The Road Ahead for Solar PV Power

Stephen Comello[*]

Stanford Graduate School of Business

Stefan Reichelstein

Stanford Graduate School of Business

Anshuman Sahoo

Stanford Graduate School of Business

March 2018

Abstract

Over the past decade, solar photovoltaic (PV) power has experienced dramatic deployment growth coupled with substantial decreases in system prices. This article examines how solar PV power is currently positioned in the electricity marketplace and how that position is likely to evolve in the foreseeable future. We first assess the current cost competitiveness of solar PV in select U.S. locations and industry segments using the levelized cost of electricity (LCOE) metric. This framework enables us to quantify the effects that supportive public policies, time-of-use pricing, and anticipated future technological improvements have on the cost of solar PV. We also build on recent analytical work that has identified circumstances under which it becomes financially attractive to add behind-the-meter batteries to an existing PV solar system. Taken together, our findings suggest that solar power, by itself and in conjunction with low cost storage, is positioned to account for a significant and growing share of the overall energy mix.

1 Introduction

Solar photovolatic (PV) power has long been heralded as an energy source with enormous potential for the electricity sector. Figure 1 shows that for new deployments, growth rates have been consistently high, particularly over the past decade with annual installation capacity increasing in each successive year. Another 100 GW in new capacity installations were added globally in 2017 to the 300 GW that had already been in place.[1] Globally, solar power now accounts for 6.3% and 1.7% of installed capacity and electricity generation, respectively (BP, 2017; GlobalData, 2018).
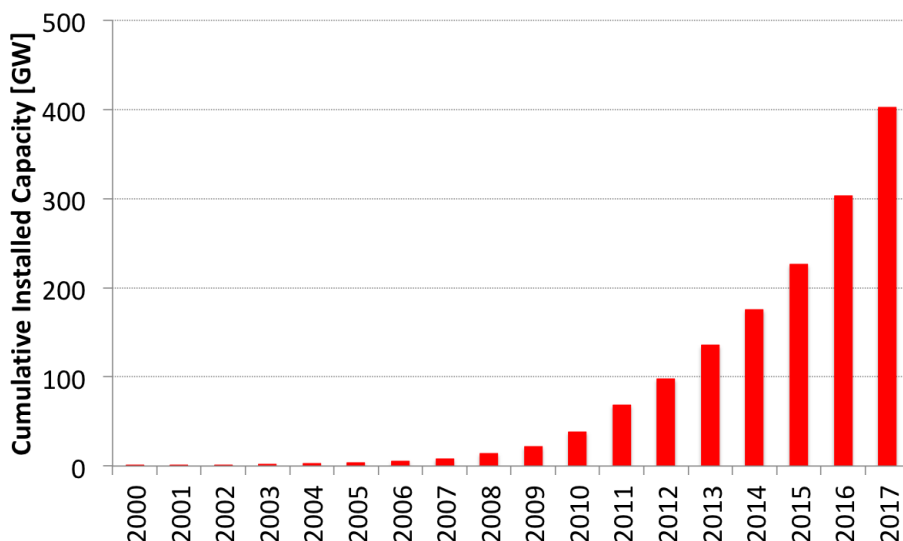

Figure 1: *Cumulative global solar PV capacity installations by end of 2017.*

As solar PV deployments grew rapidly in recent years, the prices of solar systems fell precipitously. To witness, the average sales price of PV modules has declined from about $4 per Watt in 2007 to around $0.35 per Watt by late 2017. A large body of literature has documented reductions in module prices and their underlying manufacturing costs; see, for instance, Swanson (2011), Candelise, Winskel, and Gross (2013), Sivaram and Kann (2016). At the same time, the prices of Balance of System (BOS) components, which comprise inverters, trackers, structural, and electrical components, have also come down significantly with annual reductions in the range of 5 − 7%.

Our objective in this article is to examine how solar PV power is currently positioned in

---

[1]Of the 100 GW of new capacity added globally in 2017, the U.S. market share is estimated to be about 15%.

the electricity marketplace and how that position is likely to evolve in the foreseeable future. To do so, we first assess the current cost competitiveness of solar PV in early 2018 and then examine how further technological improvements as well as potential changes in public policy are likely to shape the industry over time. Our analysis of the impact of public policy focuses on the current U.S. environment, though it will become clear that certain findings carry over to jurisdictions that have adopted different policies.

To assess the current cost competitiveness of solar PV in select U.S. locations and industry segments, we first estimate the levelized cost of electricity (LCOE) of the technology. The significance of this widely used metric is that it provides a lower bound on what an investor/developer would have to obtain as average revenue per kilowatt hour, possibly as part of a power purchasing agreement, in order to earn a normal return on investment. By the LCOE criterion, we find that in many parts of the western United States, utility-scale solar systems are currently better positioned than other electricity generation sources, in particular natural gas powered facilities or wind energy. For the commercial and residential segments, across geography we find that the corresponding LCOE figures are generally below the rates that utilities currently charge their customers, consistent with the recent pace of deployments in these segments of the industry.

Our analysis highlights that any claims about the competitiveness of solar PV power should account explicitly for the policy support mechanisms currently in place. Most important among these is the U.S. federal investment tax credit available to solar facilities. The policy of net metering is another crucial support mechanism that allows commercial and residential solar customers to obtain credit at the going retail rate for surplus electricity transferred to the grid. Both of these support mechanisms are likely to diminish in the near future. For federal tax incentives, the U.S. Congress has specified a "sliding scale" leading up to the end of 2021. Similarly, many U.S. states are currently debating or implementing restrictions on net metering. These projections naturally raise the question as to what further reductions in solar system prices will be required to maintain the cost competitiveness of solar PV in the face of weakening public policy.

Electric power is increasingly priced not on a purely volumetric basis; instead, prices vary according to the time of day and season. Since electricity prices presently are at a premium during the hours of the day when solar PV systems generate their power, time-of-use pricing improves the economics of solar PV systems in the current environment. Our

discussion here relies on earlier work that has quantified the magnitude of that synergistic effect. Yet, as the share of solar power in the overall energy mix increases, these synergies are likely to diminish. Furthermore, if some of the predicted scenarios associated with the system net load (i.e. the "duck curve") actually materialize, there may ultimately be a negative complementarity between the prevailing time-of-use prices and the pattern of solar power generation. We examine how such developments may be counteracted by a range of measures, including energy storage and the possibility of sacrificing overall output from a solar PV facility in return for more favorable timing of the solar power.

Battery storage systems are increasingly combined with both residential and commercial solar PV installations. The financial rationale for doing so relies on the potential to avoid paying a premium for electricity during peak pricing hours, and, for commercial users, on the ability to reduce demand charges. Our discussion of combining battery storage with solar PV systems is focused on residential settings where restrictions on net metering effectively yield a price premium for electricity that is self-generated and subsequently self-consumed at later hours of the day. Our analysis identifies conditions that make it financially attractive to add behind-the-meter battery storage to an existing PV solar system. At the same time, our findings suggest that in addition to the price premium, the availability of federal tax credits and state-level investment rebates is critical for economically viable battery deployments in this segment.

The final part of our analysis examines the dynamics of solar PV system prices. For photovoltaic modules, recent literature has argued that observed steep price declines are partially attributable to both intrinsic manufacturing cost reductions and excessive additions of manufacturing capacity.[2] We follow the framework in recent learning curve models to project the long-run unit cost of manufacturing modules by extrapolating from the most recent production volumes. These improvements combined with the expected reduction in balance of system prices have to be weighed against the diminishing federal tax support for solar PV. The resulting dynamic leads us to predict that the LCOE figures will see modest reductions over the next four years, culminating in a negligible increase in 2022 due to the federal investment tax credit reaching its ultimate plateau level of 10% at that point in time. Specifically, the decline in the ITC is expected to cause an increase in the LCOE of utility-scale facilities in California by approximately 2%.

---

[2]See, for instance, Candelise, Winskel, and Gross (2013).

In interpreting our projections for the future, it should be kept in mind that our focus on crystalline silicon PV modules considers only one avenue for future improvements. While crystalline silicon technology dominates the market currently, there also appears to be a tangible chance that other photovoltaic technologies may leapfrog the cost and performance of crystalline silicon based systems in the foreseeable future (Sivaram, 2018).

One of the contributions of this paper is to provide an up-to-date assessment of the cost-competitiveness of solar PV in the U.S., including recent system price reductions and the recent changes to the U.S. tax code. This change in the tax laws reduces the corporate tax rate to 21% and makes long-term assets eligible for 100% bonus depreciation.[3] As such, our work provides an update and extension to other recent assessments of solar power, such as Bolinger, Seel, and LaCommare (2017), Fu et al. (2017) and Lazard (2017a).

Beyond the inclusion of recent market developments and the new tax law, our analysis provides explicit treatment of the incentives for combined solar PV and energy storage systems. In doing so, we build on studies such as EIA (2018) and Lazard (2017a) by showing the fine-grain impact of the available support mechanisms. Our study also provides a unique assessment of the prospects of solar power, based on the recent dynamics for both module prices and balance of system costs. This quantification goes beyond the recent, more qualitative assessments found in Kabir et al. (2018) and Verdolini et al. (2018). Our framework also allows to provide new quantitative forecasts for the competitiveness of next-generation solar facilities.

The remainder of this paper is organized as follows. Section 2 provides a baseline assessment of the current cost competitiveness of solar PV power. Section 3 highlights the impact of public policy, specifically federal tax support and net metering policies at the state level, on the recent growth spurt of solar PV in the U.S. We examine the impact of increased time-of-use pricing on the economics of solar power in Section 4. Section 5 explores the economics of battery storage systems in conjunction with solar PV. The past dynamics of solar system prices and corresponding forecasts for the levelized cost of solar power over the next five years are analyzed in Sections 6 and 7. We conclude in Section 8.

---

[3]On December 22, 2017, the 115th U.S. Congress passed HR 1 into law, No. 115-97 "An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018."

2 Current Cost Competitiveness of Solar PV

Our assessment of the current cost competitiveness of solar PV focuses at first on the Levelized Cost of Electricity (LCOE), a cost concept that is widely relied upon by researchers and energy analysts; see, for instance, Lazard (2017a), Fu et al. (2017) and EIA (2018). This life cycle cost measure is stated in terms of dollars per kilowatt-hour of electricity, accounting for all upfront capital expenditures and subsequent operating costs. The LCOE is interpreted as the break-even value per kWh that a producer would need to obtain in sales revenue in order to justify an investment in a particular power generation facility. A developer who signs a power purchasing agreement (PPA) for a new project will therefore be "in the money" with a new project provided the PPA exceeds the LCOE of the facility.

In aggregate form, the LCOE can be expressed as the sum of three terms, the first two of which refer to unit variable- and fixed operating costs, respectively, while the third term captures the unit cost cost of capacity, scaled by a tax factor, which comprises the corporate income tax effects associated with the investment.[4] Formally,

$$LCOE = w + f + c \cdot \Delta, \tag{1}$$

where w refers to the time-averaged variable operating cost (in ¢ per kWh) that includes, for example, variable operations and maintenance (O&M), fuel, and possibly carbon dioxide emission charges. The unit cost f captures the time-averaged fixed operating cost (in ¢ per kWh) that is comprised of, e.g., insurance, property taxes, management costs, and fixed O&M costs. Finally, c is the unit cost of capacity (in \$ per kWh). It takes the system price (i.e., overnight capital expenditure) per kW and "levelizes" this expenditure to arrive at a unit cost of capacity per kWh. The unit-less tax factor Δ scales the unit cost of capacity to reflect the impact of the corporate income tax rate, the allowable depreciation schedule for tax purposes and any available investment tax credits.

Table 1 shows the outcome of an LCOE calculation for solar PV in California based on the LCOE Calculator (Comello, Glenk, and Reichelstein, 2017). The underlying input parameters are obtained from a variety of databases, including GTM (2017); ABB (2017); Fu et al. (2017); Bolinger, Seel, and LaCommare (2017).

For the particular application of utility scale PV in California, the input section of Table 1 summarizes the values of all relevant input variables, including the capacity factor, the rate

---

[4]The approach and notation here follows that in Reichelstein and Yorston (2013).

