finally, we compared peaking plants dispatch results from the first-order and the second-order dispatch profiles in terms of annual carbon emission, capacity factor of different electricity sources, and annual curtailment. To understand the financial costs of storage systems, we also conducted the cost sensitivity analysis at different scenarios settings on battery cost in 2030.

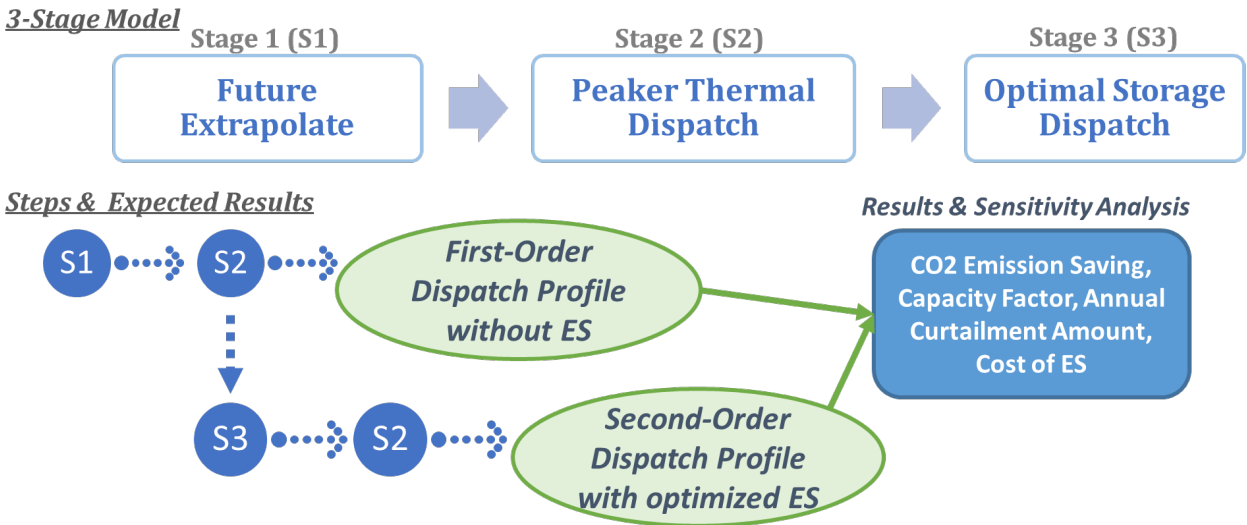


Figure 10. Modeling Methodology

Stage 1 - 2030 Future Extrapolator

In reference to the Projected 2030 Load Generation Profile, Total Load per hour per day in all of 2030 was scaled by using the IRP assumptions. Based on the IRP assumptions mentioned previously, total electricity load would increase by 10%, while in-front-of-meter (IFOM) and behind-the-meter (BTM) solar would increase by 81% and 43% respectively as compared to current hourly total solar generation. Similarly, by using the reported wind generation in 2017 from CAISO and CEC's estimation would increase by 1,100 MW, we scaled wind up by 18% in 2030. Further, we assumed that baseload generation of 2,307 MW in 2017, which includes 1,685 MW of CHP and 622 MW of nuclear, will stay the same in 2030.

We determined curtailment by first assuming that large hydro, imports, and other renewables would remain constant in 2030. Secondly, we needed to determine Net Load. Net Load was calculated by finding the difference between Total Load and the sum of solar and wind for each hour. Lastly, curtailment was calculated by examining if the difference between Net Load, and the sum of other renewables, large hydro, and imports were less than Baseload at a given hour. If the difference were less than Baseload, then curtailment for that hour would be the sum of Baseload, other renewables, large hydro, and imports. If the difference were found to be greater than Baseload, then there would be no curtailment during that hour. Additionally, hourly thermal ramp requirements were determined by finding the difference between the ramp rate from thermal generation from the hour before.

$$\text{Net Load} = \text{Total Load} - (\text{Solar} + \text{Wind})$$

$$\text{Assume } x = \text{Netload} - (\text{Other Renewables} + \text{Large Hydro} + \text{Import}),$$

$$\text{Curtailment} = \begin{cases} \text{Baseload} - x, & \text{if } x < \text{Baseload} \\ 0, & \text{if } x \geq \text{Baseload} \end{cases}$$

Stage 2: Rule-based Thermal Dispatch

In California's power sector, CO₂ emission was mainly generated from either in-state thermal power plants or imported generation. To evaluate the CO₂ emission from in-state thermal plants,

we designed a rule-based dispatch model to simulate the peak-hour operation among different thermal power plant types. In CAISO IRP, some specific characteristics of the thermal peaking power plants are projected from the aspects of capacity, heat rate, ramping capability and minimum ramping up or down time. Hence, we used this information as key parameters to determine a fixed dispatch order and establish some pre-conditional constraints.

Thermal dispatch order: We assumed the dispatch order among different thermal plants is mainly dependent on both minimum ramping up/down time and average heat rate. First, the order of thermal plant dispatch was determined according to the hours of minimum ramping up or down time. Plants with longer minimum ramping up/down time usually have lower resilience to switch on and off, so these plants are more prioritized to dispatch and less likely to be offline. Specifically, CCGT type #1, CCGT type #2, and steam turbine require at least 6 hours for ramping up or down, while Peaker type #1 and Peaker type #2 only need an hour ramping up to full capacity. Thus, CCGT types and steam turbine are generally dispatched prior to Peaker types. Besides, since all thermal plants in California in 2030 will be fueled by natural gas, plants with lower heat rate will be likely to be dispatched earlier due to relatively higher efficiency and lower cost of generation. Therefore, under these two principles, the thermal dispatch order will start from CCGT type #1, CCGT type #2, steam turbine, Peaker type #1 and lastly Peaker type #2, to meet the remaining load aside from base load and renewable load.

