Optimizing the Configuration of Photovoltaic Plants to Minimize the Need for Storage

Russell K Jones[1], *Senior Member*, and Sarah Kurtz[2], *Fellow*

1. Jones Solar Engineering, Manhattan Beach, California, USA; 2. University of California, Merced, California, USA

***Abstract*—This paper explores the application of optimizing tilt of photovoltaic (PV) plants as a statewide strategy to best match the California statewide load over the year and thus minimize storage requirements for a carbon-free grid. Through a simple cost model and energy balance model examining PV + storage in isolation, we show that, even though horizontal trackers produce the lowest cost electricity when the timing of generation is ignored, high-tilt PV plants have the potential to reduce overall system cost substantially by reducing the required storage capacity and by better utilizing surplus electricity. California should consider tilted PV configurations in capacity expansion planning and consider PV electricity pricing or incentives that encourage new PV installations that better match the seasonal load to reduce storage requirements.**

Keywords—photovoltaic, capacity planning, storage, tilt

I. Introduction

The need for action globally to address human-driven climate change is urgent. The State of California is an international leader in implementing measures to encourage clean technology and decarbonize its grid, with a legally mandated 100% carbon-free electric grid by 2045[1]. The California mandate in particular, and more generally the worldwide recognition of the urgent need and emerging realistic prospect of decarbonizing electricity production, have spurred widespread research on the approaches and economics in recent years. Early work for the case of California has shown that, for its expected heavily solar-dominated future grid, the most challenging period for meeting the demanded load is in the winter months when solar and wind energy are comparatively scarce[2].

Photovoltaics (PV) has emerged over the last decade as a major source for new electricity generation and has now become the cheapest option for new daytime generation in much of the world. The rapid growth in utility-scale PV has been mostly in the form of systems with 1-axis zero tilt (horizontal) trackers. These systems have added cost compared to fixed orientation mounting, but the additional cost is more than offset by increased energy yield on an annual basis.

The annual generation profile of PV plants can be shaped by choice of the orientation of modules. To first order, modules tilted southward at the latitude angle relative to horizontal ("latitude-tilt") maximize annual generation by minimizing the overall cosine loss imposed by the sun's elevation change through the year. Greater tilt increases winter generation at the expense of summer generation, and conversely, a tilt less than the latitude angle favors summer over winter generation. Today's commercial trackers with horizontal orientation sacrifice some winter electricity generation through simple cosine loss to favor electricity generation through the summer months when the grid needs the generation most due to summer air conditioning loads. Thus, the summer-dominated generation of 1-axis zero tilt tracking PV systems has until now been viewed as a benefit, but in a future grid with resource adequacy most challenged in the winter, the cost/benefit trade-off may be revisited.

Before the emergence of cost-competitive PV at the utility scale, PV served niche markets, and particularly in situations requiring power in remote areas where a diesel generator was impractical. Stand-alone PV systems with batteries have been in use since at least the 1970s to serve remote loads, for example in telecommunication applications[3,4]. As a result, there is a body of practical experience designing systems that must operate without fossil fuel backup. Might there be any lessons from this long experience that can inform the transition to a fossil-free electricity system on a global scale?

One key design practice for stand-alone PV-battery systems is to examine the annual patterns of both the load to be served and the available solar resource and choose the orientation of the PV modules to generate as much power as possible during the periods where the load to solar resource ratio is highest[5]. In the era before widespread access to computers, the National Renewable Energy Laboratory (NREL) produced a handbook called the "Redbook" that provided monthly solar resource estimates around the United States as a function of the type of collector (flat plate versus concentrator) and orientation (tracking versus stationary, and tilt axis angle)[6]. The data provided in the Redbook enabled quick and reasonably optimized solar array sizing for stand-alone systems. Indeed, there is an IEEE standard for sizing of stand-alone PV systems[7] that describes this procedure, and still references the NREL Redbook in its 2021 revision.

For stand-alone PV-battery systems with relatively constant loads (e.g., remote telecommunications equipment), the design process generally identifies winter as the challenging case and recommends PV module orientation optimized for winter generation. In practice, this means an elevation tilt angle of ~latitude+15°, which maximizes solar generation well throughout the winter, matching the sun elevation at noon roughly on October 30 and February 8, and with a cosine loss of

only ~1.1% of the direct irradiance on the ~December 21 winter solstice (in practice the total loss is less than 1.1% because some of the irradiance is diffuse). Tilt at latitude ± 15° has long been recognized as good design for PV systems optimized for generation in the winter or summer and are included in the Redbook tables for this reason.

Many other authors are performing detailed studies that explore the design choices for a future carbon-free grid with much greater fidelity (see, for example, [8], [9]) and to explore technology alternatives to meet the need for long duration storage most economically (for example, [10], [11], [12]). To date, those studies have not explicitly considered the effect of PV configuration choices on the resulting imposed storage (or "clean firm power") requirements. Thus, we anticipate that a study of PV orientation and resulting storage demand could be useful to those more comprehensive models by pointing to a lower cost carbon-free solution.

To address this opportunity and to see how the prior industry experience might apply to the future carbon-free grid, we examine the interrelationships between PV orientation (configuration), PV plant capacity, PV capital cost, and storage required to serve the load, considering PV and storage in isolation from other influences (e.g., other generation technologies, imports, exports, or transmission constraints). We consider the potential for reduction in required seasonal storage that can be achieved from a given amount of perfectly dispatchable energy from another source, as well as the availability and practicality of excess PV energy that may be put to other uses.

II. Methodology

We use a statewide energy-balance approach, using a representative statewide generation profile for each of the PV plant configurations considered, and using the shape of the statewide electrical load based on CAISO historical data[13]. For clarity, the quantities are normalized: the PV generation is normalized to 1 W_{DC} capacity, cost is normalized per W_{DC} capacity, and load is normalized to an average of 1 W (i.e., the total normalized annual load is 8760 Wh, but has the "shape" of the actual statewide load in California).