Table 1: *Input variables and calculated LCOE for utility-scale solar PV installations in California at end of 2017.*

The Levelized Cost of Electricity

Input Parameters		
Useful life (economic)	30	years
System Price (for solar, enter DC system price)	1.08	($/W)
Investment Tax Credit	30%	
Production Tax Credit	0	($/kWh)
Capacity Factor (for solar, enter DC-to-AC capacity factor)	0.2862	
System Degradation Factor	99.5%	
Fixed O&M Cost	10.7	($/kW - yr)
Variable O&M Cost	0.001	($/kWh)
Fuel Cost	0.000	($/kWh)
Carbon Dioxide Emissions Cost (Allowance Cost)	12.91	($/tCO2e)
Emissions performance	0.000	(kg CO2e/kWh)
Cost of Capital	8%	
Federal tax rate	21%	
State tax rate	8.84%	
Federal Tax Depreciation Method	5	
State Tax Depreciation Method	3	
LCOE calculation		
Unit Capacity Cost	0.0384	($/kWh)
Blended Tax factor	0.6887	
Average fixed O&M cost	0.0045	($/kWh)
Average variable O&M cost (including fuel)	0.0010	($/kWh)
Production Tax Credit	0.0000	($/kWh)
Levelized cost of electricity	**0.0319**	($/kWh)

of system degradation, the applicable cost of capital, the applicable depreciation schedule and the combined federal and state-level corporate income tax rate.[5] The corresponding output variables, that is, w, f, and c, as well as the resulting LCOE are shown in the lower part of Table 1. As one would expect, the operating costs amount to only around 0.5¢ per kWh, with the remainder of the 3.19¢ per kWh accounting for capacity costs.[6] While the blended tax factor would ordinarily be above one, its low value in the case of solar PV reflects two forces to be examined in more detail in the next section: the currently available federal investment tax credit and the first-year 100% bonus depreciation (full expensing) that is currently allowable under the changes to the U.S. tax code enacted in December of 2017.

---

[5]The cost of capital, r, is interpreted as a weighted average of the costs of equity and debt. The results are based on a federal tax depreciation schedule of 100% bonus depreciation and a state tax depreciation schedule of 20 year 150% declining balance.

[6]The system price of $1.08 per Watt includes the price of solar modules at $0.38 per Watt, with the residual attributable to the Balance of System (BOS) costs, reflecting the inverter, racks, and mechanical and electrical hardware. For the BOS costs, our data inputs here are obtained from a capacity-weighted average based on installation data of facilities with 1-axis trackers in California for years 2016 − 2017 furnished by datasets (GTM, 2017), (Fu et al., 2017), (Bolinger, Seel, and LaCommare, 2017) and (ABB, 2017). The weighted average of these four sources is $0.7 per Watt.

In assessing the competitiveness of utility-scale solar PV in the current environment of California, the 3.19¢ per kWh LCOE figure can be calibrated against multiple relevant benchmarks.[7] First, we conclude that a merchant power producer who would sell solar power directly into the grid would be "in-the-money" at recent wholesale rates in California, which have been around 3.46¢ per kWh on average (EIA, 2017b). Furthermore, as argued in Section 4 below, the economics of solar PV improves somewhat (around 10%) in the recent wholesale market environment because prices tend to be above average during the daytime hours when solar facilities generate their output.

A second set of relevant benchmarks is obtained by comparing the 3.19¢ per kWh figure against the LCOE of alternative energy platforms. The LCOE calculation shows that solar PV is currently more economical in California, and by a substantial margin, than alternative facilities powered either by wind, natural gas or pulverized coal. The LCOE of natural gas combined-cycle (NGCC) power plants is closet to the solar LCOE, with an LCOE of 5.23¢ per kWh. This estimation is based on a natural gas delivery price of $3.7 per thousand cubic feet and a capacity factor of 47%, the recent average capacity utilization rate for natural gas facilities in the state.[8]

Going beyond utility-scale applications, Table 2 summarizes LCOE estimates for three segments of the solar PV industry in three different locations. For the purposes of these calculations, residential solar PV is defined as distributed generation rooftop systems with lower than 10 kW of installed capacity, while commercial scale is defined as rooftop systems with 10 kW – 1 MW.[9]

In order for commercial and residential PV systems to be cost competitive, their LCOEs must be below the rates that utilities and other energy service providers charge their customers in these segments. In California, average retail rates for commercial and residential

---

[7]For thin-film technologies (e.g., cadmium-telluride solar cells), the data reported by Fu et al. (2017) suggest an LCOE of 3.24¢ per kWh. This estimate is consistent with the common observation that the crystalline silicon and thin-film technologies have seen price convergence in recent years, especially in projects located in adverse environments (Lee and Ebong, 2017).

[8]It can be verified that the LCOE for NGCC plants reduces to 4.37¢ per kWh if one were to assume a 75% capacity utilization factor.

[9]For comparison, "plug-and-play" solar PV systems typically have a rated capacity of 0.75 kW. While current U.S. regulations have limited the uptake of such small-scale solar appliances, the LCOE of such systems would be 5 to 8¢ per kWh, based on system prices provided in Mundada, Prehoda, and Pearce (2017). We note that plug-and-play systems would not be direct substitutes for residential or commercial facilities, given the former's inability to economically scale to meet larger demands.

customers are around 14¢ per kWh and 18¢ per kWh, respectively. These comparisons make the commercial segment particularly attractive for new solar PV deployments and partially explain the recent trend by energy intensive technology firms to build their own off-site solar facilities which are then connected to the central grid (Economist, 2017).

For locations in Arizona, the findings are similar to those for California. Residential- and commercial-scale solar installations would compete against average retail rates of approximately 12¢ per kWh and 10¢ per kWh, respectively. Utility-scale solar can successfully compete against pulverized coal and NGCC with LCOEs of 7.7¢ per kWh and 5.2¢ per kWh, respectively (EIA, 2017a). Finally, in Massachusetts solar PV is cost-competitive in some but not all segments. With average residential and commercial retail rates near 18¢ per kWh and 12¢ per kWh, respectively, residential- and commercial sized solar facilities are competitive. For utility-scale projects, however, solar PV would be above the LCOE of a new NGCC facility at 5.1¢ per kWh.[10]

Table 2: *Current LCOE estimates for different industry segments and U.S. states at end of 2017.*

	Utility PV	Commercial PV	Residential PV
California	3.2	6.8	11.4
Arizona	3.0	4.9	8.4
Massachusetts	6.0	8.6	15.3

Our assessment of solar cost competitiveness has so far yielded point estimates. Since several of the underlying input variables are arguably subject to interpretation and discussion, it will provide further insight to consider the sensitivity of our point estimates to variations in certain key input variables. Figure 2 presents a sensitivity analysis in which the center of the "spider chart" represents the status quo and the different "legs" correspond to the impact of the percentage change in LCOE as a consequence of a particular percentage change in one of the five input variables: capacity factor, discount rate, system price, operational life, and income tax rate. For instance, a 20% decrease in the capacity factor from its baseline 0.29 value would result in a 24% increase in LCOE, or a 16% decrease if the capacity factor

---

[10]Since the wholesale market in Massachusetts is part of the larger New England Independent System Operator (ISO-NE) market, solar installations in Massachusetts would compete with generation in the entire ISO-NE area.

increased by 20%.

The LCOE of solar PV power is most sensitive to the capacity factor, which primarily reflects the quality of the solar resource at the installation site. This observation highlights a permanent, but not insurmountable, disadvantage for northern locations. The relative insensitivity in the LCOE figure to changes in the assumed lifetime of the facility reflects that, at a discount rate of 7.5%, an expansion or curtailment of the number of years relative to the 30 year benchmark will have a relatively minor effect on life cycle cost. The even lower sensitivity of the LCOE estimate to changes in the tax rate shown in Figure 2 does not apply generally, but is driven largely by the presence of the investment tax credit.[11]
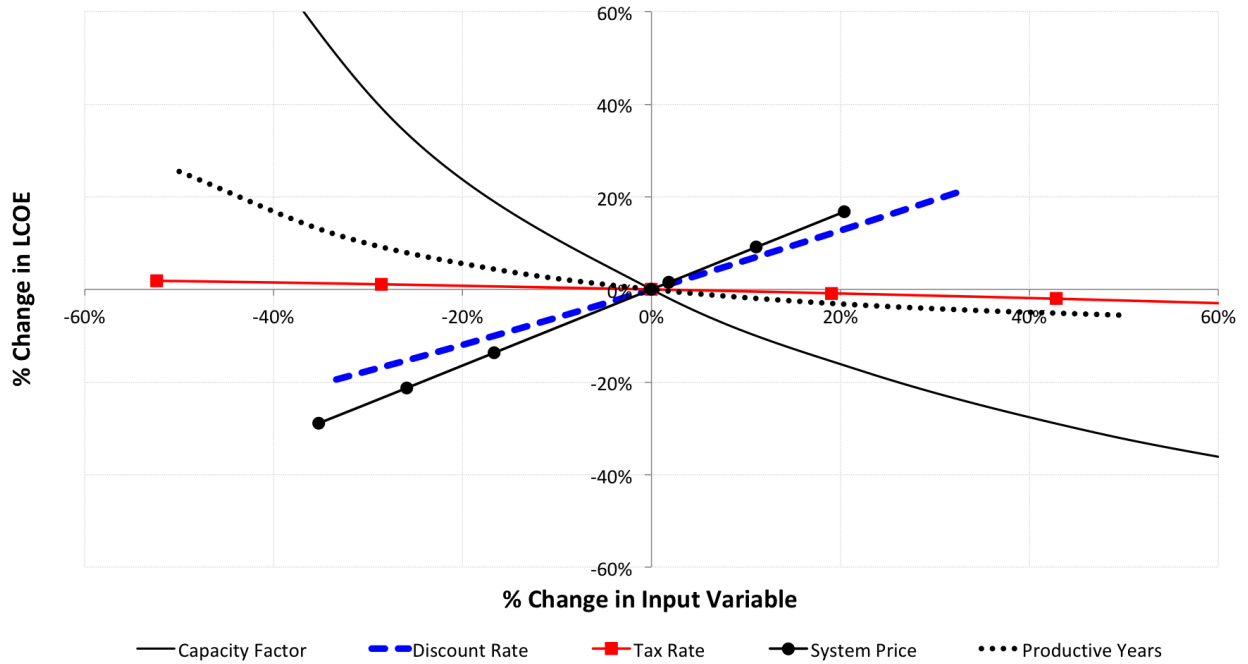

Figure 2: *LCOE sensitivity analysis for utility-scale solar PV in California*

It has been pointed out that the spectacular growth of solar PV in the U.S. and some other countries has been driven in significant part by public policy support pertaining to both tax rules and utility regulations favoring renewable energy. The following section seeks to quantify the magnitude of the effect of those policies on both the LCOE and the projected growth of new installations.

---

[11]It can be shown that, given the current investment tax credit and the allowable depreciation rules, the derivative of the tax factor, Δ, with regard to the corporate income tax rate is close to zero.

3 Public Policy Support

3.1 Federal Policy

The immediate impact of the current 30% federal income tax credit for solar PV facilities is a 30% rebate on the investment, provided the investor owes a sufficient amount of income taxes in that year.[12] In evaluating the impact of the current federal tax rules on the LCOE of a new facility, it is, however, important to consider the joint impact of the investment tax credit and the possibility of writing off the entire investment amount for federal corporate income tax purposes. The latter policy was adopted as part of the changes to the U.S. tax code at the end of 2017 and replaced the Modified Accelerated Cost Recovery System (MACRS), which stipulates a five-year accelerated depreciation schedule.

For the example of a utility-scale solar PV system in California, Table 3 summarizes the joint impact of the investment tax credit and the allowance for immediate expensing (100% bonus depreciation) by comparing the tax rules that applied to solar investments prior to the tax code change with those in place beginning in 2018. The conclusion is that in the current environment, the LCOE of California utility scale solar was essentially unaffected by the changes in the tax rules enacted in December of 2017. Yet, this somewhat counter-intuitive conclusion is very much dependent on the presence of the 30% tax credit. If, as debated by the U.S. Congress in December of 2016, the ITC had been repealed, the LCOE figure would have risen by approximately 50%.[13]

In the public debate about renewable, critics have pointed out that solar power arguably would not have grown nearly as fast without the federal tax incentives that have been in place for most of the past decade. In this context, Table 3 shows that at least for California (and other states with high insolation factors) the ITC is no longer required to make solar PV cost competitive relative to natural gas power plants. With the new tax rules, the two technologies now also have a level playing field in terms of the 100% bonus depreciation rule. Our LCOE calculator also shows that this conclusion is robust to a further hypothetical change in which natural plants would no longer have to pay for CO_2 emissions under the

---

[12]When owners of solar projects do not have the requisite tax liability, they frequently engage tax equity investors.

[13]Related to these considerations, the 2017 change in tax rules lowered the LCOE of NGCC facilities by about 0.5¢ per kWh, as natural gas does not have an ITC and the combination of a lower tax rate and the move from a 20-year 150% declining balance method to direct expensing lowered the tax factor, Δ, from 1.3 to 1.03.