Thermal dispatch constraint: In the thermal dispatch of each hour, the power output from each thermal plant type was constrained by capacities and ramp up/down rates. The plant capacity constraint indicates that the hourly power output to be dispatched at an hour should be non-negative and less than the total capacity. Additionally, the ramp rate constraint for each power plant category means that the output difference between two consecutive hours should fall within the defined hourly ramp rate range. With the consideration of these two constraints, Step 2 dispatch model simulated the hourly general generation amount of each thermal power plant type when the total thermal load to be dispatched (excluding thermal baseload) was given.

CO₂ emission calculation: The Step 2 model fits well in the expected thermal power output data excluding the thermal base load. Using the rule-based thermal dispatch model, we were able to identify the hourly generation from each thermal plant type. With the information of CO₂ emission

factors by power plant type, we estimated the hourly total CO₂ emissions from thermal generation as well as the hourly average CO₂ emission of per unit of thermal generation.

Table 4. Thermal Dispatch Order and Characteristics of Thermal Peaking Plants in 2030

Dispatch order	Plant type	Max Power (MW)	Heat Rate	Average CO ₂ Emission (ton/MW)	Ramp rate (MW/hour)	Min Up/Down time (hours)
1	CCGT1	17916 ¹	6865~7280	413.74	11466.24	6.00
2	CCGT2	2974	7381~7996	449.78	1605.96	6.00
3	Steam Turbine	652	9663~1711 7	783.32	665.04	6.00
4	Peaker1	7838 ²	9308~1290 4	649.70	29627.64	1.00
5	Peaker2	2729	12110~151 82	798.29	9224.02	1.00

¹ The maximum power capacity of CCGT type #1 includes 13,703 MW CCGT type #1 from baseline conventional resource in the CASIO balancing area, and 4213 MW CCGT from LADWP external zone (with characteristics very close to CCGT type #1 in CAISO) at the default scenario setting of 2030.

² The maximum power capacity of Peaker type #1 includes 5,555 MW Peaker type #1 from baseline conventional resource in the CASIO balancing area, and 2,283 Peaker from LADWP external zone (with characteristics very close to Peaker type #1 in CAISO) at the default scenario setting of 2030.

Two scenarios to investigate: We applied the rule-based thermal dispatch to two different scenarios of without or with energy storage to compare carbon emission from in-state thermal peaking plants.

We generated the first-order thermal dispatch profile from scenario 1 which assumed that no energy storage system would be installed in 2030. Using the interpolated 2030 generation mix profile, we obtained the hourly thermal power output requirement to be dispatched. In this case,

apart from the base load and the load fed by renewable resources, the remaining load would be only met by thermal peaking power plants.

The other scenario considers the 40% generation share of clean energy aided by energy storage discharging during peak-hour dispatch (5 -10 pm), suggesting less thermal power was required to be dispatched. We regarded this result as the second-order thermal dispatch profile. We used the interpolated 2030 generation mix profile, and then calculated the hourly energy storage requirement based on 40% clean peak standard during peak hours. In this situation, the total remaining load, excluding the base load and the load fed by renewable resources, would be reached by both energy storage discharging and thermal peaking power plants.

Stage 3 - Optimal Storage Dispatch

Once we had determined the projected generation dispatch in 2030, including the estimated curtailment, for each day of the year, we estimated the generation in an average week of each month. Using these average weeks, we built an Excel solver-based optimization model to calculate the ideal storage dispatch schedule for each month.

Before building the model, we determined the size of energy storage required based on a 40% clean peak standard. We used the following equation:

$$ESS \text{ size in MWh} = 40\% * \text{total generation} - (\text{solar} + \text{wind} + \text{other renewables})$$

Note that we assumed peak hours to be 5-10 PM. Thus, in the above equation, the terms “total gen,” “solar,” “wind,” and “other renewables” correspond to the total MWh generated from each source between 5 and 10 PM. Further, large hydro was not considered in the clean peak standard. Using this equation, we determined that the largest storage requirement was 50,533 MWh. Since we assumed an 80% roundtrip efficiency, the storage energy capacity required would be 60,640 MWh. At a constant rate of discharge during the peak hours, this corresponded to 12,128 MW of power capacity.

Next, we determined a set of assumptions for the model, which are summarized below:

- ESS can dispatch energy instantaneously whenever it is called upon
- ESS can ramp up or down at an unlimited rate
- ESS has no minimum up or down time
- Roundtrip efficiency of ESS is 80%, which is accounted for in the equation for state of charge (further below)

The model's objective function was to maximize the CO₂ emissions avoided. Thus, the goal was to charge the battery storage system when the grid's CO₂ emissions were lowest and deploy it when CO₂ emissions were highest. Since curtailed renewable energy is essentially a carbon-free resource, the model gave priority to curtailed energy for charging. If, however, curtailed renewable energy was not enough, the model charged the storage system using the grid when CO₂ emissions were lowest. This ensured that even if some renewable energy was used to charge the batteries, the system load could be met by the cleanest thermal power plants. The optimization and ESS state of charge (SOC) equations are given below:

$$\text{Maximize } CO_2 \text{ avoided} = CO_2 \text{ avoided by deploying ESS} - CO_2 \text{ incurred to charge ESS}$$

$$CO_2 \text{ avoided} = CO_2 \text{ emissions rate} * \text{thermal generation reduced by ESS}$$

$$CO_2 \text{ incurred} = CO_2 \text{ emissions rate}$$

$$* \text{additional thermal generation required to charge ESS}$$

$$ESS \text{ SOC} = (1 - \text{self discharge rate}) * SOC \text{ in previous hour} + \text{roundtrip efficiency}$$

$$* \text{power charged} - \text{power discharged}$$

The constraints for our model are summarized below:

- Storage must only be deployed during the peak hours of 5-10 PM.
- Power charged and discharged from storage must not exceed its power capacity.
- Amount of energy discharged and charged in a day must equal the day's storage requirement (based on the ESS MWh equation above).

- Total energy in storage must not exceed its energy capacity.
- Energy charged must first come from curtailed renewable energy. If not enough, energy charged may come from the relatively clean CCGT type #1 power plants.

