

The Federal Investment Tax Credit for Solar Energy: Assessing and Addressing the Impact of the 2017 Step-Down

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Executive Summary: Findings and Recommendations

Current legislation (26 USC §25D and 26 USC §48) stipulates that the federal Investment Tax Credit (ITC) for solar installations will be reduced from its current 30% rate to 10% on January 1, 2017 for solar energy systems.¹ The ITC was initially created as part of the Energy Policy Act of 2005 (P.L. 109-58) and extended through December 31, 2016 with the Emergency Economic Stabilization Act of 2008 (P.L. 110-343). Since its inception, the solar ITC has been a significant federal mechanism to spur rapid growth in the deployment of solar PV systems. In conjunction with the depreciation tax shield provided through the Modified Accelerated Cost-Reduction System (MACRS), the ITC has played a significant role in promoting new investments in solar installations and manufacturing capacity for solar systems, including modules and electric systems. The results have been considerable for the U.S. In 2006, 105 MW of photovoltaic (PV) installations were installed with an average installed PV system price of \$7.90/W. In 2013, 4,776 MW of new PV were installed an average PV system price of \$2.93/W.

The first four chapters assess the impact of the anticipated ITC step-down on the competitiveness of solar energy across the U.S., and evaluate alternative ‘phase-down’ scenarios. We focus our analysis on five key states: California, Colorado, New Jersey, North Carolina and Texas. These states were chosen to represent the diversity of solar energy market maturity, insolation rates, labor/material costs, and market structure. For each state, the solar industry is examined separately for three market segments: residential rooftop (< 10 kW capacity per installation), commercial rooftop (10 kW – 1000 kW) and utility scale (>1 MW). For utility-scale systems, we consider two technology platforms: c-Si (silicon) and CdTe (thin film) module-based systems, in conjunction with 1-axis tracking configuration, given their more favorable capacity factors.

We rely on the Levelized Cost of Electricity (LCOE) metric to assess the absolute value and relative cost-competitiveness of each system under different incentive regimes. The LCOE identifies the break-even value that a power producer would need to obtain per

¹The analysis in this report focuses exclusively on the tax credits available in connection with *corporate income taxes*. The 30% ITC is currently also available for individual taxpayers, yet this credit is scheduled to expire entirely by 2017.

kilowatt-hour (kWh) as sales revenue in order to justify an investment in a particular power generation facility. We calculate LCOEs by segment and by state, taking a “bottom-up” cost estimation approach. Accordingly, we estimate the cost of each solar energy system subcomponent, with the aggregate then providing the initial (2014) estimate for the system price and operations- and maintenance cost. For each state/segment combination, the LCOE is assessed relative to a comparison price, given by the appropriate benchmark for a particular segment in a specific state. For instance, for commercial-scale installations in Colorado, the comparison price is determined by the rate charged per kWh to commercial users by energy service providers in Colorado.

To project cost declines in future years, we forecast the LCOE for different segment and states by applying a cost dynamic to each component of the solar PV system based on a function of time. For PV modules, we rely on a model of *economically sustainable price* based on manufacturing cost fundamentals. For inverters, balance of system (BOS) and operations and maintenance costs, we apply an exponential decay function, the latter two adjusted for state-level differences in labor, material and margins costs. In all cases, element and component costs are assumed to decrease with time due to efficiency gains and accumulated experience. The rate of change at which cost decrease is specific to the segment and geography – especially BOS – based on local market conditions (labor, materials, etc.) and competitiveness.

At current (2014) costs, the current 30% ITC and ignoring any state-level incentive, we obtain the following results: (i) utility scale installations are not cost-competitive across the entire spectrum of states considered when the LCOE of these installations is compared to the wholesale price of electricity, (ii) Commercial-scale installations are currently well positioned in California and marginally competitive in Colorado and Texas when their LCOE is compared to the average commercial retail electricity rates in those states (iii) Residential installations are comfortably competitive in California, breaking-even in Colorado and North Carolina, but not yet competitive in Texas and New Jersey when compared with retail rates and presuming that net metering remains in place. At the same time, we emphasize that if the step-down to a **10% ITC were to occur at the beginning of 2017, solar PV would become uncompetitive across the board** for all segments and geographies considered. This projection already anticipates continual and sustained cost decreases in the intervening two years.

These findings suggest that if the ITC step-down were to happen as currently specified by law, there would be a ‘boom-and-bust’ cycle with a “cliff” in early 2017. To avoid such an undesirable and disruptive industry cycle, we propose and evaluate two alternative ‘phase-down’ scenarios, both of which adhere to the following conceptual guidelines:

- Federal incentives to diminish over time
- Quid pro quo relative to the current ITC rules
- In the *short-run* (2017-2020), the industry would be *better-off* than under the anticipated step-down
- In the *medium-run* (2021-2024), the industry would be *equally well-off* as under the anticipated step-down
- In the *long run* (past 2024), the industry would be *worse-off* than under the anticipated step-down
- Targeted incentives for different segments

The first of the two scenarios we evaluate is referred to as the *20/10/0 Scenario*. It entails a scheduled phasing-out of the ITC in its current form over an 8 year period. The second alternative, referred to as the *ITC Choice Scenario*, works on the same time-line, but offers the alternative of the ITC in the form of a fixed dollar amount per Watt installed. The *20/10/0 Scenario* proposes a 20% ITC 2017–2020, 10% ITC 2021–2024 and no ITC thereafter. The *ITC Choice Scenario* would provide for the years 2017-2020 for each installation a choice between a 20% tax credit or 40¢/W, 2017–2020, and 10% or 20¢/W, 2021–2024 and no ITC thereafter. Both of the proposed scenarios recognize that the years 2017–2020 are most critical to the solar PV industry as incentives in the near-term are needed most assuming that the industry continues to come down the learning curve it has been on for the past several decades.

By construction, the *ITC Choice Scenario* entails additional flexibility relative to a traditional percentage-based ITC. In absolute dollar terms, a percentage-based ITC grants the largest subsidy to the highest-cost segment – namely the residential segment. At the same time, a percentage-based ITC amounts to a form of cost-sharing. For the values examined in our policy scenario, the residential segment would choose the percentage-based ITC across

the eight years between 2017-2027, while the commercial- and utility segments would opt for the lump-sum fixed-dollar amount ITC. Provided the pace of cost reductions shown in recent years continues, a fixed 40¢/W in 2017 (20¢/W past 2020) would be effective in maintaining cost competitiveness for the utility- and commercial segments throughout 2024 assuming other conditions, as explained, are met. Beyond 2024, the ITC should no longer be needed for most of the segments and regions examined in our study. One exception to this finding is that, without any federal ITC past 2024, electricity from residential solar installations is projected to be noticeably more expensive (approximately 2-3 cents per Kilowatt-hour) than the projected retail electricity rates in several of the states we examine. To that end, state-level incentives would be required in those states past 2024 to maintain the viability of new residential solar PV installations.

Our calculations show that for the scenarios examined in this study the diminishing ITC support would be just sufficient - with little or no margin to spare - to sustain the competitiveness and current momentum of the solar industry. By smoothing the trajectory of reduced federal support, our policy alternatives should at least mitigate the anticipated 'boom and bust' cycle that is likely to emerge under the current policy. Furthermore, in contrast to the current policy, we envision the complete elimination of the solar ITC past 2024. From a governmental revenue perspective, there remains the need for scoring these proposals in terms of foregone tax revenues and foregone expenditures.

Chapter 5 of this report, contributed by Felix Mormann and Dan Reicher, provides a qualitative discussion of policy mechanisms that are either modifications or alternatives to the current ITC rules. The first part of the chapter surveys key characteristics of the 26 USC §48 solar ITC and identifies challenges posed by the use of tax credits to support solar PV deployment. The second part of Chapter 5 explores qualitative modifications, such as making the solar ITC tradable and/or refundable to improve the programs efficacy and efficiency. Thinking outside the tax-credit box, the third part proposes two other options – master limited partnerships (MLPs) and real estate investment trusts (REITs) – for federal tax policy to cost-efficiently promote the build-out of clean, low-carbon solar PV capacity. The chapter concludes with a three-part recommendation that would help the solar industry continue on its growth trajectory over the next several years, while it transitions to lower-cost financing.

To summarize, the analysis and findings reported in Chapters 1-4 are based on research by Stephen Comello and Stefan Reichelstein. Chapter 5 is the contribution of Felix Mormann and Dan Reicher. Finally, Karim Farhat contributed the material in Appendix D on state-level incentives for solar PV.

1 Cost Competitiveness of Solar PV as of 2014

Industry Segments and U.S. States

To assess the impact of the anticipated step-down of the federal investment tax credit (ITC) in 2017 on the competitiveness of solar energy systems across the U.S., we examine the solar PV industry differentiated according to geography and segment. We focus our analysis on five key states: California, Colorado, New Jersey, North Carolina and Texas. These states were chosen to represent the diversity of solar energy market maturity, insolation, labor/material rates, market structure and prevailing competitive prices. Within each state, the solar industry is classified into three segments: residential rooftop (< 10 kW capacity per installation), commercial rooftop (10 kW – 1000 kW) and utility-scale installations (> 1 MW). For utility-scale installations, we consider 1-axis tracking configurations, given their more favorable capacity factors using either c-Si (crystalline silicon) or CdTe (thin film) solar panels. Overall, our analysis covers $5 \times 4 = 20$ state/segment applications. Our principal measure of cost and cost competitiveness is the following levelized cost of electricity (LCOE).

Cost Measure: The Levelized Cost of Electricity

The LCOE concept is commonly used in the energy literature to compare the cost effectiveness of alternative energy sources. LCOE accounts for all physical assets and resources required to deliver one unit of electricity output. Fundamentally, the LCOE is a break-even value that a power producer would need to obtain per kilowatt-hour (kWh) as sales revenue in order to justify an investment in a particular power generation facility. The 2007-MIT study on “The Future of Coal” provides the following verbal definition: “*the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors*”.

The preceding definition makes clear that the LCOE takes an investor-perspective. This life-cycle cost measure reflects the time-value of money and identifies a break-even figure that must be attained as revenue per kWh *on average* in order for equity investors and creditors to attain a zero-net-present value with their investments, and thereby a competitive return on their capital. Following the presentation in Reichelstein and Yorston (2013), we represent the LCOE in the form:

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

where

- f denotes the time-averaged fixed operating and maintenance costs (in \$ per kWh)
- c denotes the unit cost of capacity related to the solar system (in \$ per kWh)
- Δ represents a tax factor that captures the effect of corporate income taxes and tax subsidies (in %).

For a detailed description of the LCOE, the reader is referred to Appendix B on page 62. We note in passing that the LCOE as presented here does not account for the fact that wholesale electricity prices and the rates paid by commercial-scale customers can vary considerably across the hours of the day and across different seasons. At the same time, solar PV systems will frequently generate most their output at times when real-time electricity prices tend to be relatively high, thus creating a *natural synergy* for solar power. The recent study by Reichelstein and Sahoo (2015) describes a method for adjusting the LCOE to account for these synergies created by positive correlation between the temporal fluctuations in electricity prices and solar PV generation patterns. For select locations in California, Reichelstein and Sahoo (2015) conclude that the effective LCOE of solar installations is about 10% lower than suggested by a traditional LCOE analysis based only on broad averages. In future research, it would be useful to quantify this adjustment factor for the individual states examined in our current analysis.

Model Input Parameters

The input variables required to calculate the LCOE fall into three types: **Physical input variables**, **Price-and cost inputs** and **Policy variables**. Table 1 lists these parameters by type. For a more comprehensive list, see Appendix A on page 61. As stated above, our analysis calculates the LCOE by different applications – differentiated by segment and state – over time, based on forecasted values of the component costs (and presumed ITC regime). Hence, LCOE components that are expected to change over time are denoted with subscript t .

Table 1: Input parameters to the LCOE calculation model.

Variable	Description	Units
CF	DC-to-AC capacity factor	%
DF	DC/AC derate factor	%
x_t	System degradation factor in period t	%
T	Useful economic life	<i>years</i>
PP_t	Module price (DC) during period t	\$/W
$IP(t)_i$	Inverter price (DC) during period t for segment i	\$/W
$BOS(t)_{ij}$	Balance of system cost during period t for segment i , U.S. state j	\$/W
SC_t	System cost (residential) during period t	\$/W
m	Transaction margin (residential)	%
SP_t	System price during period t	\$/W
FMV_t	Fair market value of system during period t	\$/W
μ	Ratio of FMV_t/SP_t	#
c_t	Unit capacity cost during period t	\$/kWh
F_t	Fixed operation and maintenance cost during period t	\$/kW-yr
f_t	Average fixed operations and maintenance cost during period t	\$/kWh
r_t	Weighted average cost of capital during period t	%
α	Effective corporate tax rate	%
Δ_t	Tax factor during period t	#
$LCOE_t$	Levelized cost of electricity during period t	\$/kWh
CP_t	Comparison/competitive market price of electricity during period t	\$/kWh
i_t	Federal investment tax credit during period t	%
CC_t	Avoided emissions cost during period t	\$/W

Cost Components by State and Segment

Among the three elements of the LCOE formula in equation (1) is the unit cost of capacity, c , derived from the system price of the energy system. To determine the system price by state and segment, a “bottom-up” cost estimation approach is employed. Such an approach is very similar to an engineering cost estimate approach, where the cost of each system subcomponent is determined and aggregated to arrive at the system price. This method seeks to remove valuation distortions caused by market dynamics, financing methods and/or short term supply/demand forces (Goodrich, James, and Woodhouse, 2012). Since the LCOE

takes an investor perspective, we define this bottom-up cost estimate as the *sales price* (in a given state and segment) that a turnkey installer would charge a would-be investor for a new solar energy system.

The three components for the system price are the solar module, the inverter and the balance of system (BOS). Solar modules are viewed as commodities that exhibit negligible cost differences across geographies and segments within the U.S. As such, on a \$/W basis, all modules are taken to be of equal cost across each configuration. As for inverters, it is assumed that these too are considered commodities, however differing in cost (\$/W basis) across segment (i.e. residential, commercial and utility).

The remaining component - BOS - exhibits cost differentiation across segments and geography. As such, the BOS cost component is further classified into subcomponents to create a more accurate set of estimates reflecting geographic- and segment-specific conditions. The subcomponents of the BOS explored are: combiners, wiring, racking and mounting, structural/foundations (utility), AC interconnection, engineering/design, labor, SG&A and margins.

Multiple data sources were used to parameterize the model. Solar PV module prices were derived from an economically sustainable module price (ESP) analysis based on the analysis in Reichelstein and Sahoo (2014) (see also Appendix E on page 80 for a complete account of their methodology). This ESP is the long term global panel price assuming equilibrium across all demand centers in the world. The estimates for current (2014) average inverter prices were determined through select interviews and analyst reports (GTM Research, 2014; BNEF, 2014). National averages of BOS subcomponents by segment were determined through select interviews and analyst reports (Lux Research, 2013; GTM Research, 2014; NREL, 2014; SNL Financial, 2014). These national averages were then adjusted using the RSMean City Cost Indexes (RSMMeans, 2014), which reflects relative labor (electrical, general, professional), material (electrical and structural) and margin (supply chain margins, overhead, etc.) costs in specific locations. The specific cities used to adjust national BOS subcomponent costs to state BOS subcomponent costs are: Fresno (CA), Boulder (CO), Atlantic City (NJ), Charlotte (NC) and Austin (TX).

The prices of modules, inverters and BOS by segment and state are aggregated to arrive at *system price* for commercial - and utility-scale systems. For residential systems, we also considered the cost of module, inverters and BOS to arrive at a *system cost*. Given

that the majority of residential solar energy systems installers and developers also have an investment role (i.e. through third-party ownership structures), an additional margin must be included to determine an “arm’s length” price that would otherwise be charged in a market transaction. Depending on the maturity of the market, this margin has been assumed to range between 10-30%.

With respect to O&M costs, national averages were again determined using a bottom up approach by segment (Jordan, Wohlgemuth, and Kurtz, 2012; SNL Financial, 2014; GTM Research, 2014) using data from interviews and source/reports. O&M costs include module replacement, inverter replacement, general maintenance and an escalation factor. Like BOS, these were then adjusted for geography using appropriate City Cost Indexes. For detailed information on data sources initial variable values, the reader is referred to Appendix A on page 61.

The Tax Factor

Provided the unit cost of capacity, c (derived from the system price) and the O&M cost f , the final element of the LCOE measure is the tax factor, Δ , as described in the opening subsection. The tax factor incorporates the effects of depreciation tax shields, effective corporate income tax and investment tax credit(s). Absent any ITC, the tax factor amounts to a “mark-up” on the unit cost of capacity. While the tax factor typically exceeds 1, it can be reduced below 1 through an ITC. Table 2 shows the relative values of the tax factor under different depreciation and ITC combinations.

Table 2: *The tax factor, Δ , for different depreciation schedules and ITC values, assuming $\alpha = 40\%$.*

Depreciation Method	ITC	Tax Factor
20 year; 150% Declining Balance	0%	1.32
MACRS	0%	1.12
MACRS	10%	0.98
MACRS	30%	0.71

All else being equal, the preceding table shows that a 30% ITC provides a 37% reduction in the cost of capacity needed to generate one kWh of electricity relative to a 0% ITC

scenario, and a 27% reduction relative to a 10% ITC scenario.

Cost Competitiveness at the End of 2014

We calculate the LCOE by segment and by state for the year 2014 and compare it to its appropriate reference price, shown in Table 3. The so-called ‘Comparison Price’ is the average residential, commercial or wholesale electricity price, respectively, in a given state. Here we rely on the projections of the EIA AEO 2014 (EIA, 2014). For a listing of input parameters by segment and by state, the reader is referred to Tables A2, A3 and A4 in Appendix A.

Table 3: *LCOE @30% ITC (LC_{30}) versus Comparison Price (CP) in 2014*

	Utility (c-Si)		Utility (CdTe)		Commercial		Residential	
	LC_{30}	CP	LC_{30}	CP	LC_{30}	CP	LC_{30}	CP
California	7.38	5.75	7.72	5.75	11.01	15.44	12.72	17.37
Colorado	6.89	5.36	7.20	5.36	9.79	9.50	12.00	11.94
New Jersey	9.26	6.36	9.64	6.36	13.66	12.32	22.36	15.04
North Carolina	7.67	6.12	8.04	6.12	10.42	9.50	12.15	12.19
Texas	7.23	4.78	7.59	4.78	9.74	9.55	13.98	10.18

All figures in 2014 cents per kWh

We conclude that under current conditions, there are only a few applications where solar PV is competitive as of today on the basis of federal tax incentives only. While solar energy systems have not yet reach broad ‘grid-parity’, it is critical to note how significant the reduction in costs (and prices) over the past 5 years have been. This holds true at the individual component level of the systems and the total system across all segments and geography. Given the cost reduction due to gains in efficiency, experience and regulatory

expediency, our analysis assumes that costs will continue to decrease. So while there may only be few instances of cost competitiveness now, the more relevant question is how solar energy systems will be positioned at the end of 2016, when the current ITC is scheduled to step-down from 30% to 10%.

2 Cost Competitiveness by the End of 2016

To project the cost competitiveness at the beginning of 2017, we make the following assumptions in forecasting the cost reductions of individual solar system components.

Price Dynamics for Modules

To obtain a forecast of sales prices for solar PV modules, we adopt an analytical approach that seeks to determine the *economically sustainable price* (ESP). The ESP is the expected competitive market price of PV modules that would result if the industry were in equilibrium. The ESP concept essentially seeks to gauge the full cost of manufacturing solar PV modules and adds a competitive mark-up to this cost measure. Reichelstein and Sahoo (2014) rely on reported capacity and manufacturing costs based on financial accounting statements of solar PV manufacturers as data inputs in a dynamic model of competition to infer equilibrium prices in an environment with falling production costs. In particular, they both forecast and backcast the economically sustainable equilibrium prices, and compare it to the observed average sales price (ASP) and the widely accepted “80% learning curve”. As shown in Figure 1, beginning in 2011, the ESP significantly exceeded the observed ASP for most quarters, consistent with widespread reports that the industry was suffering from manufacturing capacity. At the same time, the findings in Reichelstein and Sahoo (2014) point to reductions in manufacturing costs that are even faster than suggested by the 80% learning curve. We rely on these estimates to extrapolate a trajectory of future equilibrium prices (ESPs) to which ASPs should converge over time. Accordingly, as illustrated through the dashed lines Figure 1, our forecasts assume that module prices will remain flat until 2017 and then decrease according to a 78% constant elasticity learning curve consistent with long-term fundamental trend line in Reichelstein and Sahoo (2014).

