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DRAFT ELECTRICITY GENERATION TECHNOLOGY SUMMARY

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Executive Summary

This Electricity Generation Technology Summary gives an overview of renewable electricity generation technologies. It is organized to summarize:

- The generation resources available to California
- How these generation resources affect the amount and types of storage that California will need
- Data to use for modeling inputs in RESOLVE and SWITCH.

California is blessed with abundant solar resource that is widely estimated to be adequate to supply all of California's energy needs. California also has access to hydropower, wind energy, geothermal, and biomass as valuable, but less abundant, renewable generation resources. The choice of the renewable generation resources, including the location and design of those systems, will have a profound effect on the needed storage.

Our calculations suggest that a solar dominant grid requires about a quarter of a TWh diurnal storage that we expect will be used many days throughout the year. This estimate is based on today's electrical loads and could double as the average electrical load increases. The amount of diurnal storage that is needed is unchanged when wind is added to the solar-dominant grid but adding significant wind generation (which may blow more at night) reduces the frequency with which the diurnal storage is used.

The required amount of cross-day storage (storage that is charged on one day and discharged some days later as may be required during a multi-day storm) is highly variable but tends to increase when more wind generation is used.

Substantial seasonal storage will be needed to supply electricity during the winter for the most probable scenarios. The amount of seasonal storage needed can be greatly reduced by adjusting the generation profiles in any of the following ways:

- Overbuild the generation, identifying new springtime and flexible loads (such as for electrolytic hydrogen generation), then curtailing output that can't be used
- Select solar plant designs that give more consistent generation throughout the year by, for example, using south-facing latitude tilt or increasing the DC-AC ratio
- Use wind resources that generate more wind in winter – some of these exist in California, though they are easier to find in the Rocky Mountains
- Use high-capacity-factor offshore wind, giving more consistent output year-round, though these can increase the need for cross-day storage
- Use more geothermal or biomass; biomass coupled with the Allam cycle may enable negative carbon emissions while reducing need for storage, especially if biomass use can be optimized seasonally
- Import electricity from other states that have electricity available at the needed times.

This summary, combined with the Storage Technology Summary, lays the groundwork for subsequent modeling to quantify the value of long-duration storage. It does not discuss nuclear power, because California is not currently planning to deploy more nuclear power generators.

Natural gas or biogas used with the Allam cycle may provide a relatively clean alternative to all-renewable scenarios.

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1. Introduction

Modeling grid operation to fully understand the potential value of long-duration storage is built on an understanding of the generation profiles. The sun shines during the day, though some days are cloudy. The wind in some locations blows more at night, but not every day. The storage that is needed to fill the gaps will be intimately dependent on the details of the generation and fluctuations of the load, including local fluctuations. Though the generation profiles will be unpredictable in some ways (we don't know when the wind will stop blowing), the profiles are very predictable in other ways (the sun never shines at night). Hourly resolution models can help for decades-scale planning of generation adequacy. While we don't know the minute-by-minute fluctuations of when wind and solar may be available due to weather, we are able to estimate on an hourly to annual scale good representations of the available resources.

Prices for solar and wind plants have dropped impressively. The prices for geothermal, biomass, and others could also drop in the coming years. So, in this report we discuss most types of renewable generation.

We also discuss some non-renewable generation sources. While California has a preference for solar electricity, it is useful to understand the benefits and challenges of all renewable options that might affect how we use storage.

There are many factors to consider when modeling the entire energy system. We have done preliminary work to identify factors that will greatly affect the outcome of our studies. For example, there is general agreement that the state of California can provide ample solar energy. In contrast, modeling often selects to build all wind that is offered to the model. The addition of wind generation to solar generation makes a large difference in the amount and usage of storage, so understanding the wind generation possibilities is a priority.

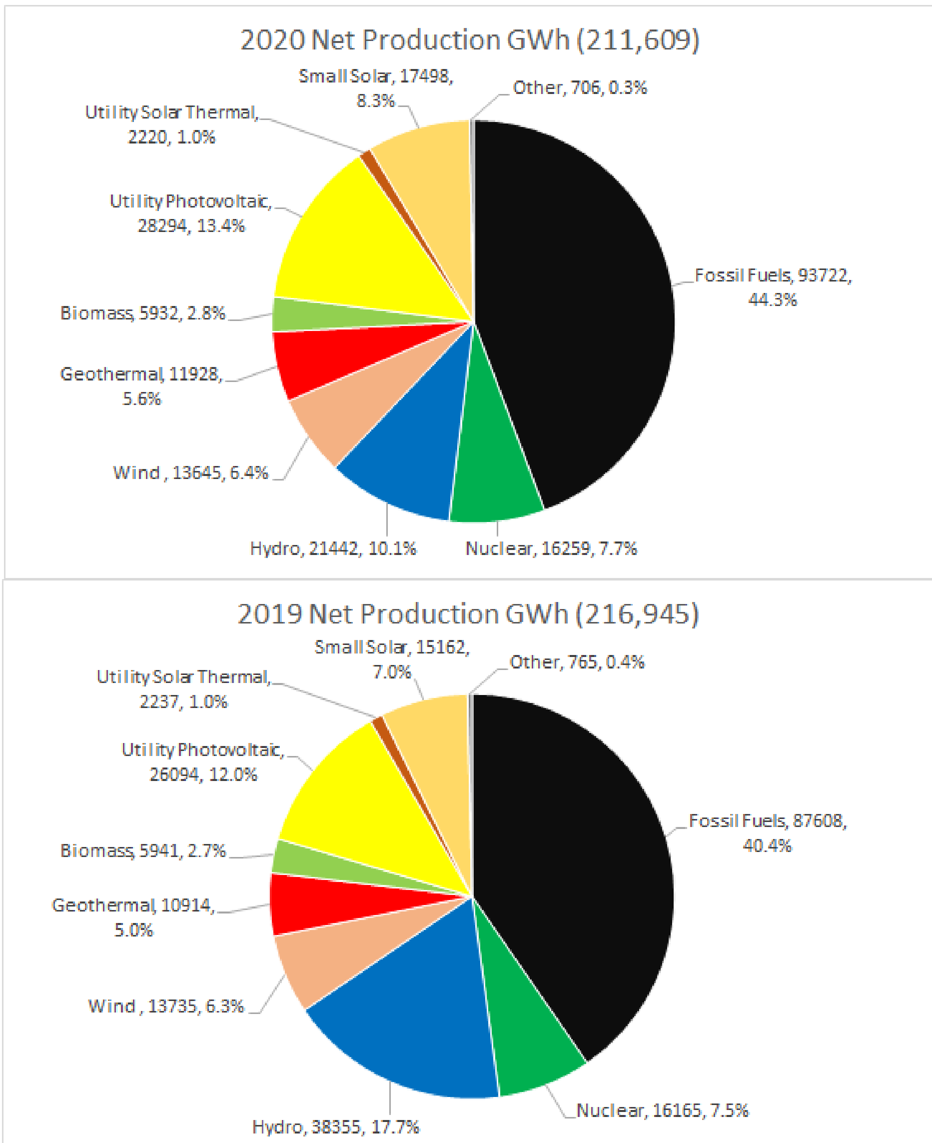
Additionally, solar generation profiles can vary according to the orientation of the solar panels and other system design elements. Given that solar electricity may be the primary source of renewable electricity in California, understanding these options may turn out to be key.

In the end, the types of generators that California installs will be a key determinant of the amount and types of storage that will be needed to manage daily, cross-day, and seasonal needs. While a study to understand the value of long-duration storage would naturally focus on a study of the storage, we assert that the generation profiles that are put into the model can have a profound effect on the value of long-duration storage.

This summary is complemented by a companion analysis of storage technology. Together, these two summaries lay the groundwork for modeling the roles and value of long-duration energy storage toward decarbonizing California's energy system.

2. Generation resources available in California

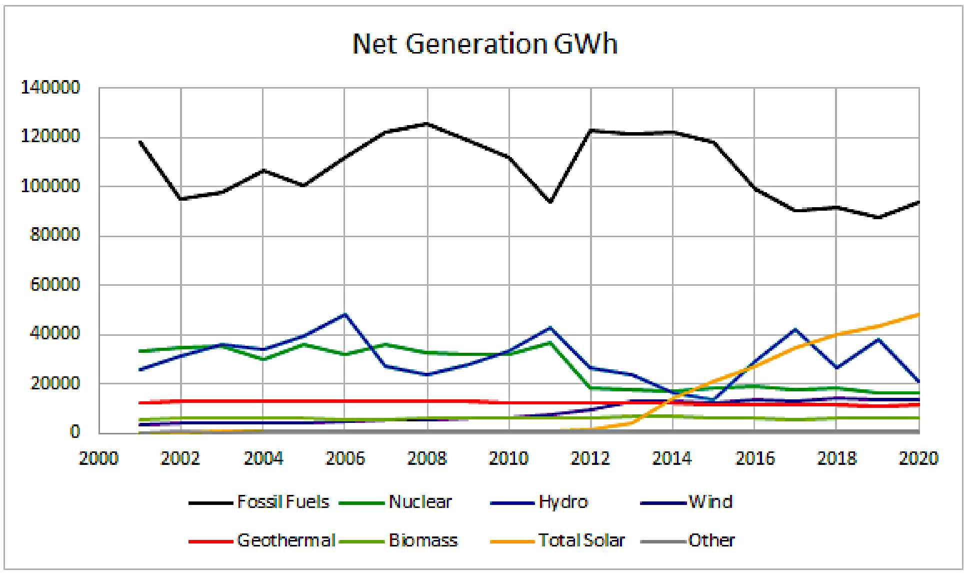
Figure 2.1 shows the breakdown by source of the 2020 and 2019 net generation in California across all sectors, including utility scale generation and local production for on-site consumption. Solar production is broken up between utility scale production (both photovoltaic and solar-thermal) for large scale retail energy production and "Small Solar" for distributed production such as solar panels attached to residential or commercial/industrial buildings.



[1]

[1] https://www.eia.gov/electricity/data/browser/

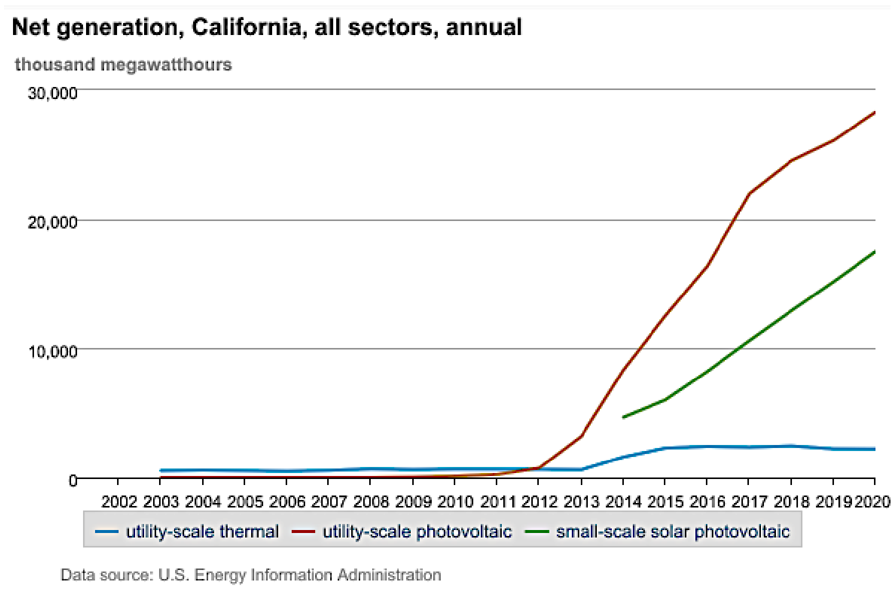
Fossil fuel electricity generation in California consists almost entirely of natural gas. Natural gas electricity production in 2020 increased over 2019 as generation from hydro dropped precipitously. Solar production grew, though not enough to make up the difference. Other sources remained relatively stable, with small increases in their proportion of the total due more to the drop in hydro than their own modest growth in production. Figure 2.2 shows the broader trend over the past 20 years, with changes to fossil fuel generation driven primarily by the cyclic rise and fall of hydropower in response to drought, and to a secondary extent by the sudden drop in nuclear generation in 2012 (following the shutdown and closure of the San Onofre Nuclear Generating Station) and the steady growth of solar generation over the past 7 years. Geothermal, biomass, and wind have remained relatively flat over the same period.

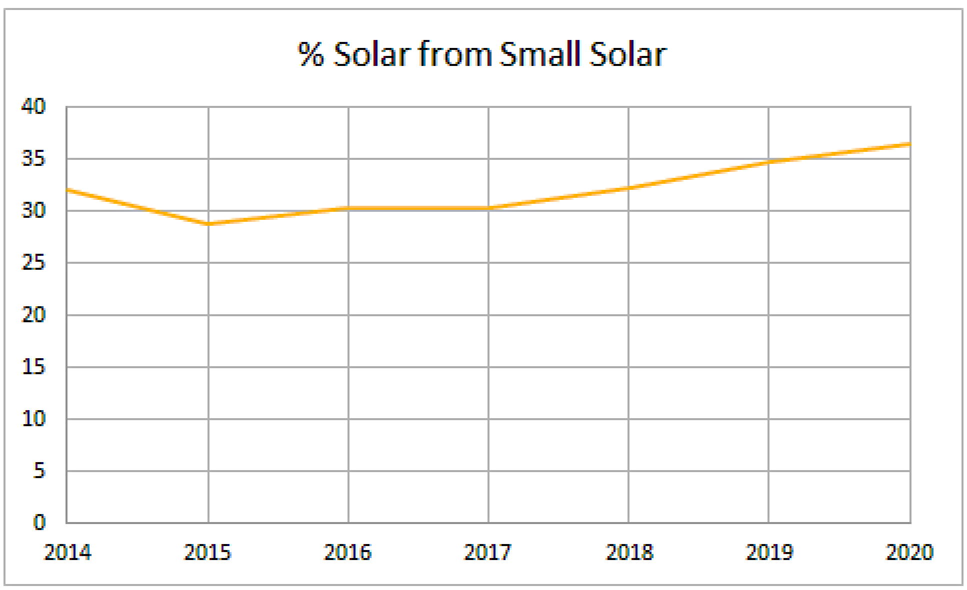


[2]

Prior to 2012, solar generation was dominated almost entirely by solar-thermal systems, which turn solar irradiance to heat that is then used to generate steam. After 2012, solar-thermal systems were quickly overshadowed by photovoltaic systems in the form of both large utility-scale solar generators and distributed small-scale systems, as shown in Fig. 2.3 below. Though this production is still dominated by utility-scale systems, Fig. 2.4 shows how the growth of small-scale systems has steadily been closing the gap over the past 5 years.

[2] https://www.eia.gov/electricity/data/browser/





California also remains one of the top importers of electricity nationwide. Fig. 2.5, based on CEC data, shows the breakdown of 2020 imported energy by source where known. Imported energy appears primarily split between wind, fossil fuels, and hydro, followed by nuclear and solar. This electricity comes from different states in the Western Electricity Coordinating Council (WECC), and some participating areas in Canada and Mexico. In summer of 2020, the California Independent System Operator (CAISO) began to document that during high loads, instead of increasing with higher load, the imports began to decrease slightly, presumably because of similarly high demand in nearby regions. We anticipate that as neighboring states transition to using more solar electricity and reduce their reliance on natural gas, they will be less prepared to provide substantial electricity during times of high demand. Thus, in our analysis we consider the need for resource adequacy without imported electricity, while also considering the effects of imports on the use of storage.

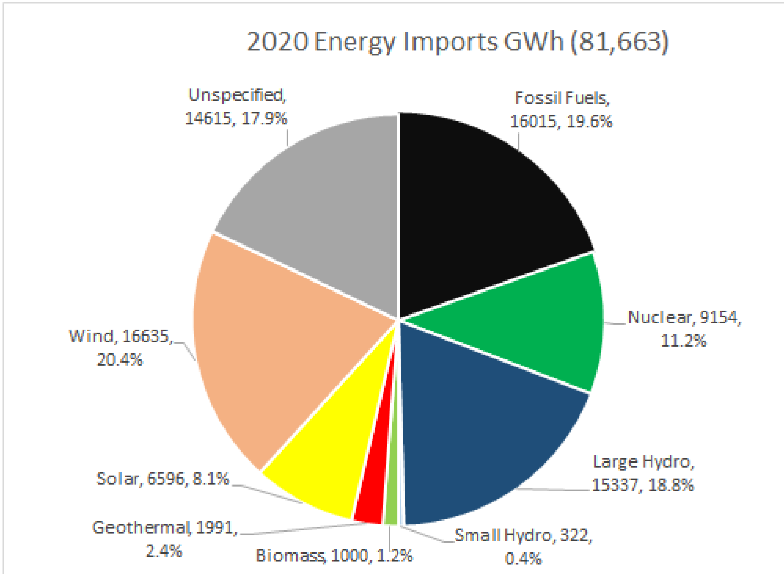


Fig. 2. 5 Electricity imported into California in 2020[3]

2.1 Solar

Solar energy is anticipated to continue to be the dominant source of renewable electricity within California. Fig. 2.6 shows how the southern part of California has some of the best solar resource in the United States. Even northern California receives more than the majority of the United States. As shown in Fig. 2.1, in 2020, solar represented > 22% of California's generation mix. As shown in Figs. 2.2 and 2.4, the rate of growth of solar has slowed in California, but it is still growing faster than any other renewable electricity source and is likely to continue to be the largest renewable electricity source in California.

[3] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation

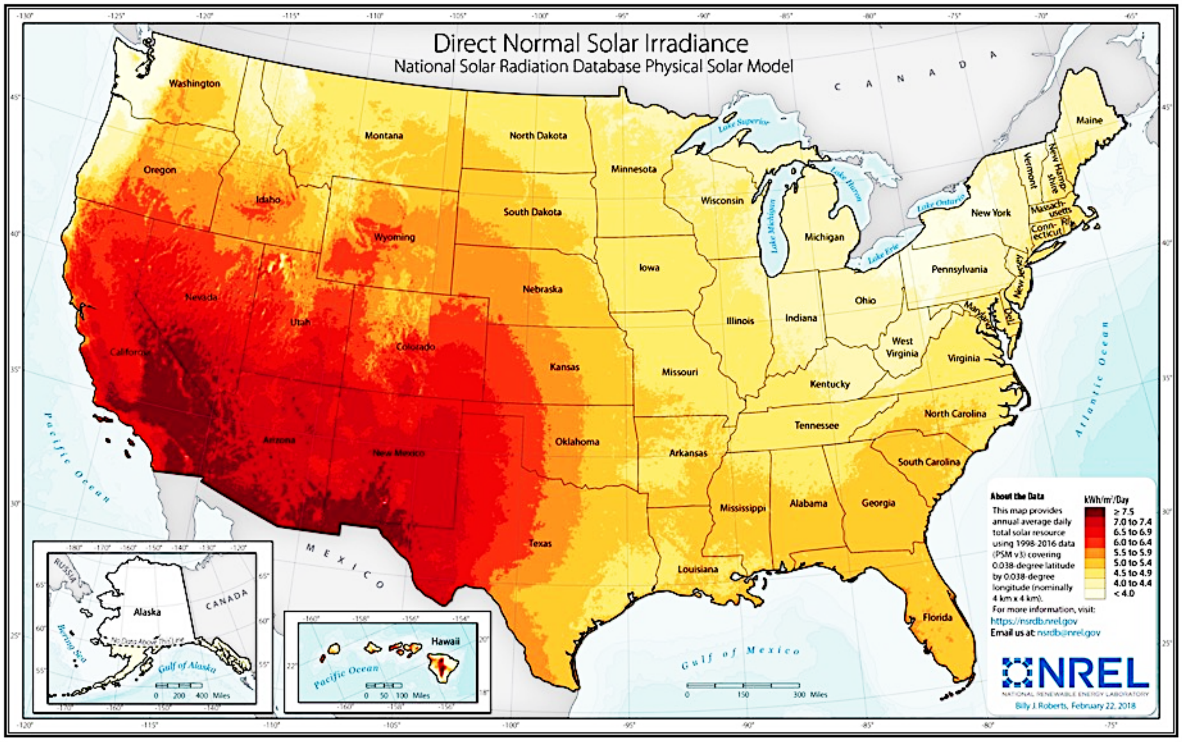


Fig. 2. 6 Annual direct-normal solar resource in U.S.[4]

The map in Fig. 2.6 helps to identify that the solar electricity generation in southern California is greater than that in northern California and that solar electricity generation inland is better than along the coast. However, more people live near the coast and fewer live in the desert, creating a need for transmission of the solar electricity if the solar resource in the desert is to be fully utilized.

