# Seasonal Challenges for a Zero-Carbon Grid in California

Mahmoud Y. Abido[a,b], Kenji Shiraishi[c], Pedro Andrés Sánchez-Pérez[a], Russell K. Jones[d], Zabir Mahmud[a], Sergio Castellanos[e], Noah Kittner[f], Daniel M. Kammen[c], and Sarah R. Kurtz[a]

[a]University of California Merced, CA, USA; [b]Cairo University, Giza, Cairo, Egypt; [c]University of California Berkeley, CA, USA; [d]Jones Solar Engineering, Manhattan Beach, CA, USA; [e]University of Texas at Austin, Texas, USA; [f]University of North Carolina at Chapel Hill, NC, USA.

***Abstract*—Today resource adequacy is most often maintained by installing natural gas plants to meet the peak load. In California, the current risk of inadequate electricity supply is highest around sunset in late summer. In a zero-carbon grid, resource adequacy will increasingly require adequate stored energy throughout the entire year. Here we seek to develop an intuition about the times of the year when resource adequacy may be most challenged for a solar-dominant system. We use a simplified approach and show that the month of the biggest challenge occurs in winter and can shift by more than two months depending on the amount of solar and storage that are built.**

***Keywords—storage, zero-carbon grid, seasonal storage, solar***

## I. INTRODUCTION

California Senate Bill 100 (SB100) [1] establishes a target of 2045 for moving to a grid that delivers electricity reliably without carbon dioxide emissions. Meeting this target will require changes in resource adequacy planning [2] [3]. This challenge was highlighted in August 2020 when the California Independent System Operator (CAISO) declared an emergency and initiated rolling black outs on two days during a widespread heat wave [4]. This was the first time in about 30 years that the state initiated rolling black outs because the reserve margin dropped below safe levels. A root cause analysis showed that the problem arose from the extreme heat (and breadth of the heat wave) and inadequate planning targets for early evening hours. Several practices in the energy markets also exacerbated the supply challenges [5].

A simple consideration of a similar situation for a grid without natural gas plants shows that storage will need to supply most of the load (about 40 GW) after sundown on a windless evening [6]. Thus, CAISO will need on the order of 40 GW of power supplied by storage [5] (more, if the load increases) and adequate energy storage to run through the night. It is less obvious whether California without natural gas plants will still be most susceptible to resource inadequacy during late August and early September or whether that risk will shift to other times of year.

It is anticipated that CAISO's future zero-carbon grid will be dominated by solar generation [7], [8], [9]. While wind and other renewable electricity will supplement solar, the wind generation in California has been reported to be highly variable and to be even less consistent than solar resource in the winter [10]. Taken on a monthly average, in California both solar generation and electrical load increase during the summer, but solar generation varies more between summer and winter than the load, while the monthly load varies less, suggesting that winter may be the more challenging season for a zero-carbon grid in California unless additional generation sources are identified for winter.

This paper uses recent historical data to estimate the storage needed for a zero-carbon grid to understand when resource adequacy may be most difficult in California. We explore the effects of building more solar on the stored energy and on the needed storage. We also explore the effect of limiting the rate of charge. Finally, we discuss the intuition that is gained from the results toward understanding how these factors affect the time of year when resource adequacy is most challenging.

## II. METHODOLOGY

The energy storage that will be needed to operate a zero-carbon grid in California is studied using historical CAISO electrical generation and load data for years 2015-2020 [11]. These datasets include 5-min. data for electrical generation by technology and for the electrical load. To simulate resource adequacy for the grid of the future, the electricity supply by thermal, nuclear, and imports are replaced with scaled-up solar generation. A hypothetical storage reservoir is created for balancing supply and demand. For each time point, the electricity available for charging the storage is calculated from equation 1.

$$Charge = Added\ Solar + Hydro + Renewables - Load \tag{1}$$

where *Added Solar* is the historical solar generation multiplied by a variable factor and the other terms in equation 1 are taken directly from the historical data [11]. When the right side of equation 1 is positive, the state-of-charge of the hypothetical storage is increased and when it is negative, the stored energy is discharged into the grid. To simplify the analysis, battery charging and discharging efficiencies are assumed to be 100% with no self-discharge loss. The minimum state of charge is set to zero, neglecting the need for any operating reserve margin or limited depth of discharge. The size of the storage reservoir is capped so that the state-of-charge at the end of the year equaled that at the beginning of the year. When the state-of-charge of the reservoir reached the cap, additional electricity available for charging is counted as surplus electricity. In practice, this electricity may be used for hydrogen production or some other load. For this study, to gain intuition about when the system may face resource adequacy issues, we calculate (1) the state-of-charge as a function of time of year, (2) size of reservoir needed, and (3) surplus electricity generated as we vary the amount of solar electricity generated.