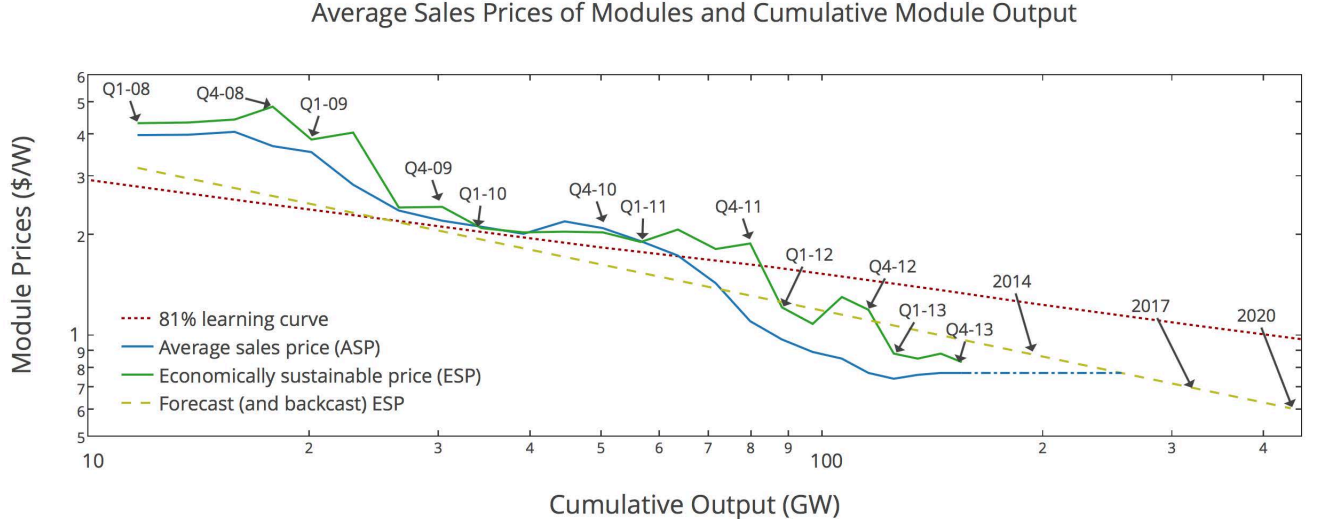


Figure 1: *Historical ASP and ESP of modules and forecast of ESP, given cumulative module output.*

Price Dynamics for Inverters and BOS

As described in the previously, we postulate a dynamic that projects price reductions as a function of time. Historical data and expert interviews, coupled with analyst reports were used to calibrate a baseline trajectory for inverters and BOS costs. For both components, an exponential decay function, as given in Equation (2), is used to describe the cost reduction over time. Such a function allows for costs to evolve at a rate proportional to its current value, resulting in a slowing of incremental cost reductions over time.

$$C(t)_{ij} = C(2014)_{ij} \cdot e^{-\lambda_{ij} \cdot t} \quad (2)$$

where:

- $C(t)_{ij}$ Cost of component for i segment, j state in period t
- $C(2014)_{ij}$ Cost of component for i segment, j state in 2014
- λ_{ij} Rate of cost reduction during period t

Since inverters are considered a commodity, cost differences are assumed be only across segment and not across states (i.e. these variables are only a function of i , not j). The functional form for the cost of inverters is then given as:

$$IP(t)_i = IP(2014)_i \cdot e^{-\lambda_i \cdot t} \quad (3)$$

Conservative annual cost reduction estimates for inverters of 2.5%, 2.3% and 2% were assumed over the period 2014 – 2024 in the residential, commercial and utility segments, respectively.

As for $BOS(t)$, national average subcomponent cost projections were made available through a mix of industry and analyst expert elicitations, in addition to a review of analyst reports including: GTM Research (2014); SNL Financial (2014); Lux Research (2013); NREL (2014). The furthest forecast provided was to 2020 (Lux Research, 2013), whereas others ranged from 2016 to 2018. In addition, historical cost data was available from analyst reports. The arithmetic mean of each subcomponent cost per year, per segment was used to create a segment-specific national average set of BOS subcomponents. In order to determine state-level averages, forecasted national average subcomponent costs were adjusted using the City Cost Indexes (RSMeans, 2014), similar to what has been described previously. Subcomponent costs – now adjusted for geographic differentiation – were aggregated by segment, by state to determine $BOS(t)_{ij}$. An exponential decay function was applied to each $BOS(t)_{ij}$ set, thus enabling the determination of λ_{ij} for each segment in each state. The functional form of Equation (2) was used to project $BOS(t)_{ij}$ across the entire period of analysis for each segment and state (2014 – 2024). Annual cost reduction estimates of 5 – 5.2%, 4.2 – 4.4% and 3.9 – 4% were obtained over the period 2014 – 2024 for BOS in the residential, commercial and utility segments, respectively. For $BOS(2014)_{ij}$ values (initial segment/state specific BOS values), see Tables A2, A3 and A4 in Appendix A.

Dynamics of Operating & Maintenance Costs

Operating and maintenance (O&M) costs, which are relatively small compared to capacity related costs, are assumed to decrease at an annual rate of 5% across all applications.

Cost Competitiveness at the End of 2016

Given the cost dynamics of PV modules, inverters, BOS and O&M outlined above, we are now in a position to forecast the capacity- and operational costs in future years. Incorporating the dynamic of the individual cost components, we calculate the LCOE for each segment and state. Table 4 shows the resulting LCOE figures for the end of year 2016 next to the applicable comparison price as well as the hypothetical LCOE that would have been obtained with a 10% ITC.

There are several noteworthy findings emerging from Table 4. The first is the cost decrease across all segment/state combinations from 2014 (see Table 3) to 2016, assuming a constant ITC of 30%. The second is the (expected) increase in LCOE from the $LCOE_{30}$ to the $LCOE_{10}$ regime. For most applications, solar PV is far from competitive under the $LCOE_{10}$ regime at the end of 2016. The third (and most nuanced) point concerns the magnitude of the LCOE increase from the $LCOE_{30}$ to the $LCOE_{10}$ regime in the residential segment, *relative to the other segments*. The current form of the ITC allows investors to claim the tax credit based on the fair market value of the system installed (FMV). This is relatively straightforward if the investor and the solar developer are two separate parties that transact with each other on an arm's-length basis, as is usually the case for commercial and utility-scale solar projects. For residential systems, developers and investors (owners) are frequently the same party and the fair market value of the system is then obtained through independent appraisers. As should be expected the FMV is greater than the full cost of the system to the developer, owing to the need for a profit margin for the developer.² Depending on the maturity of the solar residential market within a given state, this additional margin could be anywhere from 10% (California) to 30% (North Carolina). As a consequence, a reduction in the magnitude of the ITC will lead, *ceteris paribus*, to a more pronounced increase in the LCOE for residential systems.

²The corresponding mark-up is reflected in our parameter $\mu > 1$ in Table A1.

Table 4: LCOE @30%, LCOE @10% in 2016 versus Comparison Price (CP)

	Utility (e-Si)			Utility (CaTe)			Commercial			Residential		
	LCOE ₃₀	CP	LCOE ₁₀	LCOE ₃₀	CP	LCOE ₁₀	LCOE ₃₀	CP	LCOE ₁₀	LCOE ₃₀	CP	LCOE ₁₀
California	6.96	5.44	9.43	7.24	5.44	9.82	10.34	15.17	14.01	11.98	17.06	20.71
Colorado	6.50	5.63	8.70	6.76	5.63	9.05	9.23	9.32	12.33	11.34	11.83	17.29
New Jersey	8.74	6.28	11.83	9.01	6.28	12.21	12.80	11.97	17.34	20.89	14.74	28.97
North Carolina	7.25	5.78	9.76	7.56	5.78	10.18	9.84	9.52	13.21	11.50	12.53	18.29
Texas	6.83	5.48	9.04	7.13	5.48	9.46	9.20	10.17	12.15	13.25	10.77	18.45

All figures in 2014 cents per kWh

3 Alternative ITC ‘Phase-Down’ Scenarios

Under the current ITC policy, all three segments in the five states we consider are likely to experience an LCOE ‘cliff’ at the end of 2016. As shown in Table 4, the difference between a 30% and 10% ITC in 2016 moves virtually all segment/state combinations from proximity to ‘grid-parity’, to a markedly uncompetitive position. A countervailing force to the LCOE cliff in 2017 is the gradual cost decline of all components of the solar energy system due to learning, innovation and experience. If this trend continues as it has over several decades, major segments of the solar PV industry should attain true grid-parity without any federal tax credits within a decade. To that end, we have developed and evaluated two alternative phase-down scenarios that meet the following criteria:

1. Federal incentives to diminish over time
2. Quid pro quo relative to the current ITC rules
3. In the *short-run* (2017-2020), the industry would be *better-off* than under the anticipated step-down
4. In the *medium-run* (2021-2024), the industry would be *equally well-off* as under the anticipated step-down
5. In the *long run* (past 2024), the industry would be *worse-off* than under the anticipated step-down
6. Targeted incentives for different segments

These design principles – muted ‘cliff in 2017 and ultimate ITC elimination in 2024 – are illustrated in Figure 2. As shown in the green line, the proposals would set the ITC such that all segments and geographies would be better off than they would have been at a 10% ITC, but less than the current 30% from years 2017 – 2020. The proposals would then, at the end of the first four years, reduce the ITC – causing a ‘seesaw’ effect, albeit more muted than what would be projected in 2017 under current policy. Finally, after another four years 2021 – 2024, the ITC would be reduced to zero, with the only remaining incentive available being accelerated depreciation through MACRS. Despite these anticipated cost jumps, the LCOEs across segments and states are projected to fall due to continual innovation and learning-by-doing.

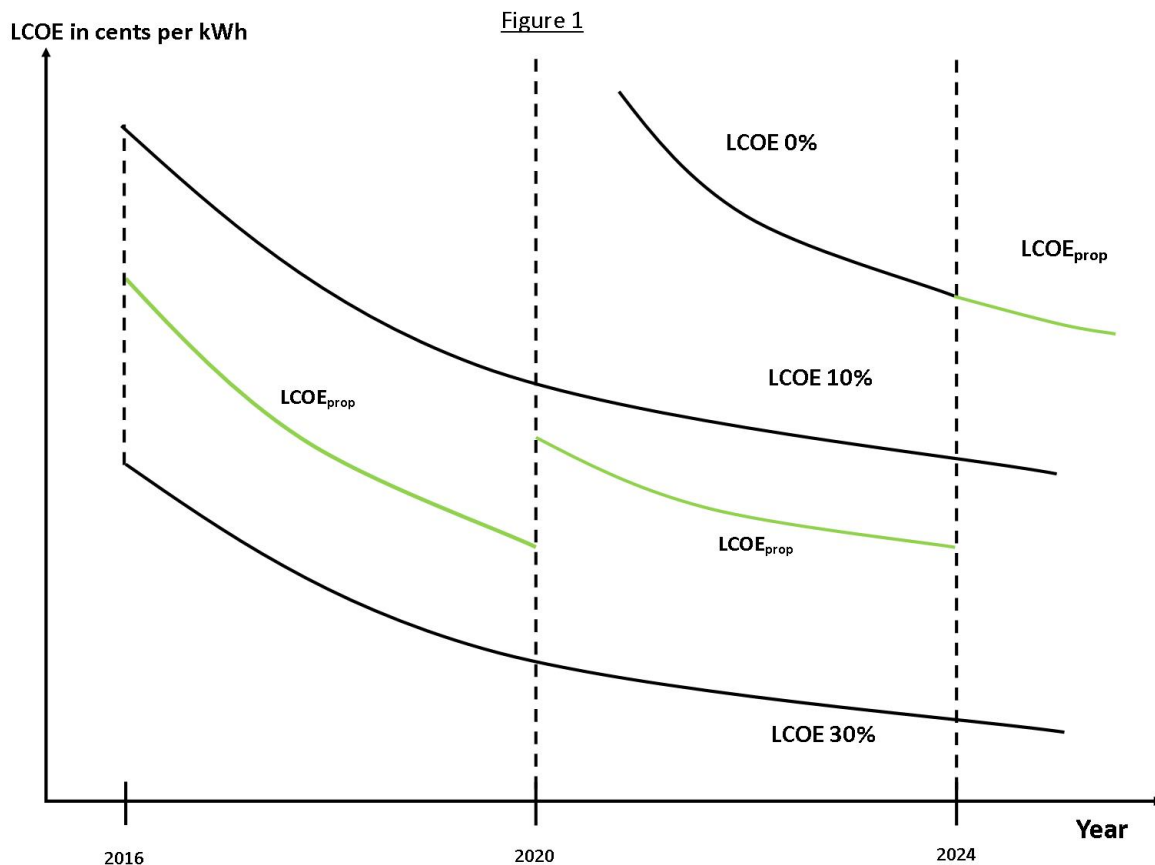


Figure 2: Glide path with ‘seesaw’ pattern and ultimate reversal past 2024

We now describe two scenarios: the *20/10/0 Scenario* and the *ITC Choice Scenario* both of which propose a scheduled phasing-out of the ITC in its current form over an 8 year period. As the name suggests, the *ITC Choice Scenario*, entails the additional choice of an ITC calculated in a different form.

The 20/10/0 Scenario

The *20/10/0 Scenario* provides a gradual reduction in the current form of the ITC over two, 4-year windows. All segments would be eligible, and all current practices would remain. The size of the tax credits and its reduction over time would be as follows:

- 2017 – 2020: MACRS with 20% ITC
- 2021 – 2024: MACRS with 10% ITC

- 2025 onward: MACRS only

The trajectory of LCOE’s by segment and by state under this scenario are shown in the green bars in Tables 5, 6, 7 and 8. Importantly, across all applications the ‘cliff in 2017 is muted compared to current policy. Further, the subsequent jump in 2021 is – on average – even less. As with the current ITC structure, the largest relative changes in LCOE occur for the residential segment for the reasons explained above. By comparison, commercial- and utility segments experience a smaller change in LCOE. The residential segment lags behind in cost competitiveness, though the gap diminishes over time due to the anticipated reduction in solar energy system price reductions and a projected trajectory of flat or increasing comparison prices.

The ITC Choice Scenario

The *ITC Choice Scenario* also specifies a gradual reduction of tax credits over time, yet it offers investors a choice in terms of how the ITC is calculated. As an alternative to the ‘percentage-based’ ITC in its current form, investors would be eligible for a so-called ‘lump-sum’ ITC, calculated in \$ per Watt. We calibrate this lump-sum ITC by considering the *avoided cost of carbon emissions*. Conceptually, this construct is based on the notion that a Watt of solar PV installed will displace a fossil fuel generation source. For instance, for modern combined cycle natural gas power plants, the CO_2 emissions rate is about .35 kg per kWh. If one multiplies this emission rate with a cost per kg of CO_2 into the atmosphere, one obtains the cost of avoided carbon emissions associated with one Watt of solar power by taking into consideration the useful life of the facility, the number of hours per year and the capacity factor of the solar facility. Combining these input variables, we arrive at the following lump-sum ITC calculated on a per Watt installed basis.

$$ITC_{LS} = 8,760 \text{ h/year} \cdot CF \cdot T \cdot AE \cdot CC \quad (4)$$

where:

- CF : Average capacity factor (in %)
- T : Years of operation (in years)
- AE : Avoided CO_2 emissions (in kg of CO_2 per kWh)
- CC : Avoided cost of carbon (in \$ per tonne of CO_2)

Much like the current percentage based ITC, the lump-sum ITC is applied to the system price of the facility based on the system’s installed (DC) capacity. As part of *ITC Choice Scenario*, the project owner can choose between two alternative tax credits *for each project individually*. The magnitude of the ITC and its reductions over time would be specified as follows:

- 2017 – 2020: MACRS with ITC of 20% of system price **or** 40¢/W installed
- 2021 – 2024: MACRS with ITC of 10% of system price **or** 20¢/W installed
- 2025 onward: MACRS only

As with the *20/10/0 Scenario*, all ITC provisions would expire in 2025. The initial 40¢/W installed figure is obtained with the following parameter inputs: (i) the useful life of the solar facility (T) is equal to 20 years; (ii) the capacity factor (CF) is 16%; (iii) the imputed price of CO₂ is \$ 40 per tonne³; and (iv) the avoided emissions are .35 kg per kWh, as discussed above in connection with natural gas power plants.⁴

In comparison with the *20/10/0 Scenario*, the *ITC Choice Scenario* has several advantages. First, for an ITC calculated on a ‘percentage’ basis, there is a diminishing impact as the cost per installed Watt decreases. On a per Watt basis, this structure gives larger subsidies to residential installations – the most costly segment of solar energy – compared to commercial and especially utility-scale projects. Under the Choice Scenario, a fixed incentive offered by the lump-sum ITC can provide targeted subsidies for the commercial- and utility segments, without impacting the residential segment. Indeed, across the geographies we have examined, residential projects will choose the percentage-based ITC, while the other two segments will choose the lump-sum ITC.

Second, since a percentage-based ITC amounts to cost sharing, it provides reduced incentives to reduce costs. In contrast, a lump-sum subsidy gives investors the full return on any cost reductions achieved. The third advantage of the *ITC Choice Scenario* is that it is grounded in the inherent benefit of solar power from a CO₂ emissions perspective. By

³This price figure is comfortably in the mid-range of various estimates, e.g., EPA and various integrated assessment models, of the social cost of one tonne of carbon dioxide emitted into the atmosphere

⁴One may question why our assessment of the avoided cost of carbon is decreasing over time. Our specification here is subordinated to the idea that, in order to be palatable politically, the proposed phase-down scenario must entail diminishing taxpayer support for solar PV. In addition, it appears likely to us that by 2021 there will be some federal carbon pricing policy in place for the U.S.

assigning a value to the avoided emissions provided by solar energy in lieu of the same electricity provided by current natural gas power plants, one obtains a level playing field for comparing the **full cost** of electricity obtained from alternative generation technologies.

The trajectory of LCOE's by segment and by state under the *ITC Choice Scenario* are shown by the purple bars in Tables 5, 6, 7 and 8. As noted above, the residential segment will generally opt for the percentage-based ITC, whereas commercial- and utility scale installations will opt for the lump-sum ITC.

4 Phase-Down Scenario Results

Residential Segment

The results for the residential segment results are displayed for all five states in Table 5, on page 18. In comparing the relative benefit provided by either the *20/10/0 Scenario* (green bars) or the *ITC Choice Scenario* (purple bars), we see that a percentage-based ITC is preferred in almost all cases. Specifically, residential-scale installations would opt for a 20% ITC (10% past 2020) over a fixed 40¢/W (20¢/W past 2020). We note that the additional 10% ITC under either of our proposals would make a substantial contribution to keeping the residential segment competitive in California, Colorado and North Carolina for the years 2017 – 2020. For the years, 2021– 2024, our numbers indicate that residential installations would have LCOE's that are around 2 – 3 cents above the respective retail rate in all of the states except for New Jersey. Beyond 2024, however, residential solar installations are likely to require additional state-level support in order to remain economically viable.

Commercial Segment

Table 6, on page 19, summarizes our findings for the commercial-scale segment. For this segment, the *ITC Choice Scenario* will clearly become a more beneficial policy proposal than the *20/10/0 Scenario*, as in each of the states, the preference would be to receive the lump-sum ITC of 40¢/W (20¢/W past 2020). With this option, commercial-scale installations would be “comfortably competitive” in California and Texas and close to break-even in the remaining three states of Colorado, New Jersey and North Carolina during the period 2017 – 2024. By 2025 – without any ITC – commercial installations in California and Texas are projected to be competitive, at break-even in Colorado, and at a small disadvantage in New

Jersey and North Carolina.