As will be discussed later, the solar resource depends on the orientation of the surface of the solar collector. Fig. 2.6 shows the direct-normal solar resource; similar maps may be found for global horizontal insolation or created for any desired orientation. All of these show that California has greater solar resource than other states, with only Arizona, New Mexico, and Nevada having similarly large solar resource.

All analyses we found of solar energy in California concluded that it would be possible to build as many solar plants as are anticipated to be needed. However, there is usually some opposition to building solar plants when the land is wanted for some other purpose, such as keeping the land undisturbed for the benefit of the natural ecosystem. Thus, while it will be possible to build enough solar to deliver the electricity needed for any scenario, it would be preferable to minimize the need for solar deployment on undisturbed lands.

[4] https://www.nrel.gov/gis/assets/images/solar-annual-dni-2018-01.jpg; Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby. 2018. "The National Solar Radiation Data Base (NSRDB)." Renewable and Sustainable Energy Reviews 89 (June): 51-60.

California's movement toward requiring solar photovoltaic (PV) panels on buildings is one strategy for capturing the solar energy without needing to dedicate land, but other dual-use approaches may also be useful. Examples include floating PV, solar canals, agrivoltaics (when solar panels share farmland), and solar coverings of parking lots.

2.1.1 Effect of orientation on storage needs

The east-west orientation of solar panels affects the need for storage in the morning as the sun is rising and in the evening as the sun is setting but has less effect on storage needed in the middle of the night or on longer time scales. The location and extent to which the systems are tilted toward the south will have a greater effect on the seasonal storage, as shown in Fig. 2.7, which compares the average solar insolation as a function of month of the year for two locations using three mounting configurations. Arcata is located in northern California, so experiences greater variations in the length of the day between summer and winter compared with locations in southern California. Daggett is located in the desert in southern California, so receives more sunshine than Arcata. For solar panels mounted in a horizontal orientation with one-axis tracking, the ratio of the peak monthly average (June) insolation to minimum monthly average (December) insolation is 3.75 for Arcata and 2.9 for Daggett (solid black lines in Fig. 2.7). If the daily load is relatively constant through the year, such variations in electricity generation will cause either an oversupply of electricity in the summer or an undersupply in the winter.

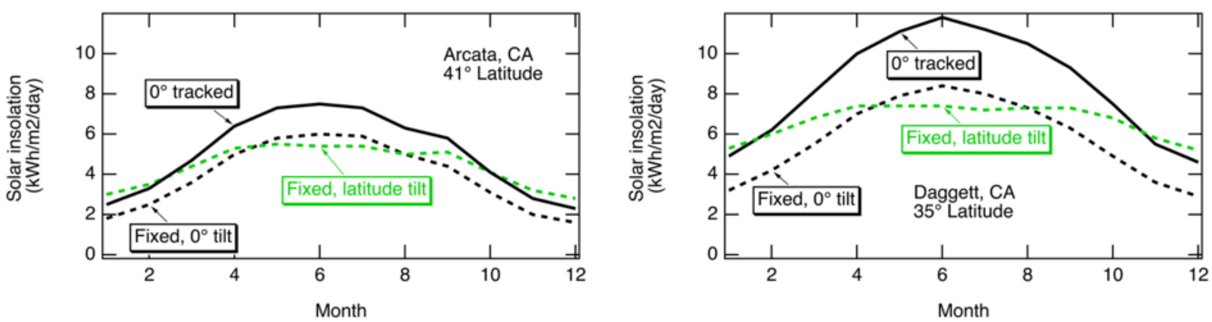


Fig. 2. 7 Monthly solar insolation as a function of mounting configuration (30-year median)[5]

Near-horizontal mounting is often used on flat roofs, reducing cost because reduced wind loading enables use of less expensive mounting hardware. For solar panels with fixed mounting and south-facing latitude tilt, the 3.75 and 2.9 ratios of maximum monthly summer insolation to minimum winter insolation is reduced to 2.0 for Arcata and 1.4 for Daggett, providing significantly more consistent output over the year. Latitude tilt mounting is often used on south-facing roofs with a slope that matches the latitude. Despite giving more electricity generation, use of latitude tilt is not so common. Latitude tilt on flat roofs or in a field can increase costs because wind loading requires use of more expensive mounting hardware while added spacing between rows of panels is needed to avoid shading between rows. Despite the challenges of using south-facing tilt, the seasonal variation in output is reduced by almost a factor of two, suggesting that mounting solar panels to face south may become more of a priority as wintertime electricity generation becomes a priority for a decarbonized grid. Southern siting helps to both increase the average output of the solar panels and to reduce the seasonal variation in the generation. The seasonal variation is not only

[5] https://nsrdb.nrel.gov/data-sets/archives.html

because of the length of the day and the position of the sun in the sky, but because seasonal weather patterns typically bring rain throughout California primarily during the winter.

The use of tracking increases the output near sunrise and sunset but does not make a substantial difference in the seasonal variation as can be seen in Fig. 2.7. Most utility-scale systems today use one-axis tracking with no south-facing tilt, since this configuration has generally been found to optimize the ratio of the electricity generation to the system cost. This optimization may be revisited as storage is increasingly needed to facilitate use of solar electricity when the sun isn't shining.

The data in Fig. 2.7 compare the solar resource (insolation) on different mounting surfaces. Solar electricity generation is mostly proportional to the insolation, but also is somewhat dependent on the temperature and other factors. To better quantify this, the solar electricity generation for a typical year was simulated by PV Watts[6] for a specific location with latitude of 37.29 and longitude -120.5 and is compared with the measured[7] solar generation and load for 2019 CAISO (representing most of California) in Fig. 2.8. The simulations used a DC-AC ratio of 1.2. The current solar PV capacity for CAISO was estimated to be 12.75 GW based on CEC data.[8] The PV Watts simulations used default assumptions and were scaled to the 12.75 GW for more direct comparison to the measured data. As would be hoped for, the general shape of the observed data is similar to that of the simulated 1-axis tracked data, reflecting this being the most common orientation for PV systems today. The fixed latitude-tilt simulated data (dotted blue line) show a greatly reduced seasonal effect relative to both the 1-axis-tracked horizontal simulation (black line) and the observed (red line).

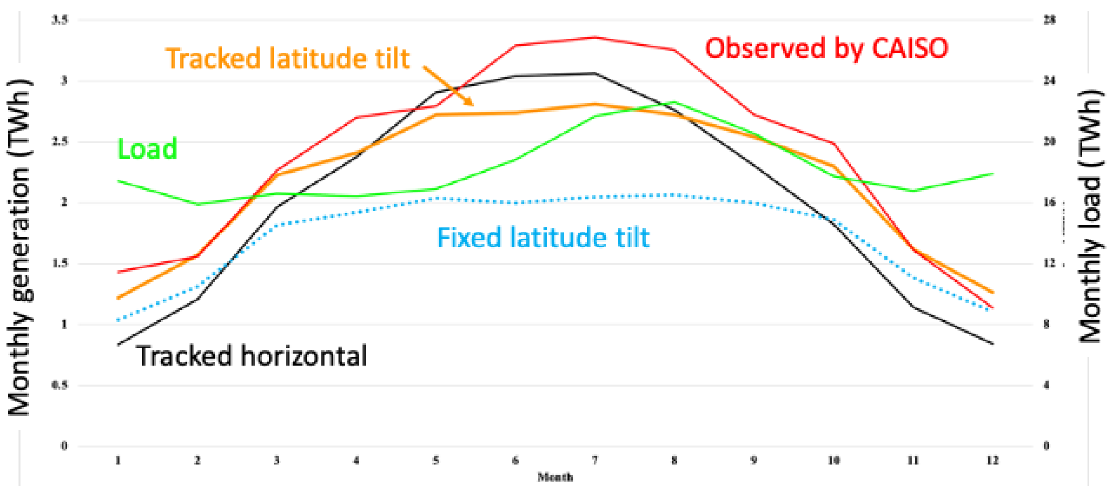


Fig. 2. 8 Simulated monthly solar electricity generation for three mounting configurations compared with solar electricity and total load reported by CAISO for 2019

[6] https://pvwatts.nrel.gov
[7] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx
[8] https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/index_cms.php

Using an energy balance approach[9] and adding solar generation as modeled in Fig. 2.8, the effect of orientation on the needed seasonal reservoir is shown in Figs. 2.9 and 2.10 for total generation of 105% and 135% relative to the total load respectively. The fixed latitude tilt in these cases reduces the needed seasonal storage by about a factor of two or three. Thus, the selected orientation can have a large effect on the needed storage.

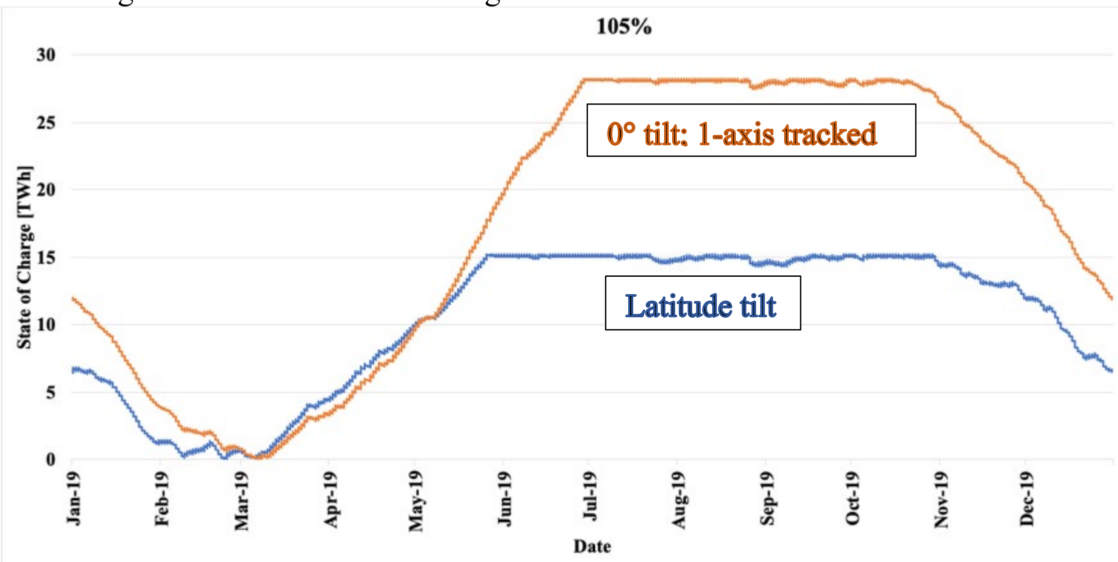


Fig. 2. 9 State of charge of storage using 2019 CAISO load and generation data, but replacing thermal and imported generation with the indicated solar generation to meet 105% of the load

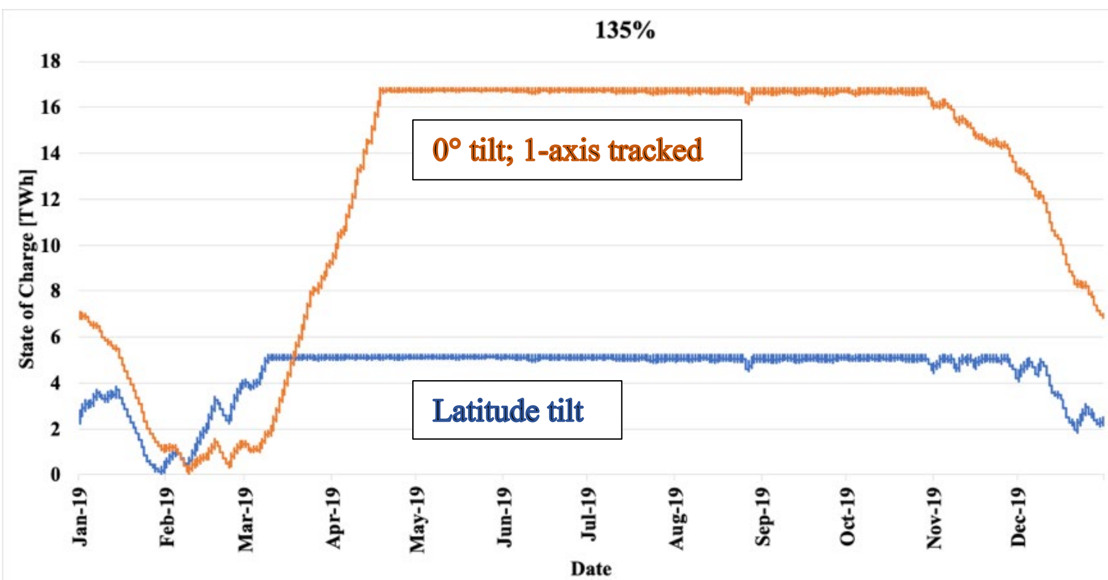


Fig. 2. 10 State of charge of storage using 2019 CAISO load and generation data, replacing thermal and imported generation with the indicated solar generation to meet 135% of the load

[9] M. Y. Abido, K. Shiraishi, P. A. Sánchez-Pérez, R. K. Jones, Z. Mahmud, C. Sergio, N. Kittner, D. M. Kammen and S. R. Kurtz, "Seasonal Challenges for a Zero-Carbon Grid," in 48th IEEE Photovoltaic Specialists (PVSC), Miami-Fort Lauderdale, FL, 2021.

2.1.2 Effect of DC-to-AC ratio on storage needs

Another strategy for using solar design to reduce needs for storage is to use higher DC-to-AC ratios. The DC power rating is obtained from the sum of the module power ratings. The AC power rating is determined by the output of the inverter. The output of solar panels is typically less than what the given power rating because of the irradiance being low or the temperature being high in addition to efficiency losses associated with the inverter. Thus, using smaller inverters can better match the solar DC output to the inverter input, but intentionally undersizing the inverters can provide higher capacity factors.

The use of high DC-to-AC ratios can be implemented in multiple ways. One is to accept the losses during times of high output and then run the plant at a higher capacity factor. The second is to install batteries to be charged and then discharged. We intend to explore the potential for both of these approaches and expect the added benefit to be dependent on the orientation of the array, as discussed in section 2.1.1.

2.1.3 Effect of solar modeling assumptions on storage needs

A summary of the strategies that can be used that affect the amount of solar that can be accessed and how the solar generation profile affects the need for storage are summarized in Table 2.1.

Table 2. 1. Effects of solar generation on roles of storage

Storage type	Storage need associated with solar-dominant generation	Modeling considerations that may affect conclusions about storage
Diurnal storage	Required every day	Tracking: Use tracking for more consistent output during the day, but nighttime diurnal storage will always be needed Orientation: For fixed tilt, east- or west-facing orientation may increase output in the morning or evening, respectively Geographical diversity: spread installations across state from east to west to capture both early morning and late afternoon sunshine; connect with transmission
Cross-day storage	Required intermittently	Geographical diversity: spread installations across state and connect with transmission
Seasonal storage	Substantial seasonal storage will be needed because generation in summer is about twice that in winter	South-facing tilt: Use south-facing latitude tilt to reduce seasonal variation Site in south: Southern siting may show smaller seasonal variations DC-AC ratio: High DC ratios tend to reduce the variability in the daily electricity generation
All types of storage	Storage needs can be reduced by building more solar than is needed to meet conventional electricity demand	Create flexible loads to meet energy needs not supplied by electricity today: EV charging can reduce diurnal storage needs; Summertime electrolysis can provide green hydrogen to meet other energy needs while reducing need for seasonal storage

2.2 Wind

The wind resource in California is far less than the solar resource, as shown in Fig. 2.11 compared with Fig. 2.6. While California is one of the best locations for solar resource, it is one of the worst locations in the U.S. for wind resource. It does have strong resource for offshore wind and in a limited set of locations associated with mountain ranges and especially in passes that guide movement of air from one side of a mountain range to the other.

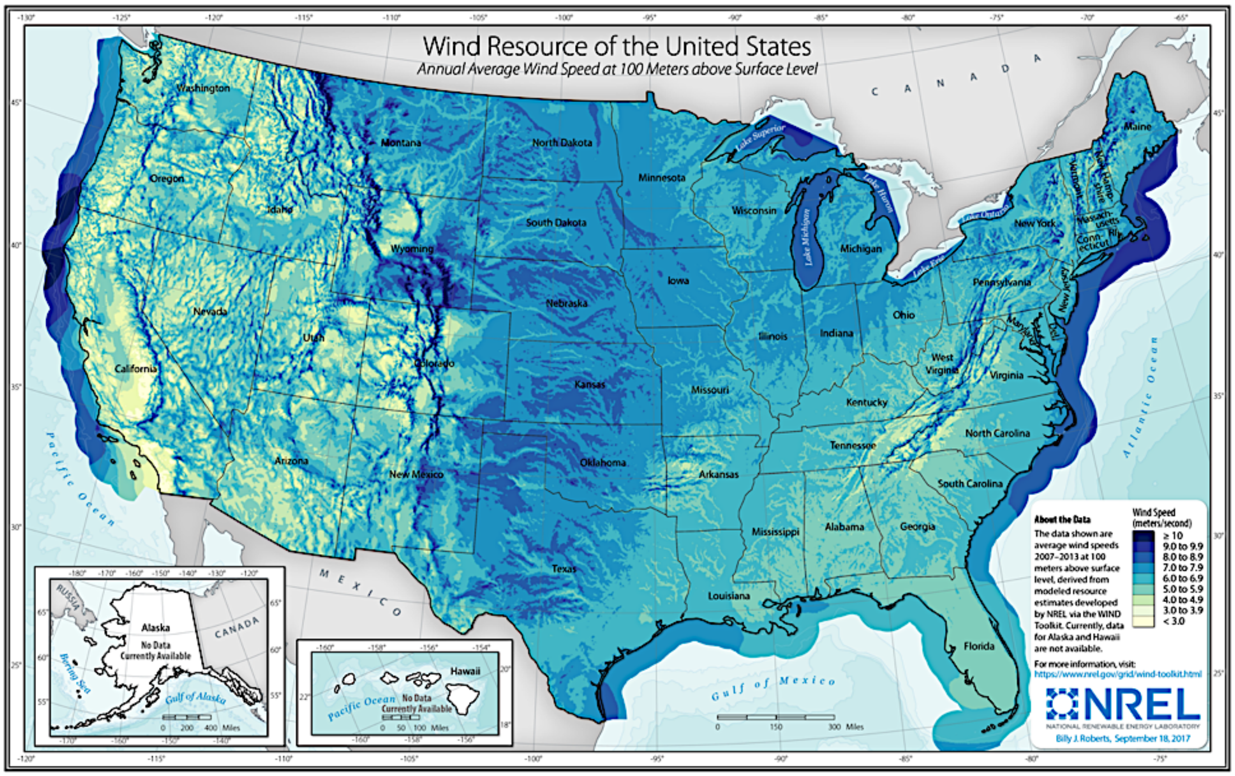


Fig. 2. 11 Wind resource based on average wind speed at 100 m above surface[10]

Despite the inferior wind resource, California currently generates 6 % to 7% of its electricity from wind. Studies typically assume that the onshore wind electricity generation in California may roughly double or triple in the coming years with additional offshore wind development as well as imports of wind electricity from Wyoming.[11]

Modeling of wind electricity generation is challenging because of the high spatial variability in wind resource. The wind blowing on one side of a mountain range may be very different from the wind blowing on the other side. Additionally, the wind resource tends to follow the mountain ranges, but the accessibility of sites along a mountain range may be challenged making deployment difficult even when the wind speed is adequate. Also, wind resources are very site specific, much

[10] https://www.nrel.gov/gis/assets/images/wtk-100m-2017-01.jpg

[11] https://www.energy.ca.gov/sb100; https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html; https://www.2035report.com/electricity/data-explorer/?hsCtaTracking=aefa383f-f7b1-45c3-99c8-9413fdc3a3c7%7C98cb714c-8c3e-4475-b718-610a20b81491

more than solar and depends on hub height and characteristics of installed turbine. For instance, increasing the height of a turbine could access a steadier wind resource with non-linear increases in power output.