California cap-and-trade rules.

Table 3: *Utility-scale LCOE in California under alternative tax regimes: pre- and post U.S. tax code changes of late 2017.*

	2017 Tax Rules	2018 Tax Rules
30% ITC	3.3	3.2
No ITC	5.0	4.6

The trajectory of system prices and balance of system costs for solar PV installations over the past decade strongly suggests that the corresponding LCOE figures will continue to fall in the coming years. Our LCOE projections shown in Section 7 below, though, will highlight the effect of the anticipated step-down in the federal tax credit that is currently available. Specifically, the tax rules enacted within the Consolidated Appropriations Act, 2016 (H.R. 2029, December 2015) specify that the ITC will remain at 30% for facilities that commence construction before the end of 2019. Thereafter, it steps down to 26% in 2020, 22% in 2021 and 10% in 2022.

The baseline LCOE calculations above have not incorporated the potential impact of the tariffs that the U.S. administration imposed on crystalline silicon modules to take effect in February 2018.[14] The effect of the tariff is a 30% mark-up on modules beginning in early 2018, decreasing by 5% per year over 4 years, whereupon it will cease altogether in early 2022. The exact impact of these tariffs remains unclear because of several exemptions.[15] A 30% tariff on modules would raise the system price by about 8¢ per Watt. In our LCOE calculation for utility-scale installations in California this would increase the LCOE from 3.19¢ per kWh to approximately 3.35¢ per kWh, an effect that is of second order magnitude. As noted in the popular press, the LCOE effect of tariffs is even more negligible for commercial and residential systems because solar cells account for a smaller share of the overall system price in smaller systems.

---

[14]Imposed via Section 201, Trade Act of 1974 (Global Safeguard Investigations), Import Relief for Domestic Industries, U.S. International Trade Commission.

[15]For instance, the first 2.5 GW of annual imports into the U.S. are exempted from the tariff. In addition, imports from "GSP-Eligible developing nations" such as India, are exempt from the tariff.

3.2 State-level Policies

Our baseline calculations in Section 2 have not included renewable energy credits (RECs) or solar-specific RECs (SRECs). These state-level incentives enable eligible solar generators to receive a stream of revenue usually denominated in $ per MWh for a fixed amount of time. RECs and SREC are tied to state-level renewable and/or solar-specific capacity installation goals, and are traded on exchanges. We note the value of RECs and SRECs has historically fluctuated considerably both across states and over time within a particular state, thereby making it a challenge to forecast and as such beyond the scope of this work. The relative impact on the LCOE differs substantially across each state. For example, in Massachusetts, SRECs currently trade for $265 per MWh. Assuming that valuation were to persist for the entire 10-year eligibility of the SREC, the LCOE would be reduced by 8¢ per kWh. In contrast, RECs currently trade at $35 per MWh in California. Assuming that valuation were to persist for the entire 3-year eligibility of the REC, the LCOE would be reduced by 0.04¢ per kWh. At the same time, it is conceivable that states like California that have adopted ambitious emission reduction goals will implement those goals by means of higher quotas for renewable power, with a likely rise in the value of RECs in the future (Barbose, 2017).

In many U.S. states, a common policy in support of commercial- and residential-scale PV systems has been net metering. This policy ensures that surplus electricity generated by the solar system at a particular point in time can be sold back to the electricity service provider (utility) at the same retail rate that the customer is charged for electricity purchases.

As the volume of residential- and commercial-scale solar installations has grown, utilities and other stakeholders have become increasingly vocal that net metering amounts to a subsidy for solar power that is paid for by the entire cross-section of ratepayers. These observers point out that net metering forces utilities to buy surplus electricity (overage electricity) at the going retail rate, though they could procure the same power at the lower wholesale rate (Darghouth, Barbose, and Wiser, 2011; McHenry, 2012). Put differently, utilities are in effect required to store the energy generated at no cost to the operator of the solar facility. As of 2017, public utility commissions in multiple states have begun the process of assessing their current policies and, in some jurisdictions, have already imposed limits on the rule of full net metering (NC CETC, 2017; Shogren, 2017).[16]

---

[16]Net metering is not an issue in countries like Germany that have set feed-in-tariffs *above* the going retail

The state of Nevada made headlines in late 2015 when its Public Utilities Commission, acting on a legislative mandate, increased the fixed charge for all solar customers and reduced the credit for any overage electricity from solar rooftops by approximately 18%. This rule would have taken effect in 2016, with the credit continuing to decline to the wholesale rate in a step-wise manner over the subsequent 12 years. One of the more contentious elements of the new regulation was its application to all existing residential solar facilities, including those which have been previously installed (i.e., no "grandfathering" provisions). As a result many solar developers, including SolarCity (now Tesla) and Sunrun, announced in early 2016 that they would withdraw from operations in Nevada. However, in the late summer of 2017 the Nevada legislature passed AB405, which mandates utilities to purchase electricity from rooftop generators at 95% of the prevailing retail rate for the first 80 MW of capacity installed.[17] This overage tariff will decrease by 7% for every additional 80 MW in cumulative rooftop capacity installed, with a guaranteed price floor of 75% of the prevailing retail rate.

As an alternative to net-metering, public utility commissions have been considering policies under which the energy transferred back to the grid is credited at some overage tariff, OT, per kWh. If the retail electricity rate is denoted by p, then full net metering would set $OT = p$. A natural question then becomes how developers will respond to the adoption of overage tariffs that credit electricity sold back to the utility at a rate below the retail rate.[18] Comello and Reichelstein (2017a) examine this question through the lens of an investor evaluating the profitability of rooftop solar PV systems. An investor/developer will typically enter into a contract with the homeowner specifying either a power purchasing or a leasing arrangement. As part of this contractual arrangement the homeowner essentially earns a "rooftop rental fee" that must be sufficient to make the rooftop available for the solar installation. The basic tradeoff in sizing a solar PV rooftop system in the presence of net metering restrictions is illustrated in Figure 3.[19]

The dotted line in Figures 3a and 3b represents the average electricity demand of a typical household in Los Angeles, California, for one 24-hour cycle. The solid curve in Figure 3a represents the generation profile of a relatively small residential solar installation. Most of

---

rate in order to promote the deployment of residential and commercial solar PV.

[17]At the end of 2015, Nevada had 129 MW of rooftop solar installed (WECC, 2016).

[18]Other studies have assessed the impact of net metering from the perspective of an incumbent utility; see, for instance, Darghouth, Barbose, and Wiser (2011), Cai et al. (2013) and Graffy (2014).

[19]These figures are taken from Comello and Reichelstein (2017a), with data provided by NREL (2016), NREL (2010) and NREL (2015).

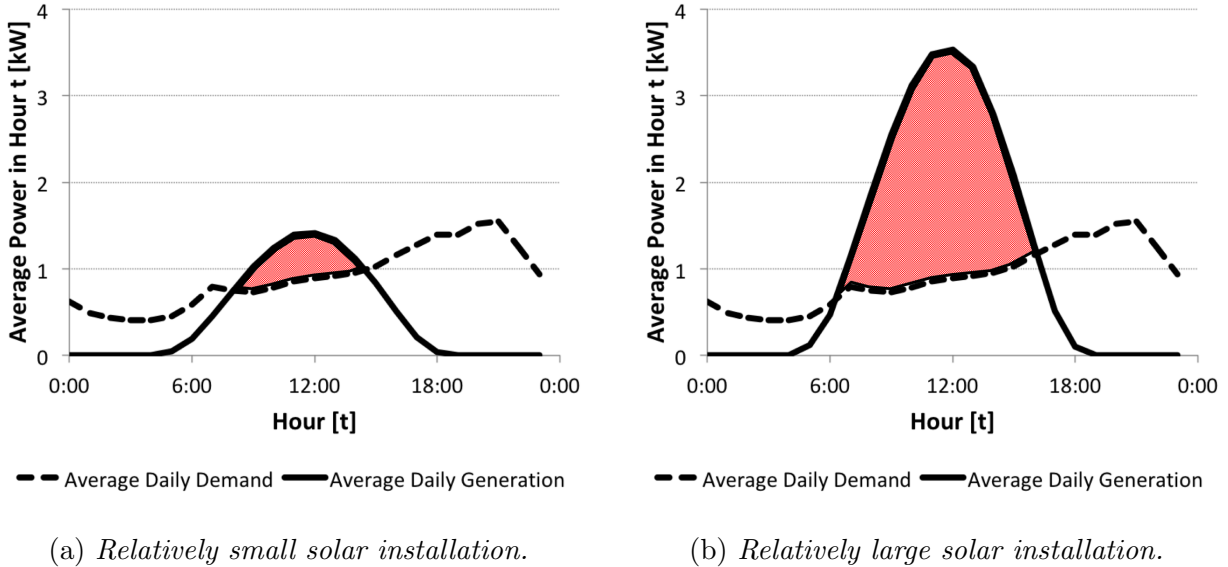(a) *Relatively small solar installation.*   (b) *Relatively large solar installation.*

Figure 3: *Average overage electricity generated and exported to the electricity grid from relatively small and large residential solar installations (fixed demand).*

the electricity generated will be valued at the going retail rate, as household consumption exceeds production. With net metering restrictions, it is only the energy represented by the shaded area (the overage electricity) that will be valued at the overage tariff, *OT*. By comparison, Figure 3b depicts a relatively large solar installation for which most of the electricity generated (shaded area) is valued at the overage tariff.

Even with full net metering, the size of residential and commercial solar PV systems is generally not limited by the physical constraints on rooftop size. As observed by Barbose et al. (2016), a system size of 15 kW would generally be considered such an upper physical bound for households. Instead, the effective constraint in virtually all U.S. jurisdictions is given by an aggregate surplus constraint which specifies that if the annual electricity generated by the solar PV system exceeds the total annual electricity consumption by the household, the resulting "net energy surplus" is credited at a substantially lower rate. For instance, despite a policy of full net metering, any net energy surplus is credited only at wholesale rates in California (AB 920 in California, and LADWP Solar Program for Los Angeles specifically). Even more extreme, such net energy surplus receives zero credit in other states, including Nevada. We refer to the size of the solar PV system that ensures that on average there is no annual net energy surplus as the *threshold* size. Comello and Reichelstein (2017a) show that with full net metering the optimal size of a solar facility will

be equal to the threshold size.

For any given overage tariff, OT, it can be shown for a solar facility with peak power capacity of k kW (and k less than the threshold size), the corresponding net present value of an investment in residential rooftop facility is proportional to the following *Hourly Contribution Margin* (HCM):[20]

$$HCM(k|p, OT) \equiv z(k) \cdot p + (1 - z(k)) \cdot OT - LCOE. \qquad (2)$$

The function $z(\cdot)$ in Equation 2 is decreasing in the size of the system (k) and ranges between zero and one. The exact shape of this function is determined jointly by the load curve of the investing household and the energy generation curve of the solar system. Referring back to Figures 3a and 3b, the weight $1 - z(k)$ can be visualized as the proportion of the shaded area relative to the total area underneath the generation curve on the interval given by the two points of intersection between the generation and demand curves.[21]

Taken together, the net present value of a PV system can thus be viewed as a fixed multiple of the hourly contribution margin which, on a per kWh basis, compares average revenue to average cost. Consistent with the characterization in Section 2 above, the average cost of solar PV power on a per kWh basis is effectively captured by LCOE. At the same time, the average revenue is a weighted average of the retail rate (avoided cost of purchases from the grid) and the overage tariff. As the size of the solar system (k) increases, the relative weight on these two revenue sources shifts towards the overage tariff because $z(\cdot)$ is decreasing in k.

The expression in Equation 2 shows that if the overage tariff is at least as large as the LCOE, the investment will continue to have a positive net present value for any k up to the threshold size. Furthermore, it can be shown analytically that under fairly broad conditions the optimal system size remains the threshold size provided $OT \geq LCOE$. Thus, the prediction is that a modest restriction on net metering should not result in smaller solar rooftop deployments, even though the profitability of the investment would obviously be lowered. The immediate question then becomes how investors would respond to overage

---

[20]The factor of proportionality is the product of i) the number of hours in a year, that is 8760, ii) the average capacity factor of the solar photovoltaic facility, and iii) the present value of an annuity corresponding to the useful life of the facility.