Utility Segment

The results for the utility-scale segment are displayed in Tables 7 (c-Si) and 8 (CdTe), on page 20 and 21, for each of the five states. Like the commercial segment, the *ITC Choice Scenario* would be the preferred policy proposal as it would induce utility-scale installations to opt for an ITC of 40¢/W (20¢/W past 2020). With this option, utility-scale installations are then projected to achieve grid-parity by 2018 in all of the states we consider, except New Jersey. Furthermore, for all of these four states, utility-scale installations are projected to be competitive without any ITC by 2025. We note that the comparison price – namely the average wholesale price in the state – is expected to rise in real terms in all geographies considered.

Table 5: Alternative ITC Phase Down: Residential Segment

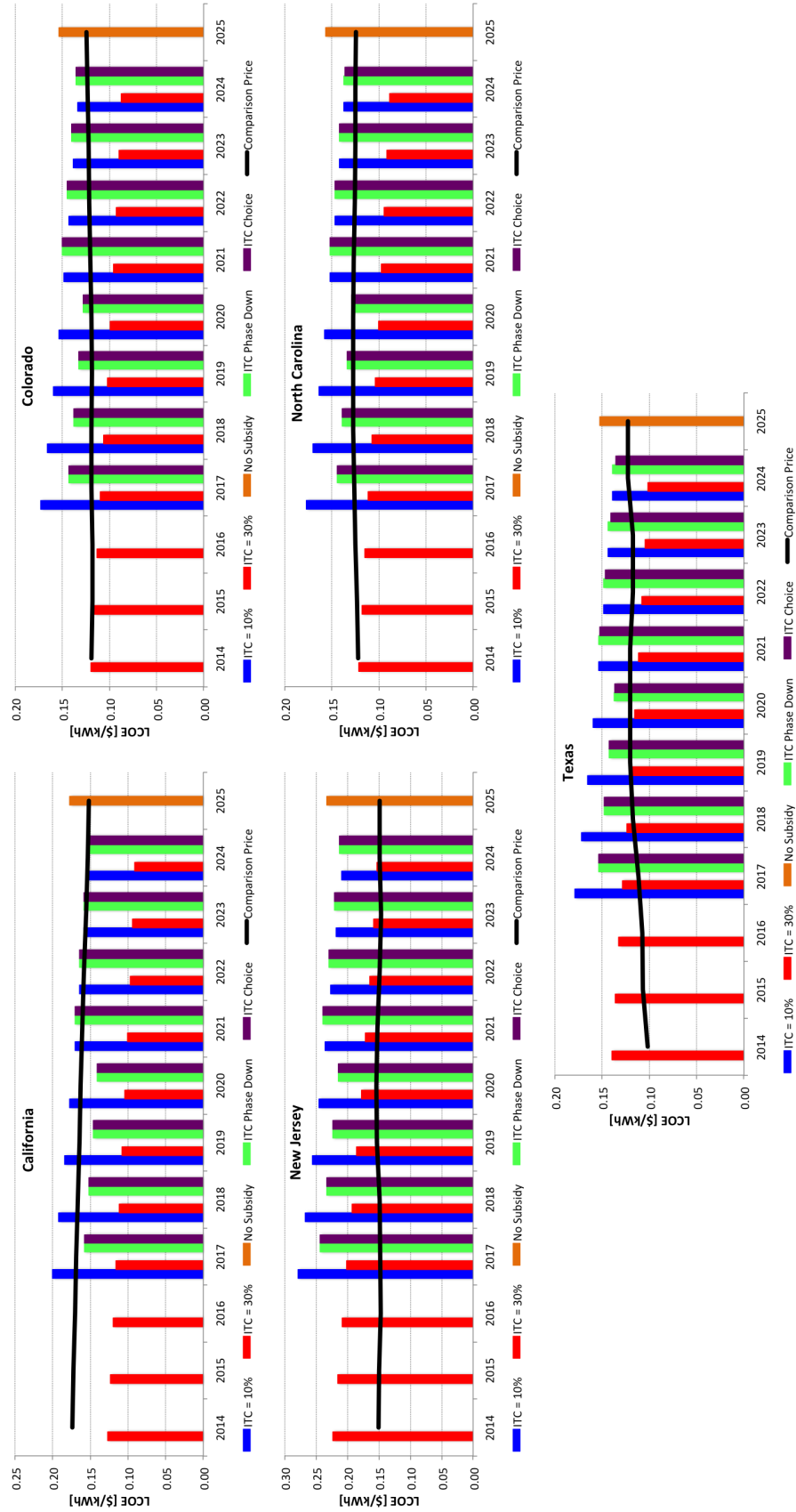


Table 6: Alternative ITC Phase Down: Commercial Segment

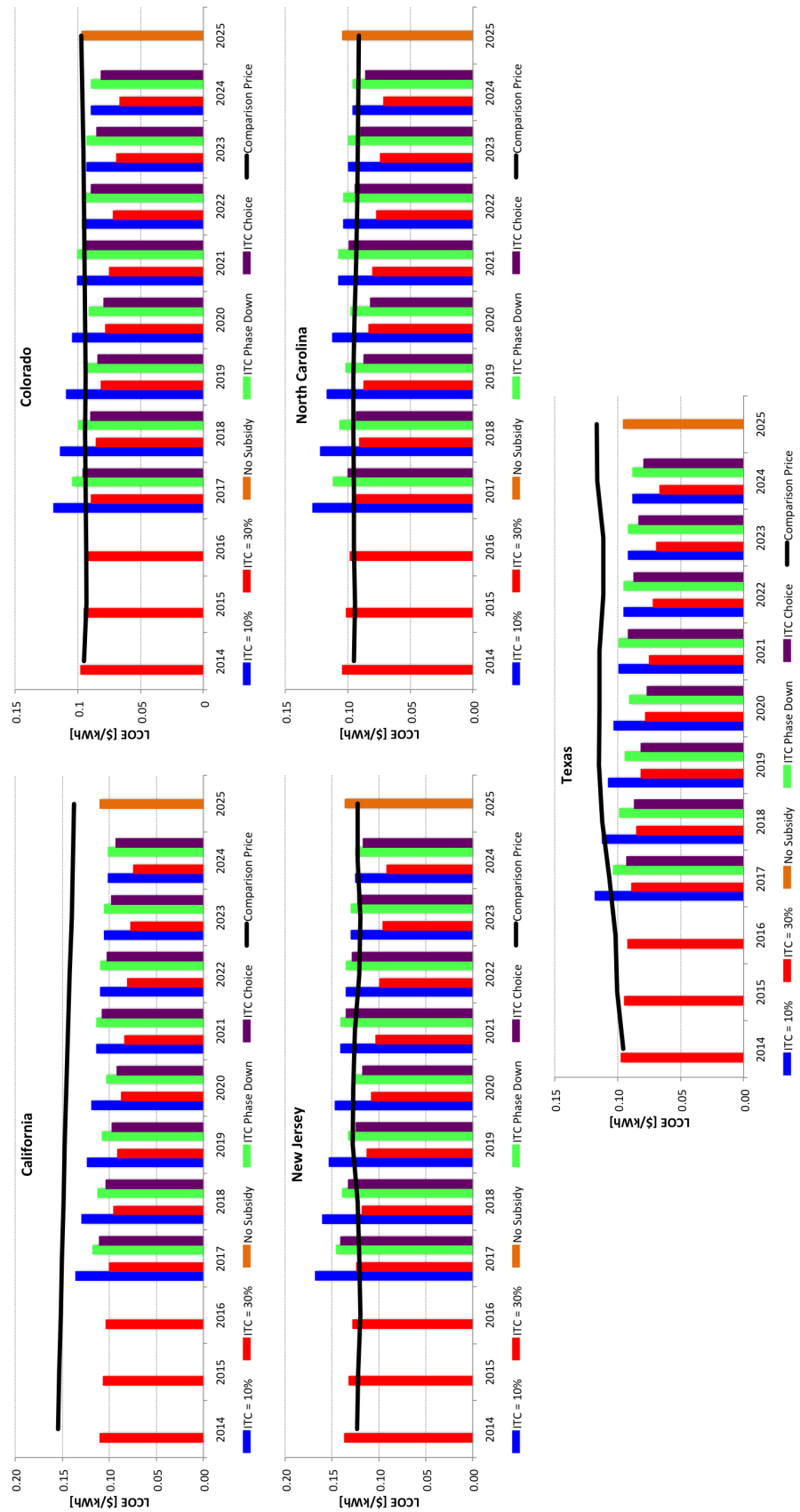


Table 7: Alternative ITC Phase Down: Utility (1-axis, c-Si) Segment

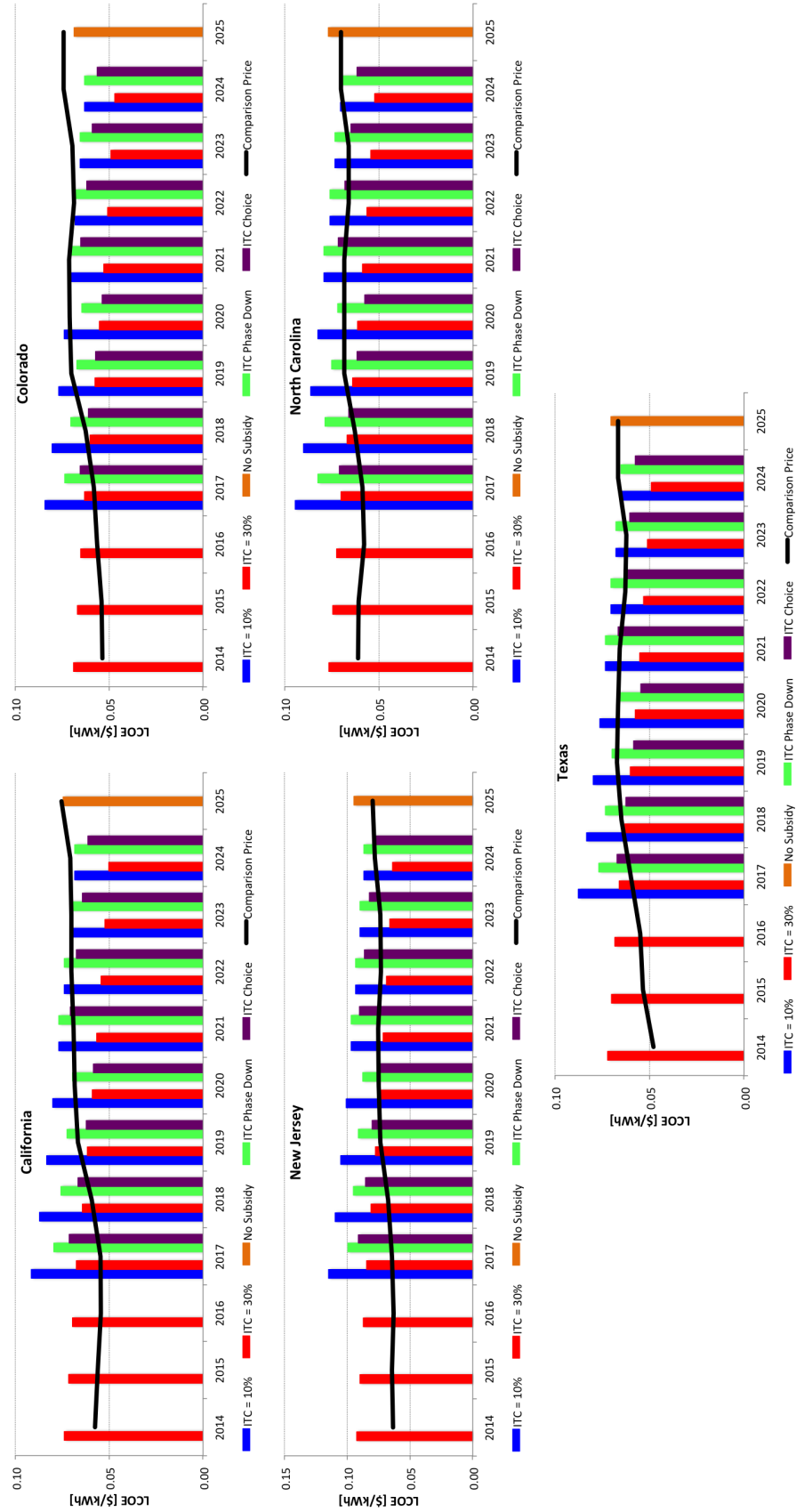
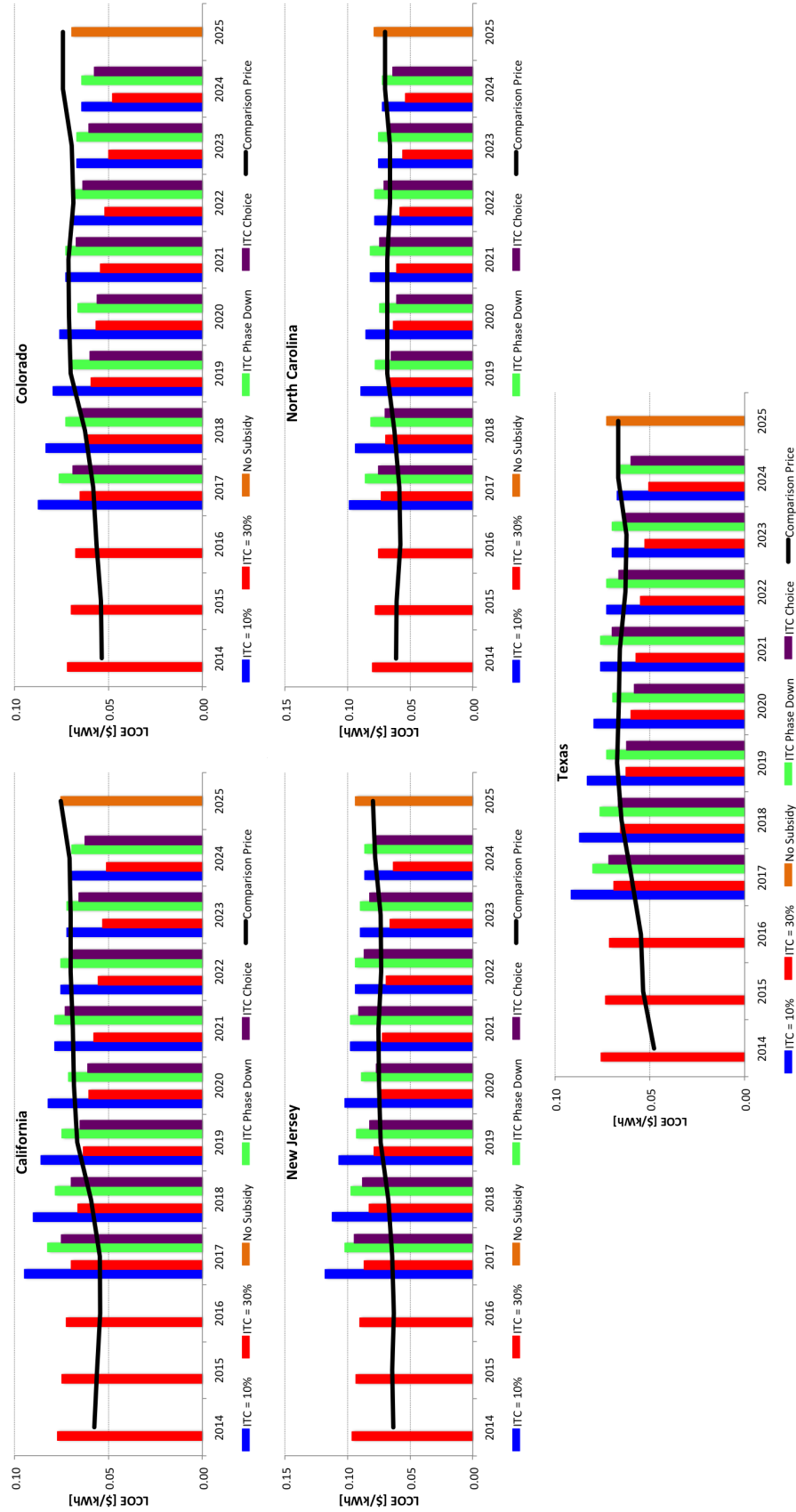


Table 8: Alternative ITC Phase Down: Utility (1-axis, CdTe) Segment



5 Qualitative Challenges and Opportunities for Federal Tax Policy Support for Solar Photovoltaics

Introduction¹

Federal deployment support for solar photovoltaic (PV) installations comes primarily in the form of tax incentives, such as accelerated depreciation rates and tax credits.² The §48 investment tax credit (ITC) rewards investors in solar PV assets with a tax credit worth 30% of qualifying capital expenditures.³ Since the Energy Policy Act of 2005⁴ established the solar ITC in its current form, annual solar PV capacity additions in the United States have steadily risen from 79 megawatts (MW) in 2005 to 160 MW in 2007, 435 MW in 2009, 1887 MW in 2011, 3313 MW in 2012, to a record 4751 MW of new capacity additions in 2013.⁵ These numbers suggest that the ITC, along with accelerated depreciation rates⁶ and state-level mandates and incentives⁷, has been an effective driver of solar PV deployment in the United States. Yet, the solar ITC, originally adopted with strong support, has become a polarizing incentive, with supporters and critics both vocal in the court of public opinion.

Support comes primarily from within the industry. Speaking for roughly 1000 member companies, the Solar Energy Industries Association hails the ITC as “the cornerstone of continued growth of solar energy in the United States” and “one of the most important federal policy mechanisms to support the deployment of solar energy in the United

¹ The Introduction to this chapter and Sections I, II, and III are based on FELIX MORMANN, *Beyond Tax Credits: Smarter Tax Policy for a Cleaner, More Democratic Energy Future*, 31 Yale J. on Reg. 303 (2014), available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2367780. The Conclusion is based, in part, on *Oversight of the Wind Energy Production Tax Credit: Hearing Before the Subcomm. on Energy Pol’y, Health Care, & Entitlements of the H. Comm. on Oversight and Gov’t Reform*, 113th Cong. 3, 8 (2013) (statement of Dan W. Reicher, Professor, Stanford Law School), <http://oversight.house.gov/wp-content/uploads/2013/10/Reicher.pdf>.

² See, e.g., STEVE CORNELI, *Clean Energy and Tax Reform: How Tax Policy Can Help Renewable Energy Contribute to Economic Growth, Energy Security and a Balanced Budget* (U.S. Partnership for Renewable Energy Finance 2012), <http://uspref.org/wp-content/uploads/2012/06/Clean-Energy-and-Tax-Reform-White-Paper.pdf> (“The most important federal policies for driving scale deployment are tax benefits, such as production or investment tax credits, and accelerated depreciation for new renewable energy investments.”); see also MARK BOLINGER, et al., *PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States* (National Renewable Energy Laboratory 2009), <http://www.nrel.gov/docs/fy09osti/45359.pdf>; ETHAN ZINDLER & TYLER TRINGAS, *Cash is King: Shortcomings of US Tax Credits in Subsidizing Renewables* (Bloomberg New Energy Finance 2009), http://www.novoco.com/energy/resource_files/advocacy/ncoep_testimony_042710.pdf; BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), http://bipartisanpolicy.org/sites/default/files/BPC_RE%20Issue%20Brief_3-22.pdf (“[A] few federal tax policies have been responsible for most of the financing directed to renewable energy projects.”).

³ See 26 U.S.C. § 48 (2012).

⁴ Pub. L. No. 109-58, 119 Stat. 594.

⁵ See SOLAR ENERGY INDUSTRIES ASSOCIATION, *U.S. Solar Market Insight Report – 2013 Year in Review* (SEIA 2014).

⁶ The federal tax code’s Modified Accelerated Cost Recovery System (MACRS) classifies wind, solar, and a range of other renewable power generation assets as five-year property, see 26 U.S.C. § 168(e)(3)(B)(vi)(I).