For a subset of the calculations, the charging rate is limited to 40 GW and the extra power beyond this limit is considered to be surplus electricity.

This approach gives realistic results in which the generation and load profiles are based on observed data. However, this approach does not (1) consider transmission constraints, [12] (2) adjust hydro generation to best meet the supply/demand imbalances, nor (3) adjust the load profile, which can be driven by electric vehicle adoption, heat pump adoption, demand management, and many other things.

In order to calculate the daily discharge, the discharge time was divided into two parts, the first one starting from midnight to the minimum state of charge in that day and the second part starting from the maximum state of charge in that day to midnight (check the inset in figure 1). The statistics were calculated over all the days for each year.

## III. Results and Discussion

The state-of-charge of the storage as a function of time of year is shown in Fig. 1 using renewables generation and load data from 2019 (eq. 1), but with the solar generation scaled up to be able to meet or exceed the total load for the year. For all curves we observe that the state of charge is a minimum sometime during the winter, but when the charging is unconstrained (dotted lines) the time for the minimum shifts from mid-March when the total generation just meets the annual load to mid-January when a large solar build out is capable of exceeding the daily demand on sunny days. A close look at the data (see inset in figure 1) confirms that the minimum state of charge occurs near sunrise. Thus, the most challenging time of year to retain adequate reserve shifts from sunset in late summer (observed today) to sunrise in the winter (when storage is required to get through the winter months).

This calculation for 2019 is compared with similar data for years 2015-2020 in Fig. 2. We select calculations with fairly similar solar build outs for all six years by adjusting the amount of solar so that the total electricity generated in each year exceeds the total load for that same year by 15 TWh, which allowed the years to be compared directly while limiting the surplus electricity. If no practical use could be found for the 15 TWh of surplus electricity, it would be curtailed, representing about 10% of the annual solar generation. In every year, the minimum state-of-charge for the energy reservoir is found to occur in late February or the first part of March, narrowing the time of low reserve margin to about one month. The predictability (about one month) of the most challenging time of resource adequacy is consistent with the current predictability of late August and early September (a time span of about one month) as the most challenging time for today's grid.

The upper part of Fig. 2 shows that the reservoir is not able to always recharge every day during the summer. The dips in the state-of-charge when the reservoir is mostly full come at different times each year. These could be caused by heat waves or by times of low solar generation. Our investigations show that the cause is dominated by low solar generation, which is associated with clouds or smoke as shown in the two satellite images [13] of California shown for a day when the reservoir is able to completely refill (July 1, 2019) and a day when the reservoir is not able to refill completely (July 25, 2019), showing the obvious cloud cover. The year 2020 is notable because of the large number of fires that burned late in the summer, corresponding to an early decline in the state-of-charge of the hypothetical battery in 2020, as shown in Fig. 2, green curve. Despite the abnormally large amount of smoke in late summer of 2020, the year ends with a state-of-charge that is comparable to 2018.

