Environmental Research Letters

CrossMark

OPEN ACCESS

RECEIVED
1 October 2014

ACCEPTED FOR PUBLICATION
19 December 2014

PUBLISHED
4 February 2015

Content from this work may be used under the terms of the Creative Commons Attribution 3.0 licence.

Any further distribution of this work must maintain attribution to the author (s) and the title of the work, journal citation and DOI.

LETTER

Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California

Carolyn Davidson, Daniel Steinberg and Robert Margolis

National Renewable Energy Laboratory (NREL), 15013 Denver West Parkway, Golden, CO 80401, USA

E-mail: carolyn.davidson@nrel.gov

Keywords: residential solar, third-party ownership, lease cost

Abstract

Over the past several years, third-party-ownership (TPO) structures for residential photovoltaic (PV) systems have become the predominant ownership model in the US residential market. Under a TPO contract, the PV system host typically makes payments to the third-party owner of the system. Anecdotal evidence suggests that the total TPO contract payments made by the customer can differ significantly from payments in which the system host directly purchases the system. Furthermore, payments can vary depending on TPO contract structure. To date, a paucity of data on TPO contracts has precluded studies evaluating trends in TPO contract cost. This study relies on a sample of 1113 contracts for residential PV systems installed in 2010–2012 under the California Solar Initiative to evaluate how the timing of payments under a TPO contract impacts the ultimate cost of the system to the customer. Furthermore, we evaluate how the total cost of TPO systems to customers has changed through time, and the degree to which contract costs have tracked trends in the installed costs of a PV system. We find that the structure of the contract and the timing of the payments have financial implications for the customer: (1) power-purchase contracts, on average, cost more than leases, (2) no-money-down contracts are more costly than prepaid contracts, assuming a customer's discount rate is lower than 17% and (3) contracts that include escalator clauses cost more, for both power-purchase agreements and leases, at most plausible discount rates. In addition, all contract costs exhibit a wide range, and do not parallel trends in installed costs over time.

Introduction

Residential solar photovoltaic (PV) systems constituted roughly one quarter of the PV capacity installed in the United States in 2013—an estimated 792 MW (GTM Research 2013). While the PV market has been growing rapidly, PV still makes up a very small portion of the total US energy mix. As costs continue to decline and the industry continues to grow, PV could begin to make a substantial contribution to the US energy mix over the next couple of decades (DOE 2012). PV costs have witnessed steady declines over the past several decades, and in the past four years, have nearly halved (Feldman and Friedman 2013). At the same time, PV incentives—including the federal investment tax credit (ITC) and various state, municipal, and utility rebates and tax credits—have substantially reduced the capital requirements to install solar. However, achieving grid parity (the ability to generate electricity at a cost that is less than or equal to the price of purchasing power from the electricity grid) will require additional cost reductions, and these cost reductions will need to be passed on to consumers.

The use of third-party-ownership (TPO) structures for PV has increased considerably over the past several years —from an estimated 10–20% in large US markets in 2009, to an estimated 65% of the US market in 2013 (GTM Research 2013, GTM Research 2014). TPO provides an attractive alternative for consumers who either do not want to assume risks associated with ownership or prefer a low money down payment option. Further, a TPO structure can make financial sense due to the challenges individual homeowners face in monetizing the ITC and modified

© 2015 IOP Publishing Ltd

accelerated cost recovery system (MACRs) depreciation[1]. Under a TPO contract, the contract type and payment structure between the solar customer (homeowner) and the system owner (solar integrator or third-party financer) can take the contractual form of a solar lease or a solar power-purchase agreement (PPA). In a solar lease, the customer pays a specified amount (agreed upon at the outset of the contract) every month, regardless of the system's energy production. In a solar PPA, the customer pays a specified amount per kilowatt-hour (kWh) of generation, so the amount paid varies monthly as a function of generation. Regardless of the type of contract (lease or PPA), customers typically pay a one-time, upfront down payment and monthly payments. The monthly payments can be flat, but in some cases, monthly payments may escalate at a flat rate through time. As a result, the timing of the payments by the homeowner varies by the magnitude of the down payment and monthly payments and the rate at which the payments escalate. Often the installer will provide the homeowner a menu of contract options by varying these parameters, with implied financial tradeoffs. Contract prices can be objectively compared and evaluated by aggregating the sum of down payments and the monthly payments over the duration of the contract and discounting. This total contract price—the real (i.e. 2012 dollars) out-of-pocket cost the customer is contractually obligated to pay—is the key economic measure for residential customers evaluating different TPO PV lease/PPA contracts.

While several current sources track installed PV prices via incentive program data and other market data sources (GTM Research 2013, Barbose *et al* 2014), there is little data on the out-of-pocket cost to the customer over the duration of the contract, which will be substantially reduced by available incentives. Further, while a few studies have evaluated the financial implications of buying versus leasing solar (Rai and Sigrin (2013), Navigant Consulting 2014), to date, no study has focused exclusively on comparing contract costs across the myriad TPO options offered to customers. In both of the above studies, results suggested that leasing provided a higher net present value than ownership—though the difference was more drastic in Rai and Sigrin (2013).

In this study, we use third-party contract data from the California Solar Initiative (CSI) to examine California's residential TPO market during 2010–2012[2]. We use a sample of 1113 contracts to evaluate how TPO contract structures vary and how this translates into a final TPO contract price. We use this data to evaluate the effect of contract structure, magnitude of down payment, and escalation clauses on the total contract price.

The remainder of this article is organized as follows. First, we discuss the study data, our sampling procedure and the method to convert contract terms into a total contract price (2012 dollars). Second, we evaluate contract characteristics: distribution of lease versus PPA and various payment structures (timing of payments and existence of escalation rates). Third, we evaluate TPO contract prices according to the structure and terms in the contract, as well as trends over time and by size. Finally, we assess whether customers appear to be selecting optimal contract structures.