⁷ The most prominent state-level mandate is the renewable portfolio standard (RPS) currently adopted by twenty-nine states and the District of Columbia, see DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY, <http://www.dsireusa.org/rpsdata/index.cfm> (last visited Dec. 5, 2014). Some states also provide direct financial incentives for solar deployment, such as North Carolina’s personal tax credit, see DATABASE OF STATE INCENTIVES FOR RENEWABLES & EFFICIENCY, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC20F (last visited Dec. 5, 2014).

States.”⁸ Policy and financial analysts, meanwhile, paint a less favorable picture of federal tax credit support for renewable energy and the solar ITC in particular. Analysts with Bloomberg New Energy Finance find that a cash subsidy in lieu of tax credits – an option available from 2009 through 2011 under the §1603 grant originally established through the American Recovery and Reinvestment Act⁹ – “offers US taxpayers a better bang for their buck.”¹⁰ The Congressional Research Service notes that “[cash] grants may be a more economically efficient mechanism than tax credits for delivering benefits to the renewable energy sector.”¹¹ In the same vein, the Bipartisan Policy Center finds that “while the tax-based incentive system has been enormously supportive for the renewable energy industry, it is also a sub-optimal tool and will likely be unsustainable as the industry matures.”¹²

The tax code anticipates the solar industry’s continued technology learning and growing maturity with the §48 ITC set to phase down from 30% to 10% at the end of 2016.¹³ This inflection point invites consideration of the ITC program’s inefficiencies and potential qualitative, adjustments to federal tax support for solar PV to foster the industry’s sustained growth beyond 2016, in addition to various quantitative options being considered in other contexts.

This analysis proceeds in three parts. Part One surveys key characteristics of the §48 solar ITC and explores the challenges posed by federal tax credit support for solar PV deployment (*infra* I.). Part Two explores qualitative modifications, such as making the solar ITC tradable and/or refundable to improve the program’s efficacy and efficiency (*infra* II.). Thinking outside the tax-credit box, Part Three proposes two other options – master limited partnerships (MLPs) and real estate investment trusts (REITs) – for federal tax policy to cost-efficiently promote the build-out of clean, low-carbon solar PV capacity (*infra* III.). The analysis concludes with a three-part recommendation that would help the solar industry continue on its important growth trajectory over the next several years, while it transitions to lower-cost financing.

⁸ See *Solar Investment Tax Credit*, SOLAR ENERGY INDUSTRIES ASS’N, <http://www.seia.org/policy/finance-tax/solar-investment-tax-credit> (last visited Dec. 5, 2014).

⁹ For a detailed account of the §1603 cash grant experience and its meaning as a policy counterfactual to federal tax credit support for solar and other renewable energy deployment, see MORMANN, *Beyond Tax Credits: Smarter Tax Policy for a Cleaner, More Democratic Energy Future*, 31 Yale J. on Reg. 303 (2014) p. 315, 319, available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2367780.

¹⁰ See ZINDLER & TRINGAS, *Cash is King: Shortcomings of US Tax Credits in Subsidizing Renewables* (Bloomberg New Energy Finance 2009), at 1.

¹¹ See PHILIP BROWN & MOLLY F. SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011) p. 30.

¹² See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 13.

¹³ 26 U.S.C. §48(a)(2)(A)(ii).

I. Characteristics and Challenges of the §48 ITC for Solar PV Assets¹⁴

Investment tax credits for renewable energy were first established by the Energy Tax Act of 1978.¹⁵ Today the federal tax code provides investment tax credits for a variety of renewable energy technologies, including solar, combined heat and power, fuel cells, microturbines, geothermal, and small wind projects.¹⁶ In contrast to the §45 production tax credit (PTC) that has been a pivotal driver of wind energy deployment, the §48 ITC does not reward the actual generation of electricity from eligible renewable technologies but, rather, investment in the equipment required to generate renewable power. Eligible solar, fuel cells, and small wind projects receive tax credits equal to 30% of the project's qualifying investment costs, whereas all other eligible technologies, such as geothermal and microturbines, receive tax credits worth 10% of their qualifying costs.¹⁷ After January 1, 2017 the investment tax credit will phase down to 10% of qualifying costs for all eligible renewable energy technologies to anticipate and encourage the industry's continuous technology learning and cost improvements.¹⁸

Notwithstanding the solar ITC's impressive track record to date, the limited reach of tax credits makes them problematic in stimulating continued growth in the solar marketplace. Only entities with hefty tax bills to offset can benefit from such tax breaks. Many developers do not have tax bills that are high enough to reap the full and immediate benefits of tax credits for renewable energy.¹⁹ Due to the high up-front costs for planning, equipment, and construction, it takes many years before a renewable power project even begins to generate taxable profits to offset with tax credits.²⁰ Without current tax liability from other sources, project developers could carry forward their tax incentives for future use but the lost time value would impose a significant discount.²¹ Meanwhile, the tax

¹⁴ The following discussion is based on MORMANN, *Beyond Tax Credits: Smarter Tax Policy for a Cleaner, More Democratic Energy Future*, 31 Yale J. on Reg. 303 (2014) p.323 et seq., available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2367780.

¹⁵ P.L. 95-618. For details regarding the legislative history of federal investment tax credits for renewable energy, see *Tax Expenditures: Compendium of Background Material on Individual Provisions*, committee print, prepared by Congressional Research Service, 111th Cong., 2nd sess., December 2010, S. Prt. 111-58, pp. 185-190.

¹⁶ 26 U.S.C. §48.

¹⁷ 26 U.S.C. §48(a)(2)(A).

¹⁸ 26 U.S.C. §48(a)(2)(A)(ii).

¹⁹ MARK BOLINGER, et al., *Preliminary Evaluation of the Section 1603 Treasury Grant Program for Renewable Power Projects in the United States*, 38 Energy Policy 6804 (2010) p. 6804; CORNELI, *Clean Energy and Tax Reform: How Tax Policy Can Help Renewable Energy Contribute to Economic Growth, Energy Security and a Balanced Budget* (U.S. Partnership for Renewable Energy Finance 2012) p. 13; BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011) p. 12.

²⁰ See BOLINGER, et al., *Preliminary Evaluation of the Section 1603 Treasury Grant Program for Renewable Power Projects in the United States*, 38 Energy Policy 6804 (2010) p. 6811.

²¹ For example, assuming an internal rate of return (r) of ten percent, a tax credit with a face value (FV) of \$100 that cannot be used for the first 10 years of a project's lifetime has a net present value (NPV) of only \$38.55, where

code's general prohibition of trading in tax attributes precludes the developer from simply selling off her tax benefits. The industry response to this dilemma has been for developers to bring in an outside investor with sufficient tax liability from other sources to monetize the project's tax credits. While such "tax equity" investment allows for the timely monetization of otherwise carried forward tax incentives,²² the pool of tax equity investors is limited to a small group of large banks and highly profitable corporations that pay taxes in the United States. Many interested investors, such as tax-exempt pension funds, sovereign wealth funds, and retail investors do not have big enough tax bills to exploit federal tax incentives for renewables. With most of the investment community sidelined,²³ solar PV and other renewable energy projects struggle to raise critical capital at reasonable cost.

The mismatch between the inherent profitability requirements of tax credits and the revenue profile of the renewable energy projects they are intended to promote requires renewable energy developers to bring in outside investors whose hefty tax bills allow them to "monetize" the federal tax credits (*infra A.*). But such tax equity investors are few and far between – and they exploit their exclusivity status to charge a premium for their involvement (*infra B.*). The tax equity market's cyclicity further reduces the value of tax credits when developers need them most (*infra C.*). To make matters worse, the tax code renders tax equity for renewable energy a highly illiquid investment thereby hindering the formation of secondary markets that could help developers refinance their projects in the near to mid-term (*infra D.*). In addition, participation of a tax equity investor in renewable power projects requires complex and costly deal structures that drive up transaction costs (*infra E.*). The need to bring in a tax equity investor, finally, limits a developer's ability to raise project capital from other, more cost-efficient sources such as commercial debt (*infra F.*).

$NPV = FV / (1+r)^{10}$. See also LILY L. BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006) (arguing that refundability could avoid the losses associated with carrying tax credits forward).

²² For more details on the mechanics of tax equity investment in renewable energy projects, see BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011) p. 17.

²³ Institutional investors, private wealth, and sovereign investment funds held over \$100 trillion in global assets under management in 2011, but have traditionally not invested in U.S. renewable energy projects. See MICHAEL MENDELSON & DAVID FELDMAN, *Financing U.S. Renewable Energy Projects Through Public Capital Vehicles: Qualitative and Quantitative Benefits* (National Renewable Energy Laboratory 2013), <http://www.nrel.gov/docs/fy13osti/58315.pdf>.

A. Tax Credits Require Taxable Profits – or Tax Equity

Federal tax credits were used to stimulate economic development long before renewable energy entered the scene in the wake of the 1970s energy crisis.²⁴ It may have seemed logical to federal policymakers, therefore, to use the same tried-and-true tool to promote the development of renewable energy when they established today’s regime of tax credits for wind, solar, and other renewables. In doing so, however, policymakers were willing to overlook the fact that renewable energy developers and their projects tend to lack the quintessential requirement to benefit from tax credits—a high enough tax bill to offset with these credits.²⁵

For most of the 1990s, a renewable energy developer’s best way out of this lack-of-taxable-income dilemma was to develop a project to the point of construction and then sell it to a bigger entity that not only enjoyed access to the capital necessary for construction to proceed but also had a tax bill large enough to use the project’s tax credits.²⁶ More recently, developers who are unwilling to give up ownership or management of their projects but lack the taxable income to use the tax credits themselves have turned to third-party investors for tax equity capital.²⁷

Tax equity is a hybrid investment position that combines characteristics of conventional debt and equity stakes.²⁸ Like traditional sponsor equity, tax equity bears the ultimate performance risk of a project. Like debt, tax equity receives preferential treatment regarding project cash flows. These include positive cash flows such as payments under a power purchase agreement with a local utility or other off-taker and, most importantly, negative cash flows in the form of tax credits and other benefits that the tax equity inves-

²⁴ In 1962, investment tax credits were introduced as a permanent subsidy, later to be used as a counter-cyclical measure. See Thomas L. Hungerford & Jane G. Gravelle, *Business Investment and Employment Tax Incentives to Stimulate the Economy* (Congressional Research Service 2010).

²⁵ See SCOTT FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011), at 1; JOHN P. HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007). Challenges related to tax credits’ inherent profitability requirements are not unique to renewable energy deployment. Start-up companies and other economic ventures with high upfront capital expenditures and modest revenue flows over a long period of time will struggle to use tax incentives, such as accelerated depreciation and tax credits, in a timely fashion. See ALVIN C. WARREN & ALAN J. AUERBACH, *Transferability of Tax Incentives and the Fiction of Safe Harbor Leasing*, 95 Harv. L. Rev. 1752 (1982), at 1758-61; see also BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006) 21, at 55 (“[T]he value of a tax incentive generally should not vary by the size of one’s lifetime earnings, whether one earns more earlier or later in the life cycle, or whether one’s earnings are more smooth or more volatile over time.”).

²⁶ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007), at 2, 6.

²⁷ See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011), at 8; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 13.

²⁸ See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011), at 17.

tor can use to offset her tax liabilities outside of the project.²⁹ In essence, the tax equity investor's capital contribution buys her the rights to the project's tax benefits—and helps the developer finance the project's high up-front capital expenditures. Bringing in a tax equity investor enables a renewable power project to monetize its otherwise useless tax credits, albeit at a discount.³⁰

B. Tax Equity is Scarce and Expensive

The need for renewable energy developers to partner with tax equity investors in order to reap the benefits of their project's tax credits might pose less of a challenge if such tax equity capital were readily available. However, only a tiny fraction of the investment community meets the profitability requirements to use its own tax bills to monetize a renewable project's tax credits.³¹ Tax equity investment is a niche market that appeals only to the largest and most sophisticated financial firms, such as investment banks and insurance companies whose exclusive status gives them a strong financial but little if any strategic interest in renewables deployment.³² Meanwhile, billions of dollars of institutional capital from tax-exempt entities like pension funds, sovereign wealth funds, and other potential investors are sidelined.³³ And even those few eligible financial firms do not always have the necessary profits or tax appetite to invest in tax equity for renewables, as evidenced by the 2008-2009 economic downturn. Between 2007 and 2009, the pool of tax equity investors shrank from twenty to eleven investors, as the available tax equity for renewable energy plummeted by over eighty percent from \$6.1 billion in 2007 to only \$1.2 billion in 2009.³⁴

²⁹ See *id.*; CORNELI, *Clean Energy and Tax Reform: How Tax Policy Can Help Renewable Energy Contribute to Economic Growth, Energy Security and a Balanced Budget* (U.S. Partnership for Renewable Energy Finance 2012), at 13; BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 9.

³⁰ See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011), at 8, 17.

³¹ See BOLINGER, et al., *PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States* (National Renewable Energy Laboratory 2009), at 10; CORNELI, *Clean Energy and Tax Reform: How Tax Policy Can Help Renewable Energy Contribute to Economic Growth, Energy Security and a Balanced Budget* (U.S. Partnership for Renewable Energy Finance 2012), at 13; FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011), at 1; BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 9, 11; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 18.

³² HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007), at 25; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 14, 19.

³³ See FELIX MORMANN & DAN REICHER, *How to Make Renewable Energy Competitive* (New York Times June 1, 2012), <http://www.nytimes.com/2012/06/02/opinion/how-to-make-renewable-energy-competitive.html>.

³⁴ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011), at 2; BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 10.

More recent trends and projections suggest little improvement in the availability of tax equity for renewable energy, notwithstanding the recent market entry of non-traditional tax investors such as Google.³⁵ Despite an overall deal volume of \$6 billion for solar and wind tax equity in 2011, the market counted little more than twenty active tax equity investors.³⁶ Even with continuing economic recovery, the tax equity market is unlikely to grow significantly beyond its current size given the highly specialized nature of tax equity investment.³⁷ Among other qualifications, investors must have substantial current and future tax liability, the financial acumen to participate in a complex project structure, and the willingness to invest in illiquid assets that tie up cash and cannot easily be resold.³⁸ A comparative glance at Europe's renewable energy investment scene reveals just how high a barrier to entry the federal tax credit regime has erected for America's renewable energy investment market: thanks to feed-in tariffs and other deployment incentives that do not hinge on tax equity, more than 140 project financiers compete for a stake in the similarly sized European market for renewable power projects.³⁹ With only a fraction of the investment community in play, project developers in the United States find themselves in fierce competition with one another over the constrained supply of coveted tax equity.⁴⁰ In the words of one major tax equity investor: "[T]he tax equity investors hold all the cards."⁴¹

Competition among developers for a spot at the tax equity table is not necessarily a bad thing. In fact, some credit competitive pressure with serving as a catalyst for the development of higher quality renewable power projects with more thorough due diligence and better risk management.⁴² The members of the elite club of tax equity investors, however, exploit their exclusivity not only to improve the quality of renewable energy

³⁵ See MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 7, 19.

³⁶ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012), at 29.

³⁷ See MENDELSON & FELDMAN, *Financing U.S. Renewable Energy Projects Through Public Capital Vehicles: Qualitative and Quantitative Benefits* (National Renewable Energy Laboratory 2013), at 2.

³⁸ MENDELSON & FELDMAN, *Financing U.S. Renewable Energy Projects Through Public Capital Vehicles: Qualitative and Quantitative Benefits* (National Renewable Energy Laboratory 2013) To make matters worse, from a developer's perspective, not every one of these tax equity investors will be interested in every renewable power project since many investors have what industry experts describe as "esoteric requirements, specific needs, or quirks." CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012), at 29.

³⁹ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 11.

⁴⁰ See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011), at 13; FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011), at 1; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 8.

⁴¹ CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012), at 37.

⁴² CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) ("No one closes over mistakes any more. No one closes over anything any more. Sponsors must fix everything.")

projects but also to exact a sizeable premium for their participation.⁴³ While long-term project debt and conventional equity capital are readily available at modest yield rates of five to six percent and seven to eight percent respectively, tax equity investors demand up to fifteen percent or more for their involvement in renewable power projects.⁴⁴ These premium yield rates and other factors⁴⁵ create challenging circumstances for renewable energy project development. Since many developers lack the profits necessary to use their tax credits, according to Rhone Resch, head of the Solar Energy Industries Association, they end up having to sell their credits to tax equity investors at a loss of 30 to 50 cents on the dollar.⁴⁶ More conservative analyses conclude that the need to bring in a tax equity investor adds up to 800 basis points, or 8 percentage points, to a project's financing costs when compared to the typical cost of project finance debt.⁴⁷ With every 100 basis points estimated to add \$2.50 to \$5.00 per MWh of renewable power output,⁴⁸ the steep cost of tax equity imposes a sizeable burden on the renewable energy industry as it struggles to become cost-competitive with coal, gas, and other fossil fuel incumbents. For American taxpayers, the premium yields for tax equity divert up to half of their tax dollars away from the solar installations and wind farms they were intended to subsidize and into the hands of Wall Street banks and other high-profit corporations.

C. Tax Credits Fail When Needed Most

The cyclical nature of tax equity poses a separate, similarly grave problem for solar and other renewable energy developers, the federal government, and its taxpayers. The 2008/09 economic downturn offers ample evidence of just how much the availability and, with it, the price of tax equity fluctuate with the overall state of the economy.⁴⁹ More

⁴³ See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011), at 18; HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007), at v; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 8.

⁴⁴ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011), at 2 (based on pre-tax yield rates); see also HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007), at v; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 11, 18; ZINDLER & TRINGAS, *Cash is King: Shortcomings of US Tax Credits in Subsidizing Renewables* (Bloomberg New Energy Finance 2009), at 5 (discussing the spread of tax equity investors' yield demands).

⁴⁵ See *infra* Sections I.C.–F.

⁴⁶ See MATTHEW L. WALD, *Sunset for a Solar Subsidy?* (New York Times November 16, 2010), 3:53 PM), <http://green.blogs.nytimes.com/2010/11/16/sunset-for-a-solar-subsidy>.

⁴⁷ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 11; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012), at 8.

⁴⁸ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011), at 11 n.8.

⁴⁹ See e.g., BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 9.

specifically, “[m]acro-trends in tax equity financing ... are highly correlated to the financial health of a limited number of large financial institutions.”⁵⁰ Even the very largest and most profitable financial institutions cannot ensure sufficient levels of profitability through an economic crisis as evidenced by the 2008 departures of Citi Group, American International Group, and others from the tax equity market.⁵¹

As a general matter, a slow economy will require renewable energy developers to pay an even higher premium for tax equity than usual. This trend exacerbates the industry’s existing struggles to become cost-competitive with conventional sources of energy. After all, tax credits are designed to cover only part of the cost of generating power from solar and other renewable sources, with the wholesale power price and state incentives intended to fill in the gap. A slow economy, however, leads to an oversupply of electricity and thereby drives down wholesale power prices, which, in turn, makes it even harder for renewable power generators to break even, let alone make a profit.⁵² Tax credits, therefore, fail solar and other renewable energy developers when they need them most to bridge the widening gap between depressed wholesale power prices and their generation costs.⁵³ Ultimately, the cyclicity of tax equity makes tax credits for renewables a suboptimal stimulus measure to promote the large-scale deployment of renewable energy, much less strengthen or revive a struggling economy.

D. Tax Equity Limits Investment Liquidity

The cyclicity challenges of tax equity are exacerbated by the tax code’s restrictions on the sale and transfer of tax equity stakes in renewable energy projects. The investment tax credit for solar and other renewable projects becomes available in full in the year that the facility is placed into service.⁵⁴ But the credit actually takes five years to linearly vest in full.⁵⁵ In other words, the investor must hold on to her stake in the project for at least five years in order to realize the tax credit’s full value.⁵⁶ If the investor decides to pull out

⁵⁰ MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 3, 45.

⁵¹ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 10.

⁵² See ZINDLER & TRINGAS, *Cash is King: Shortcomings of US Tax Credits in Subsidizing Renewables* (Bloomberg New Energy Finance 2009) p. 5.

⁵³ Existing projects may have locked in a higher price with a long-term power purchase agreement. But the cyclicity challenge is substantial for new projects that need to secure a lucrative power purchase agreement in a depressed wholesale power market.