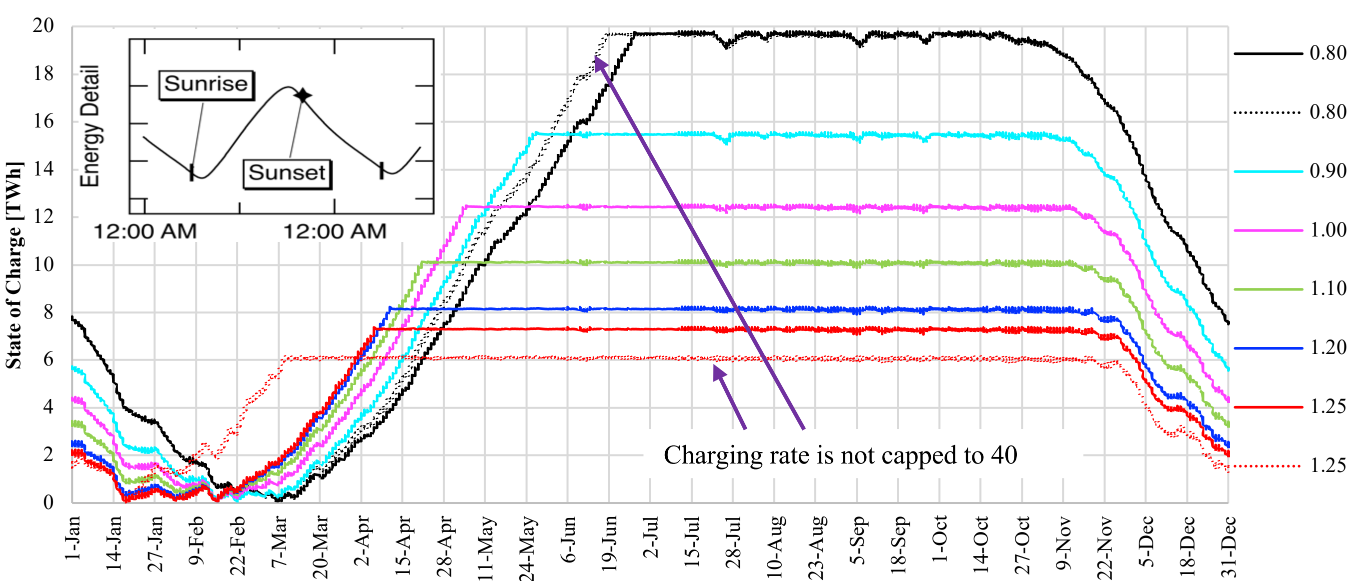


Fig. 1. Calculated state of charge for stored energy using 2019 generation and load data adjusted to reflect zero-carbon grid scenarios with variable solar. Each curve reflects a different annual solar-generation-to-load ratio (see legend). The charging rate was capped at 40 GW for all except for the 2 dotted lines.