In this paper, a shorthand convention is employed to refer to PV configurations consistent with the Redbook tables, as follows:

- Tr0: 1-axis tracking zero tilt (horizontal axis)
- TrL–15: 1-axis tracking summer tilt (latitude–15°)
- TrL: 1-axis tracking latitude tilt
- TrL+15: 1-axis tracking winter tilt (latitude+15°)
- FxL–15: fixed south-facing summer tilt (latitude–15°)
- FxL: fixed south-facing latitude tilt
- FxL+15: fixed south-facing winter tilt (latitude+15°)

A. Statewide PV Generation Profiles

The PV generation profiles were calculated using SAM's PVWATTS v7 model, implemented in Python using SAM API calls[14]. The PV system parameters used (in common for all the configurations) are:

- DC/AC ratio: 1.3
- Module quality: 1 (monocrystalline)
- Bifaciality: 0.7
- System losses: 14.07%
- Inverter efficiency: 96%

For fixed tilt configurations, the ground coverage ratio was calculated according to criteria for inter-row spacing given by the Arizona Solar Center[15], which provides for no direct beam shading in mid-winter when the sun is above its noon elevation angle, capturing about 90% of the available energy. For tilted tracking configurations, row-to-row (inter-row) shading is ignored by PVWATTS, and the ground coverage ratio refers to shading of adjacent trackers within a row (intra-row shading); a ground coverage ratio of 0.4, a typical value for horizontal trackers, was used for all the tracking configurations. In reality, the shading in inclined-axis tracker fields is rather complex, with both inter-row and intra-row shading, and often with staggered placement of rows.

Statewide utility-scale PV generation profiles were developed for a simplified analysis by first developing spatially averaged solar resource files for each county in California, and then simulating the PV configurations for each county, and finally weighting the resulting PV generation in each county in proportion to the actual generation that existed in that county in 2019[16]. Thus, the statewide profiles assume that future PV capacity growth in the state will follow what has already occurred, as illustrated in Fig. 1. The resulting capacity-weighted "average" PV system is located at 35.2° latitude.

The spatially averaged solar resource files were created using 2019 data downloaded from the National Solar Radiation Database (NSRDB)[17], again on a 0.1°×0.1° grid throughout California, by averaging the irradiance values (as well as temperature and wind speed) from each location in each county. This procedure results in smoothing of the irradiance due to geographic diversity, realistically approximating the actual aggregated PV generation while still preserving the essential differences in performance of different PV configurations with latitude, with a PV generation time series for each of the 58 California counties, for each of the configurations considered. The generation profiles are for the year 2019, consistent with the

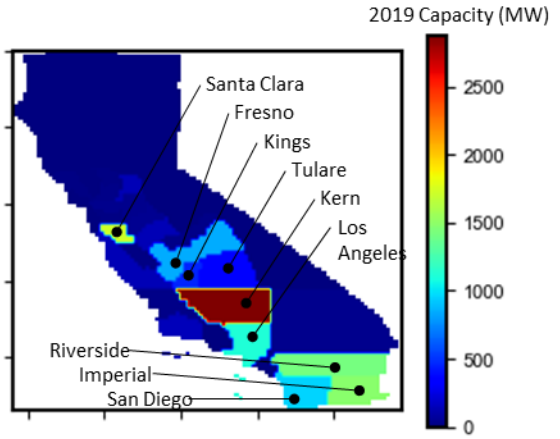


Fig. 1. Solar capacity in California by county for 2019. Statewide PV generation profiles were created by spatially averaging solar resources in each county and computing generation in each county using PVWATTS.

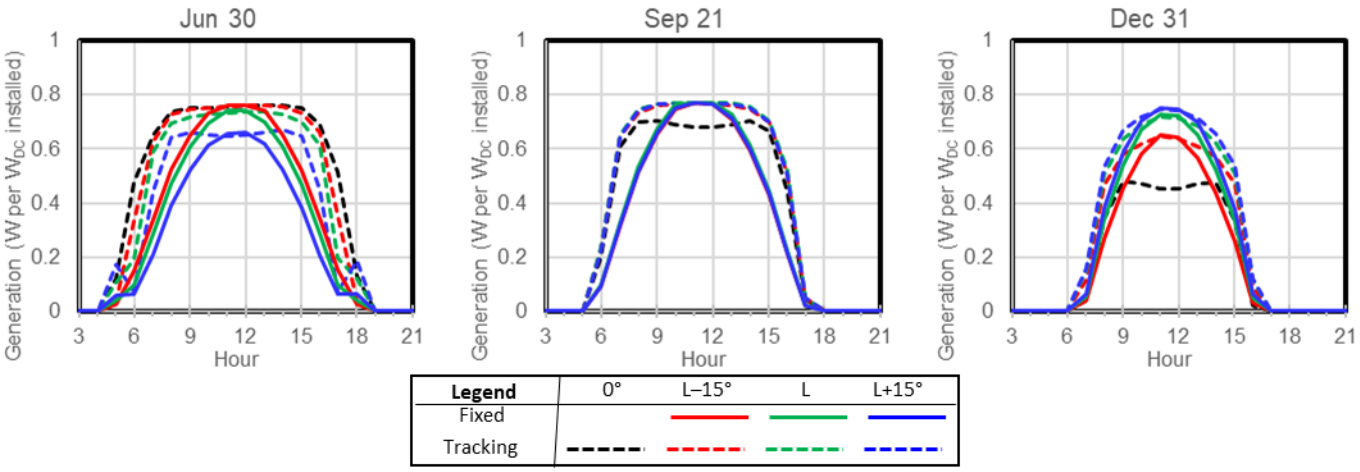


Fig. 2. Daily solar generation for different collector configurations in summer, autumn, and winter (spring is similar to autumn).