⁵⁴ See BOLINGER, et al., *PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States* (National Renewable Energy Laboratory 2009) p.11.

⁵⁵ See 26 U.S.C. §50(a).

⁵⁶ See BOLINGER, et al., *PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States* (National Renewable Energy Laboratory 2009) p.11 (pointing out that lack of liquidity is less of a problem for projects that claim the production tax credit because the latter vests and is realized in real time over a 10-year period).

of the project earlier, say after 3 years, the non-vested portion of her tax credit, in this case 40%, will be subject to recapture and the associated tax savings will need to be paid back to the Internal Revenue Service.⁵⁷ Even more problematic for investors and developers alike is that, once recaptured, the non-vested portion of the tax credit is lost for good and cannot be used to attract new investors for the project.⁵⁸ Originally intended to prevent tax shelter abuse, the tax code's "recapture" provisions severely limit the fungibility of tax equity and thereby impede the formation of a viable secondary market.⁵⁹ Indeed, the only evidence of meaningful secondary market transactions dates back to 2009 when tax equity investments were liquidated out of the portfolios of bankrupt investors such as Lehman Brothers.⁶⁰ In the words of an industry insider: "[t]hese trades are hard to execute."⁶¹

In practice, the investment illiquidity that tax equity infuses into solar and other renewable energy projects leaves developers with little to no recourse against the cyclical nature of tax equity, at least for projects that are subject to the tax code's recapture rules. If a slow economy with an even thinner-than-usual tax equity market forces a developer to pay a premium for the tax investor's participation, the developer has little hope of mitigating the damage once the economy has recovered by bringing in another tax equity investor at a lower yield rate. In addition, tax equity investors would likely lower the yield premium they demand if their investments enjoyed greater liquidity allowing them more and better exit options in the case of economic distress, reduced tax appetite, or for strategic purposes.⁶²

E. Tax Equity Requires Complex and Costly Deal Structures

Participation of a tax equity investor in a renewable energy project requires highly complicated deal structures. The three main tax equity structures today are the partnership flip, the sale leaseback, and the inverted lease.⁶³ Many of the largest players in solar

⁵⁷ See 26 U.S.C. §50(a)(B).

⁵⁸ See BOLINGER, et al., PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States (National Renewable Energy Laboratory 2009) p.11.

⁵⁹ See BIPARTISAN POLICY CENTER, Reassessing Renewable Energy Subsidies – Issue Brief (BPC 2011) p. 11.

⁶⁰ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 34.

⁶¹ CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 34.

⁶² See JOEL MEISTER, *Sunny Dispositions - Modernizing Investment Tax Credit Recapture Rules for Solar Energy Project Finance After the Stimulus* (The GW Solar Institute 2012) p. 18.

⁶³ See DIPA SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 11, 16 (offering a concise comparison across all three tax equity structures); CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 30; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 10; BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011) p. 19.

PV development, including Sunrun and Sunpower,⁶⁴ structure their deals using the partnership-flip model. SolarCity structures two-thirds of its investments as partnership flips while using sale leasebacks and inverted leases for the remaining one-third of its investments.⁶⁵

The partnership-flip structure was first used in large-scale transactions in 2003 and has since become the most common tax equity structure.⁶⁶ In this structure, the tax equity investor is the majority equity partner during the early years of the project partnership when she receives most of the cash flows from power purchase payments and, most importantly, the tax credits and other tax benefits.⁶⁷ Once all or most of the project's tax benefits have been realized and the tax equity investment has reached a pre-negotiated yield target, the tax investor's share "flips" to a minority position and the developer takes over in terms of both equity and cash flows.⁶⁸ After the flip, the tax equity investor typically retains a nominal equity interest as required by the tax code.⁶⁹ In essence, the partnership-flip structure enables the tax equity investor to serve as an "accommodation" partner who receives a shorter maturity on her investment in exchange for the ability to monetize a project's tax benefits.⁷⁰

In a sale-leaseback structure, the developer develops the project but sells the tax credit earning equipment at fair market value to a tax equity investor within 90 days of being placed in service.⁷¹ Once the sale is executed, the tax investor leases the equipment back

⁶⁴ See, e.g., <http://cleanenergyfinanceforum.com/2014/10/20/solar-securitization-tackles-tax-equity-challenges/> (last visited Dec. 5, 2015).

⁶⁵ See, e.g., <http://www.woodlawnassociates.com/tax-equity-101/> (last visited Dec. 5, 2015).

⁶⁶ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007) p. 8, 25; CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 35.

⁶⁷ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 9; MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 16. See also SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 12 (describing a more balanced allocation of positive project cash flows between the developer and tax equity investor).

⁶⁸ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007) p. 23 (noting that after the flip typically around 90% of cash flows go to the developer); BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 9.

⁶⁹ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007) p. 19 (reporting on industry practice to leave 5% of equity with the tax investor to avoid potential challenges from the Internal Revenue Service regarding the allocation of tax benefits); MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 16.

⁷⁰ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 9.

⁷¹ See MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 15. With the exception of biomass facilities, the tax code's owner-operator requirement prohibits the use of sale leaseback and inverted lease structures for renewable power projects that claim production tax credits, see CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 30.

to the developer at a fixed rent⁷² for the term of the project's power purchase agreement or longer.⁷³ Title to the equipment allows the tax investor to claim the project's tax credits and other benefits while the equipment-leasing developer continues to operate the project and receives all payments under the power purchase agreement with the off-taker of the project's electricity output.⁷⁴ Upon expiration of the lease, the tax equity investor usually has the option to retain ownership of the project's equipment or to sell it back to the developer at its fair market value.⁷⁵ In theory, the sale-leaseback structure enables the developer to raise up to 100% of the project capital through the sale of its equipment. In practice, however, tax equity investors often use their strong market position to require developers to prepay a portion of their rent effectively resulting in a discount that may amount to 20% of the project cost or more.⁷⁶

The inverted-lease structure, also referred to as a lease pass-through, at first glance appears to be the exact opposite of the sale-leaseback structure given that here the tax equity investor pays rent to the developer under their lease agreement.⁷⁷ In exchange for the lease payments, the developer passes most of the project's tax credits and benefits through to the tax equity investor.⁷⁸ To facilitate the pass-through component of the inverted lease the lessee tax investor also holds an equity stake in the project company.⁷⁹ From the project's inception, the inverted-lease structure delivers positive cash flows to the developer but, unlike the partnership flip and the sale leaseback, it requires the developer to invest significant equity capital upfront.⁸⁰

Whatever the subtle differences across the aforementioned tax equity structures, they are all "highly complicated and involve significant fees, restrictions and other costs that divert much of the value of the tax credits away from reducing the cost of the renewable

⁷² See also SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 13 (discussing the option of varying lease payments that fluctuate in correlation with the project's positive cash flows).

⁷³ MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 15.

⁷⁴ *Id.*

⁷⁵ *Id.* See also SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 13 (explaining the possibility for the developer and tax equity investor to agree on an early-buyout option for the developer, usually between years 7 and 12 of the project).

⁷⁶ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 30 (pointing to rent prepayments of up to 80% of project costs).

⁷⁷ See SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 14.

⁷⁸ SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 15.

⁷⁹ SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 14.

⁸⁰ SHARIF, et al., *The Return – and Returns – of Tax Equity for US Renewable Projects* (Bloomberg New Energy Finance 2011) p. 16.

energy project itself.”⁸¹ The personnel time and professional fees required to complete these transactions pose a particularly high barrier to tax equity investment for smaller renewable energy projects, including the distributed-generation projects that are considered vital for the construction of a smarter, more resilient, decentralized power grid.⁸² According to industry insiders even large-scale renewable projects may see a good share of the developer’s profits wiped out by transaction costs and professional fees “running to \$3 to \$4 million to close a transaction.”⁸³ In addition, the complex, customized nature of these transactions tailored to suit the specific needs of each project can cause costly delays with some deals taking up to ten months to close.⁸⁴ Some analysts estimate that the transaction costs associated with tax equity investment increase the financing costs of renewable energy projects by 300 basis points or more,⁸⁵ adding \$7.50 to \$15.00 to the production cost of each MWh of a project’s renewable power output.⁸⁶

F. Tax Equity and Debt – A Challenging Relationship

The need for tax equity drives up the cost of renewable energy projects not only through the premium yield rates that tax investors demand for their participation and the associated transaction costs but also because tax equity often forestalls less expensive debt financing.⁸⁷ Well-developed renewable energy projects can raise debt capital at interest rates that are up to 60% lower than the yield rates that developers have to pay for tax equity capital.⁸⁸ Debt, in other words, has a considerably cheaper cost of capital than

⁸¹ CORNELI, *Clean Energy and Tax Reform: How Tax Policy Can Help Renewable Energy Contribute to Economic Growth, Energy Security and a Balanced Budget* (U.S. Partnership for Renewable Energy Finance 2012) p. 13.

⁸² See BROWN & SHERLOCK, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options* (Congressional Research Service 2011) p. 12 (warning that high transaction costs “may negate the tax benefits offered by small projects”). See also MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 18.

⁸³ CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 32. See also FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 1.

⁸⁴ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 2; CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 32.

⁸⁵ See MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 34.

⁸⁶ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 11 (reporting that every 100 basis points of increase to a project’s financing costs adds \$2.50-5.00 per MWh to the project’s cost of electricity).

⁸⁷ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 4.

⁸⁸ See BIPARTISAN POLICY CENTER, *Reassessing Renewable Energy Subsidies – Issue Brief* (BPC 2011) p. 11; FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 2. See also the recent example of the oversubscribed Topaz Solar Farm’s \$850 million bond at a yield rate of 5.75%, <http://www.cleanenergyauthority.com/solar-energy-news/midamerican-holdings-topaz-solar-farm-bonds-022412> (last visited Dec. 5, 2014).

(tax) equity.⁸⁹ In fact, the cost advantages of debt over equity are significant enough to lead many industries that do not depend on tax credits to forego the tax code's depreciation benefits in favor of debt-dominated financing structures.⁹⁰ The same math suggests that the more debt a renewable power project can secure the lower its levelized cost of electricity will be.⁹¹

The bad news for developers is that the need to bring in a tax equity investor effectively creates a dual obstacle for greater debt-to-equity ratios in renewable energy projects. First, the tax code's requirements for tax equity structures preclude pure debt financing structures.⁹² Second, tax equity investors are wary of losing their preferred access to project cash flows to lenders.⁹³ While a forbearance or standstill agreement between the lender and the tax equity investor may ensure the latter's entitlement to the project's tax benefits, the lender's involvement will likely curtail the tax equity investor's rights to the project's positive cash flows from power purchase payments.⁹⁴ As a result, tax investors either refuse to participate in a debt-financed project or charge an additional premium – on top of their already high yield rates – if a renewable power developer wants to leverage the project with debt.⁹⁵ In practice, tax equity investors add between 300 and 500 basis points to their required yield rates if a developer chooses to finance the project with both equity and debt.⁹⁶ In addition to further increasing the cost of tax equity capital, bringing a lender into a renewable power project's capital structure adds considerable complexity to the deal, which also increases transaction costs and may cause costly delays.⁹⁷ Accordingly, only a handful of renewable energy projects have managed to combine the tax equity required to monetize federal tax credits with cost-effective debt financing.⁹⁸ Some analysts have gone as far as concluding that “[t]he most significant cost

⁸⁹ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007) p. v.

⁹⁰ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 34.

⁹¹ See HARPER, et al., *Wind Project Financing Structures: A Review & Comparative Analysis* (Lawrence Berkeley National Laboratory 2007) p. v.

⁹² See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 34 (describing how debt financing would take over if tax credits were replaced with direct cash subsidies).

⁹³ See *supra* Section I.A. for a discussion of the debt-equity hybrid character of tax equity with its preferred access to project cash flows.

⁹⁴ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 32.

⁹⁵ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 3.

⁹⁶ See MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 11, 17.

⁹⁷ See FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 3.

⁹⁸ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) p. 32.

of tax equity ... is that it makes obtaining project level debt more difficult.”⁹⁹ In the end, analysts estimate that even with the help of a tax equity investor developers cannot realize more than two thirds of the value of their renewable energy project’s tax credits.¹⁰⁰

G. Summary

Empirical evidence and qualitative analysis illustrate the remarkable inefficiency of using federal tax credits to promote the deployment of renewable energy technologies. Unless a project developer has sufficient tax liability from other sources, she will not be able to reap the full value of her project’s tax benefits. If she chooses to carry these benefits forward until her project breaks even and generates the necessary taxable income and, hence, tax liability to use them, she may be able to realize only a third of their subsidy value.¹⁰¹ Alternatively, the developer may monetize her tax benefits by bringing in a tax equity investor whose capital contribution effectively buys the right to use the project’s tax benefits to reduce the investor’s tax liability from other sources. But even with the help of a tax equity investor, renewable energy developers can, at most, realize two-thirds of the value of their project’s tax benefits.¹⁰² The required tax equity is scarce and expensive, especially in a slow economy, limits investment liquidity, drives up transaction costs, precludes other, lower-cost financing options and, in the end, puts more money in the pockets of investors and lawyers than solar panels on the roof or wind turbines in the ground.

II. Qualitative Adjustments – A Refundable / Tradable Solar ITC¹⁰³

The tax expenditure literature has long recognized the broader challenges associated with government use of tax incentives to subsidize socially beneficial activities, especially by emerging industries, start-up companies and other revenue-challenged firms.¹⁰⁴ Tax

⁹⁹ FISHER, et al., *Tax Credits, Tax Equity and Alternatives to Spur Clean Energy Financing* (U.S. Partnership for Renewable Energy Finance 2011) p. 3.

¹⁰⁰ See UDAY VARADARAJAN, et al., *Supporting Renewables while Saving Taxpayers Money* (Climate Policy Initiative 2012) p. 4

¹⁰¹ See VARADARAJAN, et al., *Supporting Renewables while Saving Taxpayers Money* (Climate Policy Initiative 2012) , at 4; see also *supra* note 21 (offering a sample calculation of the net present value of carried-forward tax credits).

¹⁰² See VARADARAJAN, et al., *Supporting Renewables while Saving Taxpayers Money* (Climate Policy Initiative 2012) , at 4.

¹⁰³ The following discussion is based on MORMANN, *Beyond Tax Credits: Smarter Tax Policy for a Cleaner, More Democratic Energy Future*, 31 *Yale J. on Reg.* 303 (2014) p.335 et seq., available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=236778.

¹⁰⁴ See, e.g., STANLEY S. SURREY, *Pathways to Tax Reform* (Harvard University Press 1973) (discussing the inequities from tax incentives’ greater value for high-income than low-income taxpayers); WARREN & AUERBACH,

credits for solar and other renewable energy represent a particularly dramatic example of these challenges, for a variety of reasons. However one may feel about the tax system's general suitability for promoting climate change mitigation, technological innovation, and other non-tax policy goals¹⁰⁵ through Pigouvian¹⁰⁶ tax expenditures, a government subsidy becomes untenable based purely on efficiency grounds if only one to two thirds of its value actually goes to fund the targeted activity. Moreover, the ability of a small group of high-income entities to divert significant portions of the subsidy into their own pockets raises serious concerns over taxpayer equity. Lastly, the tax credit regime's inefficiencies translate to suboptimal deployment rates that, in turn, inhibit continued growth in solar PV deployment.

A possible remedy for the aforementioned challenges would be to replace the current regime of federal tax credits with an altogether different, tax-independent policy approach to support large-scale deployment of solar and other renewables. Three types of policy proposals—calling for some version of a federal cap-and-trade scheme, RPS, or feed-in tariff—have dominated the debate on Capitol Hill in recent years. Notwithstanding the relative strengths of each of these policies, none has managed to gain much traction on Capitol Hill. Over thirty failed proposals for a federal cap-and-trade regime, RPS, or feed-in tariff raise serious doubt as to their political viability.¹⁰⁷ Federal tax incentives for renewable energy, meanwhile, have managed to garner sufficient political support for periodic extensions and renewals across various Congresses and administrations. Considering the many inefficiencies of tax credits and other tax breaks for renewables, this political success speaks less to their relative efficacy and efficiency compared to competing policies than to the political economy of renewable energy policy. The greater political appeal of “carrots” in the form of tax breaks compared to the “stick” of pricing green-

Transferability of Tax Incentives and the Fiction of Safe Harbor Leasing, 95 Harv. L. Rev. 1752 (1982), at 1758-59 (describing the difficulties that start-up and loss companies confront in using tax credits and depreciation deductions).

¹⁰⁵ Commentators have long debated whether the tax system should be used to implement public spending programs. See, e.g., EDWARD A. ZELINSKY, *James Madison and Public Choice at Gucci Gulch: A Procedural Defense of Tax Expenditures and Tax Institutions*, 102 Yale L. J. 1165 (1993); DANIEL N. SHAVIRO, *Rethinking Tax Expenditures and Fiscal Language*, 57 Tax L. Rev. 187 (2004) (both pointing to the merits of using the tax system to promote non-tax policy objectives); EDWARD D. KLEINBARD, *The Congress Within the Congress: How Tax Expenditures Distort Our Budget and Our Political Process*, Ohio N. Univ. L. Rev. 1 (2010); J. CLIFTON FLEMING JR. & ROBERT J. PERONI, *Can Tax Expenditure Analysis Be Divorced From a Normative Tax Base?: A Critique of the "New Paradigm" and Its Denouement*, 30 Va. Tax Rev. 135 (2010) (both criticizing the tax system's use to promote non-tax policy objectives).

¹⁰⁶ Named after economist Arthur C. Pigou, Pigouvian tax measures are used to remedy issues associated with externalities by helping producers internalize the (positive or negative) cost to society of their activity. For an overview of the economics behind Pigouvian tax measures, see BRIAN GALLE, *The Tragedy of the Carrots: Economics and Politics in the Choice of Price Instruments*, 64 Stan. L. Rev. 797 (2012).

¹⁰⁷ For evidence of the failed campaigns for a federal cap-and-trade regime, see S. 1733, 111th Cong. (2009); and H.R. 2454, 111th Cong. (2009). For reports of the failed campaigns for a federal RPS, see LINCOLN L. DAVIES, *Power Forward: The Argument for a National RPS*, 42 Conn. L. Rev. 1340 (2010), at 1341; and SHELLEY WELTON, *From the States Up: Building a National Renewable Energy Policy*, 17 N.Y.U. Envtl. L.J. 987 (2009). For evidence of the failed campaigns for a federal feed-in tariff, see Renewable Energy Jobs and Security Act, H.R. 6401, 110th Cong. (2008).

house gas emissions confirms common intuition.¹⁰⁸ But why do tax breaks fare so much better on Capitol Hill than other, more cost-effective carrots, such as direct cash subsidies, an RPS, or a feed-in tariff? The answer to this question lies, at least in part, in the preferential treatment of tax expenditures in terms of their budgetary consideration.

The Congressional Budget Act of 1974 has since introduced the mandatory compilation of tax expenditures into the budget process, but tax expenditures still avoid the annual review required for other spending measures.¹⁰⁹ This budgetary treatment has been suggested to lower the political saliency of tax expenditures, often allowing them to fly under the radar of public opinion and, therefore, requiring less political capital to enact than other, more direct spending measures.¹¹⁰ Moreover, discretionary spending is frequently subject to strict limits, while tax expenditures have rarely been subject to similar controls.¹¹¹ Finally, tax credits, depreciation deductions, and other tax expenditures are likely to be more philosophically appealing to those politicians and voters calling for reductions in taxpayers' overall tax burden.

The systemic preference for tax expenditures over more direct spending measures suggests that the best way to promote both fiscal sustainability and renewable energy deployment, at least in the near term, may be to fix rather than replace the current regime of federal tax credits for renewables. A number of scholars have argued for the tradability or refundability of tax credits in general.¹¹² In the context of renewable energy, either approach would go a long way in allowing developers to benefit from their tax credits without incurring the efficiency losses associated with the need to bring in a tax equity investor.