2.2.1 Effect of implementation on storage needs

Wind electricity in California today is documented to complement solar electricity generation when the diurnal cycle is considered, as shown in Fig. 2.12, reducing the need for diurnal storage on windy nights. However, its seasonal variation follows that of solar and sometimes shows an even greater decrease in winter as shown in Fig. 2.13. Note that the relative scale used in Fig. 2.13 sets the maximum monthly generation to 100% with different scaling factors used for solar and wind.

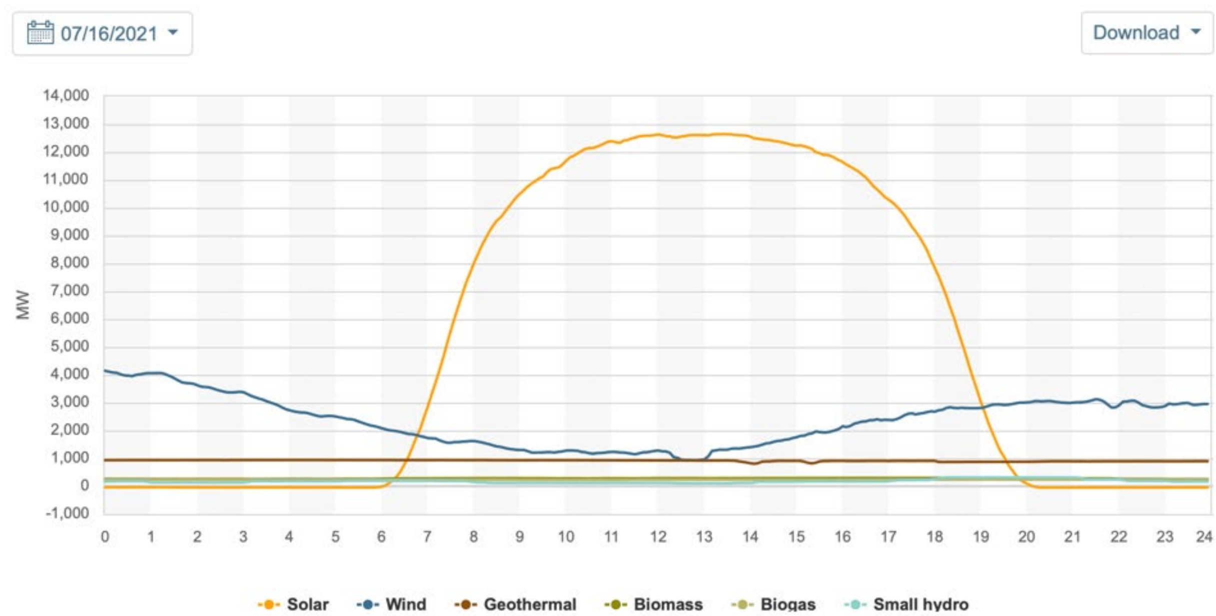


Fig. 2. 12 Renewable electricity generation reported by CAISO for July 16, 2021[12]

[12] http://www.caiso.com/TodaysOutlook/Pages/supply.html

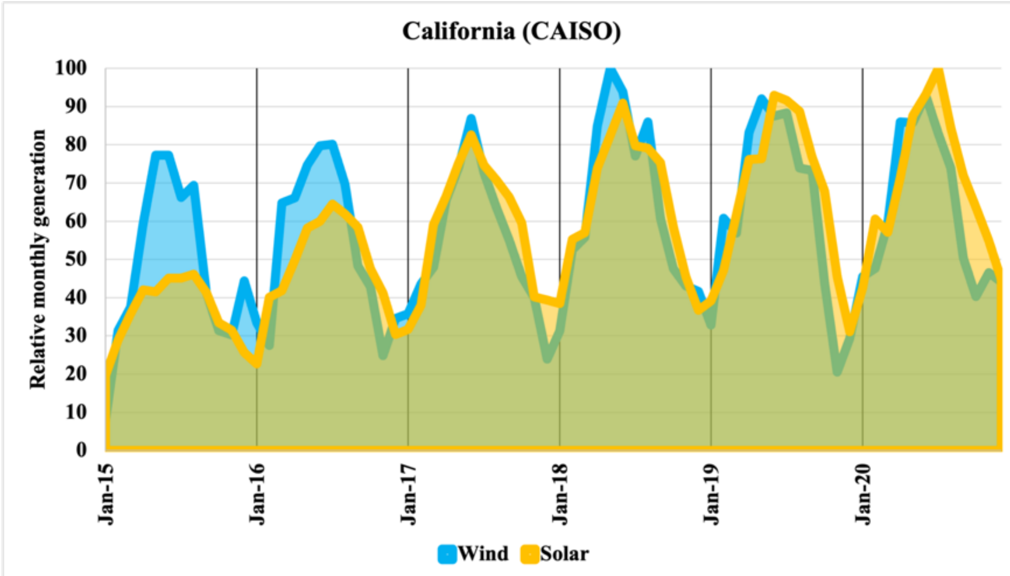


Fig. 2. 13 Monthly relative solar and wind electricity generation in California

We observe that some wind generators in California exhibit generation that differs greatly from that in Fig. 2.13. While more than 90% of California's wind generators are observed to provide maximum output in the summer, others generate more electricity in the winter, as shown in Fig. 2.14. The variability reflected by the blue-shaded regions in Fig. 2.14 mostly reflect that some plants show larger or smaller capacity factors. The seasonal variation is consistent from year to year (data not shown).

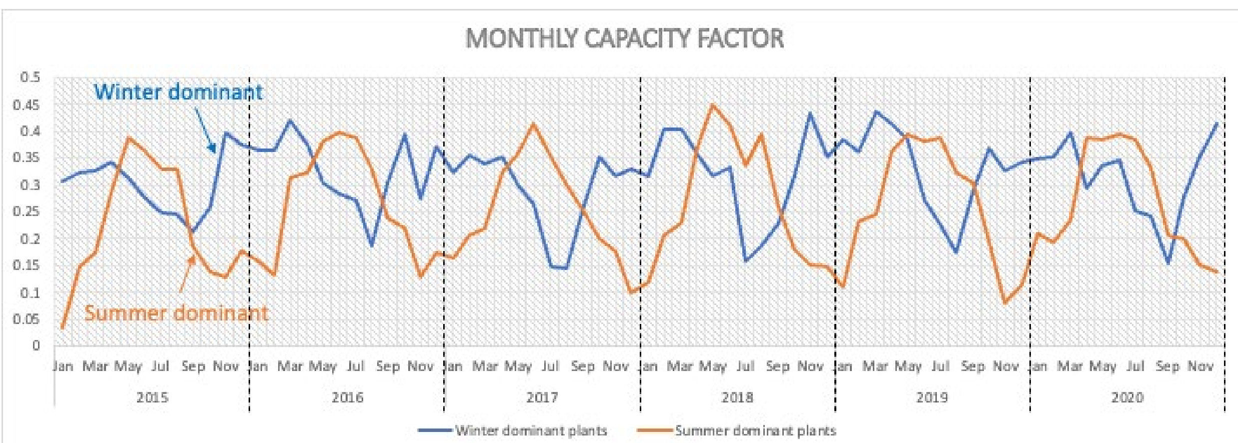


Fig. 2. 14 Monthly capacity factor for two populations of California wind generators; solid lines and blue-shaded regions represent the mean and one standard deviation of the two populations

Our calculations found that more than half of California has winter-dominant wind potential, but, consistent with Fig. 2.11, only a small fraction of those locations have strong wind resource, as shown in Fig. 2.15. The sites highlighted in the rightmost map of Fig. 2.15 are found to have high wind speeds during the winter. However, we have not evaluated which of these would be commercially viable. Nevertheless, we believe there is value in evaluating the effects on storage of selecting winter-dominant vs summer-dominant wind sites. Selecting the winter-dominant sites might reduce the need for seasonal storage as shown in Fig. 2.16. That simulation, which shows that the need for seasonal storage effectively disappears, introduces more wind than is practical. However, it underscores how wind in California comes in different flavors. Both the type of wind and the amount of wind we introduce will be important.

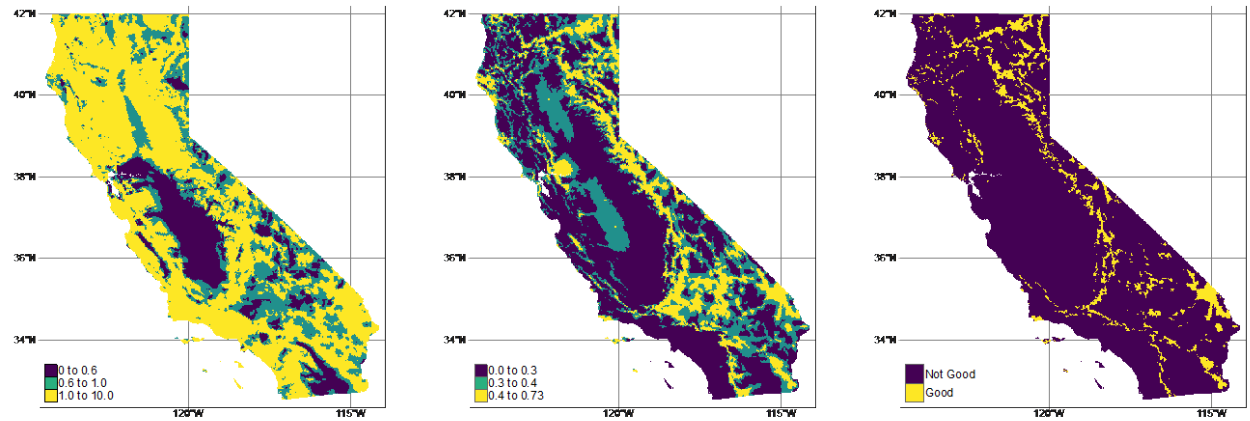


Fig. 2. 15 Maps of California wind potential. Left: Ratio of winter-to-summer wind potential; middle: simulated capacity factor; right: "Good"= winter-to-summer ratio > 1 and capacity factor > 0.4

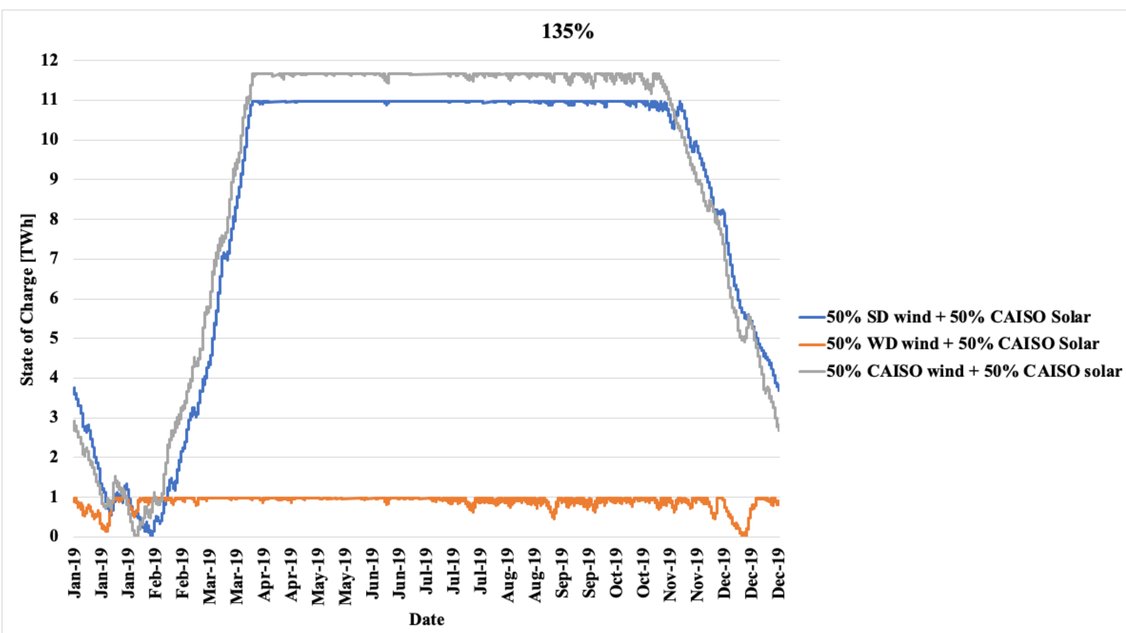


Fig. 2. 16 State of charge of storage using 2019 CAISO load and generation data, replacing thermal and imported generation with 50% solar and 50% wind generation to meet 135% of the load

Offshore wind also has the potential to provide relatively more electricity generation during the winter as shown by Fig. 2.17.

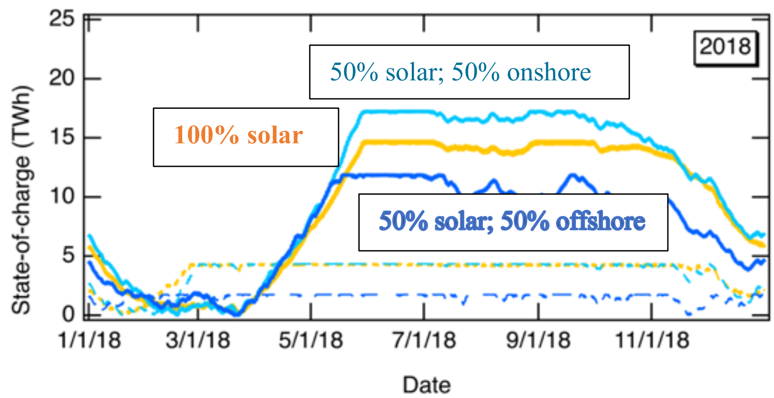


Fig. 2. 17 Calculated state of charge for stored energy using 2018 generation and load data with thermal, nuclear, and imports replaced with electricity generation as indicated to deliver 105% of load

The wind generation profiles are highly variable in different locations. Figs. 2.18 and 2.19 show the simulated wind generation for the entire year enabling the diurnal patterns to be observed on the vertical scale and the cross-day and seasonal patterns on the horizontal scale. The large diurnal value of the onshore wind is apparent in Fig. 2.14. This is especially obvious for the summer-dominant data (left of Fig. 2.18) showing that the wind farms operate at almost full potential most nights between the hours of about 17:00 and 6:00. This is consistent to what is observed today – see Fig. 2.8. Thus, these sites are very good for complementing the solar generation between the months of April and October. The onshore winter-dominant sites show a much smaller (but non-negligible) diurnal trend with very little output in the summer and variable output in the winter.

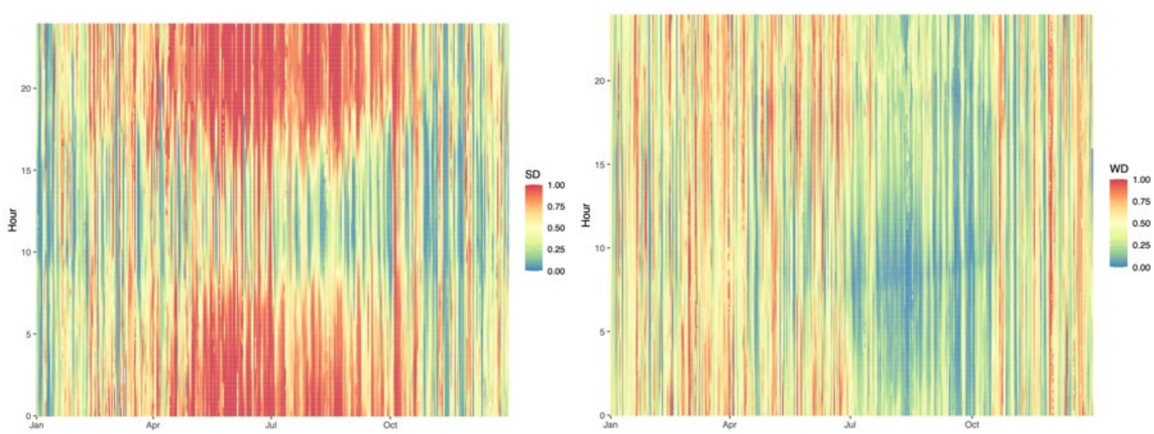


Fig. 2. 18 Wind generation profile for onshore wind (left: summer-dominant; right: winter-dominant)

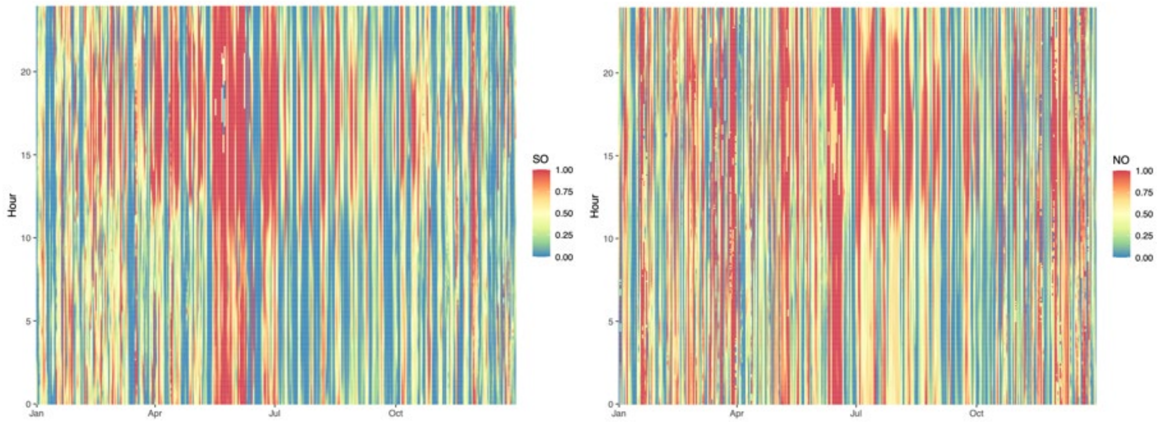


Fig. 2. 19 Wind generation profile for offshore wind (left: south; right: north)

The offshore wind shows substantially different generation, as can be seen by comparing Figs. 2.18 and 2.19. For the selected year (2019), the southern offshore wind (left Fig. 2.19) shows the greatest generation in the late spring. The nighttime generation seen so clearly for the summer-dominant wind in Fig. 2.18 is less clear for the offshore wind. The offshore wind in both the south and the north tend to increase approximately between the hours of 12:00 and 22:00. This period is usually a time of high electricity demand, suggesting that this electricity will be helpful in meeting California's peak loads, though in a different way than today's wind.

Colorado and Wyoming wind are also known for being strong in winter as shown for Colorado in Fig. 2.20. Importing substantial electricity from the other side of the Rocky Mountains will require investment in transmission lines but may prove to be one of the most cost-effective ways to supply electricity during the winter. However, recent data show that relying on imports during times of high demand may not work as well in the future as it has in the past, so the use of imports should be approached cautiously.