Methodology

The California Public Utilities Commission (CPUC) oversees the CSI, a solar incentive program available to customers of the state's three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The CSI has a $2.4 billion budget to stimulate the deployment of approximately 1940 MW of new solar capacity between 2007 and 2016 via solar rebates for residential, commercial, and utility-scale systems, including systems for low-income residents and multifamily affordable housing. To drive continual PV price reductions, the CSI incentive amount declines incrementally as the program reaches specific levels of cumulative installed capacity (separately specified in each of the three utility areas).

In this analysis, we focus on the residential sector during 2010–2012. During this period, systems in the CSI database represented about 45% of the residential PV installed nationwide (GTM Research 2013, California Solar Statistics 2014). The initial residential customer rebate was $2.50/W in January 2007, and this declined to a final rebate of $0.10/W in 2013[3]. During 2010–2012, incentives for residential systems ranged from roughly $1.50/W–$0.20/W, depending on the utility.

The CPUC requires incentive applicants to submit the installed system cost and documentation supporting that cost. For TPO systems, the CPUC requires installers to submit signed system contracts, which in many cases include the terms of the lease arrangement between the solar customer and the system owner.

The CPUC provided NREL with access to more than 50 000 residential third-party contracts signed

[1] MACRS is the tax depreciation system that allows businesses to recover the cost basis of an asset via annual tax deductions for depreciation, for commercial entities. In contrast to straight-line depreciation, where an asset is depreciated in equal increments annual over the useful life of the asset, MACRS in the case of a solar asset specifies the following 5-year depreciation schedule (20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%).

[2] Over this period, residential third party ownership in California increased from 22% to 69% of new installations (CSI 2014).

[3] The CSI program pays an expected performance-based buydown (EPBB)—a capacity-based incentive that is adjusted based on expected system performance that considers major design characteristics of the system, such as panel type, installation tilt, shading, orientation, and solar insolation available by location. By the end of 2013, CSI rebates had been exhausted in PG&E territory.

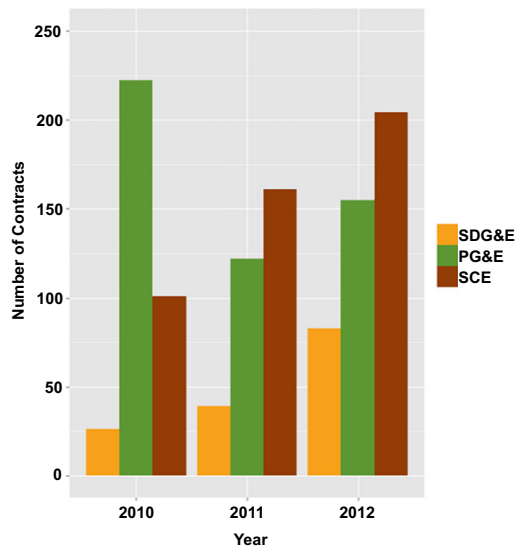


Figure 1. Number of TPO contracts in sample by year and utility.

during 2010–2012[4]. We sampled 2400 residential contracts, with a mean system size of 6.04 W_{DC}[5]. To maximize our ability to make inferences about changes over time, we stratified our sample by quarter, selecting 200 contracts for each quarter from the first quarter of 2010 to the last quarter of 2012, based on the 'completed date' as recorded in the CSI database[6]. This resulted in a sample of 1113 contracts with usable data (the remaining contracts simply provide the signed contract, without down payments or monthly payments), from 162 installers. The distribution of the contracts that did not include usable price terms closely matched the distribution of the contracts with usable price terms by utility and quarter, reducing concerns about selection bias. As a result, this sample can be considered representative of the geography and installation timeframe of the IOUs in California. The distribution of the final dataset by year and utility is displayed in figure 1.

To evaluate contract prices across leases and PPAs with varying payment horizons and escalators, we rely on a discounted cash flow (DCF) methodology. The DCF aggregates all payments, present and future, to assign a total present value to each contract in 2012 dollars, which enables us to compare contracts with different structures. For the rest of the article, we refer to this figure as the 'real contract price' or the 'TPO contract price'. This implies the real (2012 dollars) price of a lease or PPA contract to the homeowner. Future payments are discounted according to a selected discount rate intended to reflect the 'typical' consumer's tradeoff between present and future expenditures. In reality, each consumer will have a unique discount rate which will vary as a function of the opportunity cost of investing capital—i.e., what rate of return a consumer can expect from investing their money elsewhere. The cost of homeowner borrowing provides a reasonable proxy, which can range from low-rate home-equity lines of credit, to high-rate credit cards. However, additional factors present in a new market such as informational deficits, outsized perceptions of risk, aversion to sizable investments and other factors could increase a consumer's discount rate. Further, research has found that discount rates for energy conservation investments are higher than for other investment decisions (Meier and Whittier 1983, Train 1985), perhaps because of higher uncertainty over future conservation savings (Hassett and Metcalft 1993). Less research has evaluated the discount rate for green energy generation investments, but there may be a similar degree of uncertainty. Rai and Sigrin (2013) found implied discount rates as high as 60% for PV adopters in Texas.

Owing to the wide range of theoretically plausible discount rates, we evaluate contracts over a range of discount rates when possible. For figures or calculations relying on one discount rate, we use 7% as a default nominal discount rate. Equation (1) presents the formula used to calculate the price of each contract.

$$\begin{aligned}&\text{Real contract price}(\$2012)_i\\&\quad=\text{Upfront payment}\\&\qquad+\sum_{y=1}^{t}\Big(\big[\text{monthly payment}^{*}(1+e)^{y*}12\big]/\\&\qquad\big[(1+d)^{y-1}\big]\Big),\end{aligned}\tag{1}$$

where i is the individual contract, t is the term length, y is the contract year, e is the escalation rate, d is the discount rate.

In the case of a PPA, the monthly payment is estimated based on assessed average monthly production stipulated in the contract[7]. We assume system production declines of 0.05% per year (Jordan and Kurtz 2011) and calculate the estimated monthly payment as follows:

$$\begin{aligned}&\text{Estimated monthly payment}\\&\quad=\text{estimated monthly production}\times(0.995)^{y-1}\\&\qquad\times\text{PPA rate.}\end{aligned}\tag{2}$$

Based on these calculations, we assign a real contract price to each contract.