[21]Accordingly, $z(k)$ is the proportion of the unshaded area relative to the total area underneath the generation curve.

tariffs set below the LCOE. The answer hinges on the particular shape of both the load curve and the solar generation curve. For a mid-size house in Nevada, Comello and Reichelstein (2017a) derive the response function shown in Figure 4 for the optimal size of the solar rooftop system as a function of an overage tariff gradually reduced below the LCOE.
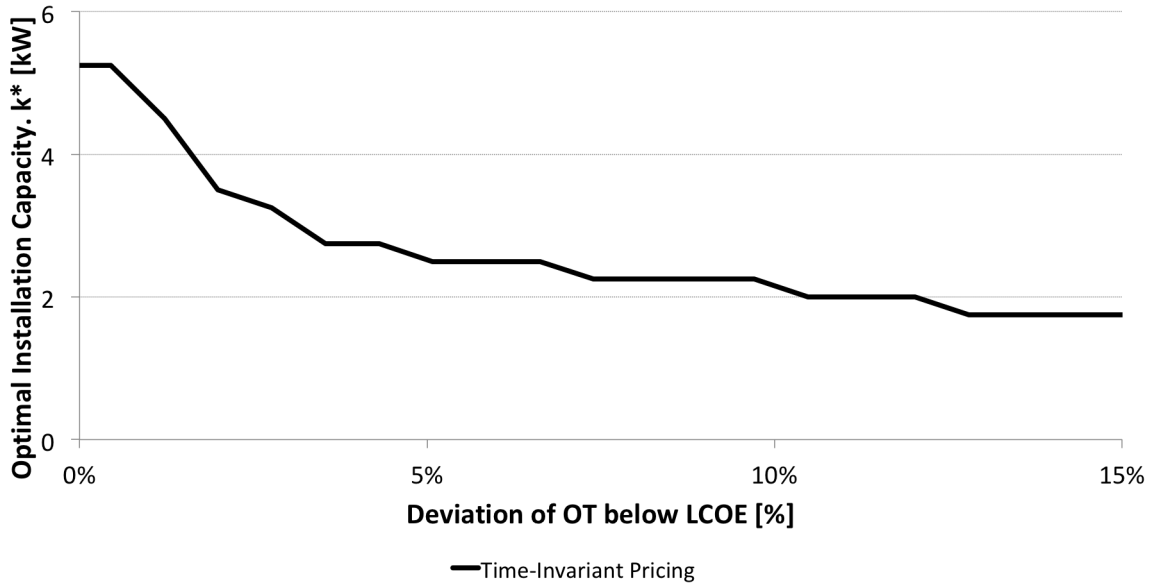

Figure 4: *Optimal size of solar PV system in Las Vegas, Nevada, in response to reductions in overage tariff.*

Qualitatively similar results emerge for Los Angeles (California) and Honolulu (Hawaii). In all cases, the LCOE becomes essentially a "tipping point" such that for overage tariffs set significantly below the LCOE, say 10% or more, the optimal size of the rooftop system will start to drop quickly, to a level where it might arguably no longer make sense for a developer to install rooftop solar. These simulation findings are consistent with the actual events in Nevada in 2016.

The Public Utilities Commission in California has largely kept net metering intact, while Nevada intends to reduce the OT gradually to 75% of the prevailing retail rate, and Hawaii chose an OT that falls between these two extremes. Currently, there are approximately 36 actions (state and utility proposals, reviews and/or pilots) related to net metering across multiple U.S. states (NC CETC, 2017). It is likely that net metering rules will come under increased scrutiny as the number of solar rooftops increases in each state and as PUC and utilities alike seek more specific compensation schemes for distributed energy resources in general.

4 Time-of-Use Pricing

As renewable energy sources in general, and solar PV power in particular, are poised to generate a share of the overall energy mix that is substantially larger than the current one, their intermittency and volatility will become more prominent concerns regarding the stability of the electrical grid. Related to the increased penetration of renewable energy is a broader trend to set the electricity price according to the time of day, and possibly the season, in order to reflect both the cost of generation and consumers' willingness to pay for electricity in real time. To illustrate, in deregulated wholesale markets, like California or Texas, average night-time prices are only approximately 50% of the overall average price per kWh (CAISO, 2017). Similarly, utilities have increasingly imposed peak price surcharges on their commercial and industrial customers to reflect the relatively high value of electricity during certain time intervals of the day. Some U.S. states have already introduced the option of time-of-use (ToU) pricing for residential customers, with California announcing that ToU pricing will become mandatory by 2019.

When electricity prices vary over time, the cost competitiveness of solar PV can no longer be captured entirely by comparing the average price to the LCOE of a facility. As pointed out in earlier studies, the intermittency of renewable energy may generate synergies or undesirable complementarities between the time pattern of power generation and that of varying prices.[22] An onshore wind park, for instance, may generate most of its electricity during the night time hours when prices tend to be low. For solar PV, in contrast, time of day prices and peak generation capacity tend to be favorably aligned in the current environment. Figure 5 provides an example generation profile for a hypothetical solar facility, based on data from NREL (2012).

Figure 6, which summarizes a summer time-of-use tariff from the utility PG&E in California for commercial customers, provides intuition for the current alignment between solar generation, as in Figure 5, and relatively high electricity rates.

To quantify any synergistic effects between generation and pricing in the current environment, we adopt the concept of the *co-variation* coefficient, as developed in Reichelstein and Sahoo (2015). Formally, let $\epsilon(t)$ represent the *deviation* at time t from the average capacity factor, CF, in the course of a day. Thus $CF(t) = \epsilon(t) \cdot CF$ and, by definition, the average value of the $\epsilon(t)$ across the hours of the day is equal to one. Similarly, let $\mu(t)$ represent the
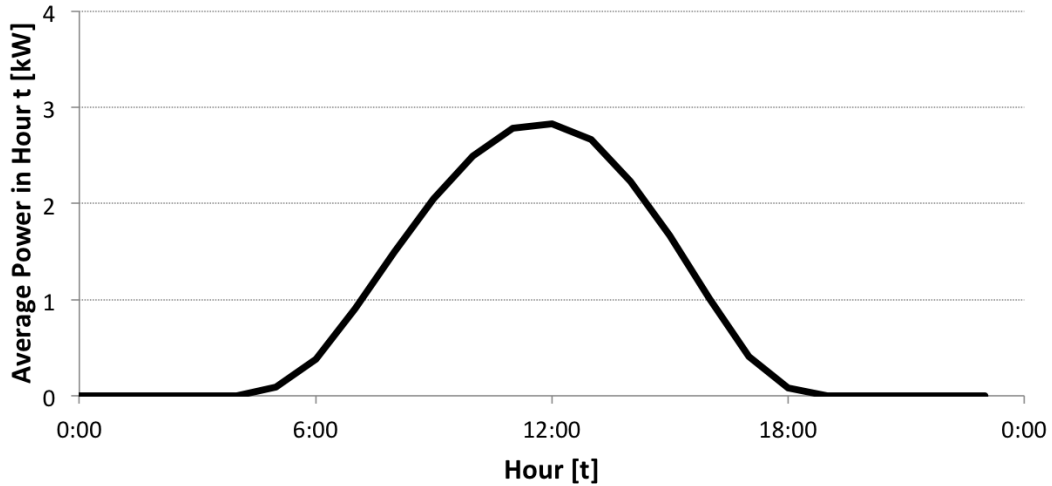
---

[22]See, for instance, Joskow (2011).

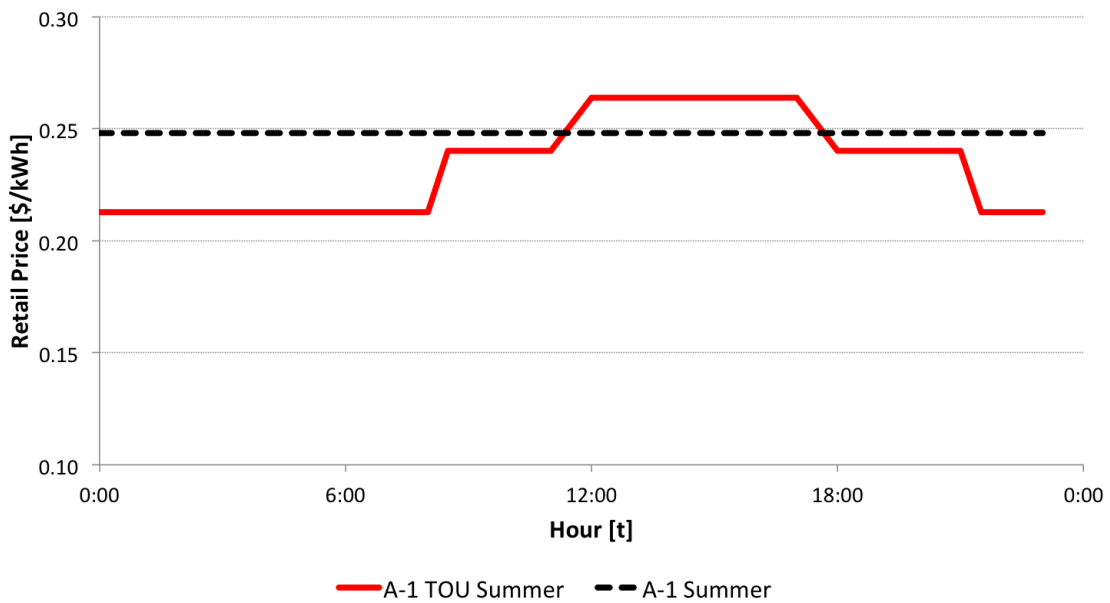Figure 5: *Typical summer generation pattern of a fixed tilt rooftop solar PV installation in San Francisco.*

A-1 TOU Summer ━ ━ A-1 Summer

Figure 6: *Small commercial retail rate structure (A-1 summer schedule; applied May – October) offered by PG&E.*

percentage deviation at time t from the daily average electricity price, p, in the course of a day. Thus $p(t) = \mu(t) \cdot p$, where the average value of $p(t)$ is again equal to one. For the twenty four hours corresponding to one day, the co-variation coefficient is then defined as:

$$\Gamma = \frac{1}{24} \int_0^{24} \epsilon(t) \cdot \mu(t) \, dt.$$

The annual co-variation coefficient is obtained simply as the mean of the daily coefficients across the entire year.[23] It is readily seen that $\Gamma = 1$ if either power generation is uniform, that is, the capacity coefficient is constant (possibly because the energy source is dispatchable), or, alternatively, if electricity prices do not vary over time. With time-varying prices an investment in a new energy facility yields a positive net-present value if and only if $\Gamma \cdot p \geq LCOE$ (Reichelstein and Sahoo, 2015). Put differently, the effective levelized cost of electricity in a ToU environment is:

$$LCOE^* = \frac{LCOE}{\Gamma}.$$

In the above example for commercial-scale solar PV in San Francisco the specific value of the annual co-variation coefficient is 1.17. Thus, the effective LCOE of solar PV power generation facilities is 15% ($0.85 = \frac{1}{1.17}$) lower than the baseline LCOE.[24]

As the share of solar PV power in the total electricity mix increases, the price premia attached to electricity in the middle of the day, say prior to 4:00 p.m., are likely to decrease relative to the pattern shown in Figure 5. In contrast, a larger share of solar power in the future is likely to increase the premium for electricity delivered in the late afternoons and early evenings. Clearly, such a shift would reduce or even eliminate the synergy effect embodied in the annual co-variation effect of $\Gamma = 1.17$ calculated for San Francisco, California. In fact, for a sufficiently large shift, the co-variation coefficient could easily drop below $\Gamma = 1$ once daytime electricity price would, in relative terms, effectively be priced at current nighttime rates.

Regarding the electricity grid overall, the impact of a significantly larger share of solar PV power has been forecast by the California Independent System Operator in the form of system net loads depicting timing imbalance between peak demand and (mainly) solar generation,

---

[23]If one views $\epsilon(t)$ and $\delta(t)$ as random variables, then

$$\Gamma - 1 = \frac{1}{24} \int_0^{24} (\epsilon(t) - 1) \cdot (\mu(t) - 1) \, dt$$

can be interpreted as the covariance of the two random variables.