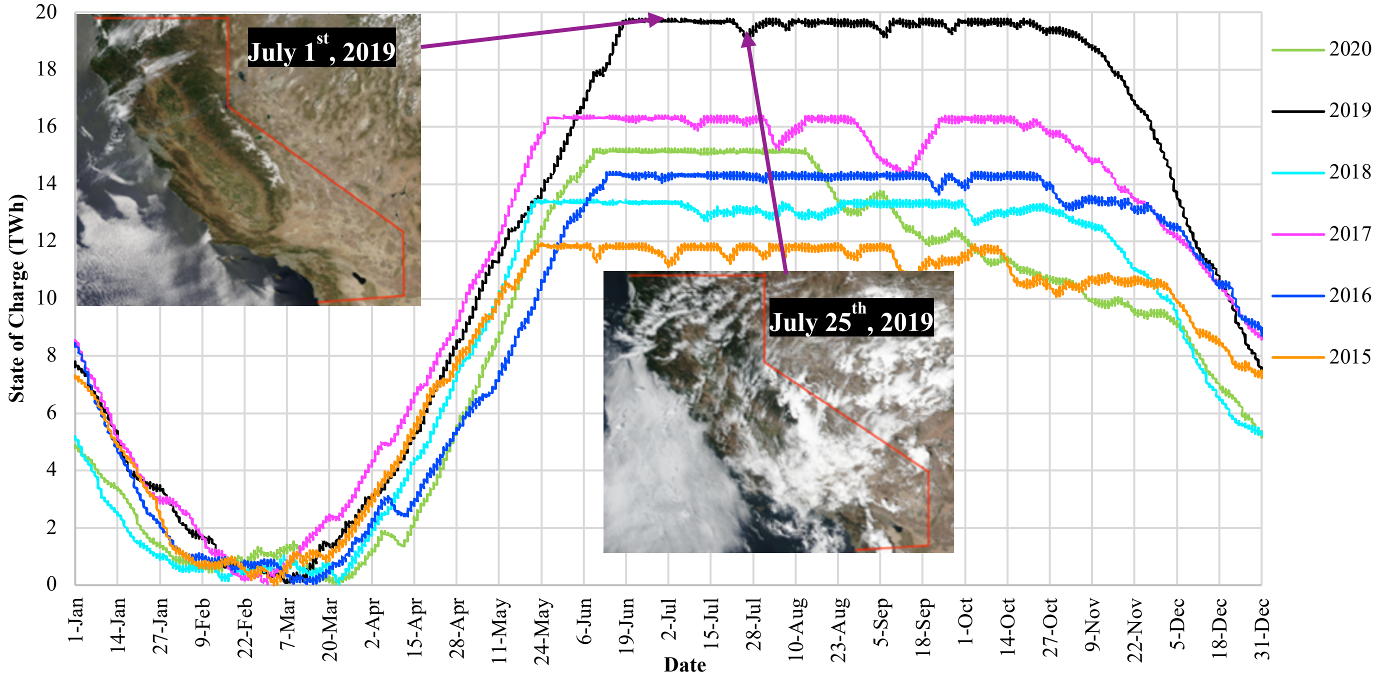


Fig. 2 Calculated state of charge for stored energy as in Fig. 1, but for six different years with the solar build selected to always supply 15 TWh of surplus.

Although smoke during the summer could be worrisome, Fig. 2 shows that a storage reservoir that is adequate for the winter will always be adequate during the summer, suggesting that our current concern for resource adequacy in late summer may disappear in the future when we have adequate storage.

Studies have suggested that it will be beneficial to be able to charge the storage quickly when the sun is shining using a charge rate that is greater than the largest discharge rate [14]. Our comparison of unconstrained charging rates with charging rates limited to 40 GW (the common maximum discharge rate) is shown in Fig. 1. When the solar build out results in generation equal to 105% of the load, limiting the charging rate delays the date when the reservoir reaches full charge but has very little effect on the top (black) curve otherwise. The effect becomes greater when the solar fleet is built out more, enabling faster charging. For the red (bottommost) curve, unconstrained charging allows the reservoir to be completely filled one month earlier. It also decreases the size of the reservoir needed from about 7.3 to 6 TWh. The decrease in the size of the needed storage is significant, highlighting the benefit of being able to charge faster in a solar-rich grid. We anticipate that the benefit of the higher charging rates will be even more apparent in situations when the storage is being filled behind the meter by a local solar plant rather than from the grid with no transmission constraints.

The size of the storage needed as a function of the solar build out is shown in Fig. 3. For 2019, these data can be taken from Fig. 1. For the other years, the data were assembled in a similar manner. Only 3 of the six years are shown for clarity. As expected, the size of storage reservoir needed decreases with increased solar investment. In general, the size of the seasonal storage that is needed decreases a factor of three to ten for the range of solar investigated here (see Figure 3). The data from Fig. 3 as well as similar data for the other three years are tabulated in Table I, showing the large effect of the solar investment on the needed seasonal stored energy.

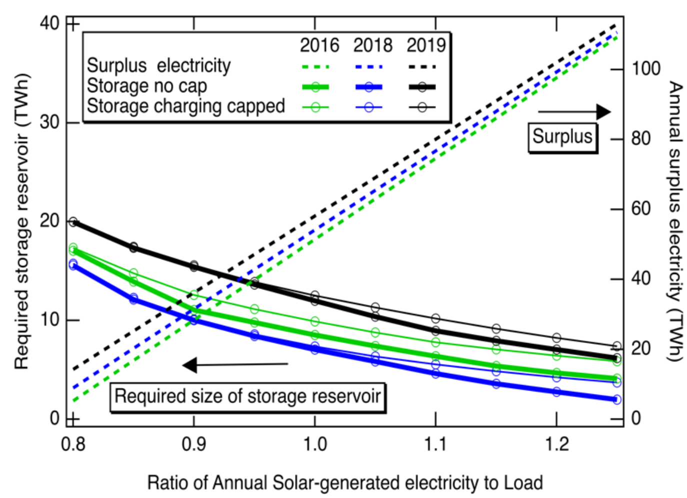


Fig. 3 Decrease of storage needed to meet minimal resource adequacy (left axis) and associated surplus electricity (right axis) as a function of solar buildout The thick and thin lines differentiate the storage needed when the storage is allowed to charge at an unlimited rate or at a maximum of 40 GW, respectively.