[4] The CPUC only began storing digital versions of contracts beginning in 2010, so contract data were not readily available for previous years.

[5] All system sizes are reported in Watts-direct current.

[6] The 'completed date' is the date when the final incentive check was created and sent to the payee. This date may be several months after the contract terms were quoted to the customer.

[7] Companies likely rely on varying methods to estimate the average monthly production. We have no way to validate estimated monthly production or evaluate whether estimates are biased upwards or downwards as this depends on exact location, system design parameters, roof features and shading.

Table 1. Number of TPO contracts by year and type.

	2010	2011	2012
Lease	236	239	299
PPA	113	83	143

Results

Contract-type trends

Within our sample, nearly 69% of third-party contracts were structured as leases, with the remaining structured as PPAs (table 1). This proportion does not change substantially from 2010 to 2012. In our sample, most installers and integrators offered one structure exclusively (or nearly exclusively), although 10 of the 162 installers in our sample offered both leases and PPAs.

Whether a lease or a PPA, some contracts included an escalator clause, in which the base payment escalates at a given rate annually. Escalators are often included to allow revenue to keep pace with inflation[8]. In our sample, PPAs more consistently contained escalator clauses; 53% included an escalator of 3.0% (the most common level) or 3.9% per year. On the other hand, most leases in our sample data did not contain an escalator clause; among those that did, most had a relatively high escalator of 3.9% per year (figure 2). A smaller proportion of leases included escalators in 2012 than in 2010 or 2011, while the proportion of PPAs including escalators increased during our study period.

Contracts also varied in the timing of payments. The amount customers paid up front varied from zero (no-money-down) to the complete contract value (prepaid contract). Some contracts required partial payment up front, with the remaining contract price paid over time. With few exceptions, customers signed 20 year contracts.

Figure 2 shows the payment timing by contract type and year. The timing of PPA payments was weighted more toward the future compared with the timing of lease payments during each of the three years studied, with most PPAs structured as no-money-down contracts. However, the proportion of no-money-down leases increased substantially over the period. It is unclear whether this shift resulted from customer preferences or financer/integrator preferences.

Overall, the lease data suggests consolidation of preferences over time, with a trend towards an increasing percentage of no-money-down lease contracts. A recent trend towards securitization of solar leases and PPAs may play a role in this shift as a contract that is fully prepaid cannot be securitized. However, without additional data, it is not clear whether this shift is a result of customer preferences or financer/integrator preferences.

Contract price analysis

In this section, we evaluate the full price of the TPO system to the end-consumer based on aggregating down payments and monthly payments from each contract to derive a real contract price. We provide an overview of the distribution of these prices, evaluating the value proposition provided by: (1) PPAs versus leases, (2) contracts with varying levels of upfront payments, and (3) contracts with and without escalators. Given that discount rates vary among consumers, we evaluate the contract price over discount rates of 0%–20%. Next, we evaluate effects of system installation year and system capacity on TPO contract price.

Impact of contract structure on contract price

Figure 4 shows the variation in contract price over the range of contracts sampled, assuming a 7% real discount rate. Both leases and PPAs exhibit a wide range. The mean contract price is \$3.04/W for leases and \$4.26/W for PPAs, with standard deviations of \$1.28 and \$1.08, respectively.

Figure 5 provides the distribution based on monthly lease payments per kilowatt and PPA rates per kilowatt-hour in order to provide a metric more comparable to terms found in TPO contracts. This is illustrated for no-money down contracts only. Monthly payments to lease a PV system range from \$12/kW to \$51/kW per month (sample mean \$24.30/kW per month), and PPA rates range from \$0.12/kWh to \$0.35/kWh (sample mean \$0.23/kWh).

PPA versus lease

Figure 6 illustrates the mean contract price, as well as the distribution of prices, for contracts with differing payment schedules. PPAs are consistently higher priced than leases, though much of this difference may be explained by the structure of the contracts; as a sample, leases are comprised of many more prepaid contracts. When comparing across similar payment structures, the difference between PPAs and leases declines as the amount of down payment declines. For the only category in which payment timing is exactly the same-0 down—the difference between PPAs and leases declines to \$0.52/W. Price differences between PPAs and leases, in all cases, are statistically significant. In the discussion section, we explore several hypotheses for this persistent pricing difference.

Contract payment timing: 'no-money-down' versus prepaid

Figure 7 illustrates the price differences in contract payment timing—focusing on leasing, which provides

[8] Nationally, nominal residential electricity prices, on average, have increased by 2.01% annually in the last 20 years (U.S. Energy Information Administration 2011) and are forecasted to increase, on average, 2.20% annually from 2014–2040 (U.S. Energy Information Administration 2014).

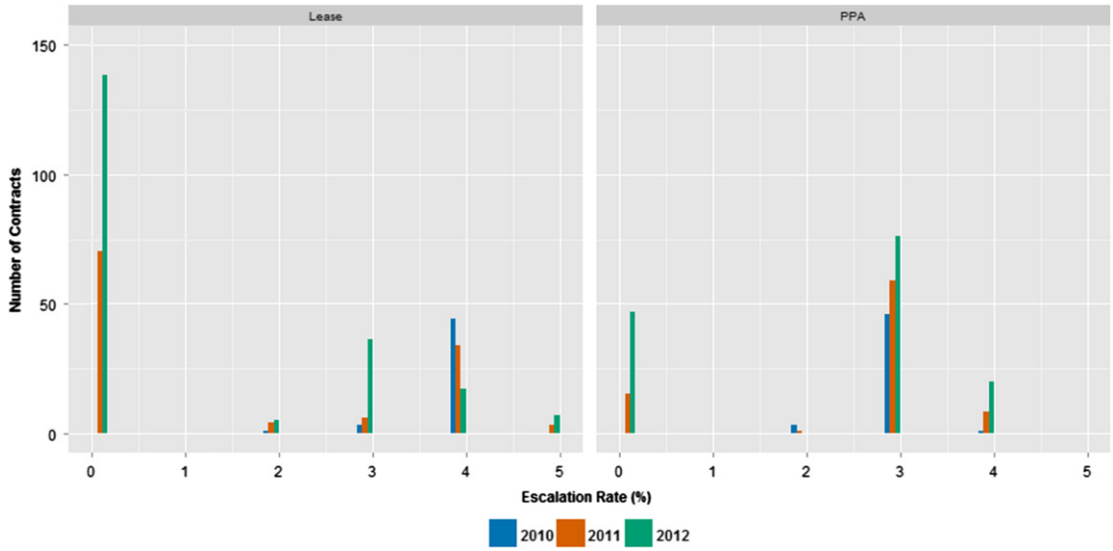


Figure 2. Escalation rate by contract type and year.