On days when curtailed energy was not enough to fully charge storage, the model was forced to increase thermal generation to meet the added load. This, however, meant that the thermal generation profile would change from what we had estimated from our thermal dispatch model (explained in the previous section) before considering energy storage. Thus, we re-ran the thermal dispatch model, compared the increased thermal generation to the original thermal generation (without energy storage), and accounted for any increases in carbon-dioxide emissions in our final results.

Results and Discussion

Stage 1 Result: 2030 Future Extrapolator

Stage 1 results show what the generation mix would look like in 2030 (Figure 11). We determined the maximum one-hour ramp-up for thermal dispatch to be 11,938 MW observed in the month of October, while the maximum one-hour ramp-down was 10,366 MW, taking place in the month of March. Maximum curtailment for a given hour was 18,363 MW in April. Additionally, we determined that a maximum of 50,533 MWh would need to be dispatched from the battery storage system to meet the 40% CPS.

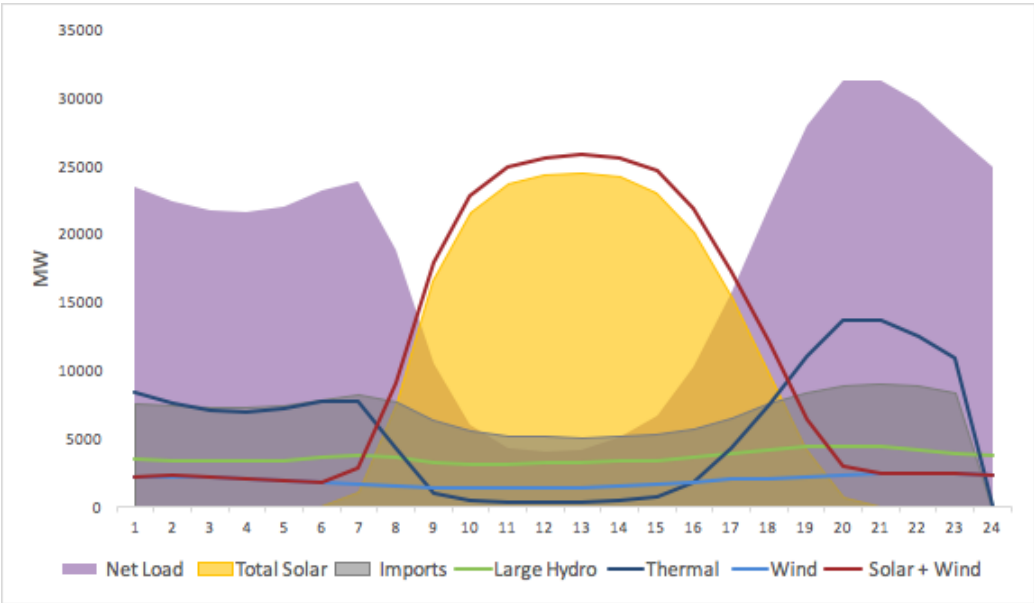


Figure 11. Projected Average Hourly Generation by Type

Stage 2 Result: First-Order Thermal Dispatch Profile

First, we assumed CAISO as a power system without energy storage dispatch in 2030, and then calculated the annual carbon emission of thermal peaking plants using 2030 extrapolated generation mix data from the base case scenario.

Figure 12 summarizes the hourly first-order thermal dispatch performance by thermal plant category on an average day of each month throughout 2030. Electricity output from all generators

is regarded as positive value, measured by the vertical axis on the left. In contrast, energy that is available for curtailment or storage charging is considered as the potential electricity input to the power system and measured as negative values on the right vertical axis.

The amount of thermal netload is a key variable to determine the dispatch profile and generation from different plants in an hour. As seen in Figure 12, apart from must-run baseload (brown shaded area), the rest of the volatile thermal load is met by peaking plants. The load changes dramatically within a day, dropping to the lowest in midday due to massive daytime solar generation but quickly climbing to the peak in the late afternoon till night. In some hours during the midday, usually around 12pm, only baseload will be required, since other loads are met by abundant renewable electricity.

Load volatility also appears to have seasonality, with the highest peak in summer, especially from July to September. Additionally, the lowest peak is likely to occur in spring, usually from March to May. The annual peak load is observed in August with an estimate of over 20 GW. This amount of load to be met by thermal peaking plants in August, is twice of that in April, when the lowest peak load, around 11 GW, will take place in the year. This may be resulted from seasonal electricity demand for different heating or cooling needs as well as seasonal changes of renewable generation.

Taking a closer look, CCGT type #1 plants (orange shaded area) are dominant in the thermal dispatch of all hours. From June to October, more thermal peaking plant categories come online to cope with the evening peak loads at around 7-8 pm, such as CCGT type #2 (dark red shaded area), steam plants (purple shaded area), Peaker type #1 (yellow shaded area), and Peaker type #2 (green shaded area).

In 2030, more wind and solar generation is estimated to be curtailed (gray shaded area) in spring and early summer, specifically from March to June, and the estimated amount is approximately equivalent to 3-4 times of that in winter months from November to February. The renewable curtailment is a potential and ideal clean source for battery charging when battery storage is introduced in the CAISO system.