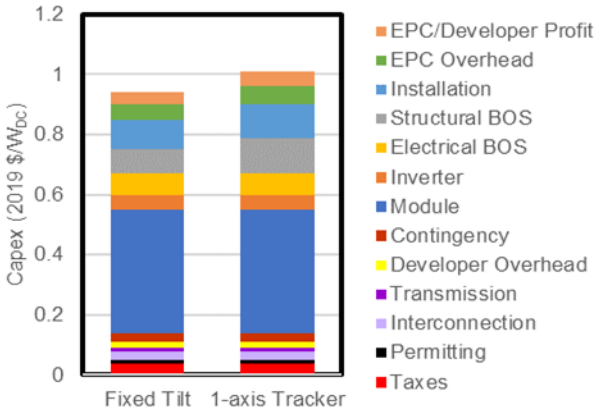


Fig. 3. Q1 2020 US benchmark utility-scale PV total cost, 2019 USD/WDC (reproduced from data in ref. 18).

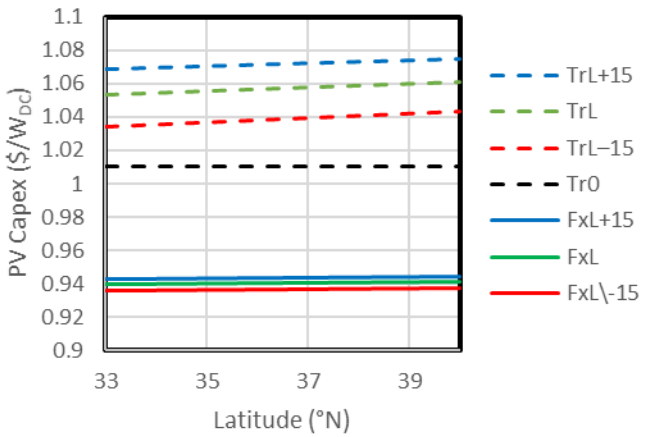


Fig. 4. Modeled cost of PV systems as a function of latitude.

CAISO data used for load[12]. Fig. 2 shows the daily energy generation for each of the configurations modeled, for an example day in summer, spring/autumn, and winter.

B. PV Cost Model

The PV capital expense (Capex) is modeled based on an NREL study[18] that is the basis for the costs reflected in the 2021 NREL Annual Technology Baseline (ATB)[19]. Fig. 3 shows the baseline costs for both fixed latitude tilt and 1-axis zero tilt PV systems from the NREL study for 100 MW systems. Note that land cost is treated as an operational expense (Opex) in the form of lease payments, rather than as a Capex cost.

Changing the inclination of the PV generators has two effects on the total cost: (a) a change in the cost of structural balance of system (BOS) cost, and (b) a change in the land use. Our analysis assumed that for fixed tilt systems 33% of the structural BOS cost varies with the tilt angle θ in proportion to (1+sin(θ)). For example, the racking on which modules are mounted depends only on module size, not inclination angle, but height (and possibly depth) of foundation posts is affected by θ. For trackers we assume 66% of the structural BOS is affected by θ. The structural BOS is a small portion of the overall capital expenditure (Capex) in both cases, with the result that the modeled Capex cost is a rather weak function of latitude as shown in Fig. 4. The same capacity-weighting procedure by county used to develop the representative statewide PV generation profiles was also applied to establish statewide PV Capex cost, with a statewide weighted-average latitude of 35.2°.

The resulting statewide estimate of the PV capacity factor, statewide estimated PV Capex (per W_{DC} installed), and ratio of capacity factor to Capex are shown in Fig. 5. Here capacity factor is defined as [annual AC generation]/[nameplate capacity × 8760] and nameplate capacity is the total DC rating of the modules in the system, consistent with the definitions used by SAM. The ratio of capacity factor to Capex is a measure of "bang for the buck" for each configuration. The Tr0 configuration increases the Capex per W_{DC} by ~7% but increases the capacity factor by ~20% compared to the FxL+15 configuration, and has the highest ratio of all the configurations considered, so it is to be expected that the vast majority of utility-scale PV systems being installed use the Tr0 configuration, as is the observed reality (see ref. 18), since under current PPA pricing schemes there is no preference for when energy is generated.

C. Statewide Energy Balance

The analysis of energy balance considers only the PV generator configurations and the statewide load profile in

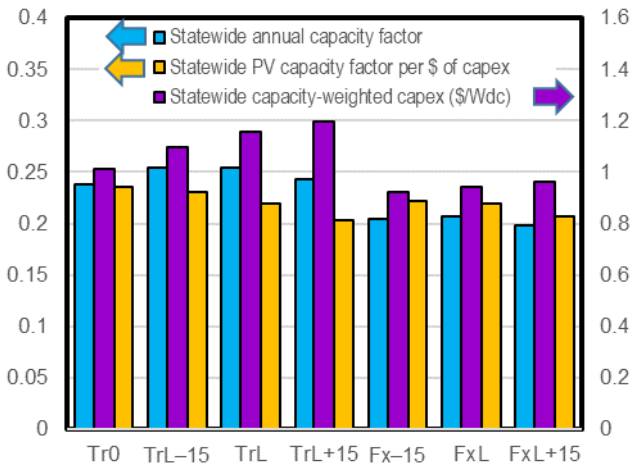


Fig. 5. Statewide analysis of PV cost-effectiveness without regard to the timing of energy delivery. Capacity factors were calculated from the statewide capacity-weighted PV generation profiles. Cost is based on Fig. 4 and a capacity-weighted latitude of 35.2°.

isolation, with the 2019 CAISO statewide load profile normalized to an average demand of 1 W (and thus 8760 Wh per year); as a result, the computed PV generation and PV capacity are also normalized per watt of average load. There is no attempt to account for any other generation such as from wind, hydro, biomass, etc., but rather, the analysis presented here just considers purely the ability of the various PV configurations to serve the load (with the hourly shape observed in California) with varying amounts of storage. The storage is also treated on a statewide basis, with no constraints related to transmission or congestion.