Figure 3. Contract payment schedule by contract type and year.

examples of both 'no money down' and fully prepaid contracts, at varying discount rates. As expected, no-money-down contracts cost more over the life of the contract in the lower range of discount rates. The two contract structures equate in price at a discount rate of approximately 17% as illustrated in figure 7.

These data suggest that, on average, a prepaid contract is financially preferable to a no-money-down contract if the consumer's expected rate of return on a competing investment is equal to or lower than 17%[9].

Escalators

As illustrated in figure 3, contracts commonly include payment escalators, although escalators are more common in PPAs than in leases. Figure 8 illustrates the real contract price of PPAs and leases with and without escalators[10]. It suggests that a contract with an escalator costs a consumer more than a contract without an escalator at nearly all plausible discount rates. At a discount rate just under 16%, leases with escalators approximately equate with leases without escalators. On average, PPAs with escalator clauses, at

[9] This omits the additional option of paying a portion of the contract upfront and paying the remainder through monthly payments over a 20-year period. However, focusing on these two categories enables comparison across contracts that have identical payment timing within the two categories—payments are either fully paid upfront, or paid in equal increments over (typically) 20 years.

[10] We combine all contracts with escalators over 2.9% and exclude seven contracts with 1.9% escalators. For both leases and PPAs, this results in a blending of escalation rates, although 94% of escalation rates are 3.9% and 2.9%.

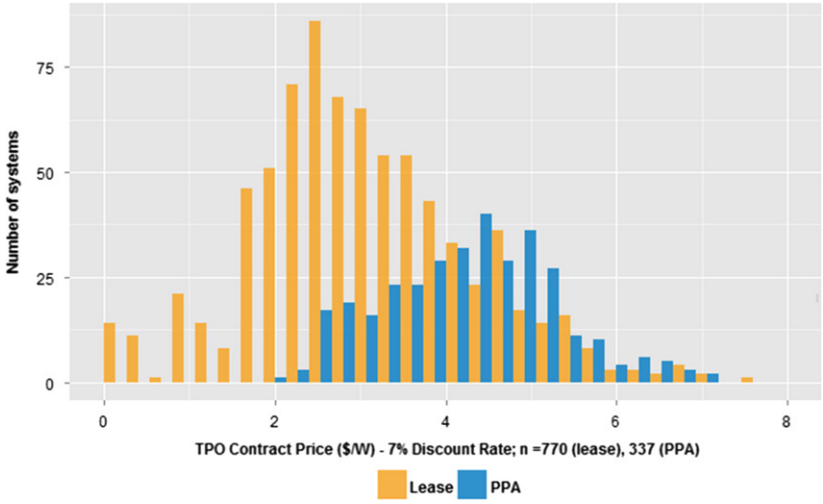


Figure 4. Distribution of contract prices for PPAs and leases (assuming a 7% discount rate).

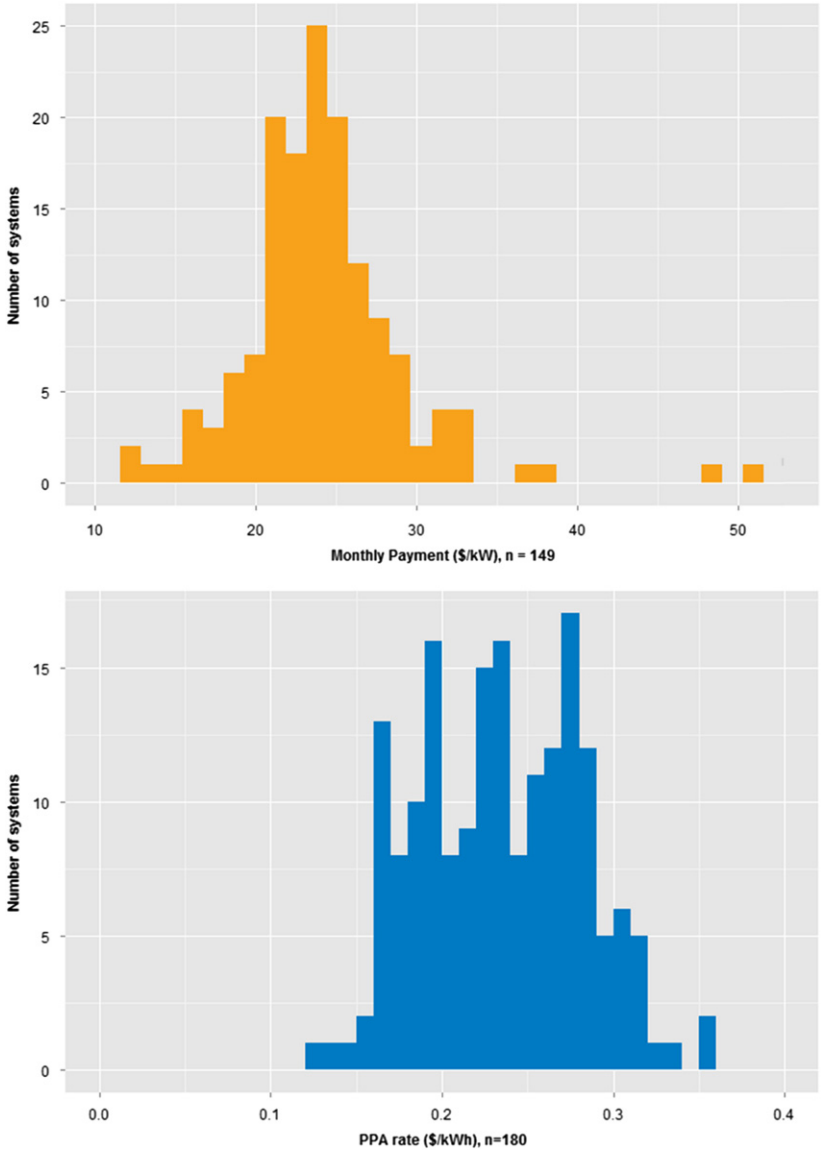
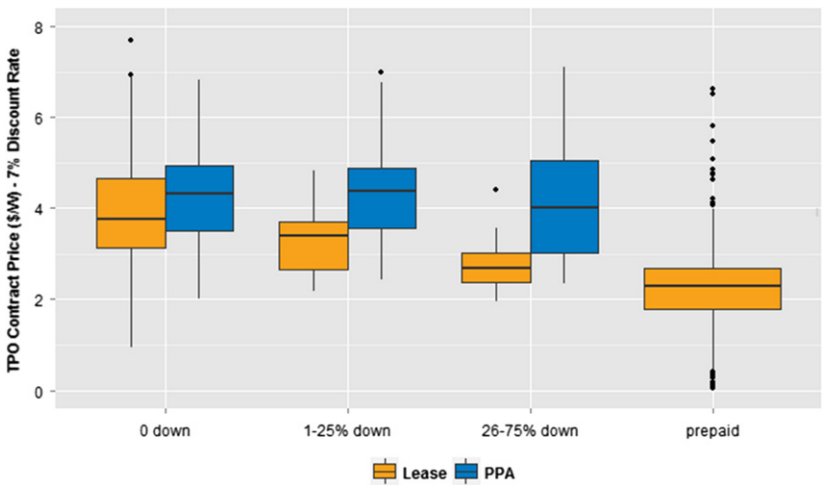