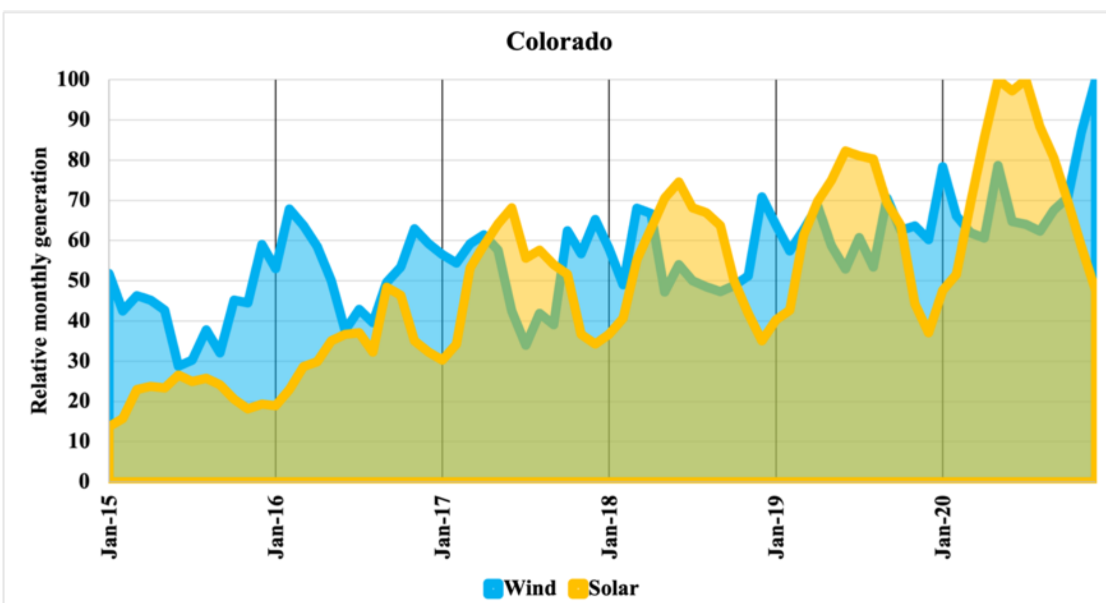


Fig. 2. 20 Monthly wind and solar electricity generation in Colorado as reported by EIA.

The effect of adding wind on the different types of storage (see Section 3 for the methodology) is summarized in Figs. 2.20 and 2.21. The available wind resource in some of these categories may be < 5 GW, but it may be possible to deploy > 10 GW of offshore wind if both the southern and northern resources are considered. The increase in the use of cross-day storage is linked to the decrease in seasonal storage as some storage that would only be cycled once per year begins to be cycled multiple times per year.

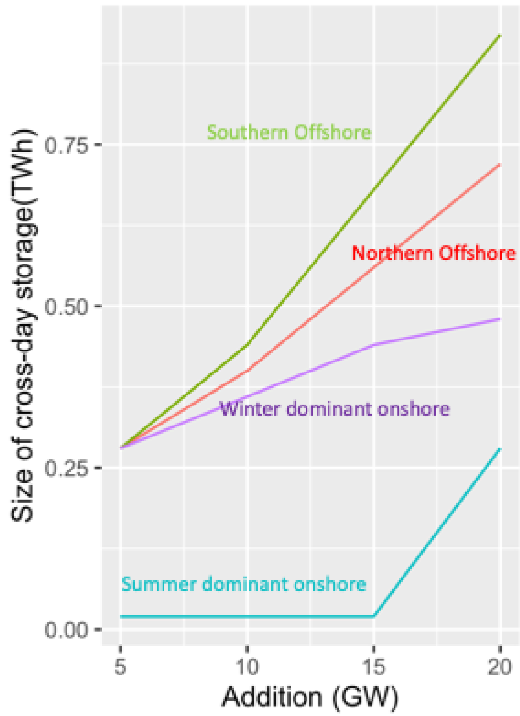


Fig. 2. 21 Effect of replacing solar generation with wind on the need for cross-day storage in California

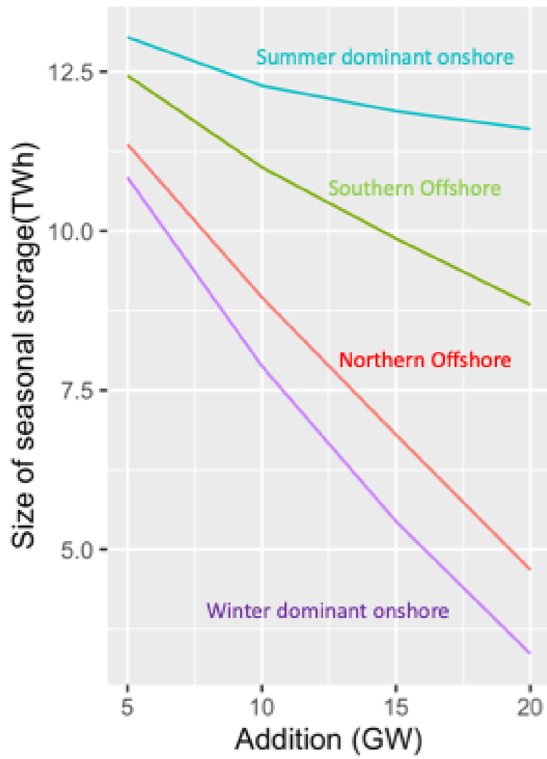


Fig. 2. 22 Effect of replacing solar generation with wind on the need for seasonal storage in California

2.2.2 Effect of wind modeling assumptions on storage needs

A summary of the strategies that can be used that affect the amount of wind that can be accessed and how the wind generation profile affects the need for storage is summarized in Table 2.2.

Table 2. 2 Effects of wind generation on roles of storage

Storage type	Storage need associated with wind generation for solar-dominant grid	Modeling considerations that may affect conclusions about storage
Diurnal storage	More wind reduces frequency of using diurnal storage	Siting: some locations complement solar better than others, see Figs. 2.18 & 2.19
Cross-day storage	More wind increases the need for and use of cross-day storage	Offshore wind tends to show greater fluctuations than onshore
Seasonal storage	Added wind can either increase or decrease need for seasonal storage	Siting: some locations have stronger wind in the winter; some have stronger wind in the summer
All types of storage	Storage needs can be reduced by building more generation than is needed to meet conventional electricity demand	Create flexible loads to meet energy needs not supplied by electricity today: EV charging can reduce diurnal storage needs; Offshore wind electrolysis can provide green hydrogen to meet multiple energy needs while foregoing the need for a transmission line

2.3 Hydropower

According to the CEC there is currently a total of 274 operational hydroelectric facilities in California, with a total installed capacity of 14,042 MW[13]. Facilities smaller than 30 MW are generally considered an eligible renewable energy resource and are referred to as small hydro, while all other hydro facilities are referred to as large hydro. In special cases, some facilities larger than 30MW may also qualify as renewable energy resources under special eligibility criteria. Of the previously mentioned 274 facilities, 202 are considered small hydro, and account for 16% of the net hydropower generation in 2020.

Hydropower has the potential to be a powerful tool in helping to meet California's decarbonization goals. However, the amount of hydroelectricity produced each year varies with rainfall and snowmelt runoff, making hydropower difficult to predict in the face of recurring drought. Figure 2.23 shows the historical monthly electricity generation from conventional large hydropower within California. Though it provides an average of around 2.5 TWh/month and reaches up to 5 TWh/month at times, only about 1 TWh/month has been reliably supplied as a minimum.

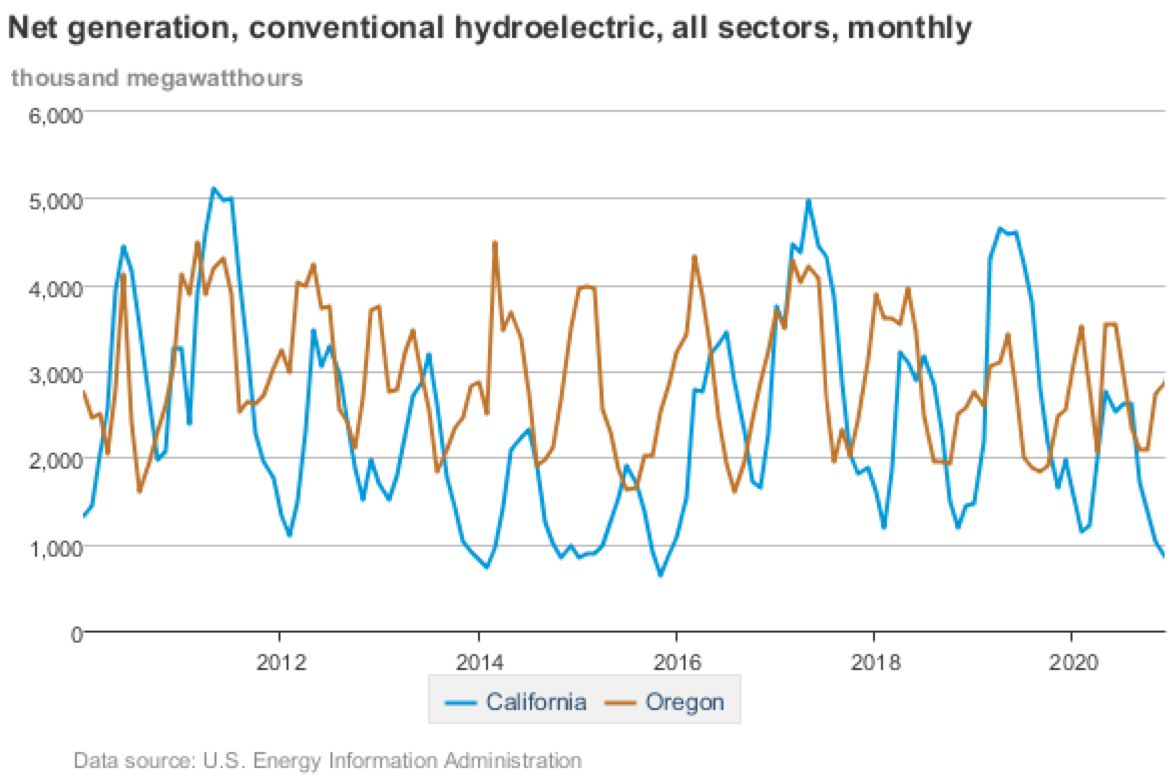


Fig. 2. 23 Electricity generation by hydropower (EIA)

[13] The CEC statistics and data page lists 274 producing facilities, but their downloadable list of hydro facilities (https://www.energy.ca.gov/data-reports/energy-almanac/data-renewable-energy-markets-and-resources) has 343 entries. Some of these have clearly been shut down at some point in the past, despite being erroneously listed as "operational" in the document, while the status of others are ambiguous. This report uses the 274 number for which yearly production data is readily available from the CEC.

2.3.1 Effect of implementation on storage needs

Both large and small hydro show higher production in the summer, following the energy demand (see Figs. 2.24-25). This is not surprising, but the ability of hydropower to respond to market demands is important in determining the potential for hydropower to reduce the need for storage. The flow of water out of a dam may be required to meet a minimum flow for a river or may need to be increased to avoid overfilling a reservoir, reducing the resource available at times when it is most needed. Within those constraints, the adjustment of the hydropower to respond to demand can translate directly into reduction in need for storage.

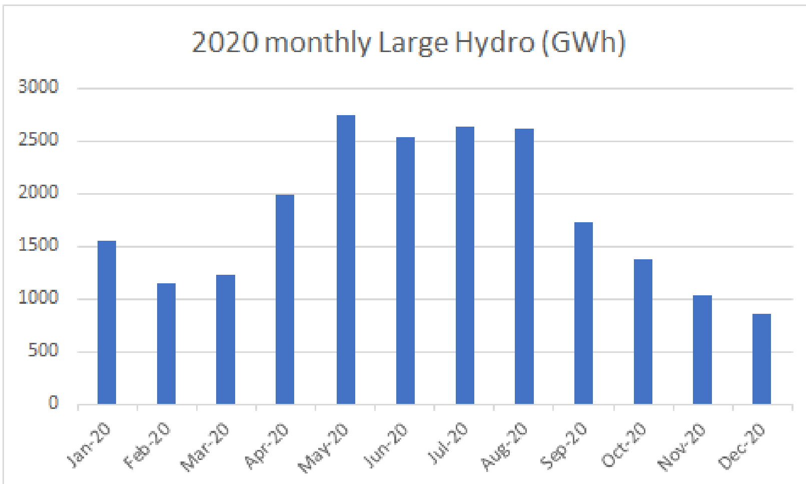


Fig. 2. 24 Large Hydro Monthly Generation (data from EIA)

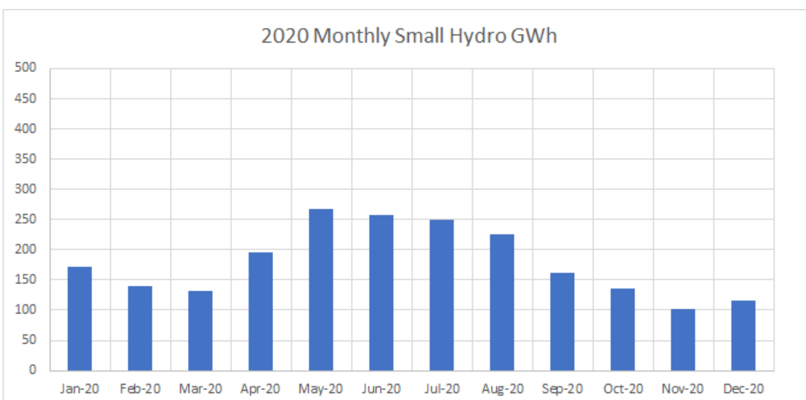


Fig. 2. 25 Small Hydro Monthly Generation (data from CAISO)

During a 24-hour cycle, large hydro production is at a low during midday when solar is dominant, and a high during evening hours of peak demand when the sun is down. It also shows a strong degree of dispatchability, with production capable of rising and falling by several hundred MW to a GW in the span of 5-10 minutes, in response to shifting demand. While small hydro shows a similar high during evening hours, the overall behavior is flatter and less responsive. Figures 2.26 and 2.27 show daily profiles for the 15th of each month for large and small hydro, respectively. The data points are from CAISO's real time power mix monitoring in 5-minute intervals. The profile for Aug. 15 appears anomalous and corresponds to a day when CAISO declared an emergency because of a heat wave. Challenges in that heat wave resulted in load shedding despite many actions taken to avoid more extensive power outages.

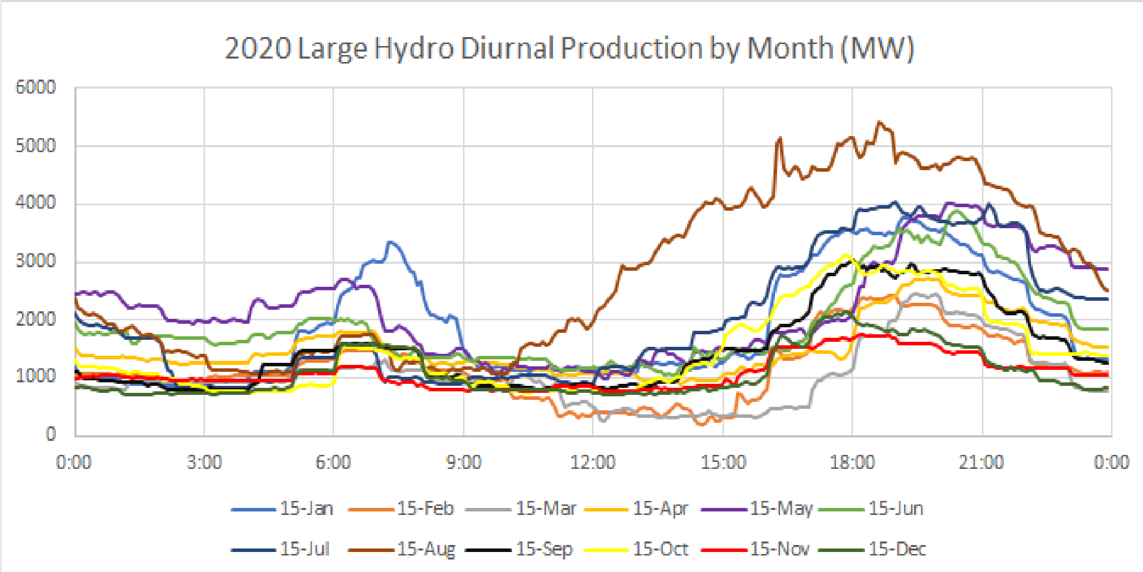


Fig. 2. 26 Large Hydro diurnal cycle by month

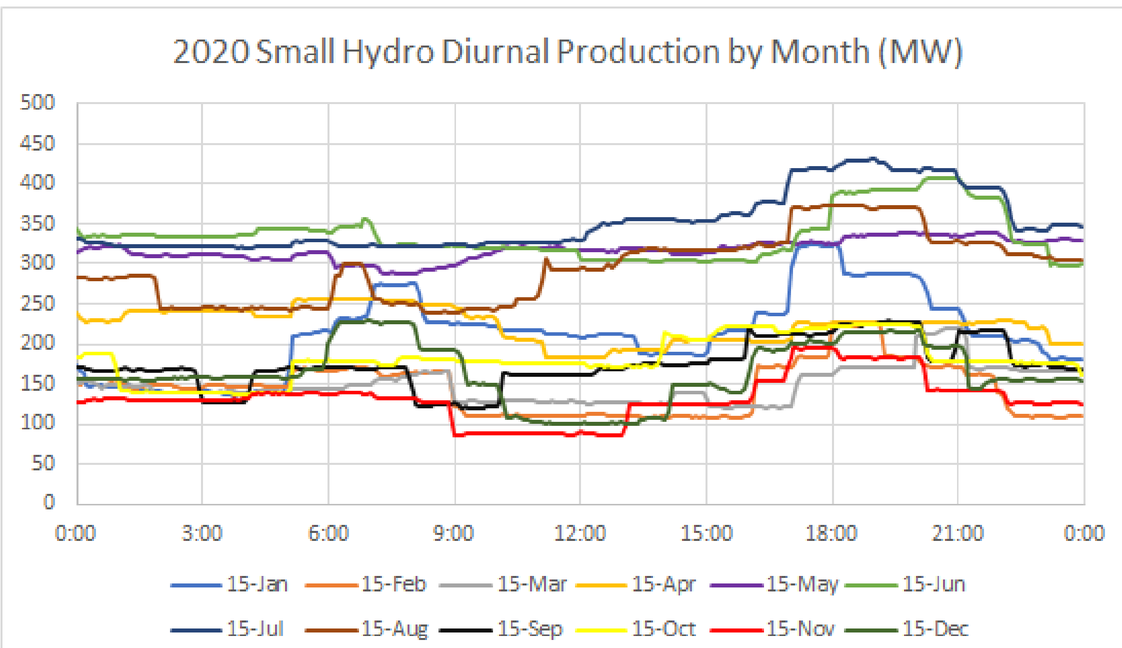
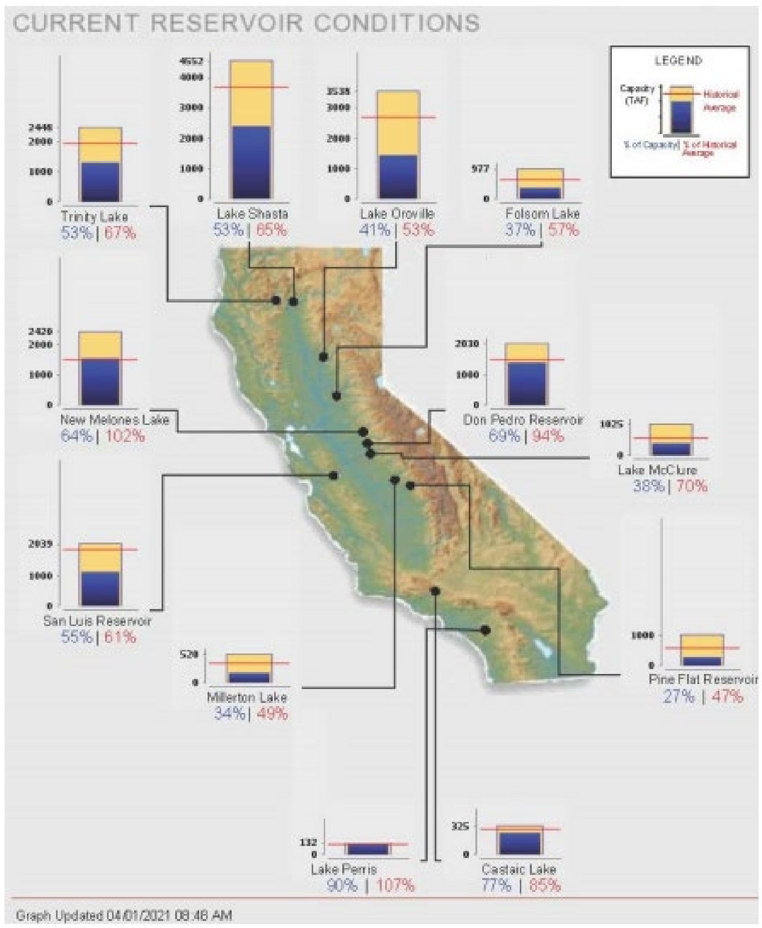


Fig. 2. 27 Small Hydro diurnal cycle by month

California ISO models hydro-generation resources as a combination of non-dispatchable "run-of-river" and dispatchable reservoir resources. The run-of-river represents what is naturally in place flowing through water systems in a given year, and has a fixed generation profile derived from historical data for north and south. Dispatchable hydro-generation concerns the capacity of large-scale reservoirs that can be tapped to provide additional power in response to system demand, and can be optimized subject to daily energy limits and maximum and minimum values governed by reservoir conditions.[14] Both large and small hydro systems can draw from either category depending on their system design. Water diversion facilities divert water from natural channels to another path with a turbine, usually returning it further downstream, and are thus highly dependent on run-of-river. Dam/pondage or pumped storage systems have a built-in reservoir, and are more dispatchable in design, even if their degree of dispatchability is limited by reservoir size, leading to the less dispatchable behavior of small hydro compared to large hydro. Figure 2.28 shows the location of major California reservoirs and their current capacity compared to weighted historical averages. As of April 2021, overall reservoir capacity sat at 70% of historical average.