For each hour `t` the storage charge state `s` is calculated from the hourly generation `G[t]` and load `L[t]` with the following procedure (here `si` is the initial charge state in each time interval, `ci` is the initial charge state at the beginning of the year, `CS` is the storage capacity, `ec` and `ed` are the efficiency of charging and discharging, and `sd` is the self-discharge rate):

```
For t in range(0,8759):
    if t=0:
        si = ci
    else:
        si = s[t-1]
    if G[t] > L[t] then:          # charging
        if (G[t] - L[t])*ec + si*(1 - sd) > CS then:
            s[t] = CS             # storage full
        else:                     # storage not full
            s[t] = si*(1 - sd) + (G[t] - L[t])*ec
    else:                         # discharging
        s[t] = si*(1 - sd) - (L[t] - G[t])/ed
```

The charging and discharging efficiency are each assumed to be 90% (for a round-trip efficiency of 81%), and the self-discharge rate is assumed to be 0.2% per day. The values of the initial charge state and storage capacity are then solved iteratively, with the constraints that the final charge is equal to the initial charge (equivalent to assuming all years are identical to this one) and that the minimum charge is zero (whereas in reality, most energy storage technologies have a maximum permissible depth of discharge beyond which service is disrupted, sometimes with permanent damage to the storage system). The excess of any net generation that results in full storage is treated as curtailment or as available for a possible secondary use.

The storage holding time required was probed by aggregating the generation and load to successively longer intervals and recalculating the charge state and required capacity for each successive interval. Each such calculation expresses the total imbalance between generation and load over the aggregation interval; for example, aggregating over 10 hours at each hour shows the total imbalance that persists over that 10-hour interval or more, but does not show imbalances over shorter intervals. Over a sufficiently long aggregation interval the imbalance (load – generation) must be negative if the annual generation exceeds the load + losses, and the storage requirement is zero for that interval or longer. Although the CAISO data are over 5-minute intervals, this analysis was limited to intervals of at least 1 hour because the solar resource data used are on an hourly basis. Thus, the calculated storage requirements omit any storage that might be needed for balancing on sub-hourly intervals.

III. Results

Fig. 6 shows the annual statewide generation profiles aggregated on a monthly basis compared to the 2019 California statewide load (generation and load profiles are normalized to a sum of 8760 for the year). The load does exhibit an increase in summer months driven by air conditioning loads, but it's apparent that the inclined configurations (winter tilt or latitude tilt) provide an improved overall match.

A. *Relationship of Storage Requirement to PV Capacity and Capex*

The interrelationship between the PV orientation and the storage required to serve the load is examined in Figs. 7–9. Fig. 7 shows the state of charge over the year calculated for the minimum PV capacity necessary to satisfy the 1W average load as indicated in the inset of Fig. 7. Since the load is normalized to 8760 Wh/year, then by definition a PV nameplate capacity equal to the reciprocal of the capacity factor provides generation equal to the load. However, this is not enough: most of the generation is first stored and later retrieved, rather than serving the load directly. If all of the generated energy passes through storage, only the generation × round-trip efficiency can be supplied to the load. There is thus a maximum storage requirement associated with the minimum PV capacity, such that the total energy supplied directly to the load, plus the total energy that is passed through storage before being supplied to the load, just equals the load, with no surplus energy generated. The inset table in Fig. 7 shows the PV nameplate capacity (in W_{DC}) corresponding to each charge state curve. Each of the fixed orientation configurations require more nameplate capacity than their tracking counterparts to satisfy the load. The fact that tracking systems have almost no generation advantage over fixed orientation at the same tilt angle when the sky is heavily overcast means that the long decline in charge state from November through February is greater for the lower-capacity tracking systems, resulting in a higher peak storage requirement to compensate.

Fig. 8(a) shows how the storage capacity (peak value of the charge state) is affected by adding PV capacity. Added capacity

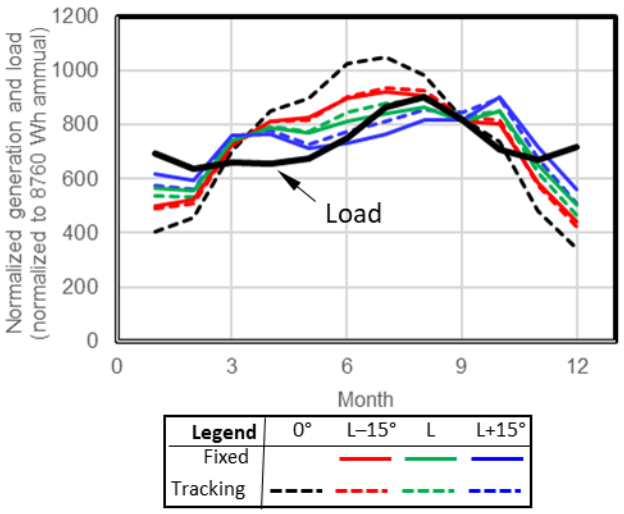


Fig. 6. Monthly solar statewide generation profile versus the statewide load for 2019 (based on the capacity-weighted generation by county).