In light of today's pervasive practice of "trading" tax credits through complex and costly tax equity deals, the tax code's official endorsement of tradability for the §48 solar ITC would divert considerably less of the tax credit's subsidy value to tax equity investors and lawyers. The ability to officially trade tax credits – without the need for costly workarounds – would ensure that, despite solar developers' common lack of sufficient tax liabilities to offset with their tax credits, the underlying taxpayer dollars actually go to fund the purchase and installation of solar equipment on the nation's rooftops and desert

¹⁰⁸ See GALLE, *The Tragedy of the Carrots: Economics and Politics in the Choice of Price Instruments*, 64 Stan. L. Rev. 797 (2012), at 841 (discussing the "social overproduction of carrots").

¹⁰⁹ See CLINTON G. WALLACE, *The Case for Tradable Tax Credits*, 8 N.Y.U. J. L. & Bus. 227 (2011), at 155.

¹¹⁰ See GALLE, *The Tragedy of the Carrots: Economics and Politics in the Choice of Price Instruments*, 64 Stan. L. Rev. 797 (2012), at 844; KLEINBARD, *The Congress Within the Congress: How Tax Expenditures Distort Our Budget and Our Political Process*, Ohio N. Univ. L. Rev. 1 (2010), at 18.

¹¹¹ See WALLACE, *The Case for Tradable Tax Credits*, 8 N.Y.U. J. L. & Bus. 227 (2011), at 272.

¹¹² See, e.g., BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006) (refundability); WALLACE, *The Case for Tradable Tax Credits*, 8 N.Y.U. J. L. & Bus. 227 (2011) (tradability).

sands. Notwithstanding the striking arguments in favor of tradable tax credits, the tax code's general prohibition of trading in tax attributes still stands strong, with only a tiny fraction of all tax credits authorized for trading.¹¹³ More importantly, making the §48 solar ITC and other renewable energy tax credits tradable would provide but a partial fix to the inefficiencies identified above. To be sure, the tax code's endorsement of tax credit trading would eliminate the need for costly and complex deal structures, render solar and other renewable energy investments more liquid, and allow for more cost-efficient debt financing. But even an officially tradable §48 ITC would still require solar developers to find off-takers with sufficient tax liabilities to offset. In other words, tradability would not dispense with the need for tax equity that continues to be scarce, expensive, and cyclical.

Refundability of the §48 ITC and other renewable energy tax credits would provide a more comprehensive remedy for the inefficiencies that the current regime of federal tax credit support infuses in the deployment process of solar and other renewables. If solar developers could choose freely whether to use their §48 ITC to offset existing tax liabilities or, in the absence thereof, to turn these credits into cash payments from the Internal Revenue Service, tax equity would no longer be part of the solar finance equation. Unlike their tradable counterparts, refundable tax credits would, therefore, remedy not only the inefficiencies associated with costly, illiquid, and debt-averse tax equity deal structures but, in addition, altogether eliminate the need for scarce, expensive, and cyclical tax equity. Critically, making the §48 ITC and other tax credits for renewables refundable would lift the tax equity-imposed restrictions on the overall market size and growth of the renewable energy marketplace. With trillions of dollars of pension funds, sovereign wealth funds, and other currently sidelined investment capital¹¹⁴ finally able to participate in the build-out of clean, renewable energy technologies, growth in the solar marketplace would cease to be limited by the profitability and, hence, tax liabilities of some two dozen tax equity investors.¹¹⁵ The §1603 cash grant interlude illustrates the industry's appreciation for a subsidy that frees developers from the tether of tax equity. Given the choice between the PTC, the ITC and the cash grant, renewable energy developers overwhelmingly opted for cash instead of credits.¹¹⁶

¹¹³ See WALLACE, *The Case for Tradable Tax Credits*, 8 N.Y.U. J. L. & Bus. 227 (2011), at 237 (citing the Low-Income Housing Tax Credit and the New Markets Tax Credit as examples of tradable tax credits).

¹¹⁴ See MENDELSON & FELDMAN, *Financing U.S. Renewable Energy Projects Through Public Capital Vehicles: Qualitative and Quantitative Benefits* (National Renewable Energy Laboratory 2013), <http://www.nrel.gov/docs/fy13osti/58315.pdf>.

¹¹⁵ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, Project Finance Newswire 28 (May 2012) at 29.

¹¹⁶ See BOLINGER, et al., *Preliminary Evaluation of the Section 1603 Treasury Grant Program for Renewable Power Projects in the United States*, 38 Energy Policy 6804 (2010) p. 6806 (noting that nearly two thirds of all wind

Despite the strong economic and distributional arguments in favor of refundable tax credits,¹¹⁷ the tax code currently reserves the refundability of tax credits for a few select situations.¹¹⁸ The opposition to refundable tax credits is based on concerns that refundability would turn the tax system into a welfare system and lead to fraud and abuse.¹¹⁹ None of these concerns, however, are insurmountable as illustrated by existing refundable tax credits, such as the Earned Income Tax Credit and the Child Tax Credit,¹²⁰

III. Beyond Tax Credits – MLPs and REITs for Solar and Other Renewables¹²¹

Thinking outside the tax-credit box, policymakers could look to other sectors of the economy for guidance on how to best use tax policy to promote investment and economic growth in solar and other renewables. MLPs and REITs, two tax-privileged structures with a proven track record of promoting investment in oil, gas, and other conventional energy infrastructure are particularly attractive. MLPs and REITs foster investment in eligible assets and activities by paying income tax only at the investor level rather than both the entity and investor levels as classic corporations do (*infra* A.). The history of MLPs and REITs reflects a trend toward gradual expansion of the scope of qualifying investments (*infra* B.). Once opened up to renewable energy investment, MLPs and REITs could significantly reduce the cost of capital for renewable power projects, foster popular support, and create stronger, more transparent markets for renewables (*infra* C.). MLPs

capacity additions in 2009 chose the cash grant over the tax credit option); see also MINTZ LEVIN & GTM RESEARCH, *Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook* (Mintz Levin 2012) p. 8 (pointing to industry estimates that 65% to 85% of utility-scale wind projects opted to elect the cash grant over tax credits). The industry's strong preference for cash in lieu of both production and investment tax credits suggests that the respective subsidies' linkage to performance risk are, in fact, less of a factor than the medium of subsidy support (cash vs. tax credit).

¹¹⁷ BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006) 43.

¹¹⁸ See BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006), at 33 (referencing the Earned Income Tax Credit, the Child Tax Credit, and a small health insurance credit as the three principal refundable tax credits).

¹¹⁹ For a summary of the primary arguments against refundability of tax credits, see BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006) p. 65-72. Due to the functional parallels between refundability and tradability, these arguments can also be applied against tradable tax credits. See WALLACE, *The Case for Tradable Tax Credits*, 8 N.Y.U. J. L. & Bus. 227 (2011), at 247 (describing the economic equivalence between tradable and refundable tax credits and arguing that “[t]he efficiency of tradable tax credits matches, and in some instances may surpass, that of refundable tax credits”).

¹²⁰ See BATCHELDER, et al., *Efficiency and Tax Incentives: The Case for Refundable Tax Credits*, 59 Stan. L. Rev. 23 (2006), at 33.

¹²¹ The following discussion is based on MORMANN, *Beyond Tax Credits: Smarter Tax Policy for a Cleaner, More Democratic Energy Future*, 31 Yale J. on Reg. 303 (2014) p. 339 et seq., available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2367780.

and REITs for renewables would impose a significantly lower burden on the federal budget than the existing regime of federal tax credits (*infra* D.). Federal policymakers have a choice between various options how to best open MLPs and REITs up to solar and other renewable energy investment (*infra* E.). Importantly, the YieldCo structure that has recently garnered much attention as a potential investment vehicle for renewable energy finance cannot replace MLPs and REITs for solar and other renewables (*infra* F.).

A. How MLPs and REITs Work

As their name implies, MLPs are limited partnerships, typically formed under the Delaware Revised Uniform Limited Partnership Act, with one or more general partners and thousands of limited partners.¹²² The general partners usually hold an ownership stake of approximately 2% and are tasked with the partnership's management.¹²³ General partners may or may not have incentive distribution rights granting them a preferred share of the MLP's cash distributions that increases with each marginal increase in the partnership's overall cash distributions.¹²⁴ The MLP's limited partners, referred to as unitholders, provide capital in exchange for the prospect of quarterly cash distributions similar to a dividend but they have no part in the partnership's operations or management.¹²⁵ MLPs are typically required to pay out all available cash to unitholders except for those cash flows that the management considers required for "the proper conduct of the business."¹²⁶

Like classic corporations, MLPs can be traded on public exchanges to increase investment liquidity and appeal to a broader range of investors.¹²⁷ MLPs typically do not own and operate their assets directly but indirectly through a subsidiary operating com-

¹²² See PATRICK W. MATTINGLY, *Master Limited Partnerships*, 28 Energy & Min. L. Inst. ch. 5 118 (2008) p. 119, 125; NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 36. Under state law, MLPs can also be organized as limited liability companies (LLCs) and other unincorporated entities while still maintaining the MLP treatment for federal tax purposes, see MATTINGLY, *Master Limited Partnerships*, 28 Energy & Min. L. Inst. ch. 5 118 (2008) p. 119.

¹²³ See MOLLY F. SHERLOCK & MARK P. KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 2; MICHAEL BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 15.

¹²⁴ See NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 39, 40; BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 20; SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 2.

¹²⁵ See BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 15 NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 36; SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 2.

¹²⁶ See BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 21.

¹²⁷ See MATTINGLY, *Master Limited Partnerships*, 28 Energy & Min. L. Inst. ch. 5 118 (2008) p. 123; NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 46.

pany.¹²⁸ Unlike classic corporations, MLPs are not taxed at both the entity and shareholder level but, instead, pass all tax items through to their unitholders who then pay tax only at their individual rates.¹²⁹ As pass-through entities, MLPs can raise capital at lower cost, allowing them to build and operate low-return assets, such as rate-regulated pipelines while still offering rates of return that are high enough to attract investors on capital markets.¹³⁰ These tax privileges, however, come at the price of added complexities to tax reporting for MLP investors and the exclusion of certain investors from MLP investment.¹³¹

To qualify for the tax code's privileged treatment as a pass-through entity while maintaining the liquidity profile of a classic corporation, MLPs must derive at least 90% of their income from qualified sources.¹³² These sources include dividends, rents, gains from the disposition of real estate and capital assets, income and gains from commodities trading, and income and gains from qualifying activities related to minerals and natural resources as well as industrial source carbon dioxide.¹³³ Qualifying activities range from exploration, development, and mining to production, processing, and transporting, to the marketing of minerals, natural resources, and industrial carbon dioxide.¹³⁴ Not all minerals and natural resources qualify, however: the tax code limits MLP eligibility to income from exhaustible minerals and natural resources, i.e., "any product of a character with respect to which a deduction for depletion is allowable under Section 611 of the Code."¹³⁵ The only statutory exception in favor of potentially inexhaustible resources allows MLPs to derive qualifying income from the transportation and storage of select renewable and alternative fuels, such as ethanol and biodiesel.¹³⁶

¹²⁸ See SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 3.

¹²⁹ See NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 43; BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 16.

¹³⁰ See NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 45.

¹³¹ See SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 4; MATTINGLY, *Master Limited Partnerships*, 28 *Energy & Min. L. Inst.* ch. 5 118 (2008) p. 128.

¹³² 26 U.S.C. §7704(c). See SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 6.

¹³³ 26 U.S.C. §7704(d)(1). See also BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 15; ERIC M. CONKLIN, *Master Limited Partnerships Primer – A Guide to Understanding the MLP* (Credit Suisse First Boston Equity Research 2005) p. 11.

¹³⁴ 26 U.S.C. §7704(d)(1)(E). See also MATTINGLY, *Master Limited Partnerships*, 28 *Energy & Min. L. Inst.* ch. 5 118 (2008) p. 120.

¹³⁵ 26 U.S.C. §7704(d)(1)(last sentence).

¹³⁶ 26 U.S.C. §7704(d)(1)(E).

For REITs, the tax code sets forth a number of organizational requirements for a corporation, trust, or association that would otherwise be taxable as a domestic corporation to claim the tax-privileged status of this financing vehicle.¹³⁷ For instance, REITs must be managed by trustees or directors and are required to issue transferable shares or certificates.¹³⁸ These shares or certificates cannot be closely held but, rather, must be owned by no fewer than 100 shareholders.¹³⁹

REITs resemble MLPs in their avoidance of double-layer taxation but achieve their status as pass-through entities in a different manner. Unlike MLPs, REITs are not tax-exempt at the entity level.¹⁴⁰ Instead, a REIT can reduce its taxable income by a deduction in the amount of the qualifying dividends that are paid out to its shareholders. These dividends are then taxed only at the shareholder level as part of their gross income.¹⁴¹ To qualify for the dividend deduction from taxable income, a REIT must distribute at least 90% of its annual taxable income to its shareholders.¹⁴² Like MLPs, most REITs are publicly traded although private REITs whose shares are not traded on public changes have recently gained in popularity, especially among tax-exempt institutional and foreign investors.¹⁴³

To qualify for tax-privileged treatment as pass-through entities, the tax code requires REITs to fulfill the requirements of a series of asset and income tests.¹⁴⁴ The most important of a total of six asset tests requires that 75% of the REIT's assets be composed of real estate interests including mortgages and shares in other REITs, cash and cash items, as well as government securities.¹⁴⁵ The two income tests reflect the emphasis on real estate. The first test requires 95% or more of the REIT's gross annual income to come from real estate rents, gains from the disposition of real estate and related mortgages, or investment income, including dividends, interests, and gains from stocks and securities sales.¹⁴⁶ The second test further emphasizes the focus on real estate by mandating that at

¹³⁷ 26 U.S.C. §856(a). See also JOSHUA L. STURTEVANT, *The S-REIT: An Investment-Driven Solution to Solar Development Problems* (The GW Solar Institute 2011) p. 12.

¹³⁸ 26 U.S.C. §856(a)(1)-(2).

¹³⁹ 26 U.S.C. §856(a)(5)-(6).

¹⁴⁰ See PATRICK DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410; STURTEVANT, *The S-REIT: An Investment-Driven Solution to Solar Development Problems* (The GW Solar Institute 2011) p. 13; DAVE LEVY, et al., *Wind REITS - The New Tax Equity*, Public Utilities Fortnightly 36 (2012) p. 37, 39.

¹⁴¹ See DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410.

¹⁴² 26 U.S.C. §857(a)(1)(A). See also STURTEVANT, *The S-REIT: An Investment-Driven Solution to Solar Development Problems* (The GW Solar Institute 2011) p. 13; LEVY, et al., *Wind REITS - The New Tax Equity*, Public Utilities Fortnightly 36 (2012) p. 39; DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410 (discussing that the minimum distribution requirement does not apply to capital gains income).

¹⁴³ See DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410.

¹⁴⁴ See 26 U.S.C. §856(c)+(d) (asset and income tests) and 26 U.S.C. §857 (taxation of REITs).

¹⁴⁵ See DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410.

¹⁴⁶ See STEFANO SIMONTACCHI & UWE STOSCHEK, *Guide to Global Real Estate Investment Trusts* (Kluwer Law 2012) p. 18; DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410.

least 75% of the REIT's gross annual income be derived from sources specifically related to real property.¹⁴⁷

B. A Brief History of MLPs and REITs

Apache Petroleum formed the first MLP in 1981,¹⁴⁸ the same year that the Economic Recovery Tax Act of 1981 gave partnerships a boost by reducing the top individual marginal tax rate from 70% to 50%.¹⁴⁹ Five years later, the Tax Reform Act of 1986 further increased the tax attractiveness of partnership business structures by reducing the top marginal income tax rate for individuals to a level below the top marginal tax rate for corporations.¹⁵⁰ The MLP structure was quickly adopted across a wide range of industries, from hotels and restaurants to investment advisors to amusement parks; even the Boston Celtics became an MLP.¹⁵¹ Fearing that widespread use of the tax-privileged MLP structure in lieu of the classic corporation would erode the corporate tax base, Congress used the Revenue Act of 1987 to restrict the tax-privileged use of MLPs and other publicly traded partnerships.¹⁵² As a general rule, any partnership whose ownership interests were publicly traded was to be treated as a corporation for tax purposes.¹⁵³ The Revenue Act of 1987, however, also established an exemption from corporate taxation for MLPs that derive at least 90% of their income from qualified sources, such as interests, dividends, rents, royalties as well as income and gains derived from minerals and natural resources.¹⁵⁴ One year later, the Technical Corrections Act of 1988 clarified that only “exhaustible” natural resources were intended to be sources of qualified income for tax-

¹⁴⁷ See SIMONTACCHI & STOSCHEK, *Guide to Global Real Estate Investment Trusts* (Kluwer Law 2012) 146 p. 18; DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012) p. 1410.

¹⁴⁸ See JOINT COMMITTEE ON TAXATION, *Tax Treatment of Master Limited Partnerships* (U.S. Government Printing Office 1987) p. 3. See also SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) 123 p. 5.

¹⁴⁹ P.L. 97-34. See also JANE R. LIVINGSTONE & THOMAS R. OMER, *Publicly Traded Partnerships, Tax Cost, and Choice of Entity*, Tax Notes 365 (2009) p. 366.

¹⁵⁰ P.L. 99-514.

¹⁵¹ See NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 12. See also JOHN W. JR. SLATER, *Publicly Traded Limited Partnership: An Emerging Financial Alternative to the Public Corporation*, 39 Bus. Law. 709 (1984) p. 710.

¹⁵² P.L. 100-203. See also H. Rept. 100-391, 100th Cong., 1st sess. 1066 (“To the extent activities that would otherwise be conducted in the corporate form, and earnings that would be subject to two levels of tax (at the corporate and shareholder levels), the growth of publically traded partnerships engaged in such activities tends to jeopardize the corporate tax base.”).

¹⁵³ 26 U.S.C. §7704(a). See also SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 6.

¹⁵⁴ 26 U.S.C. §7704(c). See SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 6.

privileged MLPs.¹⁵⁵ The accompanying Senate Report further clarified that “qualifying income does not include, for example, income from . . . hydroelectric, solar, wind, or nuclear power production.”¹⁵⁶ Following this initial wave of regulation, the tax code’s provisions regarding qualifying income for MLPs remained unchanged for over twenty years.¹⁵⁷ The Emergency Economic Stabilization Act of 2008 added certain renewable and alternative fuels as well as industrial carbon dioxide to the catalog of eligible sources of income for tax-privileged MLPs.¹⁵⁸ Today some 120 MLPs are listed on major stock exchanges with a few more trading over the counter.¹⁵⁹ More than 75% of MLPs are engaged in oil, gas, coal, and other energy-related activities.¹⁶⁰

The historic roots of REITs can be traced back to the late 1800s when so-called Massachusetts Trusts were used to pool property investments.¹⁶¹ Following a series of judicial decisions with wide-ranging effects on REITs and their taxation,¹⁶² today’s REIT regime was established in 1960 when President Eisenhower signed the REIT Act into law.¹⁶³ The Act allowed for the formation of REITs that enjoy essentially the same tax privileges as other pass-through entities so long as they meet the requirements of a series of asset and income tests.¹⁶⁴ The REIT Act’s purpose was to enable not only large institutional but also smaller individual investors to invest in large diversified portfolios of income-producing properties.¹⁶⁵ The first REITs to form, however, were so-called debt or mortgage REITs that originated construction loans.¹⁶⁶ It was not until after the Tax Reform Act of 1986 allowed REITs to not both own and manage their properties that the REIT

¹⁵⁵ P.L. 100-647. *See also* H.R. Conf. Rep. 100-1104, 5048 (5077) (“The conference agreement follows the Senate amendment; except that . . . minerals from sea water, the air, or similar inexhaustible sources, shall not be treated as a mineral or natural resource.”).

¹⁵⁶ S. REP. NO. 100-445, 424; *see also* H.R. REP. NO. 100-795, at 400.

¹⁵⁷ *See* SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 7.

¹⁵⁸ 26 U.S.C. §7704(d). *See* P.L. 110-343. *See also* Sen. Tom Harkin, Statements on Introduced Bill and Joint Resolutions, *Congressional Record*, daily edition, July 21, 2008, pp. S6973-S6974 (noting that the purpose of the amendments was to offer biofuels pipelines the same tax treatment as petroleum pipelines).