Monthly Daily Thermal Generation & Curtailment Profile Without ES (2030, CA)

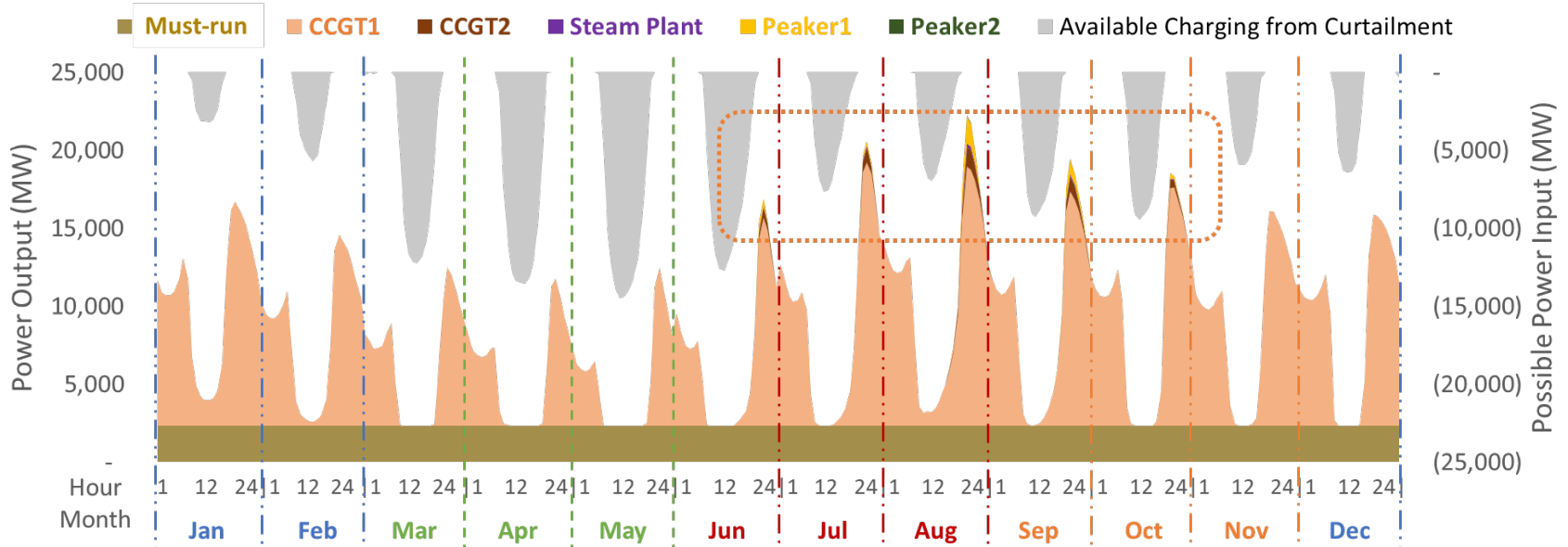


Figure 12. First-Order Thermal Dispatch Profile (No Energy Storage, CA, 2030)

Stage 3 Result: Optimal ESS dispatch profile

Based on equations and constraints explained previously for the optimal ESS dispatch model, Figure 13 below shows a two-day snippet from January of the charging and discharging profile. The model first identified curtailment and charged the system using as much curtailed energy as possible. However, since it was not enough to meet the CPS requirement for that day, it had to dispatch additional thermal generation to charge the ESS. As can be seen in Figure 13, the model successfully identified periods of low CO₂ emissions to charge and periods of high CO₂ emissions to discharge the ESS. Further, note that charging takes longer than discharging. This is because while discharging was limited to the peak hours of 5-10 PM, charging was not constrained. Thus, the model charged the ESS at varying power levels depending on the amount of curtailed renewable energy available and CO₂ emissions rate of the grid.

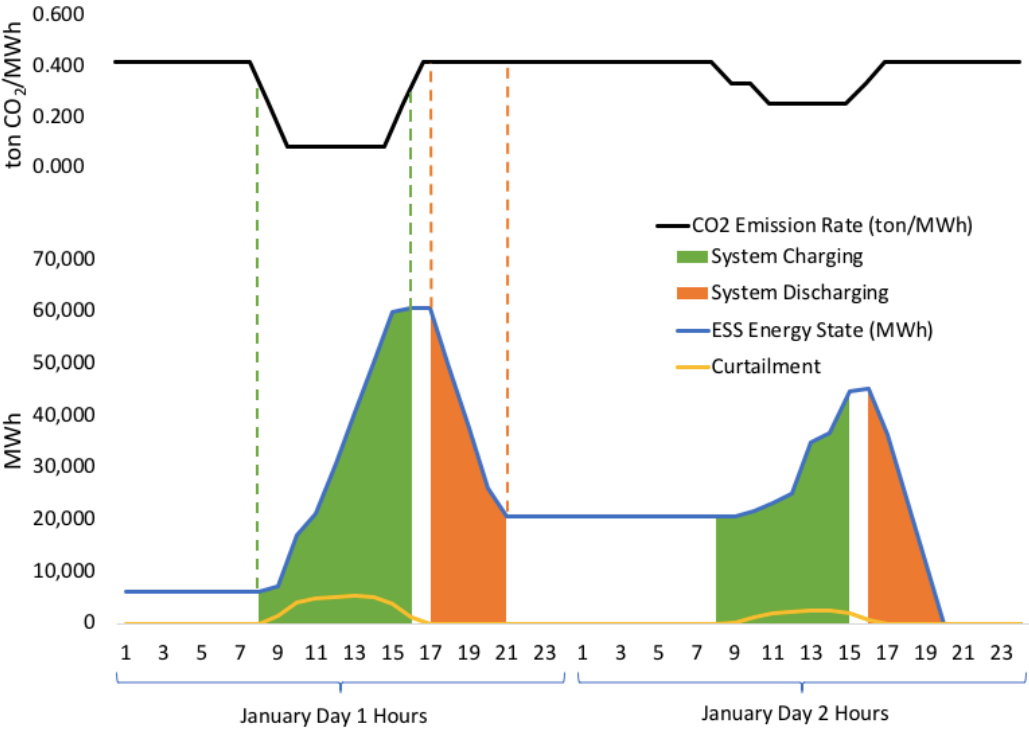


Figure 13. Optimal ESS charging and discharging profile from 2 consecutive January days

This charging and discharging profile is optimal since it charges using curtailed energy and cleaner thermal generation (low CO₂ emission rate) to minimize CO₂ incurred and discharges when the dirtiest thermal plants are in operation (high CO₂ emission rate) to maximize CO₂ reduction.

Result: Second-Order Thermal Dispatch Profile

To meet 40% CPS in 2030, energy storage is dispatched during peak hours, from 5 to 10 PM, throughout the year. In a power system with an optimized energy storage operating strategy, we simulated the hourly peaking plants dispatch and obtained a second-order thermal dispatch profile (Figure 14).