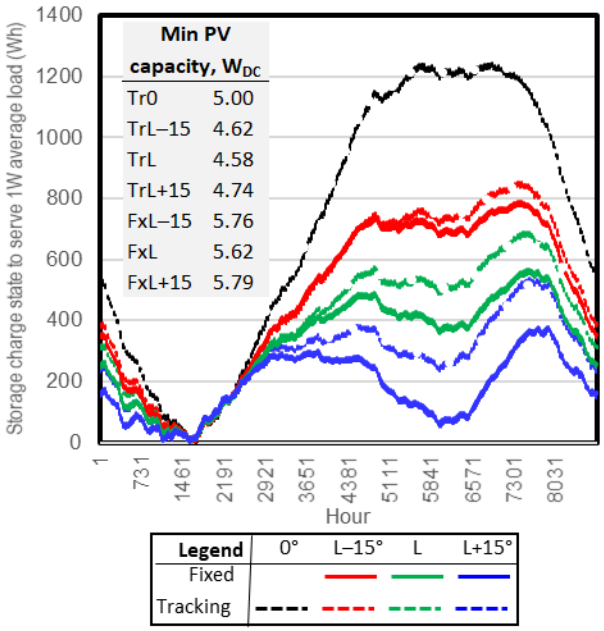
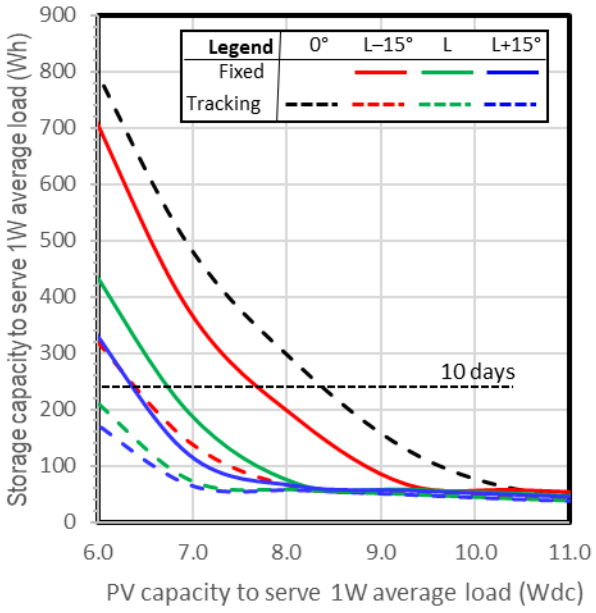
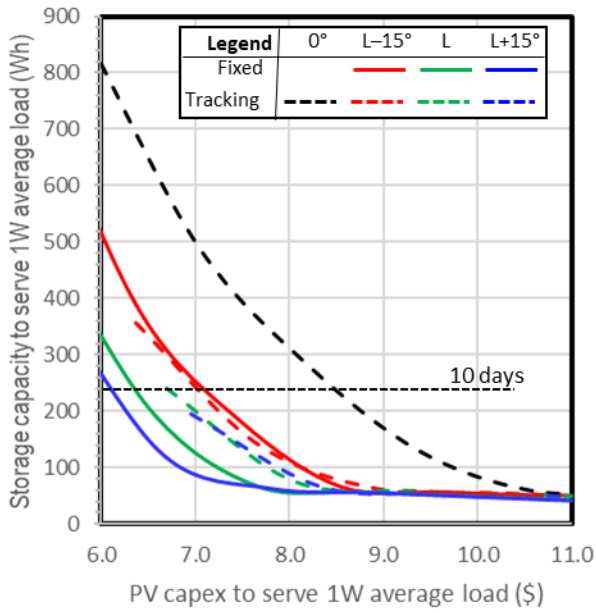


Fig. 7. Charge state throughout the year for the minimum PV capacity required to serve 1W average load for each configuration (minimum capacity and storage required jointly satisfy the constraints that minimum charge=0, starting charge = ending charge, and no surplus electricity).



(a) Storage required as a function of PV capacity



(b) Storage required as a function of PV capex

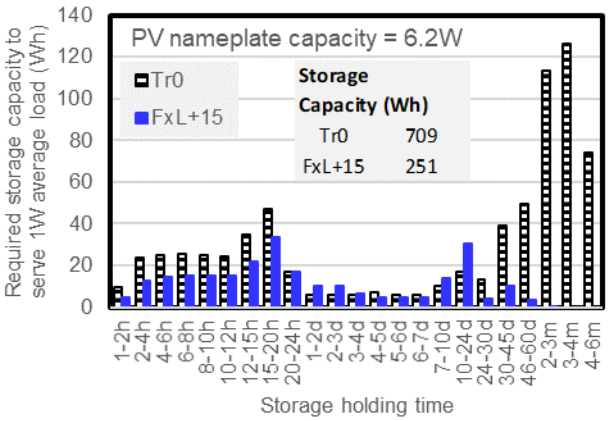
Fig. 8. Reduction of required storage to serve 1W average load as the PV capacity is increased (added PV capacity results in both reduced storage needed and surplus electricity exceeding the storage capacity).

has two effects: firstly, the rate at which storage is depleted between November and February is reduced; and secondly, the stored charge state necessary at the start of that depletion is reduced. Thus, the required storage is reduced, but more PV energy has been generated, and the excess is curtailed (or is surplus available for a secondary use). Fig. 8(b) translates the PV capacities to PV capex (required to serve the 1W average load) using the cost model of Fig. 4. Although the tracking configurations (TrL and TrL+15) have the least storage required per unit capacity, their cost premium means that the fixed orientations (FxL and FxL+15) have the lowest capex for a given storage requirement.

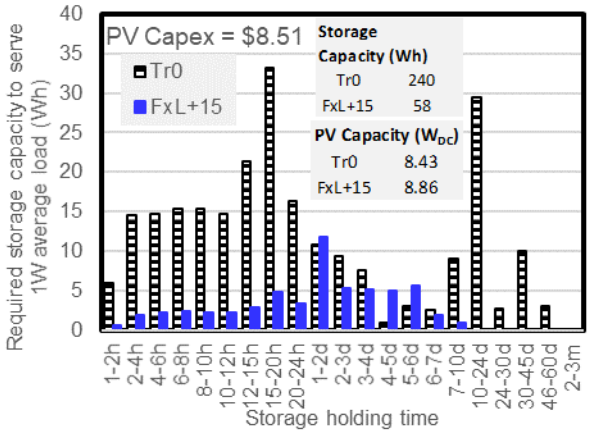
Fig. 8(a) and (b) show horizontal lines of equal storage capacity at 10 days (240 hours at a 1 W average load). Considering just FxL+15 and Tr0 configurations, we saw in Fig. 5(a) that the capacity factor of Tr0 is 20% greater than that of FxL+15 collectors, but from Fig. 8(b) we see that the capex required to serve the load is ~40% greater for Tr0 than for FxL+15 collectors for the case of 10-day storage. This is a remarkable result: whereas Fig. 5 shows clearly that Tr0 is the most cost-competitive configuration and FxL+15 is the least competitive when the timing of generation is ignored, Fig. 8(b) shows the opposite is true if the objective is to serve the whole load throughout the year, unless either storage is extremely

cheap (well under $0.01/kWh), enabling the load to be satisfied with Tr0 at capex less than the minimum feasible capex for FxL+15, or else PV is so overbuilt that both configurations have essentially equal storage requirements.