[24]The annual value of $\Gamma = 1.17$ is an average of the co-variation coefficients of $\Gamma = 1.05$ and $\Gamma = 1.29$ for the winter and summer months, respectively.

known as the "duck curve" (CAISO, 2013). Figure 7 indicates that the net-loads or ramp needs in the late afternoons (after 4:00 p.m.) will increase over time, presumably as more solar power is added to the mix. The low point of the duck curve (the "belly") corresponds almost exactly to the point in time that solar generation is at its maximum, as illustrated in Figure 5. The tendency of these net-demand minima to become progressively lower over time, with corresponding steeper subsequent ramp-needs, is attributed to a growing share of solar PV in the overall electricity mix.
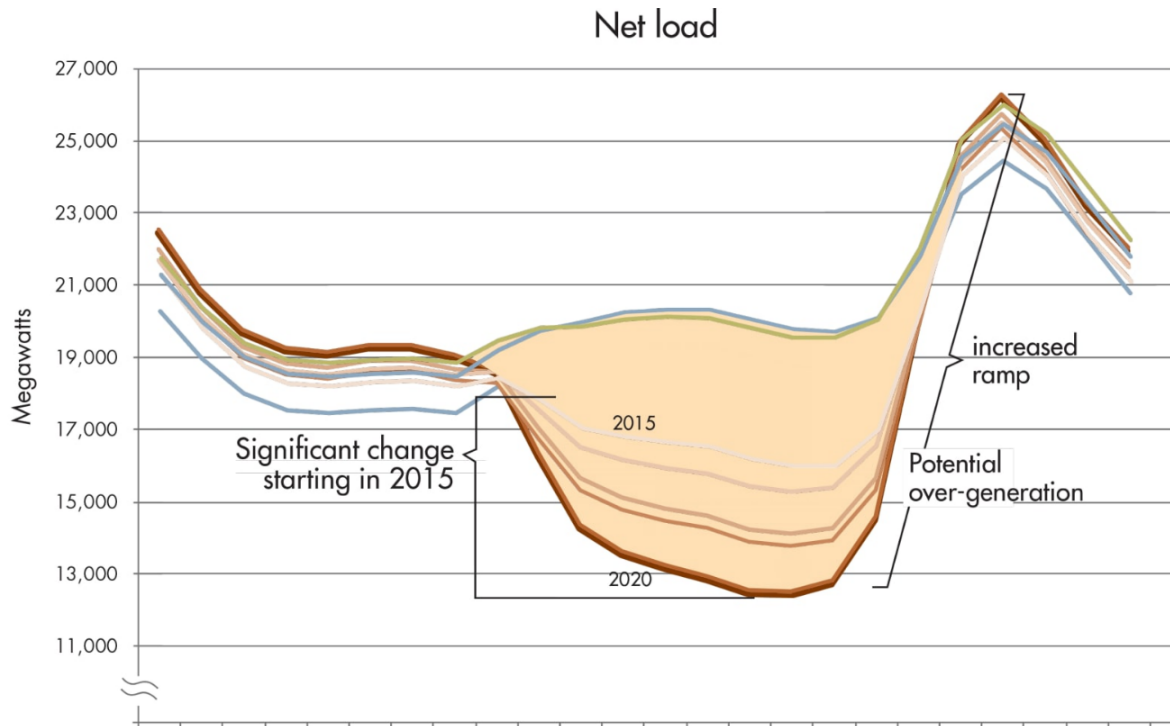

Figure 7: *California system-wide net load forecasts as assessed in 2013 for years 2015 – 2020, (CAISO, 2013).*

In interpreting Figure 7, it should be kept in mind that it portrays a very partial comparative static, holding factors other than increased distributed solar penetration constant. At the same time, the likely shift in peak pricing to late afternoons and early evenings is likely to provide incentives for a range of other measures that may counteract the steep ramp needs. The simplest one might be to deliberately angle solar PV installations in a suboptimal fashion from an overall power generation perspective and do so in return for more power generated at later hours of the day. Similarly, Goodall (2016) argues that by investing in a PV system with lower inverter capacity, one obtains a lower system price and lower overall AC output, yet the generation curve in Figure 5 becomes more angular at the

top. Other potential shifts include demand response mechanisms that "pull" load from the early evening hours forward into the middle of the day. Finally, energy storage in the form of batteries, chemical storage or possibly pumped hydropower, would allow energy generated during the main hours of the day to be released back into the grid system at later hours of the same day. Such measures might allow for a significant "flattening" of the duck curve (Denholm et al., 2015).[25]

5   Combining Solar PV with Battery Storage

Recent years have witnessed a dramatic rise in stationary energy storage installations. The annual deployment of battery storage across utility-scale, commercial and residential installations between 2012 – 2017 has increased by 37% for power capacity (per MW) and 58% for energy capacity (per MWh) in the U.S. (GTM Research, 2017). While utility scale storage accounts for the majority of the annual demand (64% – 95%), "behind-the-meter" distributed storage, located at the point of demand, has experienced the highest growth rate in deployments at 190% and 240% for power and energy capacity, respectively. The consensus view for battery storage, both in the U.S. and globally, is continued double digit growth across all segments over the coming decade (GTM Research, 2017; Lux Research, 2017).

The observed growth in storage deployments is due in part to declining costs of the energy storage modules, which is a partial result of expanded manufacturing capacity to meet the demand for electric vehicles (Kittner, Lill, and Kammen, 2017; Schmidt et al., 2017). Energy storage modules on average constitute 40% – 50% of the total system price, with power components (BOS) comprising the remainder (State of California, 2017; Fisher and Apt, 2017).[26] Regarding energy storage modules, the most prevalent option - lithium-ion batteries (li-ion) - have seen costs fall by 80% from \$1,000 per kWh to under \$200 per kWh. Forecasts for the li-ion energy storage modules project prices in the \$150 per kWh range within the next couple years (Schmidt et al., 2017; Lux Research, 2017; Kittner, Lill, and Kammen, 2017). On the other hand, much like the history for solar PV system prices, BOS costs (power components) are projected to decline at a considerably slower pace.

Battery storage systems are increasingly combined with solar PV installations. We refer to the combination of the two as a photovoltaic storage (PVS) system. From the perspective

---

[25]Denholm et al. (2015) distinguish shifts that flatten the duck curve from those that would "fatten" it.

[26]BOS includes inverter, thermal control, power electronics, hardware, software subcomponents.

of utilities and energy service providers, the energy discharged from PVS system effectively becomes "dispatchable." Such systems can ensure a constant level of output despite short-term fluctuations in solar power generation (e.g. cloud cover). In terms of daily average patterns, PVS systems enable flexibility as to when electricity is actually dispatched. The latter effect results in the provision of power when it is most valuable, for example in late afternoons/early evenings in order to address the steep system ramp rates illustrated by the "duck curve."

Some recent projects and their PPA structures provide an indication of the economics of PVS systems. For example, the island of Kauai in Hawaii has experienced a high degree of saturation of electricity on the grid during high insolation periods. In that environment, a recent PVS project combined a 17 MW solar farm with a 13 MW/52 MWh storage system. The contract entailed a 20-year PPA at 13.9¢ per kWh based on offtake during evening hours. Similarly, another project in Hawaii combines a 28 MW solar facility with 20 MW/100 MWh storage under a 20-year PPA with an offtake price of 11¢ per kWh. For these systems, the majority of dispatch occurs in the evenings, typically for 4 – 5 hours. Notably, the power purchase agreement for these systems involve prices that are substantially below the wholesale price of electricity in Hawaii which is approximately 15¢ per kWh.

Another recent PVS implementation combines solar capacity with a storage system of relatively small size. Tucson Electric Power (TEP) in Arizona recently contracted for 100 MW of solar capacity combined with a 30 MW/120 MWh storage facility. The 20-year PPA price was set at 4.5¢ per kWh. By construction, the majority of generation will be dispatched to the grid during hours of solar PV production, while a fraction of the electricity generated is retained to offset evening peak demand. The remarkably low PPA price can be interpreted as a result of favorable solar insolation and the averaging of the low generation cost with the cost of the relatively small storage capacity. For a utility like TEP in the southwestern U.S., where peak demand typically occurs in the late afternoon and early evening, the PVS system effectively flattens the duck curve shown in the previous section.

PVS systems are also being deployed increasingly behind-the-meter in commercial and residential applications. The financial rationale for investing in storage systems relies on avoided premium electricity prices during peak pricing hours. In addition, battery storage systems enable commercial users to reduce demand charges they face for peak power consumption. For that segment, 60% of proposed storage installations in California are paired

with solar PV installations. For the residential segment, 92% of the expected battery instal-lations are combined with a solar PV system (State of California, 2017). As detailed below, the current structure of tax credits and state-level rebates makes such parings particularly attractive for prospective investors.

The following application illustrates the emergence of battery storage in a competitive market, in the context of a residential setting. Building on the analysis in Section 3.2, we ask under what conditions a household consumer that has already installed a solar PV system will add battery storage if it faces restrictions on net metering. These restrictions would force surplus energy sold back to the utility during the day to be credited at an overage tariff, OT, below the retail rate, p.[27] Restrictions on net metering effectively yield a price premium for electricity that is self-generated and subsequently self-consumed at later hours of the day. The battery would be charged from the portion of solar energy shown in region II of Figure 8. The battery would discharge during times when household demand exceeds generation by the rooftop solar facility. Accordingly, region IV in Figure 8 has the same area (energy capacity) as region II. Clearly, the energy storage capacity is bounded above by the amount of solar generation that is subject to OT valuation, i.e. the combined area of regions II and III.

The storage device will be optimally sized in the two dimensions of power- and energy capacity. The size of the power component, measured in kW, governs the maximum rated charge/discharge rate. The energy component, measured in kWh, provides the total capacity of electrical charge that can be stored. Moreover, the ratio of energy capacity to rated power determine the *duration* for which the storage facility can provide the rated power. This is also the length of time needed to charge the facility assuming maximum power charging.[28]

To characterize conditions under which it would be financially advantageous to install a battery supplementing an existing solar rooftop system, we adopt the framework of Comello and Reichelstein (2017b). Given a retail price, p, and an overage tariff, OT, the net revenue obtained from a battery storage system will, on a per kWh basis, be given by the difference $p \cdot \eta - OT$, with $\eta \leq 1$ denoting the roundtrip efficiency factor of the the battery. To obtain

---

[27]Our analysis applies in particular to residential solar PV installations in countries like Germany, where the initial investment was incentivized by a feed-in-tariff that expired after a number of years. Thereafter, the operator of the solar facility faces the issue that any energy not self-consumed will only be credited for the wholesale electricity price, which is a small fraction of the prevailing retail rate in Germany.

[28]If the charge/discharge were to occur at half the rated power, the storage facility would generally be able to provide double the duration at 50% of the power output.
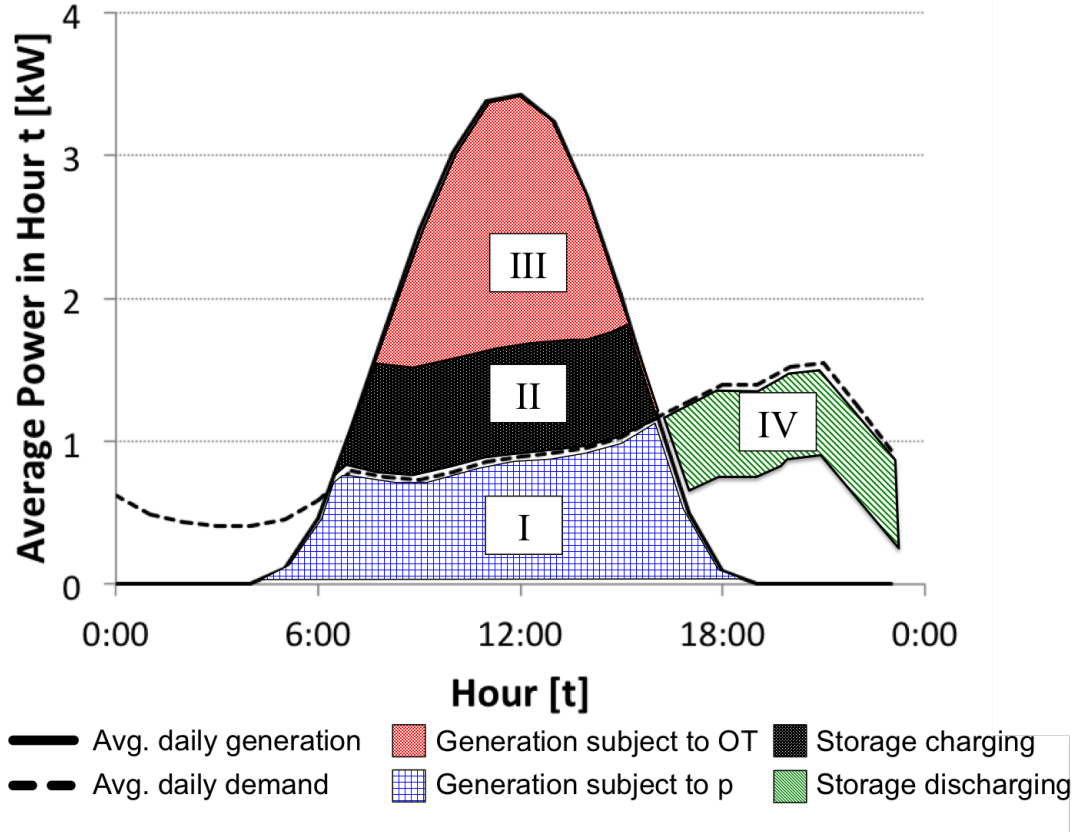
Figure 8: *Illustrative description of charging and discharging a battery combined with a residential PV system.*

the contribution margin of the system, the unit cost of an energy component is subtracted from net-revenue and the difference is multiplied by the number of energy storage units in the battery system. The corresponding contribution margin must be large enough to cover the unit cost associated with the power components of the battery storage system. Furthermore, an efficient storage system will assign as many energy components as feasible behind each kW of power to be discharged. Referring again to Figure 8, the largest amount of energy storage (in kWh) that can be accommodated with a system that can dispatch k_p kW at any given point in time is the area marked as region II. Formally, this area is given by:

$$\hat{k}_e(k_p) = \int\limits_0^{24} \left[\min\{L(t) + k_p, CF(t) \cdot k_s\} - \min\{L(t), CF(t) \cdot k_s\} \right] dt.$$

As before, $L(t)$ represents the household's demand at time t, $CF(t)$ denotes the capacity factor and k_s represents the size of the solar PV system. It is readily verified that the function

$\hat{k}_e(\cdot)$ is increasing and concave in k_p, such that $\hat{k}_e(0) = 0$.