Source: California Department of Water Resources

Fig. 2. 28 California Major Reservoir Conditions as of 04/01/2021, from 2021 CAISO Summer Loads and Resources Assessment.

2.3.2 Effect of hydro modeling assumptions on storage needs

Hydropower inherently has more possibility for alleviating needs for storage compared with wind and solar, which are instantaneously available only when the wind is blowing or the sun shining, respectively. As noted above, some hydropower is also uncontrollable (available when the water is flowing for other purposes). However, ultimately, it may be less valuable from the perspective

[14] Caiso Summer Loads and Resources Assessment 2021

that it varies substantially from year to year. The current severe drought is an example of why we are hesitant to use dispatchable hydropower as a key element of resource adequacy in a zero-carbon grid.

The amount of hydropower identified to be adjustable (likely via some dispatchability factor applied to overall hydro-capacity), can be used to reduce the need for diurnal and cross-day storage. Large scale hydro-generation systems tied to major reservoirs essentially act the same as pumped hydro energy storage systems, though they are recharged naturally on a seasonal basis by rainfall and snowpack generation and melt rather than by the electrical grid. Such systems could be used as a form of seasonal storage by preferentially curtailing hydro-generation in the summer while relying on a solar dominated grid, to save water for use in the winter. In such a system, idle losses due to evaporation in summer months would have to be accounted for as part of the modeling. A significant complication to such a model would be the extensive patchwork of environmental regulations and legal contracts that govern water rights and access for various agricultural, municipal, and commercial actors. Some waterways are legally required to maintain minimum water levels, putting upper and lower bounds on how much water can be diverted or curtailed. Modeling for seasonal storage may also be impacted in specific instances where winter temperatures may drop below freezing and disrupt flow (likely only a serious concern in specific mountainous regions and for low volume systems).

A summary of strategies that can be used that affect the amount of hydropower that can be accessed and how the chosen hydropower generation profile affects the need for storage is summarized in Table 2.3.

Table 2. 3 Effects of hydropower generation on roles of storage

Storage type	**Storage need associated with hydro generation for solar-dominant grid**	**Modeling considerations that may affect conclusions about storage**
All types of storage	More hydropower will reduce need for all types of storage	Available volume: More hydropower, even if the generation is constant, reduces the need for storage Dispatchability: The amount of hydropower that is identified to be adjustable can be used to reduce the need for all types of storage

2.4 Geothermal

Geothermal plants follow one of three system designs. The simplest and oldest of these designs is known as “dry steam”, in which steam is collected directly from hydrothermal systems and sent up pipes to run a turbine before being recondensed and reinjected into the system. This acts as a closed system but requires the presence of steam within the hydrothermal system, creating a further constraint to siting. Such systems are concentrated in the Geysers geothermal area, located 115 km north of San Francisco, and represent California’s largest concentration of geothermal plants. The second, known as “flash” systems, pipe up the hydrothermal fluid directly and subject it to lower pressure in order to rapidly flash it to steam. This provides more flexibility, but the flash process releases dissolved gasses, including CO_2 that cannot be easily redissolved when the steam is recondensed and reinjected, creating non-zero carbon emissions that must be dealt with if the geothermal system is part of the zero-carbon emissions solution. “Binary” systems similarly pipe up fluid, then use a heat exchanger to heat a secondary fluid that then spins a turbine, while the hydrothermal fluid is returned in a closed system. This provides the flexibility of flash systems without the emissions but is typically associated with higher costs.

California has two of the largest geothermal reservoirs in the United States, the Salton Sea resource area and the Geysers (both shown in the Fig. 2.29), with an estimated generation capability of 2,200 MW and 1,800 MW respectively. There are a total of 41 geothermal power plants in California, with an installed capacity of 2,712 MW. Of these, 40 (2657 MW) are currently listed as operational. 16 plants (1579 MW) are dry steam, 17 (860 MW) are flash, and 7 (218 MW) are binary.

Fig. 2. 29 California Geothermal Fields[15]

Previous estimates suggest another 2.7 GW of untapped capacity within discovered systems, and mean estimates of 11.34 GW within as of yet undiscovered systems. The use of enhanced

15 https://cecgis-caenergy.opendata.arcgis.com/documents/CAEnergy::known-geothermal-resource-areas/explore

geothermal system techniques to create hydrothermal systems out of existing hot rock formations via hydrofracture could further expand this capacity by an additional theoretical 48GW, though it should be noted that unless done at great depth, such enhanced systems would have very poor energy density (~0.5 MW/km^2) compared to traditional geothermal systems (10-20 MW/km^2).[16] Thus, near-term enhanced geothermal systems (EGS) would likely remain restricted to favorable areas. Figure 2.30 shows a map of areas favorable to deep EGS, along with already identified hydrothermal systems.

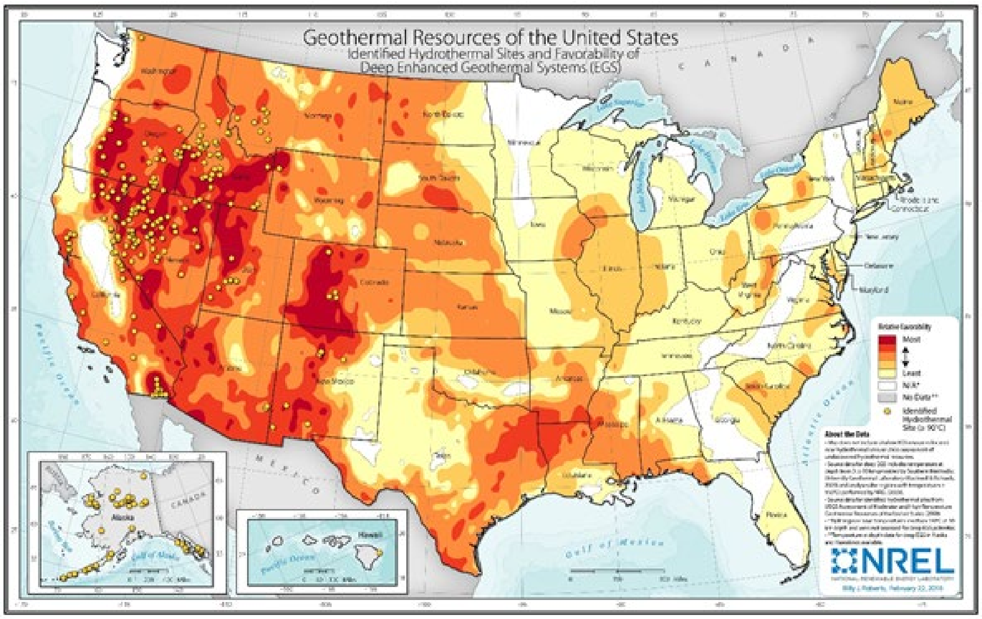


Fig. 2. 30 Identified Hydrothermal Systems and Deep EGS favorability[17]

Binary systems in particular could complement diurnal and cross-day storage by adjusting the heat exchanger to divert heat towards onsite thermal energy storage systems during the day when solar is dominant and switching back to steam generation on the turbine at night. Dry steam and flash systems are not as easily coupled to thermal storage as they rely on the mechanical energy of circulating the steam (or fluid flashed to steam) directly through the turbine rather than drawing off the heat. The flowrates of all three systems could possibly be throttled to allow for periods of thermal recharging after brief periods of increased output above standard operating conditions (such as if an emergency were declared), but this is not currently done as geothermal generators are typically designed to operate at constant steady outputs. Implementing functionality for such a "surge mode" would add additional cost when geothermal is already limited in its application by its higher cost. So, although we identify the possibility that geothermal could be used as a dispatchable generation source, we will limit our studies to accelerated deployment of plants that operate near capacity continuously.

[16] https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf

[17] https://www.nrel.gov/gis/geothermal.html

Table 2. 4 Effects of geothermal generation on roles of storage

Storage type	Storage need associated with geothermal generation for solar-dominant grid	Modeling considerations that may affect conclusions about storage
Diurnal storage	Added geothermal can decrease need for diurnal storage	Binary design: Geothermal plants with storage to store heat during the day and use it to generate electricity at night have the potential to reduce the need for separate diurnal storage.
All types of storage	Higher baseline generation from geothermal reduces the need for other generation and storage at all time scales.	Higher build limits: Theoretically, the potential for geothermal is very large. If a model is allowed to select more geothermal and if the cost is adequately low, the need for storage would be greatly reduced.

The U.S. Department of Energy (DOE) projects that enhanced geothermal systems will surpass 10 GW shortly after 2030. The timeline could be compressed based on new deployment as DOE builds on its FORGE project.[18]

2.5 Biomass

Currently, about 3% of California's electricity is generated from biomass. Similar to geothermal, assumptions about the role of biomass and biogas have very high uncertainty. A recent report by Lawrence Livermore National Laboratory details how California can achieve its goal of carbon neutrality by 2045 through negative emissions with a key pillar being conversion of biomass to fuels with capture of carbon dioxide.[19] They investigated the many sources of biomass that are available as shown in Fig. 2.31.

As a key element of a zero-carbon grid, there are two primary challenges. The first is the cost of collecting the biomass. The second is that it is questionable whether biomass would be considered a zero-carbon technology without some form of carbon capture. Our assessment suggests that the best opportunity for using biomass and biogas for decarbonization of California's electricity grid would leverage the Allam cycle. We have described that in more detail in Section 2.6, including an estimate of the amount of electricity it could generate.

[18] Sean Porse presentation, https://openei.org/apps/geovision/electricity-generation.

[19] https://www.llnl.gov/news/new-lab-report-outlines-ways-california-could-reach-goal-becoming-carbon-neutral-2045

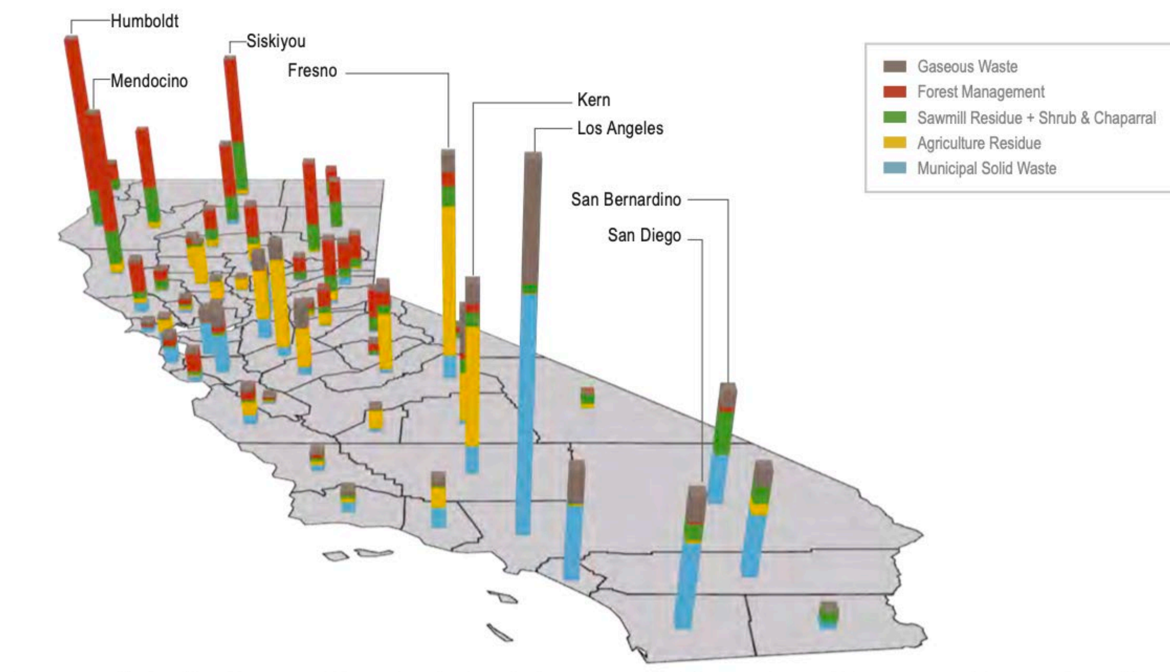


Fig. 2. 31 Biomass sources as studied for the "Getting to Neutral" study

2.6 Carbon sequestration coupled with biogas

The possibility of using carbon sequestration to enable natural gas plants to effectively operate in a zero-emissions mode has attracted a lot of attention. The approach is not a favorite of many clean-energy advocates because of the ongoing risk of methane leaks and related environmental impacts. However, there is growing concern that carbon dioxide levels are already dangerously high. This concern is motivating investment in carbon sequestration for the purpose of reducing the current level of carbon dioxide in addition to identifying ways to slow emissions. If technology for carbon sequestration is widely adopted, the development and maturation of carbon capture technology and of the associated infrastructure for sequestering the carbon dioxide is likely to result in a reduction in cost, suggesting that it will become more attractive to use in natural gas power plants.

The use of carbon capture on conventional natural gas power plants requires capture of the carbon dioxide from the flue gas which may be only 3%-6% carbon dioxide.[20] The capture of all 3%-6% concentration is energy intensive. Ironically, carbon dioxide capture is easier in a coal-fired plant because of the higher carbon dioxide concentrations.

The Allam cycle provides a compelling approach to overcoming the energy requirement for the carbon capture process. The Allam cycle combusts methane with a stoichiometric amount of oxygen using carbon dioxide as the working fluid in a closed loop, taking the place of steam in traditional power generation. Instead of tackling the task of removing all carbon dioxide from the flue gas, the Allam cycle tackles the simpler separation of extracting oxygen from air at the precombustion stage. The separation of CO_2 then becomes trivial as the net CO_2 product derived

[20] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-20493.pdf

from the combustion of fuel with pure oxygen in the combustor is removed from the high-pressure stream recycle at a high purity and pressure for delivery to an export CO_2 pipeline. The cycle includes a high pressure oxy-fuel combustor that burns a fossil fuel (methane) in a pure oxygen stream to provide a high-pressure feed stream to a power turbine. The oxygen required for fuel gas combustion is provided from an industry standard pumped liquid oxygen cycle cryogenic air separation unit. The separation of oxygen is easier because oxygen starts at a higher concentration (about 20%). Air separators are already widely used, and oxygen is readily available to feed the methane combustion.

Completing the separation at the precombustion stage provides not only the advantage of the easier separation, but it avoids the formation of some criteria pollutants like NO_x. After the combustion step, the reaction products include only carbon dioxide and water. The water can easily be removed by cooling the gas and condensing the water. The carbon dioxide is then reused in the process as a working fluid for the next combustion cycle. The excess carbon dioxide (resulting from the combustion process) can be easily removed from the process at a high pressure (200 – 400 bar) to be ready for sequestration. The use of carbon dioxide as a working fluid also avoids the need for using water in the process, which can have substantial environmental benefits.

The Allam cycle is ideal for coupling with biogas. One of the reasons biomethane is more expensive than natural gas obtained from the ground is that raw biogas is roughly half methane and half carbon dioxide. If biogas is used in the Allam cycle, the carbon dioxide does not need to be removed (though it is still important to remove sulfur compounds and other impurities). Thus, the Allam cycle and biogas are synergistic, and together, result in a clean electricity-generating process that is carbon negative.

The supply of biogas in California has typically been estimated to be too small to be of consequence. However, the CPUC is developing plans that would result in increased generation of biogas. Senate Bill 1440 (SB1440), "Energy: biomethane: biomethane procurement," directs the California Public Utilities Commission (CPUC) in consultation with the California State Air Resources Board (CARB) to "consider adopting specific biomethane procurement targets…consistent with the organic waste disposal reduction targets specified in Section 39730.6 of the Health and Safety Code."[21] Section 39730.6 sets targets of reducing landfill disposal of organics by 50 percent from 2014 to 2020 and by 75 percent by 2025.[22] The CPUC has been working on implementing these directives for some time and is now working on Phase 4a of Rulemaking 13-02-008 which recommends "approval of a mandatory biomethane procurement program for California's four large gas investor-owned utilities (IOUs) to procure on behalf of their core customers."[23]

The current intention of SB1440 is to replace natural gas sold by IOUs. If the biogas continues to be combusted at the customer's location, it will continue to contribute carbon emissions. Biogas gives us the opportunity to move to negative carbon emissions. As electrification or replacement

[21] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1440

[22] https://codes.findlaw.com/ca/health-and-safety-code/hsc-sect-39730-6.html

[28] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Gas/SB1440_Staff_Proposal_FINAL.pdf

of natural gas with hydrogen reduces customer-sited use of methane, it may be possible to redirect the biogas to power plants using the Allam cycle. The R.13-02-008 Phase 4A staff proposal estimates that 75.5 million MMBTU of biomethane may be procured by 2030. We estimate that this could generate >10 TWh of electricity using the Allam cycle. This is approximately equal to the size of seasonal storage we calculate that California will need for a fully decarbonized grid and is about 5% of the annual electricity generation (about 200 TWh) in California. Thus, although this is a small fraction, this biogas would have great potential at meeting the state's seasonal storage needs. It would not be adequate to meet the diurnal storage needs we anticipate but could supplement other storage technologies to reduce the challenge of diurnal storage.