Figure 14 presents the average day thermal dispatch and energy storage charging/discharging performance of each month in 2030. Excluding the must-run thermal load (brown shaded area), the original volatile thermal load from Figure 12 is now met by either thermal peaking plants or energy storage discharging. Thus, despite the same daily and seasonal variations in load requirement, the peaking plants of second-order dispatch profile is greatly alternated due to the participation of energy storage.

Energy storage discharging (green shaded area) is estimated to make a difference in the peak hour dispatch profile, ensuring the clean peak standard of 40% peak-hour generation comes from clean energy. Battery storage appears to discharge more for rapid ramping up requirement at the beginning of peak hour window. Storage does act a key role in peak-hour ramping up till the hour when the highest load is reached, effectively replacing heavier CO₂ emitters among the thermal peaking plants.

Additionally, the amount of battery discharging appears to have seasonal variations. Electricity discharged from battery systems is required much more in autumn and winter, but the required discharging amount appears to be very little in spring and early summer. This phenomenon may be resulted from seasonal volatility of renewable generation. In the months with a low discharging requirement, the renewable generation even during peak hours in California is so abundant that 40% CPS is achievable without much energy storage discharging.

Additionally, we could also foresee a seasonal mismatch between renewable curtailment and discharging requirement from batteries. Battery discharging has quite a different peak season from that of renewable curtailment (gray shaded area). However, renewable curtailment is usually a clean supply for energy storage charging, indicating a charging supply shortage in winter and a supply surplus in spring and summer to charge batteries from clean sources. In other words, more energy is required to charge the batteries in winter to guarantee the 40% CPS than what is available from curtailment, and extra thermal generation is required to fill in the gap.

As seen in Figure 14, the amount of battery charging (blue shaded area) exceeds the total renewable curtailment amount in winter, from November to February. Compared with the first-order thermal dispatch profile (Figure 12), thermal peaking plants are forecasted to have more power output during the daytime in winter months. Though more thermal generation is required to fill the excess load created by battery charging in the daytime, the daytime carbon emission rate of the power system is still low, thus keeping the carbon emission from the extra thermal output relatively low.

CCGT type #1 (orange shaded area) will still play a dominant role among all the peaking plants in the thermal dispatch during most hours of 2030. As for the other thermal generator types, their operating time and the generation amount are significantly reduced, even during the peak hours in the months with higher peak load.

In our analysis, we considered the conventional capacity from both CAISO balancing market and LADWP external zone. Since LADWP is an important contributor to the capacity of CCGT type #1, CCGT type #1 showed very strong dominance in both first-order and second-order thermal dispatch profiles, weakening the generation variations brought by the other power plant categories. If excluding the conventional load from LADWP external zone, we might see more volatile generation shares of all types of thermal peaking power plants in the dispatch profile.

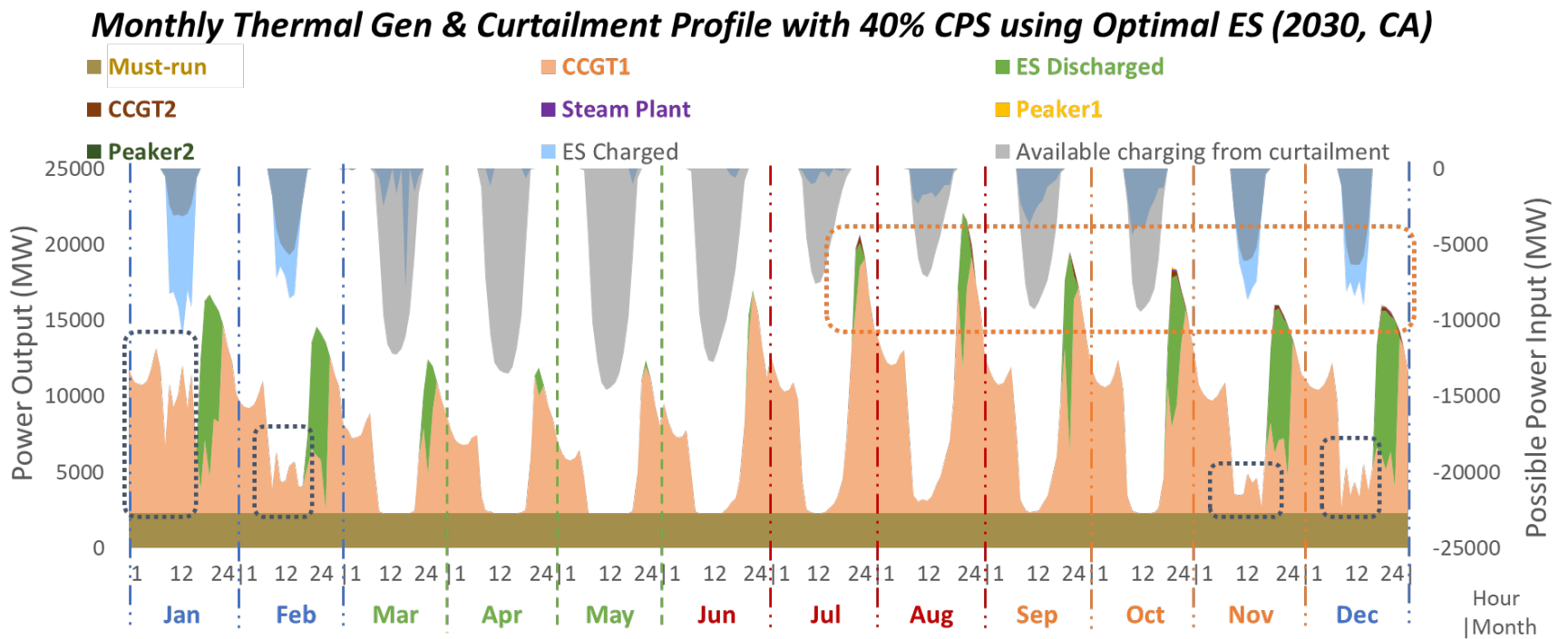


Figure 14. Second-Order Thermal Dispatch Profile (Energy Storage, 40% CPS, CA, 2030)

General Results

Energy Storage Characteristics & Optimized Performance

Putting all the stages of the model together, we were able to come to a few general results, the first being energy storage characteristics with optimization performance. Power capacity needed from the battery storage system was estimated to be 12,128 MW. Energy capacity, considering an 80% roundtrip efficiency was 60,640 MWh from utility scale batteries. Additionally, total energy discharged from batteries per year was 7,608,732 MWh, which accounts for about 32.3% of total curtailed renewable energy, and 12.4% of total electricity demand in 2030.