To capture the relevant unit cost figures, Comello and Reichelstein (2017b) derive the levelized cost of energy components (LCOEC) and the levelized cost of power components (LCOPC). As detailed below, these can then be aggregated to an overall levelized cost of storage that is conceptually similar to the LCOE given in Equation 1. Specifically:

$$LCOPC = c_p \cdot \Delta_B, \qquad\qquad\qquad LCOEC = c_e \cdot \Delta_B,$$

where c_p denotes the levelized cost of power capacity (in $ per kW), c_e denotes the cost of energy capacity (in $ per kWh) and Δ_B is the tax factor that applies to battery acquisitions. The levelized costs c_p and c_e, in turn, are defined as:

$$c_p = \frac{v_p}{N \cdot \eta \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}, \qquad\qquad c_e = \frac{v_e}{N \cdot \eta \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}.$$

The input variables for these levelized cost calculations are:

- v_p, system price of power components (in $ per kW) and v_e is the system price energy component (in $ per kWh),

- $\gamma = \frac{1}{1+r}$, discount factor based on the discount rate (cost of capital) r,

- T, useful life of the battery system,

- x_i, storage degradation factor,

- η, roundtrip efficiency factor of the battery storage system,

- N, number of full cycle (charge and discharge) occurrences per year.

As shown in Comello and Reichelstein (2017b), the overall net present value of a battery storage system is proportional to the daily profit margin (DPM) given by:

$$DPM(k_p) = [pp - LCOEC] \cdot \hat{k}_e(k_p) - LCOPC \cdot k_p. \qquad (3)$$

Here, *pp* refers to the price premium which is the time-averaged difference between $p \cdot \eta$ and *OT* adjusted for the temporal degradation of the energy discharged by the battery. Equation 3 shows that adding a battery storage system will be a worthwhile investment only if the price premium *pp* exceeds the levelized cost of an energy storage component, *LCOEC*. In

fact, since there are diminishing marginal returns to a system with a higher power rating (the function $\hat{k}_e(\cdot)$ is concave in k_p), a necessary and sufficient condition for any storage system to have a positive net present value is that the daily profit margin be positive for a small value of k_p. For small values of k_p, $\hat{k}_e(k_p)$ approaches $k_p \cdot (t^+ - t^-)$, where t^- and t^+ denote the left and right point of intersection, respectively, between the household load curve and solar generation curve in Figure 8. Thus a necessary and sufficient condition for any storage investment to have value is that:

$$[pp - LCOEC] \cdot (t^+ - t^-) > LCOPC. \tag{4}$$

Finally, an investor who seeks to optimize the size of the battery system will choose the power rating, k_p^*, which maximizes the daily profit margin in Equation 3. If $k_p^* > 0$, the unique first-order condition is given by:[29]

$$DPM'(k_p^*) = [(pp) - LCOEC] \cdot \hat{k}_e'(k_p^*) - LCOPC = 0. \tag{5}$$

We now apply this model framework to a residential setting with a rooftop solar installation of size 4.85 kW, assuming system component prices of $v_e = \$175/\text{kWh}$ and $v_p = \$1,000/\text{kW}$ respectively. Given the additional parameter values underlying our calculations, we obtain component cost figures of $LCOEC = \$0.051$ per kWh and $LCOPC = \$0.179$ per kW.[30] For these parameter estimates, Figure 9 shows the optimal combination of the power rating, k_p^* and the corresponding optimal energy capacity, $\hat{k}_e(k_p^*)$ as a function of alternative price premium values pp. Accordingly, a residential solar facility would add battery storage provided the price premium is at least 7¢ per kWh.[31] Once the price premium exceeds this critical value, the optimal size of the battery increases quickly to a power rating of about 2 kW and a corresponding average energy storage capacity of around 12 kWh, resulting in an average duration of about six hours. Clearly, the 30% federal ITC that is available for PVS systems in combination with a solar PV system is crucial, for otherwise there would be no incentive to invest in battery storage unless the price premium exceeded 11¢ per kWh.

---

[29]It is readily verified that $\hat{k}_e'(k_p)$ is given by $||\mathcal{I}(k_p)||$, where $|| \cdot ||$ denotes the length of the interval $\mathcal{I}(k_p) \equiv \{t | L(t) + k_p < CF(t) \cdot k_s\}$.

[30]Comello and Reichelstein (2017a) identify 4.85 kW as the "threshold" size (defined in Section 4 above) for a medium sized house in Los Angeles. The above levelized cost figures are based on the following additional parameter values: $T = 10$, $\eta = 0.95$, $x_i = (0.99)^{i-1}$, $r = 7.5\%$

[31]Thus, the inequality in Equation 4 will hold as an equality at $pp = 7$¢ per kWh.
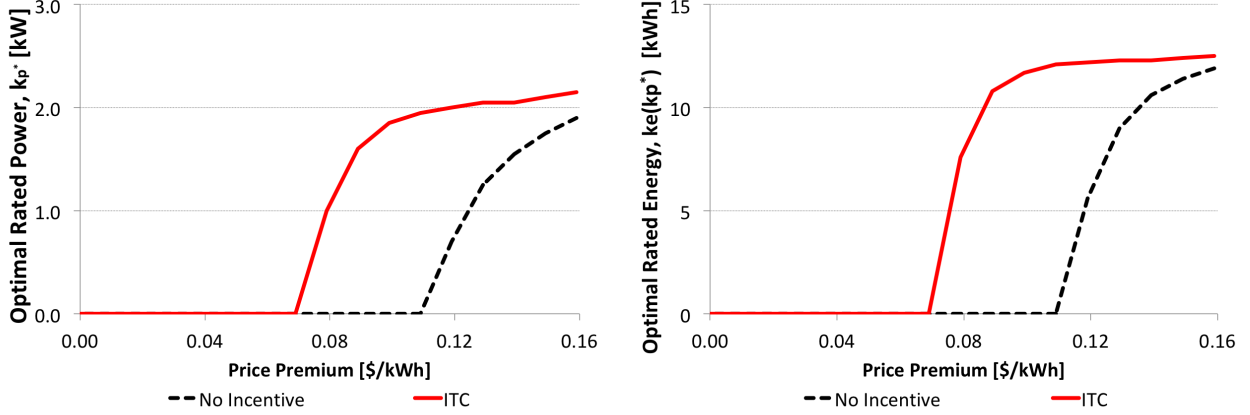
(a) *Optimal rated power given a price premium.*   (b) *Optimal energy given a price premium.*

Figure 9: *Optimal combination of power and energy components capacities for a battery installation retrofit of an existing residential solar system in Los Angeles, given a price premium.*

The preceding calculations can serve to illustrate the levelized cost of storage (LCOS) measure, introduced in Comello and Reichelstein (2017b). For a battery storage system with a power rating of k_p kW and a storage capacity of k_e kWh, the corresponding average duration is given by $D \equiv \frac{k_e}{k_p}$ hours. On a life cycle basis, the cost of storing one kWh of electricity, and dispatching it at later hours of the day, is then given by:

$$LCOS(D) = LCOEC + LCOPC \cdot \frac{1}{D}. \tag{6}$$

$LCOS(\cdot)$ is expressed in ¢ per kWh since the duration ratio, D, is stated in hours. Thus, the levelized cost of the energy component, $LCOEC$, provides an asymptotic lower bound for the LCOS metric for battery systems with a long duration.[32] At the same time, the first-order condition in Equation 5 can be restated as follows: the size of the power component is to be chosen such that the price premium equals the levelized cost of storage evaluated at the duration associated with the marginal power component, that is, $pp = LCOS(\hat{k}'_e(k_p^*))$.

For the setting shown in Figure 9, the optimal duration ratio converges to roughly six hours once the price premium exceeds 9¢ per kWh, yielding an $LCOS(6) = 0.051 + 0.179 \cdot \frac{1}{6} = 8$¢ per kWh. For an optimized battery storage system, the household will thus pay approximately 8¢ per kWh, *on average*, in order to "warehouse" a total of 12 kWh and

---

[32]In the Arizona TEP installation mentioned above, the average duration is four hours.

dispatch those during hours of the day where the household's load exceeds the amount of energy generated by the solar installation.

The LCOS measure in Equation 6 contrasts with current industry reports such as Lazard (2017b).[33] For a residential li-ion battery system, the lower range estimates by Lazard (2017b) for the cost of storage are equal 100¢ per kWh, i.e., a figure that is more than ten times our estimate provided above. Among the factors accounting for the substantial difference, we mention in particular that Lazard (2017b) assumes a duration of 2 hours and does not seek to define the levelized cost of power versus energy components. Its analysis further omits the ITC that is available to PVS systems. Finally, conceptually, the Lazard (2017b) measure includes the energy cost of charging the battery on a daily basis. In contrast, our above LCOS measure only captures the cost of warehousing one kWh for certain hours on a daily basis, while the (opportunity) cost of charging the battery is captured in our calculations on the net revenue side through the overage tariff, OT.

A significant share of the battery storage systems installed to date in the U.S. has actually been deployed in California. This may seem puzzling at first because the Public Utilities Commission in California has consistently affirmed a policy of net metering, thus making the price premium, pp, effectively zero. The key to this puzzle appears to be the additional state-level subsidies provided through California's Self Generation Incentive Program (SGIP) program. In its current form, this program offers a rebate on energy storage components. Specifically, the rebate amounts to $400 per kWh for a storage system with a duration of up to two hours. For systems with longer durations, the rebate per kWh steps down such that no additional support is given to systems with a duration exceeding six hours.

Numerical evaluation shows that the rebates under the SGIP program are so large that the resulting LCOS will in fact be negative, at least for systems with a duration between one and nine hours (Comello and Reichelstein, 2017b).[34] Thus, even absent any price premium the SGIP subsidies create an incentive to invest in PVS systems. Given the above parameter values and $pp = 0$, the optimal system size turns out to be $k_p^* \approx 1.7$ kW and $\hat{k}_e(k_p^*) \approx 11$ kWh, resulting again in a duration of about 6.2 hours. Furthermore, the optimal duration would remain close to six hours for positive and large price premia.

In future work, it would be useful to explore the co-optimization of storage and solar

---

[33]See also Pawel (2014), Julch (2016), Lai and McCulloch (2017) for approaches similar to Lazard (2017b).

[34]The minimum $LCOS$ is achieved near $D = 2.5$, which corresponds to the duration of Tesla's popular *Powerwall*, with a duration of 2.6.

facility capacities for applications related to the utility, commercial and residential segments. For the utility setting, this would include an examination of the required component cost reductions required for cost-competitiveness with dispatchable generation sources, e.g., gas peaker plants. The residential and commercial segments offer particularly complex settings, as these segments increasingly face rate structures that include time of use rates coupled with the prospect of diminishing net metering support and reduced solar investment tax credits. Moreover, commercial customers often face demand charges, which have a significant effect on the total electricity bill. For different tariff structures and load profiles, it would be important to identify the extent of policy support required for PVS installations to gain traction in these segments. Beyond these settings, it would also be fruitful to explore the cost-competitiveness of hybrid energy systems, such as PVS with combined heat and power facilities.