This vision of using waste to generate clean electricity with net negative carbon dioxide emissions still has several hurdles to overcome:

- Development: The Allam cycle is still in early stages of development. Several 250 MW plants are being planned. Results from those will help to establish confidence in the technology.
- Cost: The hardware for the Allam cycle is less complicated than conventional natural gas with carbon capture. It is predicted to be comparable in cost to conventional natural gas technology.[24] To be most useful in complementing solar and wind generation, it should be operated as a peaker plant: *i.e*. be dispatched for relatively short amounts of time.
- Biogas: The infrastructure for making and collecting the biogas is only partially in place.

With a limited amount of biogas available, it is not clear whether it would be better to use that biogas to sell to customers or to use for power generation in the Allam cycle. Nevertheless, we view biogas as an important option for addressing storage and the Allam cycle as a potential mechanism for using the biogas in a clean way for power generation with negative emissions.

2.7 Natural gas coupled with carbon sequestration

Even if carbon sequestration is added, the continued use of natural gas is anticipated to continue to contribute to methane emissions. Methane emissions can be reduced by careful detection of leakage and control of that leakage. Even if the control of the methane emissions can be controlled, combustion of natural gas in conventional systems results in emissions of other pollutants, including NO_x. Our evaluation of the options suggests that, as described above for biogas, the Allam cycle is the best candidate for clean generation of electricity from natural gas.

The use of natural gas plus carbon sequestration has been described as "clean firm power" and modeled to meet our electricity needs at a lower cost than using purely renewable energy.[25] While we could limit our energy sources to fully renewable energy (coupled with storage and demand management), it is important for us to consider how the use of all renewable energy sources compares with use of other sources.

[24] https://www.sciencedirect.com/science/article/pii/S187661021300221X

[25] Baik, et al. https://doi.org/10.1016/j.egycc.2021.100046

We have chosen to omit nuclear power from our studies because California has chosen to move away from nuclear power. Similarly, we believe that California will choose to use the Allam cycle rather than more conventional natural gas turbines because of the elimination of criteria pollutants. Thus, in addition to modeling biogas using the Allam cycle, we will also include natural gas with the Allam cycle as part of our sensitivity analysis.

2.8 Imports

We will use SWITCH with a WECC-wide model to understand the value of imports to California.

3. Effect of generation on need for storage

Our study of long-duration storage is differentiated from the traditional capacity expansion planning in two ways: 1) our focus is on long-duration storage, which requires understanding seasonal storage in addition to short-duration storage, and 2) we are more focused on what happens as we approach the 2045 timeframe and how the market evolves to get there rather than the details of meeting the grids needs in the next year or two. We note that California must place a high priority on preparing for reliable grid operation in 2021 and 2022, especially in light of the emergency that was declared in August 2020, but this study is focused on the longer term.

3.1 Types of storage – energy flows

To understand the multiple opportunities of energy storage and its different forms, a conceptual diagram is shown in Fig. 3.1. Green boxes in Fig. 3.1 represent the electricity flows to and from various types of energy storage reservoirs to meet both the immediate electrical load (red box in Fig. 3.1) and flexible loads to balance the electrical grid (green boxes). Demand management may be used to facilitate storage at the customer's site, as indicated by the Fig. 3.1 green box "Load – Stored energy."

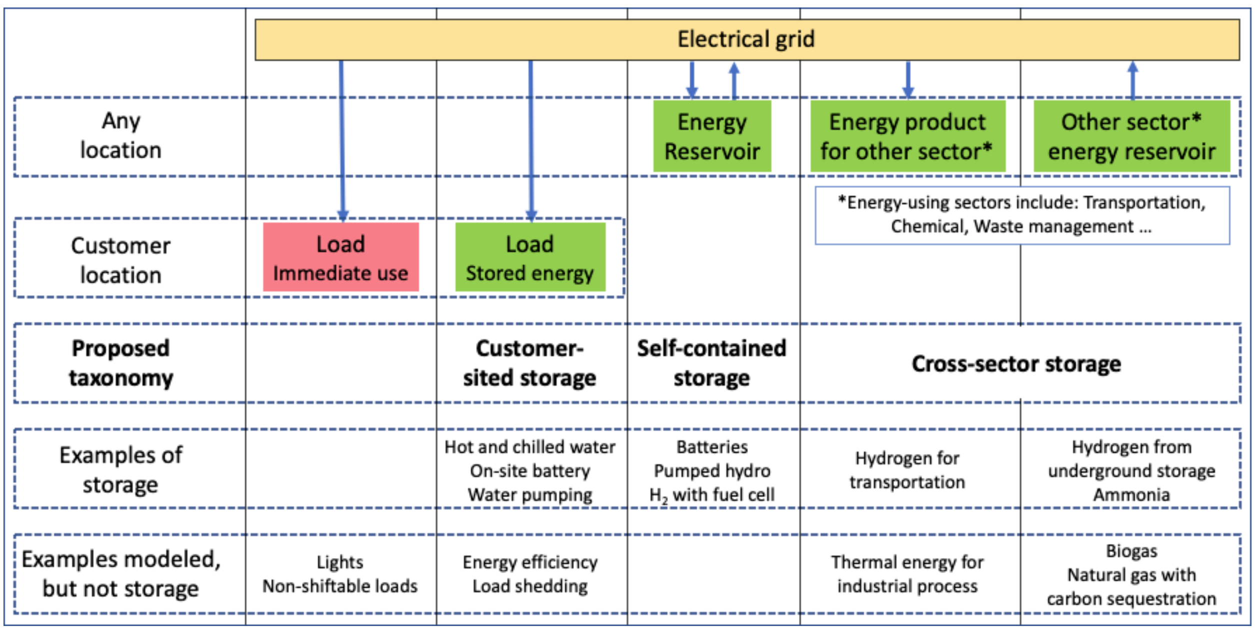


Fig. 3. 1 Electricity pathways for energy storage (green boxes) with suggested taxonomy

More generally, surplus electricity may be stored for later electricity generation (green box labeled "Energy Reservoir") or for creation of an energy product like hydrogen that may be stored at low cost until the energy is needed later for other applications (green box labeled "Energy product for other sectors"). Also, when electricity is in short supply, energy that is stored for use in other sectors may be used to generate electricity (green box labeled "Other sector energy reservoir"). A decarbonized grid may benefit from using all of these strategies.

Capacity-expansion models, which are used to evaluate low-cost long-term grid planning scenarios, commonly include batteries and pumped hydro storage, keeping track of their state-of-charge as they are charged or discharged (Fig. 3.1 green box "Energy Reservoir"). Going beyond these technical parameters and modeling the value of cross-sector storage opportunities, however, is less common. For example, some capacity-expansion models increase their input load profiles to simulate hydrogen production, which in turn dictates a larger volume deployment of electricity generation assets. A multi-sectoral capacity-expansion model would optimize the hydrogen production by considering the capital costs and operating costs of the electrolyzers offset by the value of the hydrogen that is generated, potentially turning curtailed electricity into a revenue stream. A multi-sectoral model would also calculate the cost of using hydrogen (that might be stored for transportation or chemical use) to generate electricity when electricity is in short supply. When studying the need for long-duration storage within conventional capacity-expansion model approaches, while focused studies may elucidate partial solutions, inclusion of multi-sectoral modeling will enable exploration of a wider range of solutions.

While there is no general agreement that all four green boxes in Fig. 3.1 should be called "long-duration energy storage" we assert that a full understanding of the roles of long-duration storage will require understanding the opportunities described by all four green boxes and that understanding the relative benefits of all of these will help policymakers identify the most effective actions to take.

3.2 Types of storage – taxonomy for discussing duration

As we work to envision the roles of storage in supporting tomorrow's grid, it is useful to develop a taxonomy for improved communication. For the purposes of modeling, it is useful to differentiate types of storage according to how they are modeled. We highlight here two aspects that are critical to the model implementation: a) the electricity paths (with associated costs) and b) the temporal resolution.

In Fig. 3.1 we proposed a taxonomy for the storage opportunities identified differentiating them according to the electricity paths. We suggest that "customer-sited storage" describe storage assets that are purchased and operated by the electricity customer (or business partner) at the customer's location. "Self-contained storage" assets may be connected to the grid, charged with surplus electricity, and discharged when electricity demand is high. Finally, "cross-sector storage" created to serve multiple sectors, may be charged or discharged to help balance the grid. In some cases, a storage technology may be implemented simultaneously in more than one of these ways as in the case for the transportation sector where an electric vehicle (EV) is charged for transportation purposes but might also supply electricity back to the grid (vehicle-to-grid). Hydrogen may also be used in both the "self-contained storage" and "cross-sector storage" approaches.

While it is clear that all of these energy pathways need to be modeled to fully understand the roles storage plays in balancing the grid, it is less clear that all of the opportunities should be called "storage." Fig. 3.1 gives examples of how to implement each storage opportunity and also suggests opportunities that need to be included in the modeling, but that are usually not labeled as "storage." We emphasize that in our study of "long-duration storage," we intend to model the potential of all of these, but recognize that, for example, biogas is usually viewed as a generation technology even though biogas represents a form of energy storage that may be useful for balancing the grid. We feel that it is less important to decide whether biogas is called a generation technology or storage technology and more important to agree that biogas has the potential to help balance the grid by providing a reservoir of energy.

We propose a second piece of the taxonomy (Fig. 3.2) related to the relative amount of energy stored, which is typically related to the time it takes to charge or discharge the storage using full power. When modeling the roles of storage, a short-time-resolution (hourly or even sub-hourly) model aids in understanding how storage may help meet instantaneous demand, or the peak load of the year or of the day. Reducing the peak demand is usually considered a "short-duration storage" application. We propose that long-duration storage applications include diurnal storage, cross-day storage, and seasonal storage as also shown in Fig. 3.2. The modeled contiguous timesteps need to span the time from when energy is added to a storage reservoir to when the energy is withdrawn from the reservoir, as indicated in Fig. 3.2, bottom line. For a given grid design and weather, a model can identify the cycling frequency of the short-duration and long-duration (diurnal, multi-day and seasonal) storage reservoirs. These define the storage applications that need to be met to achieve a resilient and stable grid, providing the foundation for taking actions to create a stable zero-carbon-emissions grid. Other applications such as ancillary services, emergency outage protection, and demand reduction also play a role, but are outside of this taxonomy.

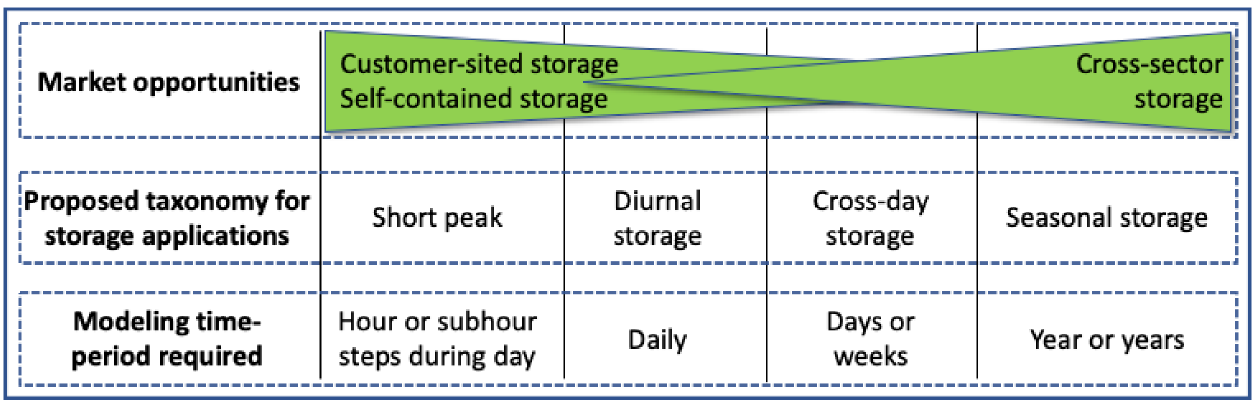


Fig. 3. 2 Taxonomy for storage applications by discharge time frame with modeling requirements for those time frames and mapping to the taxonomy in Fig. 3.1.

The grid's requirements for storage may be described in the context of these four storage applications or using more specific metrics related to the frequency of cycling and the discharge time. We anticipate that it will be useful to the grid to have access to many storage technologies to simultaneously meet all of the grid's needs. Many of those technologies may address multiple storage applications. While it is tempting to label a technology as a "short-duration" or "long-duration" storage technology, it could be possible for nearly any storage technology to address all storage applications. When policy is developed for incentive programs and for technology development, such policy should focus on the functionality that is desired (including cost calculated for a specific use case, efficiency, low idle losses, etc.) rather than applying a simplistic label that differentiates short- and long-duration storage. Focusing on the functionality rather than a preconceived vision of the solution can stimulate innovation and could lead to cross-sector solutions that aren't in the spotlight today.

3.3 Competition between types of storage including large-scale storage

The schematic in Fig. 3.2 suggests how different types of storage may compete to meet the range of storage applications. While a given storage technology may be designed to provide a small or large number of hours of discharge (defined by the energy rating divided by the discharge power rating), once the system is built, it may be used to meet any of the applications. A storage asset that can provide diurnal storage on one day and multi-day storage the next week may be more valuable to the system. Thus, when modeling storage, it is essential to include the full range of temporal applications (diurnal, cross-day, and seasonal, as shown in Fig. 3.2) in order to fully understand the value of a given storage asset to the system. Similarly, to fully understand the system, all of the electricity pathways described in Fig. 3.1 should be included. Fig. 3.2 shows how we anticipate customer-sited and self-contained storage are more likely to be used to meet applications with a shorter time frame, while cross-sector storage may be most effective for seasonal storage applications. Technology development efforts should define the desired storage applications and fund technology development to meet those needs.

Energy storage is an essential part of energy security. As shown in Fig. 3.3, the United States currently maintains energy storage mostly to supply the transportation sector (jet fuel, motor fuels, and oil to make these) and heating sector (oil and natural gas). In Fig. 3.3, the TWh of chemical energy on the left axis is translated into estimated months of electricity generation assuming 40% efficiency and U.S. use of 3800 TWh of electricity in 2020. The natural gas stored for heating applications was estimated from the depletion of the stored natural gas during the heating season. The 350 TWh "Natural gas" may be used for power generation, heating, or other uses. The "in vehicle" estimate assumed 300 million vehicles with 30 kWh of storage in each. Data were taken from EIA.[26]

The chemical industry and power sector also rely on storage described in Fig. 3.3, with chemicals and fuels sometimes mixed with those stored for the other sectors. Maintaining energy storage to simultaneously serve many sectors increases flexibility and reduces costs. If the energy represented in Fig. 3.3 were converted to electricity, it could yield more than five months of electricity for the U.S. as indicated on the right-hand axis, using a nominal efficiency of about 40%. A renewable-energy-based decarbonized energy system will require use of renewable electricity to provide energy for the non-power sectors. Including cross-sector storage in the modeling of the grid will be critical to understanding how the sectors can benefit by sharing storage.

[26] U.S. Stocks of Crude Oil and Petroleum Products https://www.eia.gov/dnav/pet/PET_STOC_WSTK_DCU_NUS_W.htm. Accessed on 02/17/2021. Weekly Natural Gas Storage Report - EIA https://ir.eia.gov/ngs/ngs.html. Accessed on 02/17/2021. Electricity data browser - Net generation for all sectors https://www.eia.gov/electricity/data/browser/. Accessed on 02/17/2021.

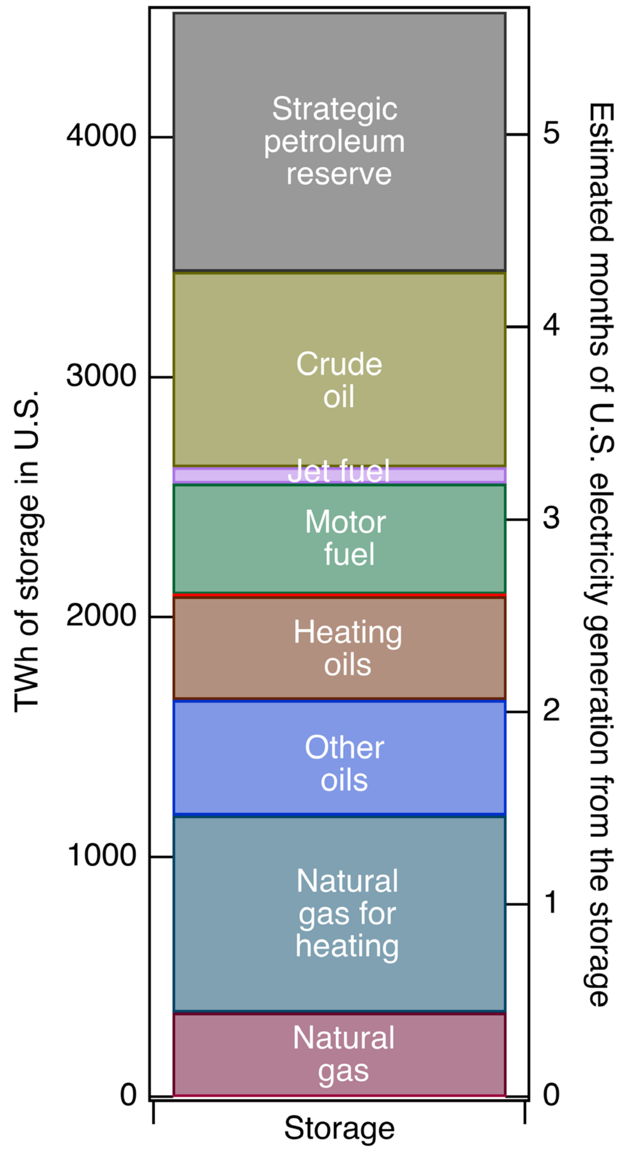


Fig. 3. 3 Approximate energy storage used to supply the transportation, heating, power, and chemical sectors today

The long-duration storage needed for seasonal storage applications may require many TWh. Just as a peaker plant today is idle much of the year, some long-duration storage assets of a decarbonized grid will be used infrequently. Thus, the storage cost for such applications will need to be low, and electricity markets will need to be redesigned to reflect the value storage provides. We suggest that inclusion of attractive cross-sector storage opportunities (such as shown on the right side of Fig. 3.1) will be helpful in keeping storage costs low while being prepared for extreme conditions such as the hot weather that occurred in August 2020 (resulting in rolling black outs in California) and the cold weather in February 2021 (resulting in millions of people without power for days in Texas and elsewhere). Today, natural gas is used both for heating and for electricity generation, so the cost of maintaining the natural gas storage and distribution infrastructure is shared by both the power and heating sectors. In a decarbonized world, hydrogen (or other fuel) storage and distribution infrastructure may be established to support the transportation, chemical, and heating sectors. The power sector may be able to ensure resource adequacy at lower cost by leveraging such infrastructure rather than creating its own large energy storage that is infrequently used.

Thus, the study of long-duration storage should consider how the different types of storage defined in Fig. 3.1 will compete for different storage applications as described in Fig. 3.2 and should also consider how cross-sector storage approaches may reduce cost by leveraging infrastructure developed for other sectors. Policy development should be technology agnostic but technically grounded so that the lowest cost, cleanest path is chosen to keep the lights on even in the most challenging times.

3.4 Approach for analyzing energy-balance model results

The effects of variable renewable electricity generation profiles were provided in section 2 by plotting the state-of-charge of a single storage reservoir that filled and emptied on a daily basis, as well as seasonally. When plotted in this way, the seasonal trends were most apparent. We can also use the energy balance approach to understand diurnal and cross-day storage. However, the accounting of these is not obvious when all storage is done in a single storage reservoir.