Fig. 9 shows the distribution of energy holding time in storage through two comparisons, using the progressive aggregation procedure described in Section IIC, now focusing just on the comparison between Tr0 and FxL+15 configurations. In Fig. 9(a) the holding time distribution is shown for systems of equal nameplate capacity of 6.2W_{DC}, and reveals that for this case, not only is the total storage requirement for Tr0 much greater than for FxL+15 (2.8 times greater), but additionally most of the increased storage needed is interseasonal storage of 1–6 months holding time. Fig. 9(b) compares systems of equal PV Capex (higher overall capacity than in Fig. 9(a) as indicated in the inset table in Fig. 9(b); this Capex corresponds to tat needed for Tr0 to serve the 1W average load with 10 days of storage) and shows an even greater penalty (4.1times greater) in storage required for Tr0, again with some of the storage requiring longer hold times.



(a) Storage holding time for equal PV nameplate capacity



(b) Storage holding time for equal PV Capex

Fig. 9. Distribution of energy storage holding time for Tr0 versus FxL+15 configurations. The holding time is the maximum energy charged and discharged annually over the indicated interval.

B. *Effect of Supplementary Dispatchable Energy on Storage Requirement*

Since the storage requirement is driven by episodes of extended low solar resource compared to the load, a useful question is how much the storage requirement can be reduced by use of a dispatchable generation source such as a gas or hydrogen turbine or hydrogen fuel cell. Fig. 10 shows the reduction in storage needed as a function of the amount of supplemental energy from a dispatchable source, assuming it is optimally dispatched (as described in section IIC). Even a very small amount of energy dispatched at the right time can significantly reduce the storage needed. The curves shown are for a case of equal capex for all the PV configurations, corresponding to the $8.51 capex needed to serve the 1W average load and achieve 10 days storage for the Tr0 configuration, and clearly illustrate that a given storage target can be met with significantly less dispatchable energy (fuel burn in the case of a turbine) for FxL+15 compared to Tr0 plants.

C. *Effect of PV Configuration on Energy Available for Secondary Uses*

There is an emerging consensus that cost-effective decarbonization of the electric grid must incorporate cross-sector coupling of electric generation (to serve newly electrified loads in transportation, heating, hydrogen electrolysis, and synthetic fuel production)[20]. All the configurations considered above have some degree of excess generation that must be lost to curtailment, or preferably, supplied to secondary loads for cross-sector use cases. Such use cases include electrolysis for intermittent generation of hydrogen, or intermittent generation of thermal energy that is stored for process heat.

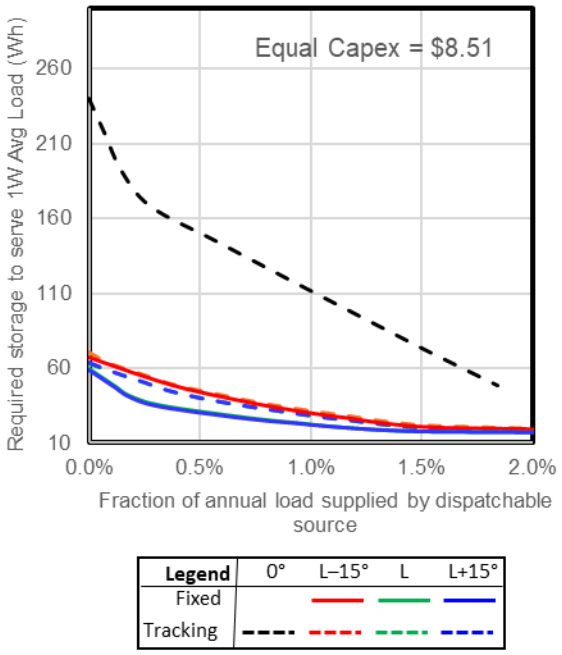


Fig. 10. Reduction of required storage by use of a dispatchable energy source (e.g., natural gas turbine, hydrogen turbine or fuel cell). It is assumed that the dispatchable source is optimally dispatched, i.e., each Wh of energy is supplied with the storage charge state at its minimum.

Fig. 11 shows the daily surplus electricity (a 3-day moving average is shown for visual clarity) for FxL+15, FxL, and Tr0 systems for the case of equal Capex of $8.51 (again, the capex that results in 10 days of storage for Tr0). Deploying cross-sector uses of this intermittent surplus electricity partially offsets the cost of the power system through revenues earned from those uses.

Whatever the nature of the cross-sector use, the surplus electricity must be supplied to some type of equipment whose capacity to use the electricity represents an investment. Ordinarily, facilities expect input electricity to be available 100% of the time, but the electricity in Fig. 11 is what is left over after meeting 100% of the loads of ordinary facilities. A facility using the surplus electricity must suffer a loss of productive capacity due to the intermittent supply of electricity, in addition to any losses it may incur from other causes such as failures or maintenance.

If the equipment can use at most C units of daily surplus electricity E, then on any given day the equipment will use C units if E > C, or E units if E < C. In Fig. 12, this equipment utilization factor is expressed in terms of the maximum electricity input it can utilize, and the resulting equipment utilization factor shown is the fraction of time the secondary use equipment receives energy at its rated capacity (analogous to capacity factor, but for availability of input electricity rather than equipment capability). At lower levels of secondary use equipment capacity (measured in Wh of peak daily electric demand) the achievable equipment factor is far higher with FxL+15 or FxL PV generators compared to Tr0. In this case, for the same $8.51 Capex, the FxL+15 generator not only reduces required storage by ~75% but also allows cross-sector use to operate at higher utilization factor (and thus cost-effectiveness).

Conversely, the secondary axis of Fig. 12 shows the effectiveness of utilizing the surplus electricity and shows that the FxL and FxL+15 PV generators also enable higher utilization of the available surplus electricity compared to Tr0 generators. By producing surplus electricity more evenly throughout the year, the inclined collectors furnish a more reliable supply to the secondary equipment with lower losses of the available surplus.