6 Dynamics of Solar PV System Prices

Our findings so far have established that solar PV-based electricity generation is cost-competitive, at least in U.S. locations with good solar resources. At the same time, we have noted already that solar also faces potential hindrances in the future. First, public utility commissions have begun to selectively restrict net metering provisions, with direct implications for the economics of residential and commercial solar facilities. Second, as more solar capacity is added, its value to the energy system will tend to decline without load shifting or additional storage deployments. Third, actions to bolster the economic value of solar PV by adding storage will add substantially to the technology's cost competitiveness. Finally, the scheduled reduction in the federal tax incentives will diminish the cost competitiveness of the technology. Countering all four trends, however, is a persistent dynamic of price reductions for solar PV systems. In this section, we describe potential cost- and price reductions for PV modules and the balance of systems (BOS) components.

6.1 Module Prices

The dramatic decline in the sales price of solar PV modules has been widely documented. A well studied relationship regresses (the logarithm of) average module sales prices (ASPs) on (the logarithm of) cumulative module output. For the years 1979 – 2010, the corresponding

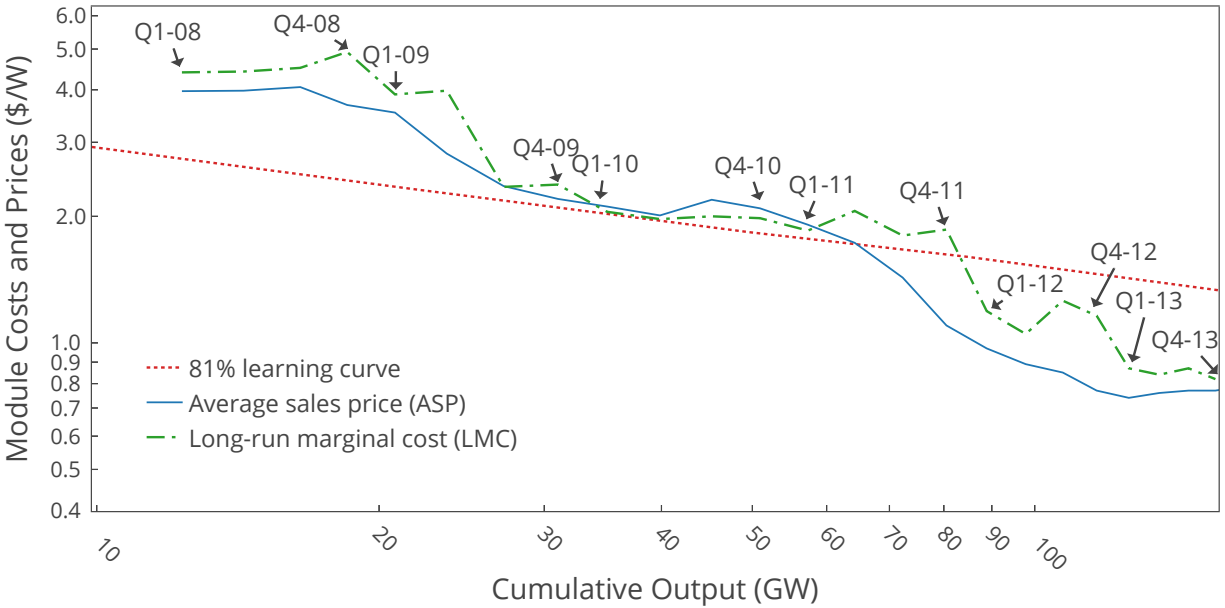ASPs / LMCs of Modules and Cumulative Module Output

Figure 10: *LMCs and ASPs between Q1-08 and Q4-13. All prices are in 2013 U.S. dollars.*

price trajectory is described accurately by an 80% constant elasticity learning curve. In line with this trend, prices would be expected to drop by 20% with every doubling of cumulative output, measured in MW. Since 2010, however, module prices have dropped much faster than the historical trend line would suggest. The solid curve in Figure 10 plots ASPs from 2010 to 2013, showing a decline in module ASPs between 2011 and 2013 that was much steeper than predicted by the 80% learning curve. The 40% price drop in 2011 alone and rebound in prices in late 2013 are particularly striking. Most observers link this price drop to both large increases in solar panel manufacturing capacity and continued reductions in manufacturing costs. Given ambiguity in the drivers of past price decreases and therefore price-based trajectories of future module prices, Reichelstein and Sahoo (2017) estimate the long-run marginal cost (LMC) of solar modules for the same time period. Since, in equilibrium, the ASP should equal the LMC, these estimates allow an approximation of cost reductions that is independent of manufacturing capacity considerations.

Figure 10 suggests a close match between average sales prices and the estimated long-run marginal costs for the years 2008 – 2010. Beginning in late 2011, the dramatic decline in the observed ASPs for most of the quarters in 2012 – 2013 result in average sales prices signif-

icantly below the estimates of the contemporary long-run marginal cost.[35] In other words, these cost estimates provide evidence that the sharp drop in ASPs for those time periods was partly due to factors beyond cost reductions, such as excessive additions in manufacturing capacity. Since in a competitive environment, such as that characterizing the module industry, the equilibrium price of a product will be driven to its long-run marginal cost, estimates of marginal costs and decline rates also allow a projection of future module prices.[36] In light of this evidence, Section 7 uses the estimates of cost declines from Reichelstein and Sahoo (2017), instead of a price-based forecast, to build a forward-looking trajectory of both module prices and the levelized cost of electricity from solar PV systems.

Econometric analyses of the LMC estimates show evidence that the sharp drop in ASPs between 2011 and 2013 was partly due to manufacturing cost reductions in excess of the 80% learning curve. Using quarterly financial statements from a subset of module manufacturers, as well as quarterly data from an industry observer (Lux Research, 2014) about manufacturing capacity and product shipments Reichelstein and Sahoo (2017) infer two rates of cost declines. These correspond to two components of the long-run marginal cost in manufacturing industries, namely, capacity-related costs for machinery and equipment and core manufacturing costs for materials, labor and overhead. In particular, the authors estimate a 62% constant elasticity learning curve for core manufacturing costs and that capacity-related costs for machinery and equipment have fallen by 24% each year. Given recent industry output, these capacity-related cost declines also outperform the 80% learning rate benchmark.

6.2   Balance of System Prices

Balance of system costs now account for the majority of the price of new solar installations. These costs have fallen recently in part due to innovations by solar developers. These firms have reduced BOS costs by focusing on vertical integration, decreasing installation time, simplifying the permitting and interconnection process, and streamlining the process of sales, marketing, and financing.

We estimate BOS prices decreasing at a rate of 6.1% annually until 2022, based on

---

[35]This conclusion is corroborated by the sharply negative earnings and declining share prices that firms in the industry experienced during those two years.

[36]The module industry can be characterized as competitive since a large number of firms supply a relatively homogeneous product. As corroborating evidence, the median market share of firms in this industry was less than 1% in 2012.

forecasts from a composite of data from Fu et al. (2017), GTM (2017), GlobalData (2018). This expected cost reduction rate is determined by taking an average of historical annual BOS cost estimates (2010 – 2017) and fitting an exponential regression curve. The R^2 for this regression is 0.90 with a t-statistic of -7.33 (df = 7). In similar fashion to Comello and Reichelstein (2016), the time-dependent relationship for BOS price decreases can be extrapolated as:

$$BOS(t) = BOS(0) \cdot e^{-\lambda \cdot t}, \tag{7}$$

where $BOS(0)$ denotes the BOS at $t = 0$ (i.e. 2017) and $BOS(t)$ denotes the cost BOS in period t. The parameter λ represents the rate of cost reductions in each period. We obtain a value of 0.061 for λ from the composite estimate above, yielding $e^{-\lambda} = 0.935$. Thus we anticipate a 6.5% annual decline in the BOS prices for the years 2017 – 2022.

7   Levelized Cost of Electricity Projections

This final section projects the LCOE of utility-scale solar PV installations in California considering both the dynamics of component system prices and public policy support mechanisms. We begin by providing an update to Figure 10, based on a capacity addition of 100 GW in 2017 and a 10% annual growth to 2022.[37]

The uniform-dash yellow curve in Figure 11 is the estimated volume-driven LMC for PV modules, based on the capacity additions in 2017 and the assumed growth rate thereafter. To project the LCOE, we use the minimum of the module ASP and LMC. For example, given that the per unit LMC for 2017 is \$0.49 per Watt, yet the ASP is \$0.38 per Watt, we use the latter for our 2017 LCOE calculation. Once the long-run marginal cost is lower, we then presume the ASP will be equal to the LMC and follow the projected trajectory. Given the estimated annual declines in BOS costs (Section 6) and expected reductions in the ITC (Section 3), Figure 12 shows the resulting trajectory for the LCOE of utility-scale solar in California.

The conclusion emerging from Figure 12 is that the gradual step-down in the ITC will be approximately offset by the anticipated cost reductions. From a policy perspective, one could argue that this is precisely how the schedule of declining ITCs should have been calibrated

---

[37]The capacity additions for 2014, 2015 and 2016 were 45 GW, 56 GW and 80 GW, respectively.
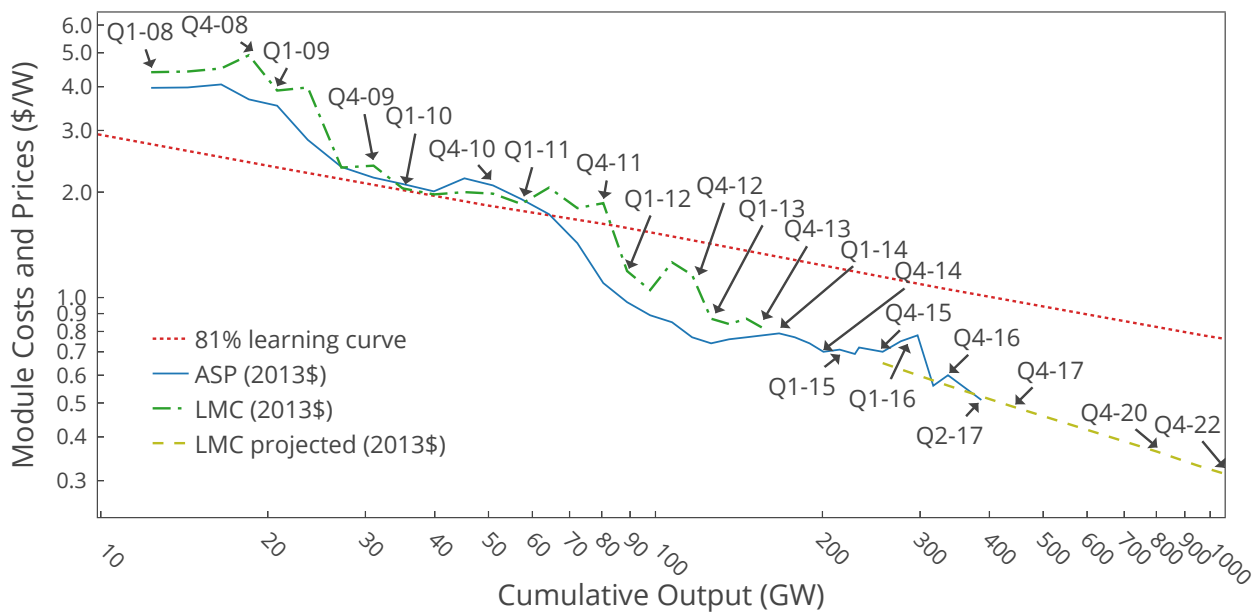
Figure 11: *LMCs projected to the end of 2022. All prices are in 2013 U.S. dollars.*
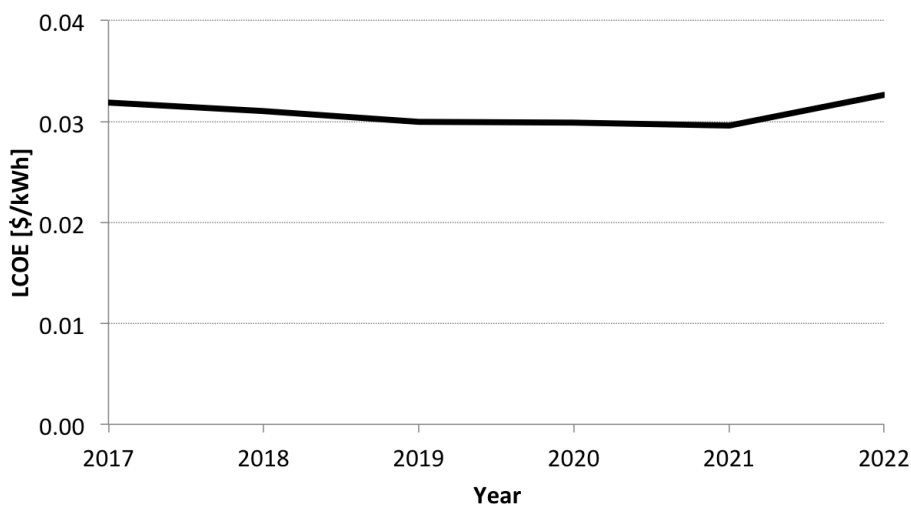

Figure 12: *LCOE of utility-scale solar in California projected to the end of 2022. All prices are in 2017 U.S. dollars.*

in the first place. Going beyond 2022, we would then expect a period of further declines in the LCOE (albeit slower ones) as the ITC will remain at 10% which current tax law has set as the long-term plateau level.