The diurnal and cross-day storage were evaluated by creating a set of hierarchical storage bins for which both charging and discharging is always prioritized for bin #1 and then for subsequent bins. Thus, if electricity is available for charging, we first fill bin #1 and then move on to bin #2. Similarly, when electricity is needed, discharging begins from bin #1 and then moves on to bin #2 rather than discharging from the most recently filled bin. The state of charge is tracked for all bins with more storage bins created as needed. The state-of-charge of all bins at the end of the year is rolled into the initial state of charge of the bins at the beginning of the year to provide an appropriate boundary condition, as shown in Fig. 3.4. As can be seen along the top edge of the graph, bin #1 is emptied and filled every day, but the majority of the bins are emptied and filled only once per year. In this example, we used 40 GWh as the size of each bin, but the size of the bin is arbitrary. Once the calculation shown in Fig. 3.4 is completed, the statistics for each bin may be considered in terms of the number of times that bin was fully filled and emptied as shown in Fig. 3.5. Each bin may be only partially cycled each day, but by calculating the statistics in this way, we can quantify the cumulative use of the storage over the year.

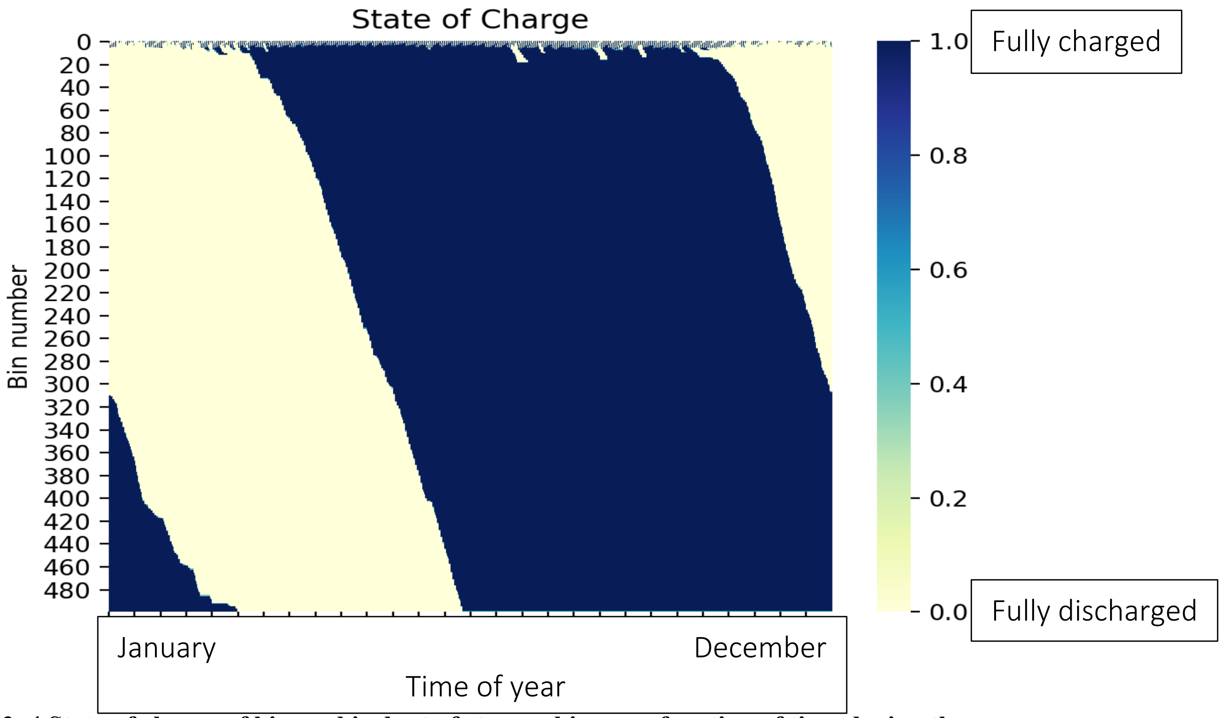


Fig. 3. 4 State of charge of hierarchical set of storage bins as a function of time during the year.

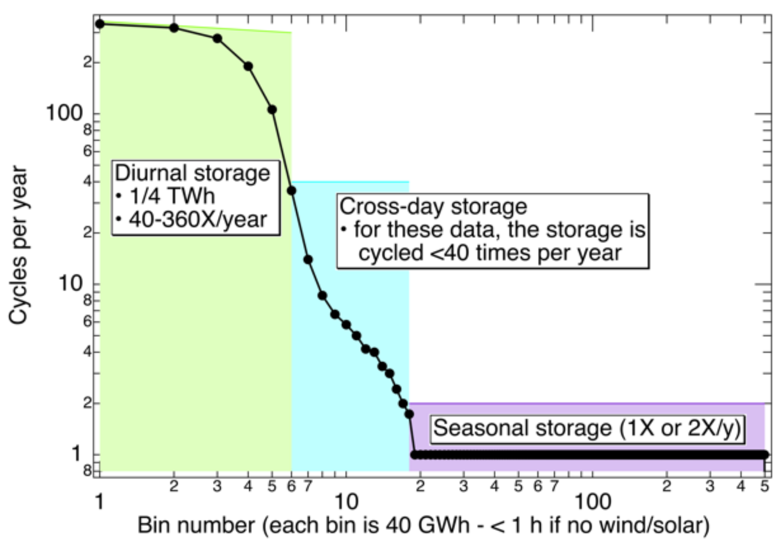


Fig. 3. 5 Number of times each storage bin is fully filled and emptied during a year

Fig. 3.5 uses logarithmic scales to better contrast the small and large numbers. Shaded regions are applied somewhat arbitrarily to differentiate the different types of storage applications. The number of bins in the diurnal storage section was determined by calculating a histogram of the energy put into storage during each night of the year. The largest energy amounts were about 0.25 TWh, or about six 0.04 TWh bins, as shown by the green shaded region on the left. Seasonal storage is taken to be those bins that are used 1 or two times per year (purple highlight in Fig. 3.5). The bins between the diurnal and seasonal storage are labeled as cross-day storage and highlighted by the blue shaded region. This data set shows bins 1 and 2 to be fully filled and emptied > 300 times/year. Bins 5 and 6 are only fully filled and emptied tens of times per year. Thus, although we have labeled all 6 bins as being "diurnal" storage, not all of the bins should be considered to be equivalent because the economics of a storage asset that is cycled every day is quite different from one that is cycled tens of times per year. While the value of analyzing the hierarchical data set is primarily found in the statistics found for each individual bin, the somewhat arbitrary categorization of the bins provides an easier way to discuss the results. For other data sets, the number of bins falling into the cross-day and seasonal storage categories will vary. From the curve, we can quantitatively define the minimum usage of storage to implement the identified generation and load profiles. Additional storage will be needed to match local supply and demand when transmission is not perfect.

While the differentiation between the diurnal and cross-day storage is somewhat arbitrary, the shape of the curve suggests an inflection point that differentiates between the diurnal application and the cross-day storage application, suggesting that our use of 0.24 TWh for the diurnal storage is a reasonable boundary to define. The boundary between seasonal and cross day storage may also be considered arbitrary. We have selected to define seasonal storage as that cycled less than two times per year as shown by the purple rectangle in Fig. 3.5. We consider the rest to be cross-day storage for the point of discussion, as highlighted by the blue rectangle in Fig. 3.5.

The use of this hierarchical approach anticipates that there will be some favored storage assets that will tend to be cycled before other resources. The reasons for using them first may depend on the operating cost, the efficiency and the degradation caused by cycling them. Our energy modeling should be sure to account for such drivers. In the meantime, the graphs of data using the approach shown in Fig. 3.5 is very helpful in developing intuition about the ramifications for storage when the generation mix is varied.

3.5 Energy-balance modeling results by storage type

The hierarchical storage calculation was applied to some of the scenarios discussed above. The details of the calculations will be published separately. Here we share the resulting trends as a way to inform the capacity expansion optimization we will complete in the next stage of the project.

The storage needed to support generation mixes from multiple wind resources is shown in Fig. 3.6. In this simulation, as described above, the thermal, nuclear, and imported generation from reported values is replaced with an expansion of the current solar generation profile, resulting in the "solar only" curve in Fig. 3.6. Then, 10 GW of wind was substituted for however much solar would have generated the same electricity as the 10 GW of wind, to create the curves for the other scenarios. Focusing attention on the left side of the graph (first six bins that are likely to be needed to provide electricity through a windless night), the "solar-only" scenario cycles these bins more frequently while the summer-dominant wind cycles them less frequently. The other scenarios lie between the "solar-only" and "summer-dominant wind" results and are not easily differentiated in the graph. In general, replacing some solar generation with wind generation tends to create a need for up to 0.5 TWh of storage that may be cycled a handful of times per year. The biggest variation we see is in the amount of seasonal storage that is needed. The "solar-only" scenario required almost 400 bins, or about 16 TWh of seasonal storage. The addition of 10 GW of winter-dominant onshore wind could reduce that need to < 10 TWh of storage.

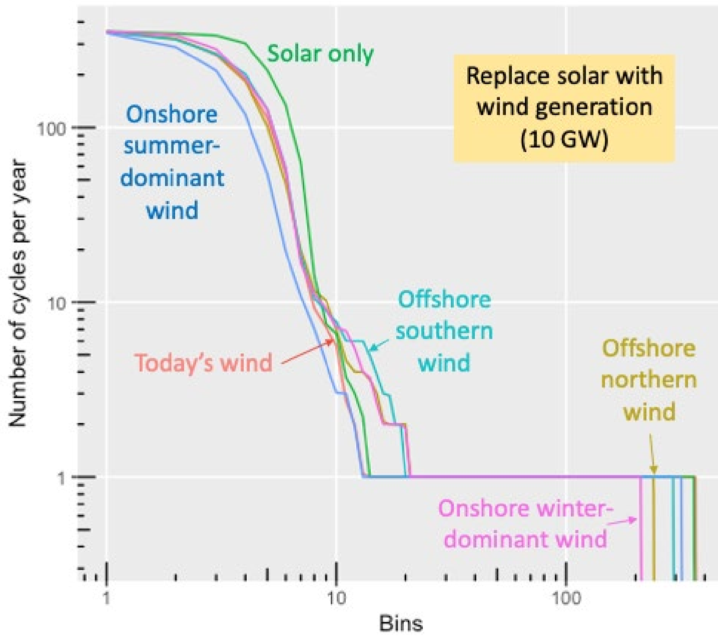


Fig. 3. 6 Storage requirements for six generation-mix scenarios

As shown in Figs. 2.21 and 2.22 above and repeated in Fig. 3.7 for convenience, replacing solar generation with 5 to 20 GW of most types of wind would increase the storage that would be cycled a handful or even tens of times per year (labeled as "cross-day" storage), but would decrease the need for seasonal storage. The exception is the summer-dominant onshore wind that has little effect on the cross-sector and seasonal storage relative to the use of solar.

The addition of 20 GW of any of these types of wind is implausible, but 5 GW to 10 GW may be plausible. The calculation of the additional 20 GW underscores the very large effect that would be possible if more wind resource could be found. For example, it may be possible to find more wind in the Rocky Mountains.

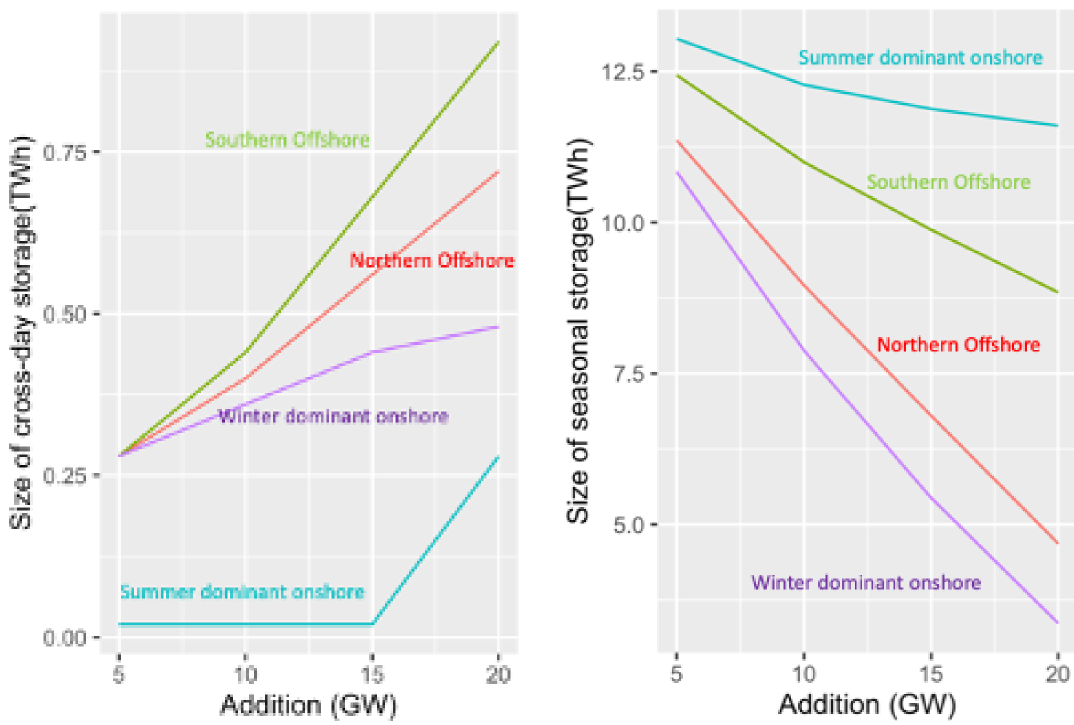


Fig. 3. 7 Effect of wind generation on needed cross-day and seasonal storage reservoirs

3.6 Modeling requirements for understanding types of storage

The stability of the grid requires instantaneous balancing of supply and demand but understanding long-duration storage is focused on longer time horizons. Inspecting Fig. 2.17 where all storage is treated as one large reservoir, we see that the storage can be maintained as mostly full during the summer, then is depleted in an annual cycle reflecting the reduced availability of solar energy in the winter. The data suggest that the following time horizons may be differentiated:

- **Seasonal:** Understanding seasonal issues requires full-year modeling with an emphasis on October to March.
- **Daily**: The diurnal cycle of charging during the day and discharging at night can be studied by considering 24-hour days, but the statistics of the diurnal cycle vary throughout the year. The interaction between the nighttime storage (requiring 10-15 hours of storage) with the seasonal storage will affect the use of the diurnal storage.
- **Events**: In Fig. 2.17, we can see that there are irregular dips in the data. Satellite photos show how clouds can lead to a temporary depletion of the storage. We anticipate that the dips seen in Fig. 2.17 arise from clouds, smoke, or other events that lead to a net shortage of electricity over a few days. The dips are seen to vary from a short time (a day or two) to about a month or even to multiple months.

Our goal of quantifying the relative amounts of short- and long-duration storage (including the relative amounts of variable types of long-duration storage) requires that we simultaneously model these. However, it is not clear that hourly calculations are required since California's fleet of storage is currently comprised of 4-hour and longer-duration storage.

The daily charging and discharging of the storage typically results in a minimum state of charge one to two hours after sunrise and a maximum state of charge one to two hours before sunset. While the details of the dispatch of that storage may depend on the hourly simulation, the calculation of the needed storage capacity depends primarily on these minima and maxima. Thus, in general, we may select two timesteps each day to define the resource adequacy for the amount of energy needed to be retained in storage. We also need to include the hour of the day when the power demand is a maximum in order to appropriately size the generators to meet that peak demand.

After the capacity expansion is optimized, we may optimize the dispatch on an hourly basis using the selected capacity expansion. The linear optimization of the dispatch can be done a year at a time using the full 8760 hours of data. Because the computational challenge scales closer to the square of the number of timepoints/calculations, we may complete the calculations faster by calculating the optimal dispatch one year at a time. Thus, we propose to reduce the computational complexity by completing the capacity expansion optimization using two to four timesteps per day, then optimizing the hourly dispatch in a second calculation, preferably using variable weather data sets to test the reliability. This approach is consistent with the way results would be implemented in the real world. Any surprises that occur during the dispatch will inform an improved version of the capacity expansion modeling, perhaps by revising the approach to determining the needed reserve, as discussed in the next section.

4. Modeling inputs

This section describes plans for how to model each technology generation. The format for the RESOLVE files is not yet finalized.

4.1 Solar

The following inputs have been calculated using the 2021 NREL ATB. For solar, a 30-year financial recovery time was used with a 4% interest rate. The Moderate CAPEX cost was taken starting at $1076/kW in 2025 and decreasing to $672/kW in 2045. The annualized costs based on these numbers are tabulated in Table 4.1.

Table 4. 1 RESOLVE inputs for generic solar resource

timestamp	attribute	value
None	can_retire	0
None	can_build_new	1
None	curtailable	1
1/1/20	variable_cost_provide_power	0
1/1/20	variable_cost_increase_load	0
1/1/25	Annualized CapEx ($/kW/y)	62.2
1/1/30	Annualized CapEx ($/kW/y)	44.9
1/1/35	Annualized CapEx ($/kW/y)	42.9
1/1/40	Annualized CapEx ($/kW/y)	40.9
1/1/45	Annualized CapEx ($/kW/y)	38.9
1/1/25	Annual O&M ($/kW/y)	20
1/1/30	Annual O&M ($/kW/y)	17
1/1/35	Annual O&M ($/kW/y)	16
1/1/40	Annual O&M ($/kW/y)	16
1/1/45	Annual O&M ($/kW/y)	15

The costs are assumed to be the same for all RESOLVE solar plants. Candidate resources use the same names and locations as RESOLVE has used in the past, but we now calculate hourly generation profiles for the entire year for all years starting from 2015 through 2020 and for both 1-axis tracked, 0° tilt and latitude tilt configurations. We anticipate exploring other configurations as well. These data are lengthy, so are not shown here.

We will adjust the costs for solar plants installed with different mounting configurations to reflect the difference in cost.

The SWITCH model includes four categories of solar power plants: Central PV, Commercial PV, Residential PV and concentrating solar power (CSP). For Central PV, the original SWITCH model included fixed tilt system a total of 2585 resources where 984 are existing power plants and 1601 potential candidate resources that share the same technology assumption as shown in Table 4.2. The huge number of candidate resources incorporates into the model a high-resolution spatial granularity that captures resources located at different locations inside of the load zone with different annual capacity factor and interconnection cost. The interconnection cost of each candidate technology was determined using a cluster analysis that identified potential locations near substations within a load zone and this analysis was detailed in a prior work[27]. The SWITCH model also contemplates commercial and residential PV as well as CSP with and without energy storage, however from previous results, these are not selected due to higher costs and are considered only outside of the optimization, by making assumptions that are consistent with expectations.

Table 4. 2 SWITCH solar energy technologies assumptions including cost values for 2050 period.

Solar resource	No. Plants	Overnight cost[1] ($/kW)	Fixed O&M ($/kW)	Interc. cost[2] ($/kW)	Legacy capacity (GW)	Capacity limit[3] (GW)	Lifetime (years)
Central (Fixed tilt)	2585	703	8.29	0-230	21.9	3292	30
Commercial	216	820	5.87	-	-	52	30
Residential	215	884	6.63	-	-	125	30
CSP (w/ 6 hrs storage)	1432	4024	52.54	31-230	-	3695	20
CSP (w/o storage)	1473	3937	56.14	0-230	0.4	5362	20

Note: Cost number represent the average of the selected period to study from 2046-2055.
[1]The overnight capital cost is the capital expenditure required to achieve commercial operation of a plant, excluding the construction period financing cost and the interconnection cost.
[2] Interconnection cost varies through the WECC and by load zone. Values shows the range
[3] Maximum allowed capacity to expand by the model. Limits varies according to land constraints per each load zone.

4.2 Wind

4.2.1 Onshore Wind

The following inputs have been calculated using the 2021 NREL ATB. For land-based wind, a 30-year financial recovery time was used with a 4% interest rate. The Moderate CAPEX cost was taken starting at $1171/kW in 2025 and decreasing to $808/kW in 2045. The annualized costs based on these numbers are tabulated in Table 4.3.