Figure 5. Distribution of monthly lease payments (top) and PPA rates (bottom); no-money down contracts.



	Lease	PPA
	Mean Contract Price ($/W) and observations	
0 down	$3.79 (n=351)	$4.31 (n=251)
1-25% down	$3.39 (n=27)	$4.38 (n=71)
26-75% down	$2.70 (n=46)	$4.01 (n=15)
prepaid	$2.30 (n=346)	NA (n=0)
All contracts	$3.04 (n=770)	$4.27 (n=337)

Figure 6. Real contract price by contract type, discount rate, and payment structure.

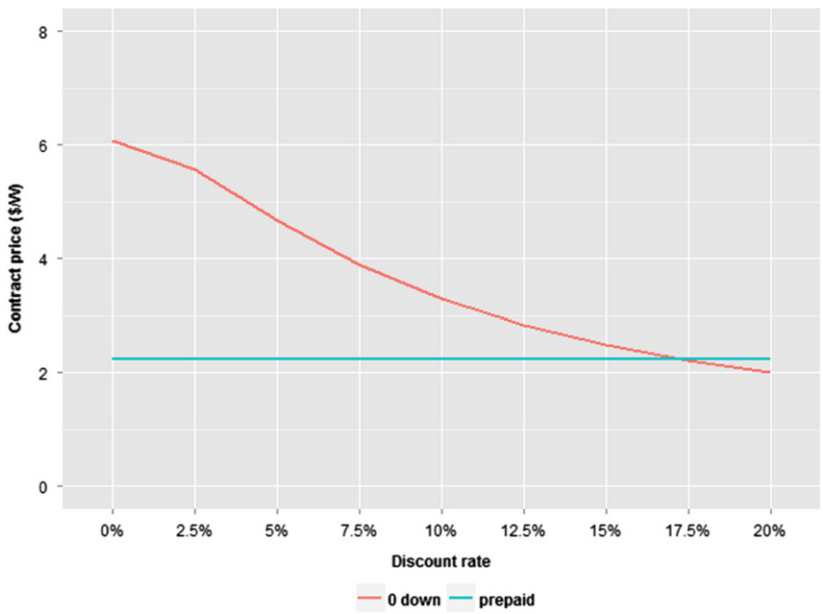


Figure 7. Present-value lease price by payment structure and discount rate.

every discount rate, cost more than PPAs without escalator clauses.

Contract price by reported price, installation year, and system capacity

In this section, we evaluate contract prices in relation to reported PV system prices, year of system installation, and system capacity.

As installed costs decline, we would expect installers to pass a portion of the cost declines along to TPO contracts and reduce prices. Installed prices reported to the CSI program declined by roughly $2.00/W during 2010–2012. Over this same period, the CSI incentive declined by $0.87/W, from a median of $2.40/W in the first quarter of 2010 to $1.53/W in the last quarter of 2012. That is, reported prices declined more rapidly than did incentives. However, the average price of contracts changed less over this period, with both lease and PPA prices *increasing* in 2010–2011, and then PPA prices decreasing in 2012,