Annual Emissions with and Sans Storage

Before the integration of a battery storage system, the generation mix in 2030 is estimated to emit 21.87 million tons of CO₂. After the installation of a utility scale battery storage system, the 2030 generation mix would then emit 19.49 million tons of CO₂. That is a difference of 2.39 million tons of CO₂.

Performance of CAISO System with ES and 40% CPS

Other than determining a 10% reduction in emissions in comparison between the 2030 generation mix with and without battery storage, there were some key performance indicators to notice. The first one being curtailment of solar and wind. It was estimated that wind and solar curtailment would be reduced by 35.41% with batteries. Thus, having utility scale batteries, maximizes the full potential of renewables more than just having the resources curtailed during over generation.

The second being the change in capacity factors for renewables (specifically solar and wind), thermal, and battery storage. With a battery system in place, the capacity factor for wind and solar was estimated to increase to 20.92% from 18.73%. For thermal, the capacity factor would decrease from 18.54% to 16.60%, thus slightly reducing the need for GHG emitting plants during the year. The capacity factor for the battery system in 2030 was estimated to be 7.16%, which is very low. This is due to solar curtailment during the summer months, causing low utilization, which drastically brings down the capacity factor.

Cost Sensitivity Analysis

To evaluate the financial performance of carbon emission reduction from 40% CPS using energy storage dispatch, we conducted a sensitivity analysis about different cost scenarios of lithium-ion batteries. We designed three scenarios of low, medium, and high levelized lithium-ion battery cost. The levelized lithium-ion battery cost value was predicted by CAISO (CAISO IRP 2017), including the cost of capital and maintenance. Assuming the battery system is all made of lithium-ion in 2030, we computed the total levelized cost for the CAISO storage system, cost of electricity discharging for companies under the 40% CPS, as well as carbon dioxide abatement cost in each scenario. The formulas of each indicator are listed as below.

$$\begin{aligned} \text{Annual Cost (\$/year)} \\ &= \text{Levelized Cost (\$/MWh} \cdot \text{yr}^{-1}) \times \text{Total Energy Storage State (MWh)} \end{aligned}$$

$$\text{Cost of Discharge (\$/MWh)} = \frac{\text{Annual Cost (\$/year)}}{\text{Annual Electricity Discharged (MWh/year)}}$$

$$\text{CO}_2 \text{ Abatement Cost (\$/ton CO}_2 \text{ avoided)} = \frac{\text{Annual Cost (\$/year)}}{\text{Annual CO}_2 \text{ Emission Avoided (ton/year)}}$$

Comparing the results of three different cost scenarios in 2030, we found that the annual cost could vary greatly from lithium-ion battery costs. The total annual cost of a 12,128 MW battery system is around 1 billion dollars/year in the low-battery-cost scenario, while this value could reach high up to 4.6 billion dollars/year when the battery cost is expensive. Due to 40% CPS, cost of per unit electricity discharging for the companies could range from \$127.52/MWh to \$605.70/MWh depending on different battery costs. It could take \$407 ~ \$1931 to reduce one tonne CO₂ emission by discharging batteries during peak-hour dispatch for 40% CPS. (Table 5)

Overall, achieving 40% CPS by discharging energy storage during peak hours can be expensive. In comparison with the generation cost of natural gas peaking power plants (usually less than \$100/MWh), storage discharging is not economical. In terms of the reliability of market balancing, energy storage may become affordable if compared with the cost in Energy Imbalance Market. In

2017, the maximum value of average electricity price in the real time CAISO market was \$1000/MWh due to the electricity imbalance in some minutes. Referring to average electricity price in 2017, we found that 1.087% of the time, CAISO’s electricity price was above \$127.52/MWh, which is the battery discharging cost in the low-cost scenario from our calculations. When it comes to electricity balancing and ensuring grid reliability, battery storage seems to be a relatively economic approach. Nevertheless, battery storage is still much higher than the average electricity price during most hours. Though the electricity price is likely to be higher when the market comes across peak load during summer months, the hourly average electricity price of these months is still lower than the calculated battery discharging cost (Figure 15).

Capacity factor of energy storage is closely relevant to both the cost to discharge per unit electricity from batteries and the cost to reduce per unit CO₂ emission. 40% daily CPS will lead to a low annual capacity factor of energy storage system and even idleness in some spring and summer months. Hence, the CPS as currently formulated would likely be economically impractical. If the energy storage system has more operating hours guaranteed in a year with a more reasonable revised CPS, the cost of storage discharging could possibly be tremendously reduced.