33

8 Conclusion

Over the past decade, solar PV installations have seen a dramatic rise in global deployment. Simultaneously, the price of such systems across all segments has fallen precipitously, with lower module costs driving the majority of these declines. This paper has examined how solar PV power is currently positioned in the electricity marketplace and how that position is likely to evolve in the foreseeable future. Specifically, we have evaluated the current cost-competitiveness of solar PV in different parts of the U.S., and then examined how further technological improvements as well anticipated changes in public policy are likely to shape that assessment in the near future.

We find that for many parts of the western U.S., utility-scale systems are currently better positioned than other sources of generation according to the levelized cost of generation criterion. Commercial and residential segments also fare well because the LCOE of those systems is below the going retail rate utilities charge their customers. However, we also show that our conclusions about cost-competitiveness relies substantively reflect policy support mechanisms, such as net metering and federal investment tax credits. As the share of solar power increases within the overall energy mix, the likelihood of over-generation during times of high insolation will result in an increasingly unfavorable complementarity between the prevailing time-of-use prices and the pattern of solar power generation.

We identify the parallel emergence of storage facilities, in particular those combined with solar facilities and their ability to make solar "dispatchable" by supplying stored electricity at later times of the day, when it would be more economical to do so. Moreover, we explore the application of storage combined with solar PV in a residential setting where restrictions on net metering yield a price premium for electricity that is self-generated and later self-consumed. Our modeling approach identifies conditions that make it financially attractive to add behind the meter storage to existing solar systems. In the sample context of a medium-sized home in Los Angeles, we find that – similar to solar PV – federal tax credits and state-level investment rebates are essential in enabling the economical deployment of batteries in this segment and application.

Our final analysis combines the trajectory of module and BOS cost reductions with scheduled diminishing federal support mechanisms for solar PV to project the near-term effects on the LCOE. In applying this dynamic to utility-scale facilities in California, we find that over the next 5 years, expected cost improvements will be essentially offset by the

reductions in public policy support, leading to a projection of an LCOE that remains at its current low level.

References

ABB (2017), "Velocity Suite - Market Intelligence Services," URL `http://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite`.

Barbose, G. L. (2017), "U.S. Renewable Portfolio Standards: 2017 Annual Status Report," Tech. rep., Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA (United States).

Barbose, G. L., N. R. Darghouth, D. Millstein, S. Cates, N. DeSanti, and R. Widiss (2016), "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Tech. rep., Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA (United States).

Bolinger, M., J. Seel, and K. H. LaCommare (2017), "Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States," Tech. rep., Lawrence Berkeley National Laboratory, lBNL-2001055.

BP (2017), "BP Statistical Review of World Energy," Tech. rep., British Petroleum Company, 66th Edition.

Cai, D. W., S. Adlakha, S. H. Low, P. D. Martini, and K. M. Chandy (2013), "Impact of residential PV adoption on Retail Electricity Rates," *Energy Policy*, 62, 830 – 843, doi: http://dx.doi.org/10.1016/j.enpol.2013.07.009, URL `http://www.sciencedirect.com/science/article/pii/S0301421513006526`.

CAISO (2013), "What the duck curve tells us about managing a green grid," `http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf`.

CAISO (2017), "Weekly Performance Reports," URL `http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=22DA08C9-FC10-4337-BE94-5B58527B8396`, california Independent System Operator.

Candelise, C., M. Winskel, and R. J. Gross (2013), "The dynamics of solar PV costs and prices as a challenge for technology forecasting," *Renewable and Sustainable Energy Reviews*, 26, 96–107.

Comello, S., G. Glenk, and S. Reichelstein (2017), "Levelized Cost of Electricity Calculator: A User Guide," `stanford.edu/dept/gsb_circle/cgi-bin/.../GSB_LCOE_User%20Guide_0517.pdf`.

Comello, S., and S. Reichelstein (2016), "The US investment tax credit for solar energy: Alternatives to the anticipated 2017 step-down," *Renewable and Sustainable Energy Reviews*, 55, 591–602.

Comello, S., and S. Reichelstein (2017a), "Cost competitiveness of residential solar PV: The impact of net metering restrictions," *Renewable and Sustainable Energy Reviews*, 75, 46–57.

Comello, S., and S. Reichelstein (2017b), "Economics of Residential Battery Storage Installations," Tech. rep., Stanford Graduate School of Business, working Paper.

Darghouth, N. R., G. Barbose, and R. Wiser (2011), "The impact of rate design and net metering on the bill savings from distributed PV for residential customers in California," *Energy Policy*, 39(9), 5243–5253.

Denholm, P., M. O'Connell, G. Brinkman, and J. Jorgenson (2015), "Overgeneration from Solar Energy in California. A Field Guide to the Duck Chart," Tech. rep., National Renewable Energy Lab.(NREL), Golden, CO (United States).

Economist, T. (2017), "Big Business Sees the Promise of Clean Energy," 14, 59 – 78.

EIA (2017a), "Electric Power Monthly," Energy Information Administration.

EIA (2017b), "Wholesale Electricity and Natural Gas Market Data," URL `https://www.eia.gov/electricity/wholesale/`, energy Information Agency.

EIA (2018), "Annual Energy Outlook 2018," Tech. rep., U.S. Department of Energy, Energy Information Agency.

Fisher, M. J., and J. Apt (2017), "Emissions and Economics of Behind-the-Meter Electricity Storage," *Environmental Science & Technology*, 51(3), 1094–1101, doi:10.1021/acs.est.6b03536, URL `http://dx.doi.org/10.1021/acs.est.6b03536`, pMID: 28001057, `http://dx.doi.org/10.1021/acs.est.6b03536`.

Fu, R., D. Feldman, R. Margolis, M. Woodhouse, and K. Ardani (2017), "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017," Tech. rep., National Renewable Energy Laboratory, nREL/TP-6A20-68925.

GlobalData (2018), "GlobalData Power Database," URL `https://power.globaldata.com/`.

Goodall, C. (2016), "The Switch," Tech. rep., Profile Books, London.

Graffy, S., Elisabeth Kihm (2014), "Does Disruptive Competition Mean a Death Spiral for Electric Utilities," *Energy Law Journal*, 35, 1.

GTM (2017), "US Solar Market Grows 95% in 2016, Smashes Records," `https://www.greentechmedia.com/articles/read/us-solar-market-grows-95-in-2016-smashes-records`.

GTM Research (2017), "U.S. Energy Storage Monitor: Q2 2017 Full Report," Tech. rep., Greentech Media (GTM) Research.

Joskow, P. (2011), "Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies," *American Economic Review Papers and Proceedings*, 100(3), 238 – 241.

Julch, V. (2016), "Comparison of electricity storage options using levelized cost of storage (LCOS) method," *Applied Energy*, 183, 1594 – 1606, doi:http://dx.doi.org/10.1016/j.apenergy.2016.08.165, URL `http://www.sciencedirect.com/science/article/pii/S0306261916312740`.

Kabir, E., P. Kumar, S. Kumar, A. A. Adelodun, and K.-H. Kim (2018), "Solar energy: Potential and future prospects," *Renewable and Sustainable Energy Reviews*, 82, 894 – 900, doi:https://doi.org/10.1016/j.rser.2017.09.094, URL `http://www.sciencedirect.com/science/article/pii/S1364032117313485`.

Kittner, N., F. Lill, and D. Kammen (2017), "Energy storage deployment and innovation for the clean energy transition," *Nature Energy*, 2(17125), –, doi:10.1038/nenergy.2017.125, URL `http://dx.doi.org/10.1038/nenergy.2017.125`.

Lai, C. S., and M. D. McCulloch (2017), "Levelized cost of electricity for solar photovoltaic and electrical energy storage," *Applied Energy*, 190, 191 – 203, doi:http://dx.doi.org/10.1016/j.apenergy.2016.12.153.

Lazard (2017a), "Lazard's Levelized Cost of Energy Analysis," Tech. rep., Lazard Ltd., version 11.0.

Lazard (2017b), "Lazard's Levelized Cost of Storage Analysis," Tech. rep., Lazard Ltd., version 3.0.

Lee, T. D., and A. U. Ebong (2017), "A review of thin film solar cell technologies and challenges," *Renewable and Sustainable Energy Reviews*, 70, 1286 – 1297, doi:https://doi.org/10.1016/j.rser.2016.12.028, URL `http://www.sciencedirect.com/science/article/pii/S136403211631070X`.

Lux Research (2014), "Q1 2014 Supply Tracker," Available by subscription to Lux Research.

Lux Research (2017), "Quantifying Growth Opportunities in the $105 Billion Energy Storage Market," Available by subscription to Lux Research.

McHenry, M. P. (2012), "Are small-scale grid-connected photovoltaic systems a cost-effective policy for lowering electricity bills and reducing carbon emissions? A technical, economic, and carbon emission analysis," *Energy Policy*, 45, 64–72.

Mundada, A. S., E. W. Prehoda, and J. M. Pearce (2017), "U.S. market for solar photovoltaic plug-and-play systems," *Renewable Energy*, 103, 255 – 264, doi:https://doi.org/10.1016/j.renene.2016.11.034, URL `http://www.sciencedirect.com/science/article/pii/S0960148116310035`.

NC CETC (2017), "The 50 States of Grid Modernization," Tech. rep., North Carolina Clean Energy Technology Center, 2017 Q2 Quarterly Report.

NREL (2010), "Building America House Simulation Protocols," Tech. rep., National Renewable Energy Laboratory, nREL/TP-550-49426.

NREL (2012), "PVWatts version 1," `http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/`.

NREL (2015), "PVWatts version 5.2.0," `http://pvwatts.nrel.gov/index.php`.

NREL (2016), "Residential Base Demand Profile based on TMY3," URL `http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-resource/b341f6c6-ab5a-4976-bd07-adc68a2239c4`.

Pawel, I. (2014), "The Cost of Storage How to Calculate the Levelized Cost of Stored Energy (LCOE) and Applications to Renewable Energy Generation," *Energy Procedia*, 46, 68 – 77, doi:http://dx.doi.org/10.1016/j.egypro.2014.01.159, URL `http://www.sciencedirect.com/science/article/pii/S1876610214001751`, 8th International Renewable Energy Storage Conference and Exhibition (IRES 2013).

Reichelstein, S., and A. Sahoo (2015), "Time of day pricing and the levelized cost of intermittent power generation," *Energy Economics*, 48, 97–108.

Reichelstein, S., and A. Sahoo (2017), "Relating Product Prices to Long-Run Marginal Cost: Evidence from Solar Photovoltaic Modules," *Contemporary Accounting Research*.

Schmidt, O., A. Hawkes, A. Gambhir, and I. Staffell (2017), "The future cost of electrical energy storage based on experience rates," *Nature Energy*, 2(17110), –, doi:doi:10.1038/nenergy.2017.110, URL `https://www.nature.com/articles/nenergy2017110`.

Shogren, E. (2017), "In solar scuffle, big utilities meet their match," *High Country News*, 49(14), URL `http://www.hcn.org/issues/49.14/solar-energy-solar-eclipse-big-utilities-meet-their-match-in-solar-scuffle`.

Sivaram, V. (2018), *Taming the Sun: Innovations to Harness Solar Energy and Power the Planet*, The MIT Presss, Cambridge, Massachusetts.

Sivaram, V., and S. Kann (2016), "Solar power needs a more ambitious cost target," *Nature Energy*, 1, 16036.

State of California (2017), "Weekly Statewide Report," URL `https://www.selfgenca.com/home/resources/`, accessed August 29th, 2017.

Swanson, R. (2011), "The Silicon Photovoltaic Roadmap," The Stanford Energy Seminar.

Verdolini, E., L. D. Anadon, E. Baker, V. Bosetti, and L. Aleluia Reis (2018), "Future Prospects for Energy Technologies: Insights from Expert Elicitations," *Review of Environmental Economics and Policy*, 12(1), 133–153, doi:10.1093/reep/rex028, URL `+http://dx.doi.org/10.1093/reep/rex028`, `/oup/backfile/content_public/journal/reep/12/1/10.1093_reep_rex028/1/rex028.pdf`.

WECC (2016), "2016 State of the Interconnection," Tech. rep., Western Electricity Coordinating Council, 5th Edition.