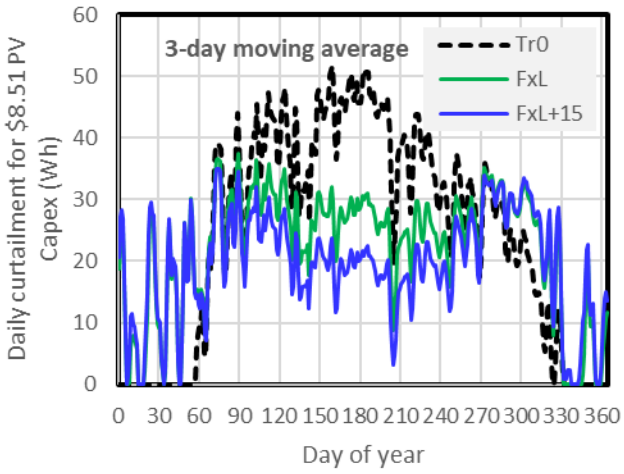


Fig. 11. Daily curtailed energy of Tr0, FxL, and FxL+15 generators of equal Capex for normalized CAISO load.

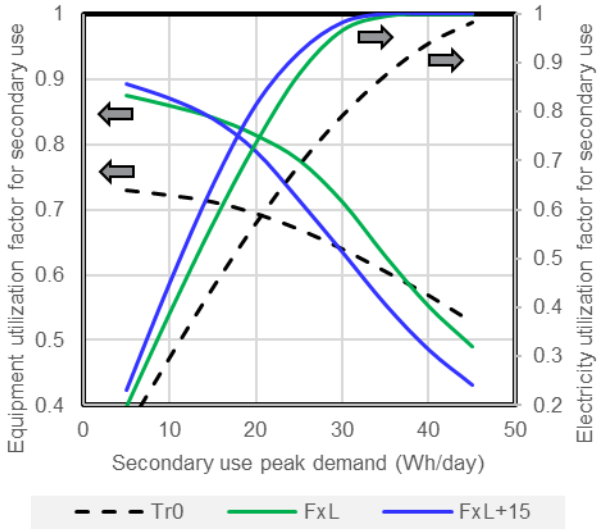


Fig. 12. Surplus electricity and equipment utilization factor for secondary use versus secondary use peak energy demand, for PV generators with equal Capex = $8.51 serving 1W primary load. The secondary use equipment is assumed to be able to use at most the indicated peak demand per day.

IV. Discussion

As stated previously, the analyses presented here consider only the shapes of the PV generation and the California load in isolation. It is therefore not representative of the California grid: it considers California as an island with no energy imports or exports and makes no accounting of transmission or congestion constraints. A realistic representation of the grid would obviously include future growth of on-shore and off-shore wind generation, anticipated changes in the load from electric vehicles or electrification of heating loads, and the potential for energy imports and exports. A realistic grid model would also include a diversity of PV generator and storage technologies, each with their own unique performance and cost metrics. On the other hand, the analysis has used fairly well-understood PV costs based on historical data and shows that the system (PV + storage) cost may be minimized by using inclined axis PV collectors, even though they are clearly more expensive when considered independently of storage on an annual cost per kWh basis. This insight is perhaps useful. The extent to which the renewable generators themselves can be tailored to reduce the storage has not been widely recognized. The above analyses show a clear potential to accomplish this with PV, and analogous opportunities may exist with wind generators as well (choosing sites with high winter winds that might be seen as uneconomical when considered in isolation). Although the FxL+15 configuration is the most cost-effective when considered in isolation, it may not be when these other generation sources are included in the analysis.

Only Capex cost is included in this analysis. As mentioned previously, land costs are treated as Opex. In a more comprehensive treatment, the Opex cost could be included, but even though the land use is strongly affected by inclined axis tracking, the land use for fixed tilt systems is closer to that of horizontal tracking systems. In any case Opex generally has a

rather small impact on the levelized cost of electricity (LCOE) of PV systems.

It's worth noting also that the assumed DC:AC ratio of 1.3 means that some PV energy is being lost at the inverter, and effectively assumes all the storage is AC-driven. But modern battery charge controllers are often designed to use DC coupled power precisely to avoid this loss, and other storage technologies may be able to make use of DC energy as well, if collocated with the PV plant. Inclusion of this energy would result in reduced storage requirements for all configurations and would likely further favor FxL+15 systems since they have more incremental DC energy to capture in the winter than the other configurations.

The analyses are based solely on the loads as they existed in 2019. However, there's reason to believe that winter loads will increase in the coming years due to electrification of heating loads (mostly in the winter) and electric vehicle charging (year-round). On the other hand, summer cooling loads will increase due to climate change. It's difficult to predict how the load shape will evolve, and load shape changes may well change the optimal PV generation mix. Latitude tilt systems may best prepare for uncertain future load scenarios by just maximizing overall generation and balancing winter and summer performance.

Given the common practice in power purchase agreement (PPA) contracts of setting a single price for all electricity delivered through the year, it's worth considering how buyers of utility PV might adjust contracting terms to favor inclined collectors with better winter generation. Solar PPAs have many creative pricing terms, and seasonal adjustments are uncommon but not unprecedented[21]. For example, the electricity price could have a premium for delivery in the winter months. In that case, using the generation and Capex figures in Fig. 7, and premium pricing for electricity delivered over the 12 weeks centered on the Dec. 21st winter solstice, we find the result shown in Table 1: a winter price premium of 240% is needed for Tr0 and FxL+15 plants to have equal revenue per dollar of Capex. Table 1 uses a base price of 2.5¢/kWh as an example, but presumably this price would be the main PPA negotiating point. In this example, the annual revenue equates to a simple payback interval of 14.9 years.

TABLE I: WINTER GENERATION INCENTIVE TO EQUALIZE REVENUE PER UNIT CAPEX FOR TR0 AND FXL+15 PV PLANTS.