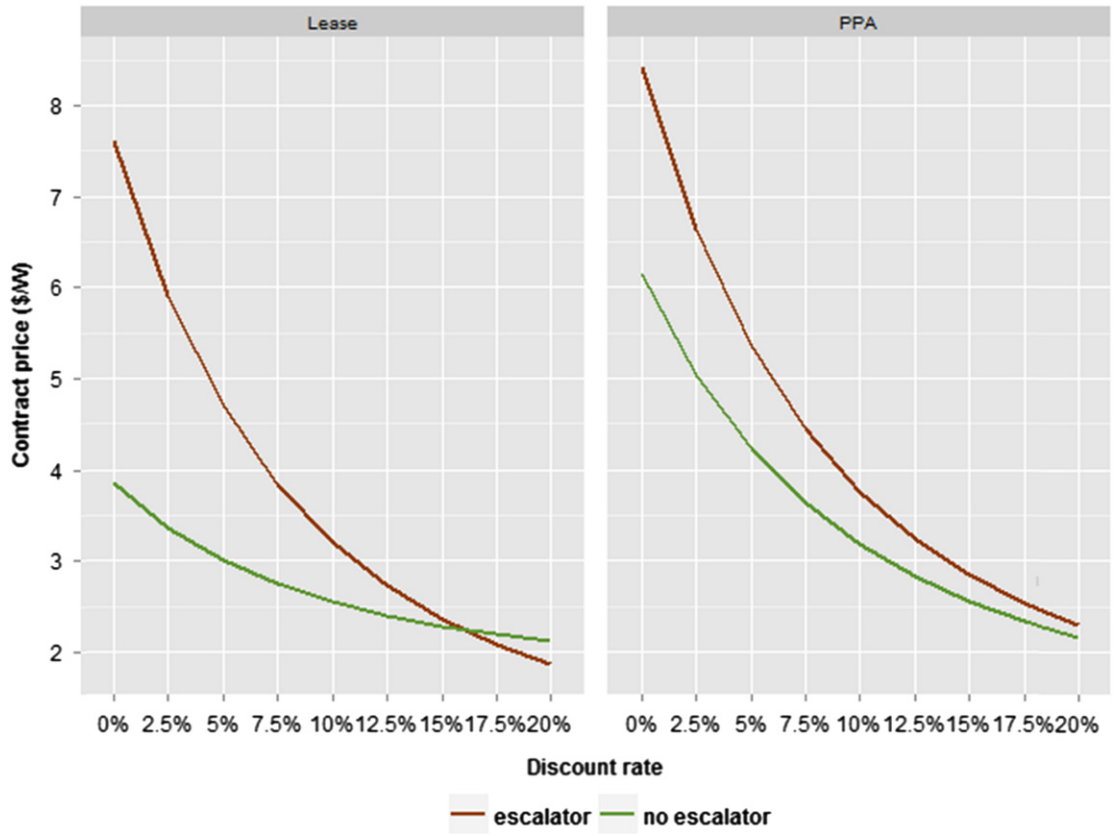


Figure 8. Real contract price by discount rate, contract type, and escalator.

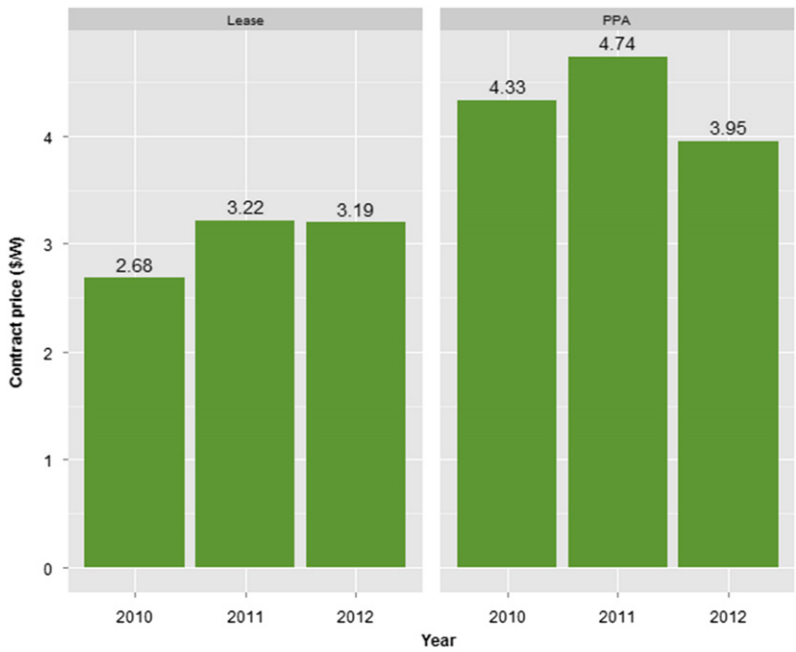


Figure 9. Real contract price (mean) by year for leases (left) and PPAs (right), 7% discount rate.

while lease prices remained flat (figure 9)[11]. While difficult to isolate the cause of these changes without further data, this suggests that factors beyond the installed cost of systems drive trends in contract prices. This may reflect costs associated with the TPO model (acquiring financing, operations and maintenance, system monitoring), outlined in Feldman

[11] The increase in lease prices between 2010 and 2011 was found to be statistically significant at <1%, however the difference between lease prices in 2011 and 2012 was statistically insignificant. The increase and subsequent decrease in PPA prices in 2010, 2011 and 2011, 2012, respectively, are both significant at <1%.

and Friedman (2013), but also likely reflects consumer demand dynamics.

We would also expect to observe economies of scale based on system size in contract prices, because larger systems enable the installer to spread certain fixed or lumpy costs (system permitting, business overhead) over a larger installed system. Barbose *et al* (2014) found that the mean installed reported price, nationwide, for systems of 5–10 kW was approximately \$0.50/W lower than for systems of 2–5 kW in 2012[12]. Similarly, Davidson and Steinberg (2013) found a difference of approximately \$0.70/W, focusing on host-owned systems in California. Our data suggests that contract prices (for leases and PPAs) are higher for small systems (2–5 kW)—statistically significant at <5%, but exhibit no statistically significant difference in price between 5 and 15 kW (figure 10)[13]. There is no notable difference in the distribution of leases and PPAs across the difference size categories—70–75% are between 2 and 7 kW, and ~25% are 7–10 kW for both contract types,

Each of these systems is associated with a corollary publically-reported price. While in the case of host-owned systems, this represents the transaction between the system owner (homeowner) and the installer, in the case of TPO systems, this can represent either the appraised value of the system (by an independent third-party), or the price of an intermediate transaction between the installer and the financer. We would expect reported prices to be higher than the end customers' price as lease/PPA prices net incentives (in this case, the CSI rebate, ITC and MACRS depreciation). The reported prices for the systems in our sample exhibit a wide range from \$5.10/W to \$7.98 \$/W (20th and 80th percentile), with a mean of \$6.38/W. Figure 11 illustrates the distribution of differences between prices reported to the CSI and the calculated contract price for each system in our sample. This illustrates a \$2.96/W difference, on average, though the distribution shows two peaks.While reported price and contract price are distinct metrics, they may be assumed to be strongly correlated given that they represent different transactions for the same system—but this is not the case in our sample. The Pearson correlation coefficient between the two metrics is 0.08.