¹⁵⁹ *See* NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 23.

¹⁶⁰ *See* NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 29.

¹⁶¹ *See* JONATHAN S. KILPATRICK, *REITs 101* (Greenfield Advisors 2012) p. 2; STURTEVANT, *The S-REIT: An Investment-Driven Solution to Solar Development Problems* (The GW Solar Institute 2011) p. 8.

¹⁶² *See, e.g.,* *Eliot v. Freeman*, 220 U.S. 178 (1910); *Crocker v. Malley*, 249 U.S. 223 (1918); *Morrissey v. Commissioner*, 296 U.S. 344 (1935); *Commissioner v. North America Bond Trust*, 112 F.2d 545 (2nd Cir. 1941) (cert. denied 314 U.S. 701 (1941)).

¹⁶³ The REIT Act was part of the Cigar Excise Tax Extension Act of 1960, P.L. 86-779.

¹⁶⁴ *See* 26 U.S.C. §856(c)+(d) (asset and income tests) and 26 U.S.C. §857 (taxation of REITs).

¹⁶⁵ *See* SIMONTACCHI & STOSCHEK, *Guide to Global Real Estate Investment Trusts* (Kluwer Law 2012) p. 8; STURTEVANT, *The S-REIT: An Investment-Driven Solution to Solar Development Problems* (The GW Solar Institute 2011) p. 10.

¹⁶⁶ *See* KILPATRICK, *REITs 101* (Greenfield Advisors 2012) p. 2.

Act's promise began to be fulfilled as so-called equity REITs holding actual real estate assets took over.¹⁶⁷ In 1991 the first REIT went public marking "the dawn of the modern REIT era."¹⁶⁸

Over the past twenty years, a series of legislative and administrative acts have further bolstered the market appeal of REITs. The REIT Simplification Act of 1997 allowed REITs to provide a small amount of non-customary services to its tenants without disqualifying associated rental income from REIT eligibility.¹⁶⁹ The REIT Modernization Act of 1999 enabled REITs to form taxable subsidiaries that may deliver atypical services to REIT tenants and others.¹⁷⁰ The Internal Revenue Service, meanwhile, has issued a number of broadly applicable revenue rulings and fact-specific private letter rulings to clarify and broaden the definition of REIT-eligible assets and income.¹⁷¹ Today there are approximately 190 publicly listed REITs, most of which trade on the New York Stock Exchange.¹⁷²

C. What MLPs and REITs Can Do for Solar and Other Renewables

MLPs and REITs combine the tax privileges of traditional partnership structures with the fundraising advantages of classic corporations. Merging the best of both worlds, MLPs and REITs for renewables would enable project developers to tap into pools of capital that are wider, deeper, and cheaper than under existing financing structures (*infra* 1.). The broad investor appeal of both structures would help promote popular support for renewable energy development (*infra* 2.). The investment liquidity of publicly traded MLPs and REITs could create new markets and improve overall market transparency (*infra* 3.). Standardization can help reduce deal complexity and associated transaction costs (*infra* 4.).

¹⁶⁷ P.L. 99-514. See SIMONTACCHI & STOSCHEK, Guide to Global Real Estate Investment Trusts (Kluwer Law 2012) p. 9; KILPATRICK, REITs 101 (Greenfield Advisors 2012) p. 2.

¹⁶⁸ SIMONTACCHI & STOSCHEK, Guide to Global Real Estate Investment Trusts (Kluwer Law 2012) p. 9.

¹⁶⁹ P.L. 105-34. The REIT Simplification Act was part of the Taxpayer Relief Act of 1997.

¹⁷⁰ P.L. 106-170. The REIT Modernization Act was contained in the Ticket to Work and Work Incentives Improvement Act of 1999. For an example of REIT use of the taxable subsidiary option, see LEVY, et al., *Wind REITS - The New Tax Equity*, Public Utilities Fortnightly 36 (2012) p. 42.

¹⁷¹ See, e.g., Rev. Rul. 69-94, 1969-1 C.B. 189 (railroad trackage, roadbed, bridges, and tunnels); Rev. Rul. 75-424, 1975-2 C.B. 270 (microwave transmitting and receiving towers); LTR 200752012, Doc 1999-4359, 1999 TNT 20-27 (data centers); LTR 200725015 (electricity transmission and distribution systems); LTR 201129007, Doc 2011-15976, 2011 TNT 142-32 (cell towers); LTR 201204006, Doc 2012-1665, 2012 TNT 19-25 (LED billboards).

¹⁷² See NATIONAL ASSOCIATION OF REAL ESTATE INVESTMENT TRUSTS, *REITWatch June 2013* (NAREIT 2013) p. 1.

1. Access to Capital Markets Lowers the Cost of Financing

MLPs and REITs have proven highly effective at raising capital on the New York Stock Exchange and other public capital markets. Despite the tax code's restrictions on eligible investment assets and activities, MLPs boast a current market capitalization exceeding \$490 billion with REITs weighing in at over \$670 billion.¹⁷³ Remarkably, MLPs and REITs have been able to raise these impressive amounts of capital while offering only modest annual dividend yields of 6.3% and 4.3% respectively.¹⁷⁴ Comparing these numbers to the yield rates of up to 15% or more that tax equity investors currently charge,¹⁷⁵ it becomes obvious by just how much renewable energy projects could reduce their cost of equity capital given access to MLP and REIT financing.

Moreover, unlike current tax equity structures,¹⁷⁶ both MLPs and REITs lend themselves to a well-balanced financing mix of equity and debt capital.¹⁷⁷ The capacity to combine low-cost equity capital from public markets with readily available debt at low interest rates puts MLPs and REITs in a prime position to drive down the overall cost of capital for renewable power projects. At a time when financing charges can drive up a renewable energy project's overall cost of electricity by 50% or more,¹⁷⁸ MLPs and REITs could go a long way in cutting the cost of renewable power.

2. Broad Investor Appeal Promotes Popular Support

The capital market success of MLPs and REITs is also a testament to both structures' ability to appeal to a broad spectrum of investors, ranging from pension funds, sovereign wealth funds, and other large-scale institutional investors to small-scale retail investors who trade stocks for their personal accounts.¹⁷⁹ The exclusivity of today's elite circle of tax equity investors has earned renewable energy tax credits the reputation of a "rich

¹⁷³ See NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 31; NATIONAL ASSOCIATION OF REAL ESTATE INVESTMENT TRUSTS, *REITWatch June 2013* (NAREIT 2013) p. 1.

¹⁷⁴ See BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 8; NATIONAL ASSOCIATION OF REAL ESTATE INVESTMENT TRUSTS, *REITWatch June 2013* (NAREIT 2013) p. 1. See also THEODORE DURBIN, et al., *MLP-ification: Focus on Energy* (Goldman Sachs Equity Research 2013) p. 7 (reporting average current yields of 6.5% for MLPs).

¹⁷⁵ See *supra* Section I.B.

¹⁷⁶ See *supra* Section I.F.

¹⁷⁷ See BLUM, et al., *MLP Primer* (Wells Fargo Securities Equity Research 2010) p. 73; NATIONAL ASSOCIATION OF REAL ESTATE INVESTMENT TRUSTS, *REITWatch June 2013* (NAREIT 2013) p. 2.

¹⁷⁸ See MICHAEL MENDELSON, et al., *The Impact of Financial Structure on the Cost of Solar Energy* (National Renewable Energy Laboratory 2012) p. 21; UDAY VARADARAJAN, et al., *The Impacts of Policy on the Financing of Renewable Projects: A Case Study Analysis* (Climate Policy Initiative 2011) p. 24.

¹⁷⁹ See MORMANN & REICHER, *How to Make Renewable Energy Competitive* (New York Times June 1, 2012) 33; BRUCE BULLOCK, et al., *Leveling the Playing Field: The Case for Master Limited Partnerships for Renewables* (Southern Methodist University 2012) p. 8.

man's policy."¹⁸⁰ In contrast, MLPs and REITs for renewables could usher in a veritable democratization of America's energy future. Just as REITs were originally introduced to encourage small-scale individual investment in commercial real estate, so could MLPs and REITs enable individual investors to participate in a renewable energy project and its profits.¹⁸¹ Publicly traded shares in renewable energy MLPs and REITs would allow millions of Americans to invest in the nation's energy future.

Besides lowering the industry's cost of capital, the democratization effect of "crowdfunding" for renewables through MLPs and REITs offers another, less salient but similarly important, benefit to renewable energy developers. Recent scholarship has identified behavioral factors such as local acceptance as key determinants of a renewable energy policy's deployment success.¹⁸² When renewable energy projects struggle to overcome local not-in-my-backyard reservations they often suffer from longer lead times and expensive litigation that drive up overall project costs, as evidenced by the fierce opposition to wind power projects in Vermont, Wisconsin, Wyoming, and the Nantucket Sound.¹⁸³ Conversely, renewable power projects that enjoy local support proceed more swiftly and more cost-effectively, as illustrated by the deployment success of participatory structures such as wind cooperatives, citizen wind farms, and community solar projects.¹⁸⁴ Greater involvement in renewable energy projects fosters higher levels of local acceptance.¹⁸⁵ With their own stake in America's clean energy future, MLP and REIT investors will likely become more supportive of local renewable power project development, instead of feeling like the victims of an aesthetic assault on their backyards by anonymous, corporate developers exploiting a "rich man's policy."¹⁸⁶ Thanks to its favorable impact on zoning, permitting, and other local gate-keeping functions, widespread MLP and REIT investment in renewables has the potential to reduce a project's lead times and thereby translate to real savings for renewable power developers.

¹⁸⁰ DAVID TOKE, *Are Green Electricity Certificates the Way forward for Renewable Energy? An Evaluation of the United Kingdom's Renewables Obligation in the Context of International Comparisons*, 23 *Environment and Planning C: Government and Policy* 361 (2005) p. 194.

¹⁸¹ *See supra* Section III.B.

¹⁸² *See* FELIX MORMANN, *Enhancing the Investor Appeal of Renewable Energy*, 42 *Envtl. L.* 681 (2012) p. 709.

¹⁸³ For details on local zoning efforts against wind development in Wyoming, the protracted conflict over wind power projects off Cape Cod, and debates over the aesthetics of ridgeline wind projects in Vermont, see TIMOTHY P. DUANE, *Greening the Grid: Implementing Climate Change Policy through Energy Efficiency, Renewable Portfolio Standards, and Strategic Transmission System Investments*, 34 *Vt. L. Rev.* 711 (2010) pp. 775 et seq. See also ROBERT J. MICHAELS, *National Renewable Portfolio Standard: Smart Policy or Misguided Gesture?*, 29 *Energy L.J.* 79 (2008) p. 98.

¹⁸⁴ *See* FELIX MORMANN, *Requirements for a Renewables Revolution*, 38 *Ecology L. Q.* 901 (2011) p. 963.

¹⁸⁵ *Id.* at p. 963.

¹⁸⁶ *See* MORMANN, *Enhancing the Investor Appeal of Renewable Energy*, 42 *Envtl. L.* 681 (2012) p. 723; TOKE, *Are Green Electricity Certificates the Way forward for Renewable Energy? An Evaluation of the United Kingdom's Renewables Obligation in the Context of International Comparisons*, 23 *Environment and Planning C: Government and Policy* 361 (2005) 180 p. 194.

3. Investment Liquidity Creates Markets and Transparency

With publicly traded shares, MLPs and REITs could dramatically improve the liquidity of renewable energy investment. In contrast to the tax code's restrictions on the sale and resale of tax equity stakes in renewable power projects,¹⁸⁷ renewable energy MLPs and REITs trading on major exchanges would allow investors to time their investment decisions according to their own needs as well as market developments. By promoting greater investment liquidity, MLPs and REITs for renewables could provide three distinct benefits to investors and developers over the useful life of a project. First, the option value of being able to sell shares whenever necessary or convenient would greatly increase the ability of renewable power developers to raise much needed up-front equity capital to finance their projects.¹⁸⁸

Second, MLPs and REITs would help create a sound secondary market for existing renewable energy projects to refinance themselves. This would be especially important in light of the current marketplace with its heavy reliance on scarce tax equity. Once a project's eligibility for tax credits and the associated recapture period have lapsed, the project no longer needs to maintain costly tax equity capital. Meanwhile, new projects are constantly searching for tax investors in order to monetize federal tax credits. In the interest of overall market efficiency, therefore, tax equity that is no longer needed for existing projects should be re-invested as quickly as possible in order to incubate new renewable power projects.¹⁸⁹ Similarly, the developer should be free to pull out and re-invest her own equity capital to develop the next project as soon as possible. In both cases, however, re-investment first requires a viable exit option. MLPs and REITs can provide that exit option by allowing renewable energy projects to replace developer equity and tax equity with shareholder capital raised on public markets.

The third benefit from greater investment liquidity for renewables through publicly traded MLPs and REITs hinges on the role of capital markets as conveyors of information. As demand and supply determine the trading prices of shares, they also provide critical information to investors. The trading prices for renewable energy MLP and REIT shares may help investors better assess a project's technological reliability, resource quality, and other critical characteristics. Furthermore, publicly traded MLPs and REITs are subject to the usual capital market reporting requirements, which would further improve

¹⁸⁷ See *supra* Section I.D.

¹⁸⁸ See MEISTER, *Sunny Dispositions - Modernizing Investment Tax Credit Recapture Rules for Solar Energy Project Finance After the Stimulus* (The GW Solar Institute 2012) (highlighting the premium investors place on asset liquidity).

¹⁸⁹ See ALEX KOVACHEVA & MICHEL DI CAPUA, *Master Limited Partnerships for US Renewables: Panacea or Pie in the Sky?* (Bloomberg New Energy Finance 2012) p. 8.

the transparency of renewable energy development and investment.¹⁹⁰ Together, the increased transparency of capital markets and the resulting competitive pressures can be expected to further strengthen the professionalism and quality of renewable power project development.¹⁹¹

4. Standardization Reduces Deal Complexity and Cost

Finally, MLPs and REITs for renewables would significantly reduce the complexity of project financing structures and, with it, associated lead times and transaction costs.¹⁹² Tax equity deals require one-off structures that need to be custom-tailored to meet the specific needs of the individual tax investor. In the few instances that a developer can convince the tax investor to bring in a lender to help finance the project with debt capital, the deal structure is further complicated by the need to negotiate and execute forbearance and standstill agreements between the lender and tax equity investor.¹⁹³ In contrast, MLPs and REITs allow for relatively standardized deal structures that help reduce complexity and transaction costs.¹⁹⁴ Moreover, renewable energy developers that use MLPs and REITs to finance and operate their projects need not reinvent the wheel. Instead, they can model their financing and operating structures after one of the many MLPs or the growing number of REITs for conventional energy sources with similar risk and return profiles.¹⁹⁵

D. Budget Implications of MLPs and REITs for Solar and Other Renewables

The most commonly voiced concerns over opening MLPs and REITs to renewable energy investment revolve around fears that extending the structures' tax privileges to renewables "could narrow the corporate tax base, which is one of the reasons access to this structure was limited in the first place."¹⁹⁶ In light of federal government debt exceeding

¹⁹⁰ See, e.g., SIMONTACCHI & STOSCHEK, *Guide to Global Real Estate Investment Trusts* (Kluwer Law 2012) p. 20; MATTINGLY, *Master Limited Partnerships*, 28 *Energy & Min. L. Inst.* ch. 5 118 (2008) p. 126.

¹⁹¹ See CHADBOURNE & PARKE LLP, *State of the Tax Equity Market*, *Project Finance Newswire* 28 (May 2012) p. 37 (discussing the impact that competition among developers for scarce tax equity has had on the quality of projects).

¹⁹² For a detailed discussion of the cost and complexity of tax equity financing structures for renewable energy, see *supra* Section I.E.

¹⁹³ See *supra* Section I.F.

¹⁹⁴ See, e.g., MATTINGLY, *Master Limited Partnerships*, 28 *Energy & Min. L. Inst.* ch. 5 118 (2008) p. 126; SIMONTACCHI & STOSCHEK, *Guide to Global Real Estate Investment Trusts* (Kluwer Law 2012) p. 14.

¹⁹⁵ For an overview of the many energy-related MLPs that could serve as model structures for a renewable energy MLP, see NATIONAL ASSOCIATION OF PUBLICLY TRADED PARTNERSHIPS, *Master Limited Partnerships 101: Understanding MLPs* (NAPTP 2013) p. 30.

¹⁹⁶ SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) intro, p. 9

\$16 trillion some analysts and politicians suggest that, rather than extend MLP and REIT eligibility from oil, gas, and other conventional energy sources, the two structures and their respective tax privileges should be abolished altogether.¹⁹⁷ Similarly, the End Polluter Welfare Act, introduced in both chambers of the 112th Congress in 2012, called for the elimination of virtually all tax privileges for fossil fuels, including their eligibility for MLP investment.¹⁹⁸ To be sure, elimination of the panoply of tax subsidies for oil, gas, coal, and other conventional energy would go a long way in cutting federal tax expenditures. To do so at the expense of access to similar incentives for emerging low-carbon renewable energy technologies, however, would further entrench high-carbon energy incumbents. Thanks to decades of federal subsidies these incumbents have reached such strong market positions that emerging renewables struggle to overcome significant marketplace barriers to entry even when they receive federal (and state) incentives to help them become cost competitive, let alone without them.¹⁹⁹ Moreover, sweeping elimination of all energy subsidies would raise the cost of energy to industry and consumers which, in turn, would likely stifle overall economic activity and growth, threatening American leadership and competitiveness in the global economy.²⁰⁰

Concern over the budgetary impacts of new tax policy is well warranted at a time of “fiscal cliffs” and austerity measures.²⁰¹ It is important, however, to evaluate the budget effects of new tax policy in context. In the case of MLPs and REITs for renewables this context assuages fears that extension of both structures to renewable energy investment could erode the corporate tax base. As discussed earlier, the vast majority of renewable energy projects use some version of the classic partnership structure to finance themselves.²⁰² Given the partnership’s character as a pass-through entity, these project companies do not pay income tax at the entity level. In other words, these renewable energy projects already do not pay any corporate income tax. Hence, if these projects are given access to the MLP and REIT structures it is not their tax status that will change but their ability to raise low-cost capital on public markets. With or without access to MLPs and REITs, the income of most renewable energy projects does not factor into the corporate

¹⁹⁷ See, e.g., DOUG KOPLOW, *Too Big to Ignore: Subsidies to Fossil Fuel Master Limited Partnerships* (Earth Track 2013) p. 24 (arguing that MLPs should be abandoned altogether).

¹⁹⁸ See H.R. 5745; S. 3060, available at <http://www.govtrack.us/congress/bills/112/hr5745/text> (last visited Dec. 5, 2014).

¹⁹⁹ For a detailed discussion of the marketplace barriers to entry for renewable energy technologies, see MORMANN, *Requirements for a Renewables Revolution*, 38 Ecology L. Q. 901 (2011) p. 919.

²⁰⁰ See MORMANN & REICHER, *How to Make Renewable Energy Competitive* (New York Times June 1, 2012) 33; SHERLOCK & KEIGHTLEY, *Master Limited Partnerships: A Policy Option for the Renewable Energy Industry* (Congressional Research Service 2011) p. 10.

²⁰¹ See <http://politicalticker.blogs.cnn.com/2010/02/03/cnn-fact-check-the-last-president-to-balance-the-budget/> (last visited Dec. 5, 2014).

²⁰² See *supra* Section I.E.

tax base. Since the counterfactual to renewable energy MLPs and REITs is often not the renewable energy corporation but rather the renewable energy partnership, fears that opening MLPs and REITs to renewables would erode the corporate tax base are unfounded.²⁰³ It is impossible to erode what was never there.