[27] Nelson, J. et al. High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures. Energy Policy 43, 436–447 (2012).

Table 4. 3 RESOLVE inputs for generic onshore wind resource

timestamp	attribute	value
None	can_retire	0
None	can_build_new	1
None	curtailable	1
1/1/20	variable_cost_provide_power	0
1/1/20	variable_cost_increase_load	0
1/1/25	Annualized CapEx ($/kW/y)	67.7
1/1/30	Annualized CapEx ($/kW/y)	54.9
1/1/35	Annualized CapEx ($/kW/y)	52.2
1/1/40	Annualized CapEx ($/kW/y)	49.4
1/1/45	Annualized CapEx ($/kW/y)	46.7
1/1/25	Annual O&M ($/kW/y)	41
1/1/30	Annual O&M ($/kW/y)	39
1/1/35	Annual O&M ($/kW/y)	37
1/1/40	Annual O&M ($/kW/y)	36
1/1/45	Annual O&M ($/kW/y)	35

Previously, E3 has prescribed different costs to wind plants. We have not differentiated here the wind plant costs for onshore wind. We will retain candidate resources using the same names and locations as RESOLVE has used in the past, but we now calculate hourly generation profiles for the entire year for all years starting from 2015 through 2020. These data are lengthy, so are not shown here. We intend to also add a few new sources that have winter-dominant wind generation to observe their effect on the use of storage.

The WECC-wide inputs to SWITCH include 1860 candidate and existing onshore wind resources with a possible deployment limit approaching 500 GW. Within California, SWITCH documents 310 existing and candidate onshore resources with a total of 15.6 GW offered to the model. A summary of the technology and cost assumptions is shown in Table 4.4

Table 4. 4 SWITCH wind energy technologies assumptions including cost values for 2050 period.

Wind resources	No. Plants	Overnight cost[1] ($/kW)	Fixed O&M ($/kW)	Interc. cost[2] ($/kW)	Legacy capacity (GW)	Capacity limit[3] (GW)	Lifetime (years)
Onshore Wind	1860	1042	33.7	0-485	27	500.0	30
Offshore Wind	48	2227	112.3	50-457	-	6.4	30

Note: Cost number represent the average of the selected period to study from 2046-2055.
[1]The overnight capital cost is the capital expenditure required to achieve commercial operation of a plant, excluding the construction period financing cost and the interconnection cost.
[2] Interconnection cost varies through the WECC and by load zone. Values shows the range
[3] Maximum allowed capacity to expand by the model. Limits varies according to land constraints per each load zone.

4.2.2 Offshore Wind

A recent study by NREL describes the six best offshore wind candidate sites for California.[28] These are summarized in Table 4.5. Based on the mean water depth, we have assigned an ATB class, but recognize that the categorization should also reflect the distance to the interconnection and other considerations. Because most of the sites have mean depths that are class 14, we have summarized the class 14 data in Table 4.6, omitting the class 13 data for Channel Islands North and Bodega Bay for brevity of this summary document.

Table 4. 5 Candidate California offshore wind sites identified by NREL study

Identified area	Latitude (°)	Longitude (°)	Mean Depth	Potential Capacity (MW)	ATB Class
Channel Islands South	**33.734614**	120.18475	746 m	2259	14
Channel Islands North	34.188565	120.66088	575 m	1335	13
Morro Bay	35.458256	121.50439	713 m	3702	14
Bodega Bay	38.355489	123.52929	446 m	2397	13
Humboldt Bay	40.133304	124.73094	870 m	1293	14
Crescent City	41.699739	124.76659	805 m	5256	14

The inputs in Table 4.6 have been calculated using the 2021 NREL ATB. For offshore wind, a 30-year financial recovery time was used with a 4% interest rate. Depending on the water depth, the CAPEX cost varies somewhat. Using the Moderate CAPEX cost a Class 14 site starts at $4741/kW in 2025 and increases to $3395/kW in 2045.

Table 4. 6 RESOLVE inputs for generic offshore wind resource

timestamp	attribute	value
None	can_retire	0
None	can_build_new	1
None	curtailable	1
1/1/20	variable_cost_provide_power	0
1/1/20	variable_cost_increase_load	0
1/1/25	Annualized CapEx ($/kW/y)	274.2
1/1/30	Annualized CapEx ($/kW/y)	235.0
1/1/35	Annualized CapEx ($/kW/y)	218.6
1/1/40	Annualized CapEx ($/kW/y)	206.3
1/1/45	Annualized CapEx ($/kW/y)	196.3
1/1/25	Annual O&M ($/kW/y)	76
1/1/30	Annual O&M ($/kW/y)	70
1/1/35	Annual O&M ($/kW/y)	65
1/1/40	Annual O&M ($/kW/y)	62
1/1/45	Annual O&M ($/kW/y)	60

[28] https://www.boem.gov/sites/default/files/environmental-stewardship/Environmental-Studies/Pacific-Region/Studies/BOEM-2016-074.pdf

The inputs to SWITCH include 48 candidate offshore wind resources with a possible deployment limit approaching 6.4 GW. All of these are associated with California. The offshore wind sites with generation capacity limit > 30 MW are shown in Table 4.7.

Table 4. 7 SWITCH wind energy technologies assumptions including cost values for 2050 period.

Wind resources	No. Plants	Overnight cost[1] ($/kW)	Fixed O&M ($/kW)	Interc. cost[2] ($/kW)	Legacy capacity (GW)	Capacity limit[3] (GW)	Lifetime (years)
Onshore Wind	1860	1042	33.7	0-485	27	500.0	30
Offshore Wind	48	2227	112.3	50-457	-	6.4	30

Note: Cost number represent the average of the selected period to study from 2046-2055.
[1]The overnight capital cost is the capital expenditure required to achieve commercial operation of a plant, excluding the construction period financing cost and the interconnection cost.
[2] Interconnection cost varies through the WECC and by load zone. Values shows the range
[3] Maximum allowed capacity to expand by the model. Limits varies according to land constraints per each load zone.

4.3 Hydropower

Neither SWITCH nor RESOLVE has been configured to allow build of new hydropower resources as shown in Tables 4.8 and 4.9. CAISO reports 1232 MW of small hydro as of Jan. 1, 2021,[29] which agrees well with the value used in RESOLVE RSP.

Table 4. 8 Comparison of small hydropower resources

Zones for SWITCH*	SWITCH Existing	SWITCH Allowed new	Resources for RESOLVE*	RESOLVE Existing	RESOLVE Allowed new
CA_IID	**	0 MW	IID_Small_Hydro_for_Other	0 MW	0 MW
CA_LADWP	**	0 MW	LDWP_Hydro_for_Other	56 MW	0 MW
Other CA zones	**	0 MW	CAISO_Small_Hydro & CAISO_Small_Hydro_for_Other	974 MW	0 MW
CA_SMUD	**	0 MW	BANC_Small_Hydro_for_Other	0 MW	0 MW

*The zones used by SWITCH and RESOLVE do not directly map onto each other. These are approximated.
**SWITCH does not differentiate large hydro and small hydro, so all are reported in Table 4.9.

Table 4. 9 Comparison of hydropower resources

Zones for SWITCH*	SWITCH Existing**	SWITCH Allowed new	Resources for RESOLVE*	RESOLVE Existing	RESOLVE Allowed new
CA_IID	88 MW	0 MW	IID_Hydro_for_Other	84 MW	0 MW
CA_LADWP	45 MW	0 MW	LDWP_Hydro	234 MW	0 MW
Other CA zones	9573 MW	0 MW	CAISO_Hydro	7070 MW	0 MW
CA_SMUD	212 MW	0 MW	BANC_Hydro	2724 MW	0 MW

*The zones used by SWITCH and RESOLVE do not directly map onto each other. These are approximated.
**SWITCH does not differentiate large hydro and small hydro, so both are reported here.

[29] http://www.caiso.com/Documents/Key-Statistics-Dec-2020.pdf

4.4 Geothermal

The following inputs have been calculated using the 2021 NREL ATB. For geothermal, like other technologies, a 30-year financial recovery time was used with a 4% interest rate. The costs of geothermal plants can be highly variable. For example, the 2025 Moderate CAPEX cost for Hydro/Flash is $6033, while Hydro/Binary is $7902, and NF EGS/Binary is $39,426. By 2045, these are expected to decrease a little, but not a lot with the Moderate CAPEX cost for Hydro/Flash being $5148, with Hydro/Binary is $6888, and NF EGS/Binary is $31,729. The uncertainties conveyed in the NREL ATB are quite substantial, noting that the Moderate $31,729 could drop to $7050, more than a factor of 5 decrease. This would be well worth exploring based on the value of geothermal generation to the bigger system. The annualized costs based on the Moderate Hydro/Binary numbers are tabulated in Table 4.10.

Table 4. 10 RESOLVE inputs for generic geothermal resource

timestamp	attribute	value
None	can_retire	0
None	can_build_new	1
None	curtailable	0
1/1/25	Annualized CapEx ($/kW/y)	457
1/1/30	Annualized CapEx ($/kW/y)	429
1/1/35	Annualized CapEx ($/kW/y)	419
1/1/40	Annualized CapEx ($/kW/y)	408
1/1/45	Annualized CapEx ($/kW/y)	398
1/1/25	Annual O&M ($/kW/y)	175
1/1/30	Annual O&M ($/kW/y)	169
1/1/35	Annual O&M ($/kW/y)	169
1/1/40	Annual O&M ($/kW/y)	169
1/1/45	Annual O&M ($/kW/y)	169

Candidate resources will use the same names and locations as RESOLVE has used in the past. Current and new options will follow those that have been used by RESOLVE in the past unless new opportunities come to light. These are summarized in Table 4.11.

Table 4. 11 Summary of geothermal plants

Resource	Planned installed capacity (MW)	Capacity limit (MW)	Note
BANC_Geothermal_for_Other	0		No new builds
CAISO_Geothermal_for_Other	38.7		No new builds
IID_Geothermal_for_Other	709.5		No new builds
LDWP_Geothermal_for_Other	0		No new builds
NW_Geothermal_for_Other	132.1		No new builds
SW_Geothermal_for_Other	664.9		No new builds
CAISO_Geothermal_for_CAISO	1812.6		No new builds
IID_Geothermal_for_CAISO	83		No new builds
NW_Geothermal_for_CAISO			No new builds
Greater_Imperial_Geothermal		1352.1	
Inyokern_North_Kramer_Geothermal		24	
Northern_California_Ex_Geothermal		469	
Riverside_Palm_Springs_Geothermal		32	
Solano_Geothermal		135	
Southern_Nevada_Geothermal		320	
Total	3441	2332	

The generation profiles for the geothermal plants will be assumed to be flat.

The WECC-wide inputs to SWITCH for geothermal include 99 existing geothermal installations and 238 candidate geothermal resources as shown in Table 4.12. Each geothermal resource is assumed to provide baseload generation through its lifetime.

Table 4. 12 SWITCH geothermal energy technologies assumptions including cost values for 2050 period.

Geothermal resources	No. Plants	Overnight cost[1] ($/kW)	Fixed O&M ($/kW)	Interc. cost[2] ($/kW)	Legacy capacity[3] (GW)	Capacity limit[4] (GW)	Lifetime (years)
Geothermal	338	6970	173	0-395	4477	15	30

Note: Cost number represent the average of the selected period to study from 2046-2055.
[1]The overnight capital cost is the capital expenditure required to achieve commercial operation of a plant, excluding the construction period financing cost and the interconnection cost.
[2] Interconnection cost varies through the WECC and by load zone. Values shows the range
[3] Legacy plants include scheduled assets that are either on the queue or listed under EIA-860.
[4] Maximum allowed capacity to expand by the model. Total value for all the load zones included in the model is shown, but limit varies according to land constraints per each load zone.

4.5 Biomass

The following inputs have been calculated using the 2021 NREL ATB. For biomass, like other technologies, a 30-year financial recovery time was used but with a slightly higher 5% interest rate. The costs of biomass plants provided in the NREL ATB have no variability, suggesting that the NREL analysis for biomass was not as thorough as for other technologies. The CAPEX in 2025 is $4275, decreasing to $3738 in 2045. The annualized costs associated with these changes were calculated and tabulated in Table 4.13.

Table 4. 13 RESOLVE inputs for generic biomass resource

timestamp	attribute	value
None	can_retire	0
None	can_build_new	1
None	curtailable	0
1/1/25	Annualized CapEx ($/kW/y)	278
1/1/30	Annualized CapEx ($/kW/y)	270
1/1/35	Annualized CapEx ($/kW/y)	261
1/1/40	Annualized CapEx ($/kW/y)	252
1/1/45	Annualized CapEx ($/kW/y)	243
1/1/25	Annual O&M ($/kW/y)	150
1/1/30	Annual O&M ($/kW/y)	150
1/1/35	Annual O&M ($/kW/y)	150
1/1/40	Annual O&M ($/kW/y)	150
1/1/45	Annual O&M ($/kW/y)	150

Candidate resources will use the same names and locations as RESOLVE has used in the past. The generation profiles for the biomass plants will be assumed to be flat but will be limited by the available biofuel.

The WECC-wide inputs to SWITCH include a seven categories of bioenergy generation assets as shown in Table 4.14. This set of resources have three main sources of fuel: Bio-liquid, Bio-solid and Biogas. In total for the model include existing bioenergy assets include 131 Biogas, 12 Bio-liquid, 52 Bio-solid. Yet, under the current state of the baseline, the model is configured such that it only allows to expand certain configurations within certain load zones. Table 4.14 shows the technology breakdown as well as the technology and cost assumptions for each bioenergy resource.

Table 4. 14 SWITCH bioenergy energy technologies assumptions including cost values for 2050 period.

Technology	Energy resource	No. Plants	Overnight cost[1] ($/kW)	Fixed O&M ($/kW)	Interc. cost[2] ($/kW)	Heat rate MMBtu / MWh	Legacy capacity[3] (GW)	Capacity limit[4] (GW)	Lifetime (years)
Biogas	**Gas**	59	2118	64.38	0-92	6.96-14.7	0.15	0.16	20
I.C. Engine	Gas	68	-	-	-	6.79-72.5	0.26	0.26	20
I.C. Cogen	**Gas**	41	1588	48.28	-	4.65-40.4	0.08	0.20	20
S. T.	Gas	4	-	-	-	7.8-50	0.08	0.08	20
	Solid	24	-	-	-	6.91-53.71	0.65	0.64	20
S. T. Cogen	**Liquid**	16	3226	80.01	-	4.51-13	0.35	0.61	40
	Solid	46			-	4.78-21.73	0.52	1.00	40

Note: Cost number represent the average of the selected period to study from 2046-2055. IC = Internal combustion, ST = Steam turbine
[1]The overnight capital cost is the capital expenditure required to achieve commercial operation of a plant, excluding the construction period financing cost and the interconnection cost.
[2] Interconnection cost varies through the WECC and by load zone. Values shows the range
[3] Legacy plants include scheduled assets that are either on the queue or listed under EIA-860.
[4] Maximum allowed capacity to expand by the model. Total value for all the load zones included in the model is shown, but limit varies according to land constraints per each load zone.

4.6 Carbon sequestration coupled with biogas

The following inputs have been calculated using the 2021 NREL ATB and RESOLVE input files. Like other technologies, a 30-year financial recovery time was used but with a slightly higher 5% interest rate. The annualized costs and other data were calculated and tabulated in Table 4.15.

Table 4. 15 RESOLVE inputs for biogas plus carbon sequestration

timestamp	attribute	value
1/1/25	Annualized CAPEX ($/kW/y)	278.1
1/1/30	Annualized CAPEX ($/kW/y)	270.35
1/1/35	Annualized CAPEX ($/kW/y)	261
1/1/40	Annualized CAPEX ($/kW/y)	251.8
1/1/45	Annualized CAPEX ($/kW/y)	243.2
1/1/25	Fuel Costs ($/MMBtu)	3
1/1/30	Fuel Costs ($/MMBtu)	3
1/1/35	Fuel Costs ($/MMBtu)	3
1/1/40	Fuel Costs ($/MMBtu)	3
1/1/45	Fuel Costs ($/MMBtu)	3
1/1/25	Fuel Costs ($/MWh)	43
1/1/30	Fuel Costs ($/MWh)	43
1/1/35	Fuel Costs ($/MWh)	43
1/1/40	Fuel Costs ($/MWh)	43
1/1/45	Fuel Costs ($/MWh)	43
None	Heat rate (MMBTU/MWh)	13.5
1/1/25	fixed_o_and_m_dollars_per_kw_yr	11.115
1/1/30	fixed_o_and_m_dollars_per_kw_yr	11.115
1/1/35	fixed_o_and_m_dollars_per_kw_yr	11.115
1/1/40	fixed_o_and_m_dollars_per_kw_yr	11.115
1/1/45	fixed_o_and_m_dollars_per_kw_yr	11.115
1/1/25	Variable Operation and Maintenance Expenses ($/MWh)	-30
1/1/30	Variable Operation and Maintenance Expenses ($/MWh)	-30
1/1/35	Variable Operation and Maintenance Expenses ($/MWh)	-30
1/1/40	Variable Operation and Maintenance Expenses ($/MWh)	-30
1/1/45	Variable Operation and Maintenance Expenses ($/MWh)	-30
None	can_build_new	1
None	can_retire	0
none	generation_efficiency	0.57

4.7 Carbon sequestration coupled with natural gas

As described above, we will model carbon sequestration coupled with natural gas using the Allam cycle. The capital costs are the same as for the Allam cycle using biogas, but the cost of the fuel is different.

The price of natural gas just increased as shown in Fig. 4.1. There is high uncertainty in modeling future natural gas prices. These must be modeled through scenarios.

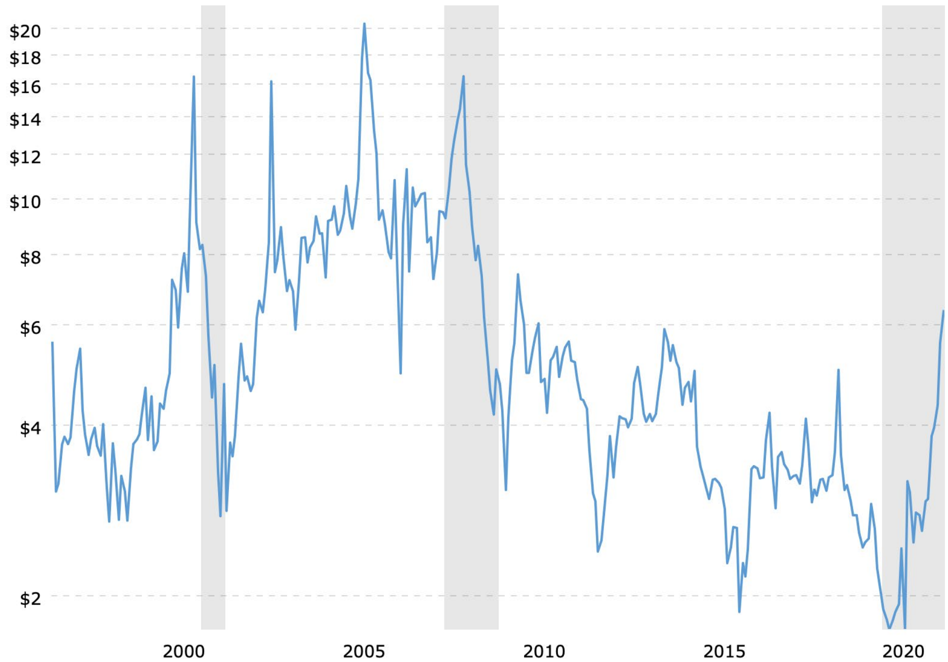


Fig. 4. 1 History of natural gas prices[30] per MMBTU

[30] https://www.macrotrends.net/2478/natural-gas-prices-historical-chart

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