Discussion and implications

The real contract price (discounted sum of all lease/PPA payments) of both leases and PPAs exhibit a rage of over \$7/W based on a 7% discount rate. Our findings suggest that differences in total contract price are partially driven by differences in contract structure and timing, although we note that a number of other factors may be contributing to these differences as well, not least of which is consumer willingness to pay, and price discrimination by installers.

First, we find that, on average, PPAs cost \$1.23/W more than leases assuming a 7% real discount rate—though this difference declines to \$0.52 when evaluating no-money-down contracts (the majority for the most recent year of data)[14]. Absent differences in payment timing, a number of potential reasons explain why a contract structured as a PPA costs the customer more than a lease, on average. The following are three potential factors:

(a) A PPA, relative to a lease implies two risks to the owner/financer: (1) seasonal revenue difference—lower revenue in winter months when systems are producing less; (2) ongoing production variance. The downside risk of system underproduction (due to cloud cover, low insolation, soiling, malfunction) is transferred from the host to the owner/financer since the host pays only for actual electricity generated. The owner/financer can be expected to be compensated for bearing this risk, and the host customer may be willing to pay a premium to reduce this risk. Further, PPAs typically stipulate a payment cap, regardless of production. The potential to receive 'free' energy if the system produces more than estimated in the contract may increase the host customer's perceived value.

(b) Due to this payment cap, system production may be overestimated (in the contracts) by the owner/financer in order to minimize the likelihood that 'free' energy is delivered to the customer above the cap. Estimates of monthly payments rely on production estimates, so if a system produces less than the amount estimated in the contract, the customer ultimately pays less than anticipated. Without system design parameters, there is no way to validate estimates of system production.

(c) Most companies that provided PPAs did not provide leases, so this could reflect installer-specific practices.

Second, we find that prepaid contracts, on average, cost less than no-money-down contracts at discount rates up to 17%—suggesting that consumers may have very high discount rates. This figure is consistent with the low end of implied discount rates for PV lessors in Rai and Sigrin (2013). Further, since a prepaid contract is analogous to purchasing a system in terms of payment timing, insights can be applied from research on the financial tradeoffs of buying versus leasing in other

[12] This excluded systems categorized as providing an appraised value, rather than a system cost.

[13] For this study, we did not have access to detailed system cost information that would fully characterize the costs of a given system. The cost—particularly the labor requirements—will vary by house based on factors such as system layout and roof structure/obstructions.

[14] This difference is found to be statistically significant at >0.1%.

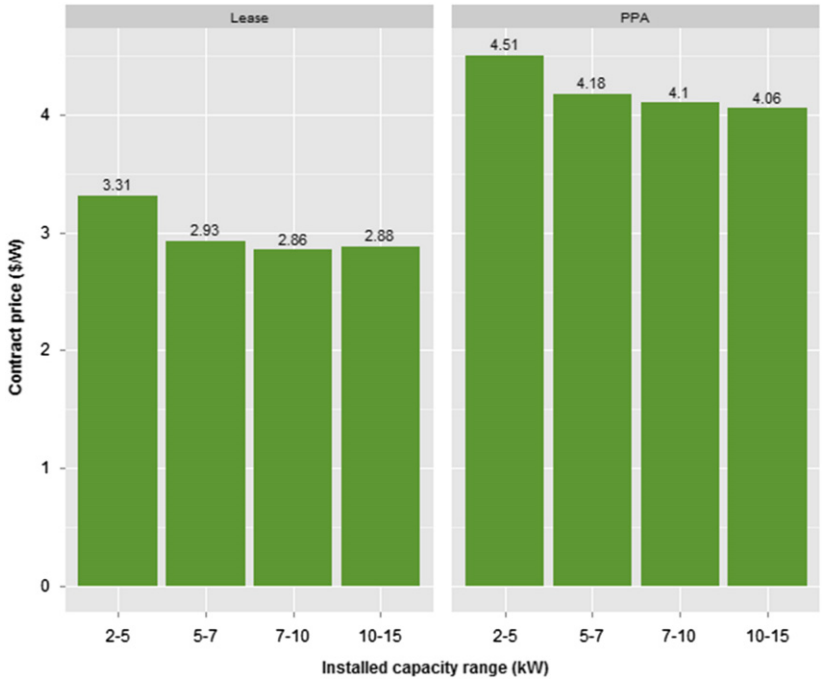


Figure 10. Real contract price (mean) by system capacity for leases (left) and PPAs (right), 7% discount rate.

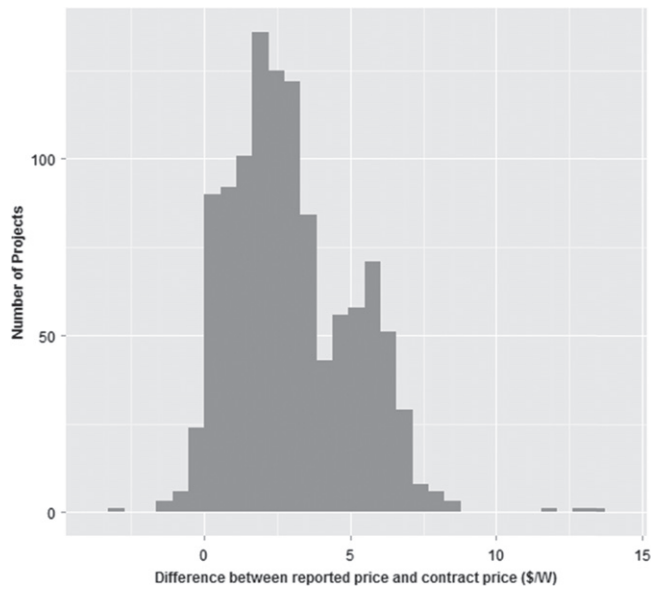


Figure 11. Difference between CSI-reported installed price and calculated contract price, 7% discount rate.

consumer durables. Typically, financial analysis suggests that monthly leasing provides a greater benefit than prepaying a lease (assuming this is analogous to a purchase) when the discount rate that equates the two cash flows is less than the after-tax rate of return that the lessee can obtain on invested capital. Although the implied discount rate in consumer durable markets sometimes appears high, this may be attributed to other consumer values. For example, Dasgupta *et al* (2007) and Nunnally and Plath (1989) found that the implied discount rate for automobile leases were higher than available returns on capital, but Mannering identified frequency of vehicle upgrades as a consumer value that could explain this consumer behavior[15].