Table 5. Sensitivity Analysis on Lithium-ion Battery Cost

Scenario	Low Cost	Medium Cost	High Cost
Levelized Cost (\$/MWh·yr)*	16,000	38,000	76,000
Annual Cost (\$/year)	970,233,600	2,304,304,800	4,608,609,600
Cost of discharge (\$/MWh)	127.52	302.85	605.70
CO ₂ abatement cost (\$/ton CO ₂)	406.59	965.65	1,931.30

*Source: CAISO IRP (2017)

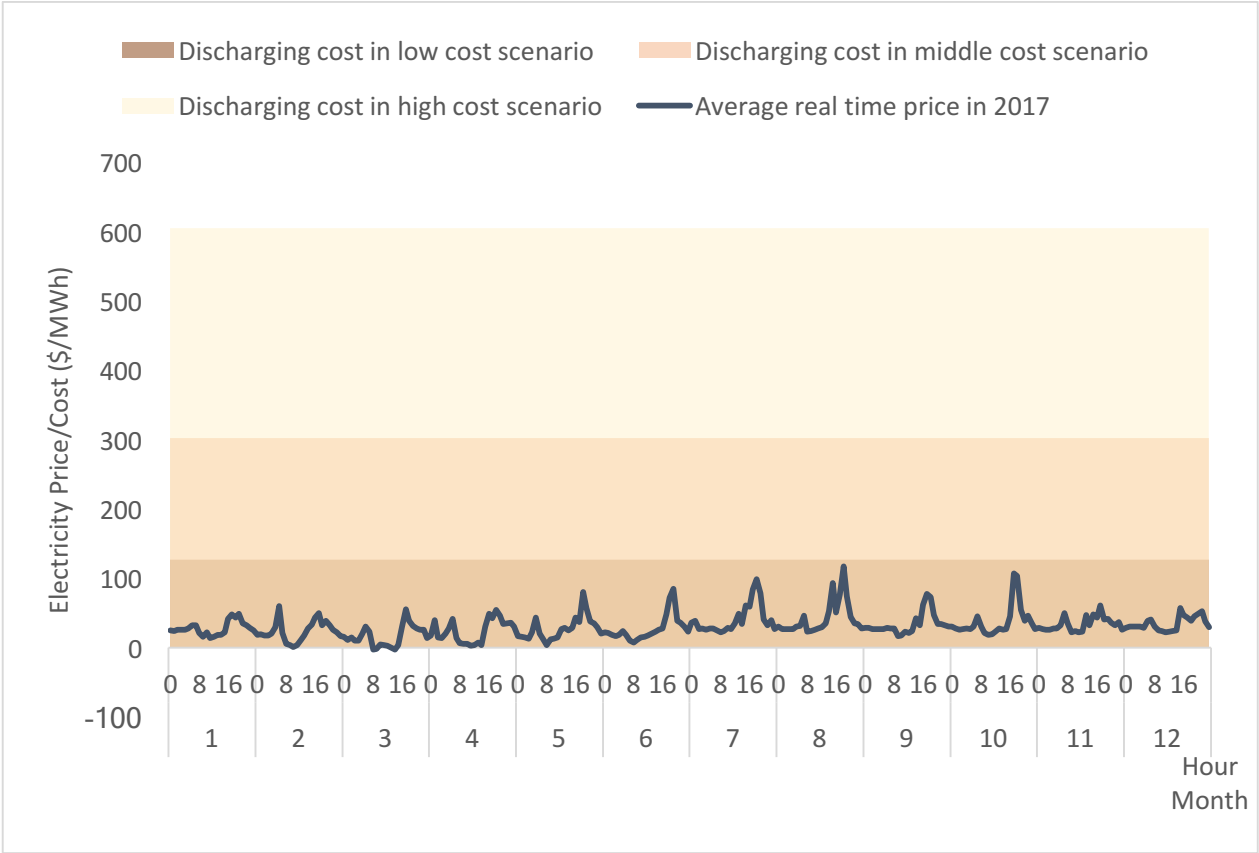


Figure 15. Comparison between Better Discharging Cost from Different Scenarios in 2030 and Electricity Price on Average Day of Each Month in 2017

Source: Energy Online LGG Consulting,

<http://www.energyonline.com/Data/GenericData.aspx?DataId=20>

Conclusions

The total CO₂ reductions were 10% after the deployment of energy storage systems at a CO₂ abatement cost of \$406 - \$1,930 per ton abated. The model found that the maximum one hour ramp up for thermal dispatch was 11,938 MW, observed in October. The maximum one-hour ramp down was 10,366 MW observed in March. Maximum curtailment at any given hour was 18,363 MW observed in April. The amount of storage required was a massive 60 GWh, and the energy discharged annually was 7,600 GWh, resulting in a low capacity factor of 7%. Further, the annual cost was also a prohibitive \$1 – 4.6 billion/year. However, on the positive side, curtailed renewable energy reduced by 35%, while the capacity factor of solar and wind increased, and that of “peaker” plants decreased.

Policy Recommendation

Our analysis found that a Clean Peak Standard with battery storage is a feasible pathway to reduce greenhouse gas emissions in California. However, it is not cost effective if implemented as a daily CPS (daily CPS means that 40% of peak hour electricity must come from clean resources on a *daily* basis). As a consequence, we suggest a new CPS – *annual average CPS*. The new CPS keeps the same percentage, 40%, and the same peak hours, 5-10PM. However, instead of meeting the 40% target every day, system operators will be required to meet the target on an *annual* basis. This allows the CPS to drop to a lower target in the winter months to reduce the ESS size and save costs but increase to a higher target in the spring and summer months to maximize ESS utilization and curtailed renewable energy. As shown previously in Figure 14, due to lower renewable energy generation during the peak hours of winter months, it is impossible to meet the 40% CPS without dispatching some thermal generation and using massive ESS sizes. On the contrary, due to excessive renewable generation during the peak hours of spring and summer months, the 40% target is met using very little storage (Figure 14). Further, it also fails to utilize the vast amounts of curtailed energy – more than 65% of annual curtailed energy is wasted. This mismatch leads to extremely large system size requirements, driving up costs while driving down utilization.

Thus, taking the shortcomings of the daily CPS into account, we recommend an *annual average CPS* with a flexible clean-peak target that may be able to solve the seasonal mismatch issue, increase CO₂ reductions, and make the system cost-effective. Since energy storage systems can

offer ancillary services such as voltage and frequency regulation, black-start capability and fast-ramping capability, we think that with relevant market mechanisms, ESS may even become more cost-competitive than traditional “peaker” plants. Finally, a carbon abatement credit market, where an operator receives monetary compensation for every ton of CO₂ abated, may further make such systems financially attractive.

