OPTIMIZED PV + STORAGE SYSTEM DESIGNS FOR NODAL ELECTRICITY VALUE

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Overview

Energy storage is an important mechanism for mitigating the decline in the energy and capacity value of solar photovoltaics (PV) at high PV penetrations. [1] Previous research has explored optimal PV + storage system designs as a function of storage duration, capacity, and cost [2], and as a function of the storage charging strategy (including solar-only charging or combined solar + grid charging) [3]. Additional system design flexibility can be obtained by allowing the ratio of the direct-current (DC) PV module capacity to alternating-current (AC) inverter capacity to vary, taking advantage of low module costs to increase the AC capacity factor and allow simultaneous charging of storage and direct dispatch of AC power to the grid. A trend toward increasing PV/inverter ratios has been observed for utility-scale storage-free PV arrays installed in the U.S. [4], but the impact of inverter overloading on the revenue and optimal system design of hybrid PV + storage plants has yet to be rigorously explored.

Here, we determine optimal dispatch strategies, PV/inverter ratios, and storage/inverter ratios for hybrid PV + storage systems at thousands of locational marginal pricing (LMP) nodes across the US over the years 2010-2018. We consider both the revenue from wholesale energy provision at the nodal LMP and capacity provision at the clearing price or average contract price for the Independent System Operator (ISO) for each node. We calculate the break-even cost of storage in order for storage to add net value (rather than cost) to hybrid systems, and observe changes in optimal system designs over time as solar penetration increases and LMP profiles evolve.

Methods

A linear optimization model is used to calculate the optimal hourly storage charge and discharge, hourly PV output to the grid, PV/inverter capacity ratio, and storage/inverter capacity ratio to maximize the yearly electricity revenue of the plant, factoring in hourly storage O&M expenses and annualized PV and storage capacity costs. The model thus weighs the revenue benefit of increased PV/inverter or storage/inverter loading against the increased capacity costs associated with these system designs. Perfect foresight of hourly LMPs and critical-peak hours over a calendar-year horizon is assumed, and all storage installations are assumed to have an energy capacity to power ratio of 4 MWh/MW.

We consider two sources of revenue: wholesale energy revenue, given by the combined AC output of the hybrid plant times the hourly historical LMP, and capacity revenue. Capacity revenue is given by the yearly capacity credit of the hybrid PV + storage system times the historical yearly capacity value within the ISO. The capacity credit is taken as the AC capacity factor of the hybrid PV + storage system during the ~300 hours of the year with the highest ISO net load, where net load is modeled as the hourly demand minus the hourly simulated generation of existing utility-scale PV installations within the ISO boundary. [5] Input data for the optimization include historical nodal LMPs from thousands of nodes across the US, and hourly modeled PV output generated using the National Solar Radiation Database (NSRDB) [6] and PVLIB Toolbox. [7]

We consider DC-coupled PV + storage, with storage constrained to charge only from PV rather than from the grid for purposes of energy arbitrage. We do not explicitly consider the impact of the Investment Tax Credit (ITC), which would reduce the upfront capital cost of this system by 30%. Instead we explore the sensitivity of our results to different capital costs for solar and storage; the gap between today's costs and calculated breakeven costs could be made up through technology cost reductions or through policy support mechanisms such as the ITC.

Results

As the assumed cost of storage capacity decreases, the optimal PV/inverter ratio, storage/inverter ratio, and net system revenue increases. Yet our results demonstrate significant variability in performance across nodes and years, even within the same ISO. In the California ISO (CAISO) in 2017, the addition of storage to a PV plant achieves breakeven at a storage cost of ~\$50/kWh for the bottom 5% of nodes but at ~\$125/kWh for the top 5% of nodes, assuming an upfront PV capacity cost of \$0.80/W_{DC}. There is also variation in the optimal system design over time. As the penetration of solar has increased in California (from ~2% of peak demand in 2010 to ~28% of peak demand in 2017 [8-9]) and driven down midday LMPs, the same amount of storage has added increasing amounts of revenue to a hybrid PV + storage system. Yet declining natural gas prices from 2014-2017 lead to reductions in the profitability of PV + storage systems over this period across all nodes. Focusing again on California and assuming an upfront PV capacity cost of \$0.80/W_{DC}, nearly all PV systems would break even with 2014 LMP profiles even without storage, but with 2017 LMP profiles no PV-only systems break even based on market revenue; a storage cost of ~\$100/kWh is required for a hybrid system to break even at the median node.

Conclusions

Our results enable quantification of the degree to which storage costs must fall in order for storage to add value to utility-scale PV installations across the U.S. Including the effects of tax incentives and internalizing the benefits of greenhouse gas and criteria air pollutant emissions reductions would improve the economic outlook of hybrid PV + storage systems and increase their value relative to standalone storage for energy arbitrage. The modularity of system design for hybrid PV + storage systems leads to important synergies, including reduced balance-of-system costs due to cost sharing between the PV and storage components and increased capacity value. The trends that are driving the increase in value for hybrid PV + storage systems – including falling PV and storage costs and declining LMPs during daylight hours with rising solar penetration – are expected to continue, making assessment of optimal hybrid system designs under up-to-date grid conditions increasingly important. Future work can incorporate additional value streams such as ancillary service provision, and can apply these techniques to hybrid systems employing other variable renewable energy sources.

References

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