However, analogies to other consumer durables are limited in that the adoption decision of a typical consumer durable does not directly offset another

[15] It is possible that some customers may not have the access to inexpensive capital to prepay a lease (savings, home equity lines of credit, etc)—but unlikely, as financers typically require a FICO score >700 to qualify for a lease or a PPA.

substantial household cost. Given a sufficiently high monthly savings on electricity costs, a homeowner may prefer to save their cash or divert it to other purposes, and opt for a monthly lease/PPA, foregoing the relatively higher return by not prepaying the lease[16].

Third, we find that changes in key drivers of installed costs do not necessarily impact the price of a TPO contract to the customer. This is reflected in the fact that TPO contract prices do not consistently decline over the period of analysis, though we do see modest evidence of economies of scale based on system size. In the absence of sufficiently informed customers, firms can price discriminate, selling systems above their marginal cost at prices influenced by consumers' willingness-to-pay. A consumer's willingness-to-pay for PV is, in part, a function of the savings produced by offsetting purchased electricity. However, without access to pre-solar electric bills, we cannot test whether this drives contract prices. As a relatively nascent market, several factors likely preclude competitive TPO pricing, including asymmetric information regarding attributes of PV systems and high search and cognitive costs to seek and compare quotes.

Conclusion

This analysis indicates that the choice of contract type and payment structure may have implications for the total cost to the customer over the lifetime of the contract. Our sample data suggest the following findings:

1. PPA contracts appear to cost more than leases, and this trend persists when contracts are categorized by the amount of upfront payment. This could be driven by several factors, including higher perceived value/lower risk of the PPA contract structure to the customer, company-specific pricing for companies that only offer PPAs, and/or overestimating system production resulting in higher *apparent* PPA payments per watt[17].
2. Delaying lease payment increases the total price to the customer at most plausible discount rates. Specifically, no-money-down contracts are more costly than pre-paid lease contracts assuming a customer's rate of return is lower than 17%.
3. Contracts that include escalator clauses cost more over the lifetime of the contract, for both PPAs and leases, at most plausible discount rates.

Variation in contract prices across different contract structures suggests insufficient customer information and/or very strong customer preferences for certain contract structures. There are likely high search costs and high cognitive costs involved in obtaining multiple bids and comparing bids that might vary by factors such as system size/configuration and perceived quality in addition to variations in contract structure. Future research could better evaluate the degree to which customers are electing the optimal choice by evaluating quotes to the same homeowner, and accounting for the full economic value of the system by understanding a homeowner's pre-solar electricity expenditure.

However, as the market continues to develop, increased competition, particularly in regions with an active solar market, will likely put downward pressure on TPO prices. Tools and resources that facilitate sharing contract bids and/ or comparing multiple bids can reduce information asymmetry by reducing the search cost for consumers and providing data on prices for similarly sized systems.

Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged. Appealing to a broader market, particularly homeowners with lower electricity expenditure and/or in areas with less abundant sunlight may require offering lower-cost contracts to homeowners.

[16] However, in these cases, assuming a homeowner can access a sufficiently low interest rate home equity loan, it would be advantageous to prepay a system with a home equity loan.

[17] PPA contract costs are estimated based on assumed production —and may be ultimately be higher or lower depending on realized system production.

Acknowledgments

The authors would like to thank Camron Barati for his diligent data collection, without which this report would not be possible. The authors would also like to thank James Loewen, Ben Sigrin, Galen Barbose, Ted James and Laura Vimmerstedt for their support and input.

References

Barbose G, Darghouth N, Weaver S and Wiser R 2014 Tracking the Sun V An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013.

California Solar Statistics 2014 http://californiasolarstatistics.ca.gov/(accessed 7/10/2014)

Dasgupta S, Siddarth S and Silva-Risso J 2007 To lease or to buy? A structural model of a consumer's vehicle and contract choice decisions *J. Mark. Res.* **44** 490–502

Davidson C and Steinberg D 2013 Evaluating the impact of third-party price reporting and other drivers on residential photovoltaic price estimates *Energy Policy* **62** 752–61

DOE (United States Department of Energy) 2012 SunShot Vision Study February 2012

Feldman D and Friedman B 2013 *Financing, Overhead and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing of Residential and Commercial Photovoltaic Systems* NREL/TP-6A20-6040 (Golden, CO: National Renewable Energy Laboratory)

GTM Research 2013 US Solar Market Insight. The Vendor, Installer and Financier Landscape 2013–2016, 1–70

GTM Research 2014 US Residential Solar Financing 2014–2018

Hassett K A and Metcalft G E 1993 Energy conservation investment: do consumers discount the future correctly? *Energy Policy* **21** 710–6

Jordan D C and Kurtz S R 2012 Photovoltaic degradation rates—an analytical review *Prog. Photovolt.* **21** 12–29

Meier A and Whittier J 1983 Consumer discount rates implied by purchases of energy-efficient refrigerators *Energy* **8** 957–62

Navigant Consulting 2014 *California Solar Initiative: Third-Party Ownership Market Impact Study* (Navigant Consulting)

Nunnally B and Plath D 1989 Leasing versus borrowing: Evaluating alternative forms of consumer credit *J. Consum. Affairs* **23** 383–92

Rai V and Sigrin B 2013 Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets *Environ. Res. Lett.* **8** 014022

Train K 1985 Discount rates in consumers' energy related decisions: a review of the literature *Energy J.* **10** 1243–53

U.S. Energy Information Administration 2011 2011 Annual Energy Review

U.S. Energy Information Administration 2014 Annual Energy Outlook 2014(www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=4-AEO2014&region=0-0&cases=full2013full-d102312a,ref2014-d102413a)