In contrast to the need for seasonal storage, the amount of storage needed diurnally changes very little with increased solar investment. For years 2015 – 2020 the diurnal storage varied between 0.23 and 0.31 TWh, showing, typically, only about a 10% reduction with the higher solar investment. The average load during the nighttime discharging periods was in the range of 20 – 30 GW over the six years. The seasonal storage needed is up to a factor of 100 times the storage needed on a nightly basis, demonstrating the low probability of running out of energy in a single night during seasons when the large reservoir is close to full.

TABLE I. CALCULATED ENERGY STORAGE RESERVOIR SIZE AND ASSOCIATED HOURS OF DISCHARGE ASSUMING 25 GW LOAD USING 2015-2020 DATA

| Year | Seasonal | | Diurnal | |
|---|---|---|---|---|
| | Energy Storage [TWh] | Hours of Discharge at 25 GW Load | Energy Storage [TWh] | Hours of Discharge at 25 GW Load |
| **Annual Solar Generation = 80% of Annual Load** | | | | |
| 2020 | 22 | 880 | $0.27 \pm 0.09$ | $10.9 \pm 3.6$ |
| 2019 | 20 | 800 | $0.27 \pm 0.13$ | $10.7 \pm 5.2$ |
| 2018 | 15.8 | 632 | $0.27 \pm 0.10$ | $10.7 \pm 3.9$ |
| 2017 | 16.3 | 652 | $0.26 \pm 0.10$ | $10.5 \pm 4.1$ |
| 2016 | 17.4 | 696 | $0.28 \pm 0.11$ | $11.4 \pm 4.3$ |
| 2015 | 19 | 760 | $0.31 \pm 0.10$ | $12.3 \pm 4.2$ |
| **Annual Solar Generation = 125% of Annual Load** | | | | |
| 2020 | 2.5 | 101 | $0.25 \pm 0.06$ | $9.9 \pm 2.3$ |
| 2019 | 7.4 | 296 | $0.24 \pm 0.10$ | $9.6 \pm 3.8$ |
| 2018 | 3.7 | 148 | $0.25 \pm 0.07$ | $9.8 \pm 2.8$ |
| 2017 | 3.6 | 144 | $0.24 \pm 0.07$ | $9.6 \pm 2.8$ |
| 2016 | 5.9 | 236 | $0.25 \pm 0.07$ | $10.2 \pm 2.8$ |
| 2015 | 4.9 | 196 | $0.28 \pm 0.10$ | $11.0 \pm 2.4$ |

As the needed storage decreases with added solar investment, the surplus electricity (dashed lines in Fig. 3) increases linearly with the amount of solar. This surplus electricity may be curtailed, but, more likely, it will be used to meet some other load. For example, the surplus electricity could be used in generating hydrogen. As renewable energy is used to meet energy needs for a wide range of applications, this “surplus” electricity may become a very critical resource for meeting the broader energy needs.

## IV. CONCLUSIONS

Today’s challenge of maintaining adequate reserve margin during late summer may become a challenge in winter or spring for a solar-driven, zero-carbon grid. If the solar investment delivers about 80% of the electricity needed to meet load in a year, the tightest reserve margin may fall in March. If the solar fleet is built about 50% bigger, the tightest reserve margin may shift to January and require a storage reservoir that is less than half the size. Limiting the rate of charging to 40 GW increases the amount of storage needed slightly but has a bigger effect on the time during which the storage reservoir is close to being depleted, moving that time to later in the winter. Thus, our intuition about resource adequacy for a zero-carbon grid will be informed by the solar investment as well as that storage’s ability to charge quickly.

Cloudy, smokey days during the summer may cause a depletion of energy in the storage reservoir, but will not lead to tight reserve margins during the summer – a major change from today’s picture. This change will only be reinforced by expected changes in load patterns driven by electrification of heating in place of gas furnaces (resulting in growing winter loads). We note that these conclusions would not apply to locations that have a strong wind resource during the winter and have not considered the challenges of matching supply and demand on a local level.

## V. ACKNOWLEDGMENTS

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