Parameter	Tr0	FxL+15	Δ
Capex ($ per W_{DC})	$1.01	$0.96	
Annual generation (Wh per W_{DC})	2090	1814	15%
Winter generation (Wh per W_{DC})	257	316	23%
Base price per kWh (for example)		$0.025	
Premium for winter delivery		240%	
Annual revenue/$ Capex	$0.067	$0.067	0

V. CONCLUSION

The use of PV orientation to tailor the annual generation profile to best match the load is perhaps a case of knowledge that is "well-known to those who know it well," namely to PV specialists, but maybe not to utility system planners and policymakers. One of the aims of this paper has been to show that the same principles guiding the design of stand-alone PV systems in years past are applicable to the whole grid as we seek to rid it of carbon emissions. In effect, the future carbon-free grid driven by renewable energy is a stand-alone system, only bigger.

The simplified assumptions used in the analyses here make any quantitative assessment of cost savings achievable through optimized system-wide PV orientation doubtful, but the analytical results nevertheless clearly point to significant savings in total capital costs by optimized PV orientation. This work should therefore motivate planners working with more robust and complete models for optimal capacity expansion and dispatch to include PV orientation options in their list of design choices for system planning.

These analyses should also alert state policymakers and utility buyers to the need to consider how best to ensure PV plants procured in the coming years help to optimize the whole system for lowest cost through contract requirements and remuneration schemes. Remuneration of PV plants on the simple basis of kWh produced regardless of the timing of production will simply serve to ensure growth of generation at times it's not needed, at the expense of generation that is lacking when it's needed most.

ACKNOWLEDGEMENTS

The authors acknowledge Dr. Ron Sinton for his review and thoughtful feedback

REFERENCES

[1] Liz Gill, Aleecia Gutierrez, Terra Weeks, "2021 SB 100 Joint Agency Report, Achieving 100 Percent Clean Electricity in California: An Initial Assessment", California Energy Commission Report No. CEC-200-2021-001, March 15, 2021, Updated September 3, 2021, retrieved from https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

[2] Mahmoud Y. Abido, Kenji Shiraishi, Pedro Andrés Sánchez-Pérez, Russell K. Jones, Zabir Mahmud, Sergio Castellanos, Noah Kittner, Daniel M. Kammen, and Sarah R. Kurtz, "Seasonal Challenges for a Zero-Carbon Grid in California", 48th IEEE Photovoltaic Specialist Conference, 2020.

[3] D. J. Kuhn, I. J. Muirhead and N. F.Teede, "Photovoltaic System Design for Remote Telecommunication Installations", INTELEC '85 - Seventh International Telecommunications Energy Conference, 14-17 Oct. 1985.

[4] B. Mortensen, P. Ahm, "Photovoltaic Systems as Energy Source for Telecom Equipment", INTELEC '81 - Third International Telecom-munications Energy Conference, 19-21 May 1981.

[5] Hans S. Rauschenbach, Solar Cell Array Design Handbook, Section 3.12, Van Nostrand Reinholdt, 1980.

[6] NREL/TP-463-5607: Marion, William, and Stephen Wilcox, "Solar Radiation Data Manual for Flat-plate and Concentrating Collectors." Apr. 1994. https://doi.org/10.2172/10169141

[7] IEEE Approved Draft Recommended Practice for Sizing of Stand-Alone Photovoltaic (PV) Systems, IEEE Std 1562-2021, revision of IEEE Std 1562-2007, approved 16 June 2021.

[8] Caitlin Murphy, Trieu Mai, Yinong Sun, Paige Jadun, Matteo Muratori, Brent Nelson, and Ryan Jones, "Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States", National Renewable Energy Laboratory. NREL/TP-6A20-72330. 2021, https://www.nrel.gov/docs/fy21osti/72330.pdf.

[9] Wesley J. Cole, Danny Greer, Paul Denholm, A. Will Frazier, Scott Machen, Trieu Mai, Nina Vincent, and Samuel F. Baldwin, Quantifying the challenge of reaching a 100% renewable energy power system for the United States, Joule (2021), https://doi.org/10.1016/j.joule.2021.05.011

[10] Oliver Schmidt, Sylvain Melchior, Adam Hawkes, and Iain Staffell, "Projecting the Future Levelized Cost of Electricity Storage Technologies", Joule 3, 81–100, January 16, 2019.

[11] Jacqueline A. Dowling, Katherine Z. Rinaldi, Tyler H. Ruggles, Steven J. Davis, Mengyao Yuan, Fan Tong, Nathan S. Lewis, and Ken Caldeira, "Role of Long-Duration Energy Storage in Variable Renewable Electricity Systems", Joule 4, 1907–1928, September 16, 2020.

[12] Ejeong Baik and, Sally M. Benson, "The role of carbon capture and storage in decarbonizing California's electricity grid", 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15. Abu Dhabi, UAE, March 2021

[13] California Independent System Operator, "Managing Oversupply," http://www.caiso.com/informed/Pages/ManagingOversupply.aspx . [Accessed 10 May 2021].

[14] System Advisor Model, National Renewable Energy Laboratory, https://sam.nrel.gov/

[15] Arizona Solar Center, website, "PV Row to Row Spacing", https://azsolarcenter.org/pv-row-to-row-spacing.

[16] California Energy Commission, California Solar Energy Statistics &Data, https://ww2.energy.ca.gov/almanac/renewables_data/solar/index_cms.php

[17] 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.

[18] David Feldman, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis, "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020", National Renewable Energy Laboratory, Report No. NREL/TP-6A20-77324, January 2021.

[19] Annual Technology Baseline, Natonal Renewable Energy Laboratory, https://atb.nrel.gov/electricity/2021/data, retrieved October 15, 2021.

[20] Noah Kittner, Sergio Castellanos, Patricia Hidalgo-Gonzalez, Daniel M. Q4 Kammen, and Sarah Kurtz, "Cross-sector storage and modeling needed for deep decarbonization," Joule (2021), https://doi.org/10.1016/j.joule.2021.09.003

[21] "Pricing structures for corporate renewable PPAs", World Business Council for Sustainable Development (WBCSD), 2021