Limitations of Study

We recognize that since our analysis was designed to merely provide a general overview of the effectiveness of a Clean Peak Standard and energy storage, it suffers from a few limitations. In order to keep our optimization model simple and capable of running on Excel, we chose to ignore the “minimum up/down time” constraint for thermal power plants. This meant that our model could turn on or turn off thermal power plants every hour. In reality, the CCGT type #1 plant from the CPUC IRP has a minimum up/down time of 6 hours, meaning, once on (or off), it must stay in that state for 6 continuous hours. Further, to facilitate comparison between 2017 and 2030, we chose to keep imported energy constant. However, we expect imports to reduce as CAISO expands its renewable and energy storage capacity.

While projecting demand in 2030, we used the default scenario in the IRP. Demand response and/or accelerated adoption of electric vehicles (EV) would not only change the total demand but also change the demand profile. For instance, if EVs were adopted widely by 2030, and people chose to charge at night, net load might peak in the night as opposed to evening. Further, with the advent of smart meters and time-of-use electricity rates, consumers may be more incentivized than currently to reduce their load during peak hours. This means that the net load curve might look different from what we estimated. With the recent reduction in federal Investment Tax Credit for rooftop solar PV systems, the CEC estimation of an additional 16 GW of behind-the-meter solar might be too sanguine. Thus, in 2030, we may not have as much solar as we estimated for our modeling.

Another issue that we did not delve into was using ESS in a price arbitrage model, where the batteries charge when locational marginal price (LMP) is low and discharge to the grid when LMP is high. Since both LMPs and GHG emissions are directly related to total load, their hourly profiles

should be fairly correlated. Thus, while a price arbitrage model for ESS might have results similar to ours, we believe it would be worthwhile to investigate further.

Finally, we acknowledge that many of the CPS's implementation details are still under debate – specifically, whether it should be an annual average (Huber, 2016), or a daily average with varying peak hours (Walton, 2017). AB-1405 suggests having a daily average where the four-hour peak load period is chosen around the hour of the day that exhibits the highest peak demand. Further, it proposes that the CPS must be met at least 15 days in a month. Even though we chose to model with fixed peak hours and a daily CPS, we believe our findings shed light on some of the issues of the policy under consideration in AB-1405. We do not think choosing a peak-hour window based on the day's peak demand would work very well, especially in summer. Further, we do not think it would be a good idea to have the CPS met on a daily basis a minimum of 15 days in a month. Choosing peak load hours based on net load (when thermal generation is highest) as opposed to overall load, and having an annual average CPS would go a long way in maximizing carbon reductions and minimizing abatement cost.

Acknowledgement

We would like to express our special thanks to our project advisor, Professor Lincoln F. Pratson, Ph.D., for his patient guidance and recommendations in this study. We would also like to acknowledge our client, California Energy Storage Alliance (CESA), especially Jin Noh, who kept us updated about the policy trends in California and new discussions in the industry. Without their passionate contributions, our Master's Project could not have been so successfully conducted. Last but not the least, we want to show our profound gratitude to the Nicholas School of Environment at Duke University, for creating such an inspiring learning environment for students like us, who hold enthusiasm about a cleaner energy development path and great ambitions to achieve a more sustainable world.

Annexure

Annex 1. Sectoral Emission in California

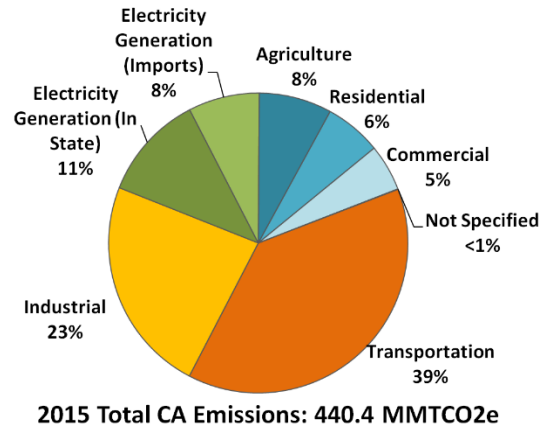


Figure 16. Emission by Economic Sector (California, 2015)

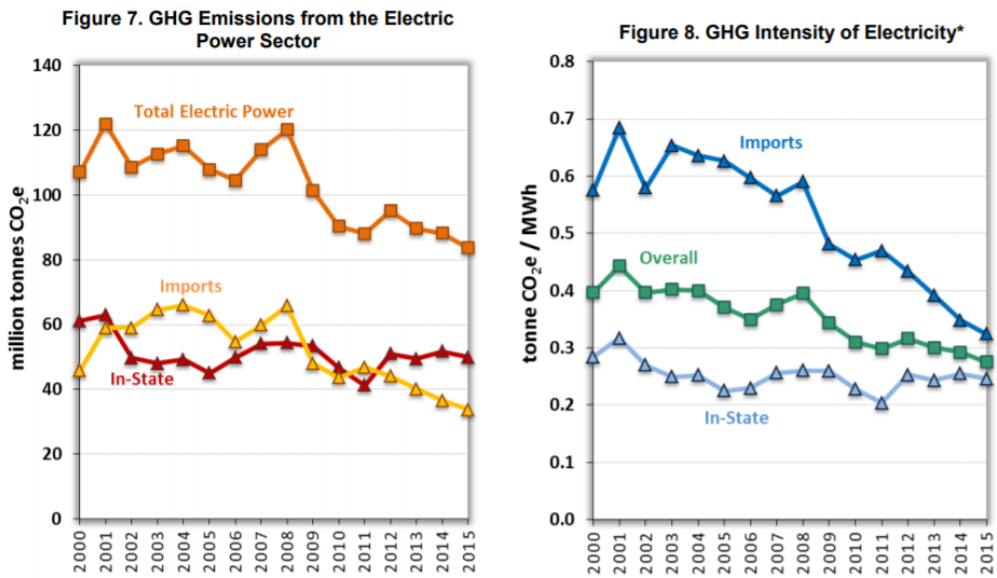


Figure 17. GHG Emission of Electric Power Sector (California, 2015)

Source: California GHG Emission Inventory

https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2015/ghg_inventory_trends_00-15.pdf

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