Even the absolute (as opposed to additional) cost to taxpayers of giving renewable energy access to MLPs and REITs is expected to be relatively modest. In its recent scoring of the MLP Parity Act's projected impact on the federal budget, the Joint Committee on Taxation forecast that the Act's implementation would require tax expenditures of \$307 million over five years and \$1.3 billion over ten years.²⁰⁴ These numbers are remarkable for two reasons. First, they suggest a significantly lower cost to taxpayers than the existing regime of federal tax credits for renewables, pegged at a total of \$12.6 billion for fiscal years 2013-17.²⁰⁵ Second, the MLP Parity Act, as analyzed by the Joint Committee on Taxation, would grant MLP access not only to renewable energy but also to a range of other clean energy technologies, including energy efficiency, carbon capture and sequestration, combined heat and power, electricity storage, and renewable fuels.²⁰⁶ Accordingly, renewable energy MLPs should be expected to cost taxpayers only a fraction of the MLP Parity Act's overall projected cost. Importantly, the MLP Parity Act's relatively low budgetary impact should not be misunderstood as an indication that the Joint Committee on Taxation does not expect the MLP structure to be popular among clean energy developers and investors. The Committee's forecast of the budget impact of existing, fossil energy MLPs for 2013-17²⁰⁷ suggests that one federal tax dollar supports some sixty dollars of tax-advantaged MLP capital over five years.²⁰⁸ Based on this back-of-the-envelope calculation, the Committee's scoring of the MLP Parity Act suggests that clean energy MLPs could, in fact, raise close to \$18 billion of equity capital in the first five years and nearly \$60 billion over ten years.²⁰⁹

²⁰³ It should be noted that the choice between partnership and corporate structure might be more challenging if the current system of tax credits and the resulting need for tax equity were eliminated.

²⁰⁴ See Mormann, Reicher and Muro, *Clean Energy Scores a Success with the Master Limited Partnership Act*, BROOKINGS INST. (2013), <http://www.brookings.edu/research/opinions/2013/12/19-clean-energy-mormann-reicher-muro>.

²⁰⁵ See JOINT COMMITTEE ON TAXATION, *Estimates of Federal Tax Expenditures for Fiscal Years 2012-2017* (U.S. Government Printing Office 2013), at 31.

²⁰⁶ See H.R. 1696, S. 795, 113th Congress (2013).

²⁰⁷ See JOINT COMMITTEE ON TAXATION, *Estimates of Federal Tax Expenditures for Fiscal Years 2012-2017* (U.S. Government Printing Office 2013), at 32.

²⁰⁸ See Mormann, Reicher and Muro, *Clean Energy Scores a Success with the Master Limited Partnership Act*, BROOKINGS INST. (2013), <http://www.brookings.edu/research/opinions/2013/12/19-clean-energy-mormann-reicher-muro>.

²⁰⁹ *Id.*

E. How to Open MLPs and REITs for Solar and Other Renewables

REITs could be opened to renewable energy investment in one of two ways. In a first-best scenario, Congress would amend the pertinent sections of the tax code to add wind turbines, solar panel installations, and other renewable energy facilities as qualifying assets.²¹⁰ Additionally, income from the generation and sale of electricity produced with these assets would need to be defined as REIT-eligible income.²¹¹ Alternatively, the IRS could issue new regulations, revenue rulings, or private letter rulings to clarify that renewable energy facilities meet the asset and income test requirements for REIT eligibility. Given their broader reach, regulations or revenue rulings would create greater policy certainty than fact-specific private letter rulings and thereby encourage more investment.²¹²

In May of 2014, the IRS proposed new regulations to clarify the definition of real property for the purposes of REIT eligibility, with an eye in part toward renewable energy power generation assets.²¹³ The proposed regulations and their sample application by the IRS to solar power generation assets suggest a Pyrrhic victory, at best, for solar and other renewables. Based on its proposed rules, the IRS grants REIT eligibility only to smaller-scale, commercial and residential solar assets but denies REIT eligibility to utility-scale solar assets.²¹⁴ This differential treatment appears to be based, in large part, on the IRS's questionable assumption that solar assets for smaller-scale installations are custom-tailored and, once installed, cannot be removed and reinstalled elsewhere without damage.²¹⁵ In reality, most of the equipment used for solar rooftop and other smaller-scale installations is mass-produced in the same standardized production cycles as utility-scale equipment and can be removed and reinstalled without major complications. More fundamentally, the proposed rules' functional definition of a property's "passive" character departs from the physical definition used in previous IRS rulings, creates legal uncertainty, introduces an element of arbitrariness, and causes significant reclassification of previously REIT-eligible real property to personal property that no longer qualifies for REIT financing.²¹⁶ In its final regulations, the IRS should revert to the well-established

²¹⁰ See 26 U.S.C. § 856(c) (2012).

²¹¹ See 26 U.S.C. § 856(d).

²¹² For a detailed discussion of the correlation between policy certainty and renewable energy investment, see MORMANN, *Enhancing the Investor Appeal of Renewable Energy*, 42 *Env'tl. L.* 681 (2012), at 705.

²¹³ See Definition of Real Estate Investment Trust Real Property, 79 *Fed. Reg.* 27,508 (proposed May 14, 2014) (to be codified at 26 C.F.R. pt. 1).

²¹⁴ *Id.* at 27,514, 27,515 (Examples 8 & 9).

²¹⁵ *Id.* (Example 9(ii)-(iii)).

²¹⁶ See Felix Mormann & Dan Reicher, Comments on Proposed Rules for REIT Real Property Definitions (IRS REG-150760-13), Aug. 10, 2014, available at <http://www.regulations.gov/#!documentDetail;D=IRS-2014-0015-0008> (last visited Dec. 5, 2014).

physical definition of passive, REIT-eligible real property. Adherence to the proven passive definition of REIT-eligible real property ensures consistency with long-standing IRS precedent, avoids the aforementioned issues of arbitrariness, and fosters legal certainty. If the IRS and the Department of Treasury insist on abandoning its previous, well-established physical definition in favor of an inconsistent, arbitrary functional definition of passive real property, that definition should be amended to be more consistent with previous rulings by revising § 1.856-10(d)(2)(iii)(A) of the proposed regulations to read as follows:

“Other inherently permanent structures serve a passive function, such as to contain, support, shelter, cover, ~~or~~ protect, **convert, or transport**, and do not serve an active function, such as to manufacture, create, **or** produce, ~~convert, or transport.~~”

Recent analysis suggests that the pertinent REIT provisions can, indeed, be construed to justify an IRS ruling that solar photovoltaic systems and wind turbines are REIT eligible, while biomass-burning and geothermal systems would be more difficult to fit under the asset and income rules.²¹⁷ Others see greater, albeit not insurmountable challenges to applying existing REIT provisions to entire wind turbine installations.²¹⁸ To add further complexity, IRS regulations or rulings on the tax treatment of renewable energy installations as REIT-eligible real property could create unwanted inconsistencies between federal and state law that treats some of these installations as tax-exempt personal property.²¹⁹ IRS regulations or rulings in favor of renewable energy REITs may appear the more viable path forward from a political economy perspective. The aforementioned challenges suggest a holistic legislative overhaul of the tax code’s REIT provisions—in close coordination with state governments—as the better, albeit more politically challenging path forward.

In the case of MLPs, the tax code’s express reference to *exhaustible* natural resources leaves little room to construe the statutory language in a way that would justify IRS regulations or rulings in favor of MLP eligibility for renewable energy projects.²²⁰ The legislative materials leave no doubt that Congress intended to exclude wind, solar, and other

²¹⁷ See DOWDALL, *Using REITs for Renewable Energy Projects*, Tax Notes 1409 (2012), at 1418; FELDMAN, et al., *The Technical Qualifications for Treating Photovoltaic Assets as Real Property by Real Estate Investment Trusts (REITs)* (National Renewable Energy Laboratory 2012), at 10.

²¹⁸ See LEVY, et al., *Wind REITS - The New Tax Equity*, Public Utilities Fortnightly 36 (2012), at 39.

²¹⁹ See FELDMAN, et al., *The Technical Qualifications for Treating Photovoltaic Assets as Real Property by Real Estate Investment Trusts (REITs)* (National Renewable Energy Laboratory 2012), at 10 (warning that many states treat solar photovoltaic equipment as tax-exempt personal property).

²²⁰ See 26 U.S.C. § 7704(d)(1) (2012).

renewable energy technologies.²²¹ This restrictive interpretation of the tax code’s MLP provisions is further supported by the evident need for Congressional action to add ethanol, biodiesel, and other renewable fuels to the list of qualifying natural resources.²²² Accordingly, the best—and likely only—path forward would require Congress to amend the tax code to expressly include income derived from the generation and sale of electricity from renewable energy among MLP-qualifying sources of income. The Master Limited Partnerships Parity Act introduced in the 113th Congress²²³ with bipartisan co-sponsorship in both the House and Senate provides for such an amendment.²²⁴ In pertinent part, the Act proposes to add the following language to the tax code’s catalog of MLP-eligible sources of income:

(ii) RENEWABLE ENERGY- The generation of electric power exclusively utilizing any resource described in section 45(c)(1) or energy property described in section 48 (determined without regard to any termination date), or in the case of a facility described in paragraph (3) or (7) of section 45(d) (determined without regard to any placed in service date or date by which construction of the facility is required to begin), the accepting or processing of such resource.²²⁵

It remains to be seen whether growing bipartisan support will lead to the enactment of the MLP Parity Act by both chambers of Congress and become law. The timing for such an initiative, however, could hardly be better. Tax reform has become a top priority for federal policymakers on both Capitol Hill and in the Administration. One can only hope that they will seize the opportunity to gradually replace wasteful and inefficient tax policy such as the tax credit regime for renewables with smarter tax policy, including MLPs and REITs for renewable energy.

F. Context: Why YieldCos Cannot Replace MLPs and REITs for Solar and Other Renewables

The renewables industry has recently begun to experiment with so-called “YieldCos” that use the classic corporate structure to raise low-cost equity capital on public markets.

²²¹ See S. REP. NO. 100-445, 424; see also H.R. REP. NO. 100-795, at 400.

²²² See *supra* Section III.B.

²²³ Based on a more limited version introduced in the 112th Congress. See H.R. 6437, 112th Cong. (2012); S. 3275, 112th Cong. (2012).

²²⁴ See H.R. 1696, 113th Cong. (2013); S. 795, 113th Cong. (2013).

²²⁵ H.R. 1696, 113th Cong. (2013); S. 795, 113th Cong. (2013). Besides renewable energy, the MLP Parity Act aims to open MLPs to a range of other sustainable energy investments, including building energy efficiency, combined heat and power, electricity storage, and renewable thermal energy. *Id.*

NRG Yield, the first YieldCo to go public in July 2013, aims to achieve similar tax efficiencies to MLPs and REITs by putting together a carefully balanced portfolio of income-generating assets and tax benefit-generating assets in order to minimize overall tax liabilities at the entity level. In the case of NRG Yield, close to 600MW of tax-benefit earning renewable power assets were bundled with some 2,300MW of fossil fuel and heat assets.²²⁶ There is some question, however, to what extent the YieldCo approach can be scaled to address the massive capital needs of the growing renewable energy industry. Few market participants possess the necessary expertise or, even more importantly, have sufficiently diversified asset portfolios to replicate this approach, casting serious doubt on the capacity of YieldCos to reduce the cost of capital for renewable energy at the same scale as MLPs or REITs.²²⁷ In the words of two Bloomberg analysts: “[NRG’s] approach is difficult to replicate—many renewable owners do not own these types of assets and thus cannot enjoy this access to the offsetting revenue streams of fossil generation.”²²⁸

Given the context of this report, a more important challenge to the YieldCo model’s viability and scalability lies in the uncertain future of federal tax credit support for renewable energy. After all, the YieldCo structure relies on renewable energy assets to generate sufficient tax credits and other benefits to offset income from other portfolio assets in order avoid paying income tax at the entity level.²²⁹ With the §45 PTC for wind already expired since the end of 2013 and the §48 ITC set to phase down from 30% to 10% at the end of 2016, it is questionable whether, going forward, solar and other renewable power assets will be able to provide significant tax benefits.

Without this tax shield, however, YieldCos cannot achieve the same level of *de facto* tax exemption at the entity level that MLPs and REITs enjoy by law and, critically, independent of the future fate of federal tax credit support for renewables. Notwithstanding the YieldCo model’s appeal to some sophisticated renewable investors, its dependence on the current regime of significant federal tax credit support for renewables makes it, on the whole, an imperfect substitute to MLPs and REITs for solar and other renewables.

²²⁶ See JOSEPH SALVATORE & STEFAN LINDER, *Yieldcos, FAITs, and More: Sizing the Market for North American Exit Vehicles 2* (Bloomberg New Energy Finance 2013).

²²⁷ See SALVATORE & LINDER, *Yieldcos, FAITs, and More: Sizing the Market for North American Exit Vehicles 4* (Bloomberg New Energy Finance 2013).

²²⁸ *Id.*

²²⁹ For a comparison of the key characteristics of MLPs and YieldCos, see SEAN T. WHEELER, *Comparison of Typical MLP and Yieldco Structures* (Latham & Watkins 2014).

Conclusion to Chapter 5²³⁰

The nation finds itself at a tricky moment when it comes to the future of the solar Investment Tax Credit (ITC). On the one hand, this federal incentive, along with state renewable energy mandates and incentives, has done much to drive large-scale solar energy deployment in recent years. Solar photovoltaic projects, in particular, have finally begun to realize their practical potential as a clean and abundant source of electricity, six decades after their invention.²³¹ On the other hand, as the price of solar panels and related hardware has dropped significantly over the last several years, the “soft cost” challenges of financing solar projects using the ITC loom larger and larger. Many solar developers do not have sufficient tax liabilities to reap the full value of their project’s tax benefits. The principal remedy today is to bring in a tax equity investor with a large enough tax bill from other sources whose capital contribution allows the developer to monetize its tax credits. The required tax equity is scarce and expensive, especially in a slow economy, limits investment liquidity, drives up transaction costs, precludes other, lower-cost financing options and, in the end, puts an inordinate amount of money in the pockets of investors and lawyers rather than solar panels on the roof or the ground.²³² This dependence on third-party tax equity has earned the ITC a reputation as a complicated, costly, and controversial means for the nation to back the important growth of solar energy.

The good news is that there are smart adjustments that can be made to the ITC itself, as well as attractive alternative tax policy options. Making solar tax credits *tradable*, just like the Low-Income Housing Tax Credit and the New Markets Tax Credit, would be one positive step. Making solar tax credits *refundable*, just like the Earned Income Tax Credit and the Child Tax Credit, is an even more attractive option.²³³ A refundable ITC would free solar developers from their dependence on third-party tax equity, a highly desired outcome as illustrated by the overwhelming success of the §1603 cash grant alternative to the solar ITC from 2009 to 2011.

In terms of alternatives to the ITC, Master Limited Partnerships (MLPs) and Real Estate Investment Trusts (REITs) could leverage large amounts of lower cost capital to the solar industry, just as these tax-advantaged financing vehicles do today for oil, gas and coal infrastructure (MLPs) and electricity transmission lines (REITs).²³⁴ Importantly, un-

²³⁰ The following is based, in part, on *Oversight of the Wind Energy Production Tax Credit: Hearing Before the Subcomm. on Energy Pol’y, Health Care, & Entitlements of the H. Comm. on Oversight and Gov’t Reform*, 113th Cong. 3, 8 (2013) (statement of Dan W. Reicher, Professor, Stanford Law School), <http://oversight.house.gov/wp-content/uploads/2013/10/Reicher.pdf>.

²³¹ See <http://www.aps.org/publications/apsnews/200904/physicshistory.cfm>.

²³² See *supra* Section I.

²³³ See *supra* Section II.

²³⁴ See *supra* Section III.

like the highly limited access to investment provided by tax equity, publicly traded shares in renewable energy MLPs and REITs would allow millions of Americans to invest in the nation's energy future. And unlike YieldCos, an emerging vehicle for clean energy finance, MLPs and REITs do not require carefully balanced asset portfolios and federal tax credits to deliver critical tax advantages to renewable energy investors.

The challenge politically is the complicated – and divisive – situation regarding the current ITC and other financing options. The solar industry is pressing hard for a significant extension of the ITC to postpone its phase-down at the end of 2016.²³⁵ Others, representing the traditional energy industry, are advocating for the end of the ITC.²³⁶ At the same time, pending legislation in the U.S. Senate and House would extend MLPs to renewables, including solar, and other energy sources. Meanwhile, the IRS has recently proposed new regulations to clarify the definition of real property for the purposes of REIT eligibility. The proposed regulations would, in part, allow REIT financing of some kinds of solar projects, while disallowing others.

Out of this complex and politically charged environment we need to develop a *smart transition* to more cost-effective policy support for U.S. solar energy projects. This transition must build a policy base for federal solar support that is both predictable – avoiding uncertainty about the availability of the current incentive – and lower-cost, providing access to cheaper capital from a much broader base of investors.

A smart transition would involve a three-pronged approach:

1. *A gradual phase-out of the ITC while making it refundable.* First, as analyzed in chapters 1-4 of this report, Congress should adopt a gradual phase-out of the ITC over a number of years instead of the current “cliff” that drops the credit from 30% to 10% in 2017 and then continues the smaller credit indefinitely. And as long as the ITC is in effect it should be made refundable. The greater efficiency of a refundable credit – without the need for tax equity – will direct more of the ITC's incentive value to solar projects and less to investors and lawyers, while reducing the burden on taxpayers per unit of energy produced.
2. *The near-term Congressional adoption of the MLP Parity Act.* The currently proposed legislation, likely to be reintroduced in the new Congress, enjoys broad bipartisan support in both the Senate and House. Importantly, from a po-

²³⁵ See, e.g., <http://www.pvsolarreport.com/seia-warns-against-investment-tax-credit-phase-out/>.

²³⁶ See, e.g., <http://blogs.rollcall.com/energy-xtra/wyden-wants-wind-and-solar-tax-credits/?dcz=>.

litical standpoint, the pending bill extends well beyond solar to include other renewables and also energy efficiency, cogeneration, carbon capture and storage, and biomass. There is a well-established and long-standing investment community focused on MLP investments largely in oil, gas and coal-related infrastructure – with a current market capitalization of nearly \$500 billion. Over time, these and other MLP investors can back solar and other clean energy projects, with an attendant increase in capital availability, cut in capital cost, and reduced impact on the federal treasury versus tax credits.

3. *An IRS decision to expand REITs to include solar and other renewables.* We welcome the Department of Treasury’s current initiative to clarify the Internal Revenue Code’s definition of real property for the purposes of Real Estate Investment Trusts (REITs), especially regarding renewable energy property. However, as we have testified and commented, the proposed rules are inconsistent with previous IRS rulings and fail to reflect the realities of renewable energy property. As a result, they do too little to promote the cost-effective deployment of renewable energy generation assets, especially solar energy. The Treasury Department should finalize the current rulemaking to cover a broad array of solar projects and technologies as well as other renewable energy sources. REIT eligibility for solar, wind, geothermal, and other renewable energy property is smart and sustainable policy that honors the legislative intent behind the 1960 REIT Act, fosters policy parity, and advances key U.S. economic, security, and environmental objectives.

This three-pronged approach would allow the solar industry to develop projects using an improved ITC for a predictable period of time, as it also works with the MLP and REIT finance community to transition over time to these long-standing, lower-cost mechanisms. This approach would ensure that the solar industry continues on its important growth trajectory over the next several years, while it transitions to lower-cost financing using MLPs and REITs. Solar project developers and investors could land in a place that much of the rest of the energy industry has long enjoyed: lower-cost, government-authorized financing mechanisms *not* requiring periodic Congressional extensions. This would be a big step forward for an industry that is generating more and more good-paying U.S. jobs while it also generates more and more low-carbon electricity.

Appendix

Appendix A: Model Input Variables

Tables A2, A3 and A4 provide the 2014 input variables to the LCOE model by state for residential, commercial and c-Si utility respectively. All values are in 2014\$.

Table A1: Comprehensive list of input parameters to the LCOE calculation model.

Variable	Description	Units
CF_{DC}	DC capacity factor (based on hours of insolation)	%
CF	DC-to-AC capacity factor	%
DF	DC/AC derate factor	%
x_t	System degradation factor in period t	%
T	Useful economic life	years
PP_t	Panel price (DC) during period t	\$/W
$IP(t)_i$	Inverter price (DC) during period t for segment i	\$/W
$BOS(t)_{ij}$	Balance of system cost during period t for segment i , US state j	\$/W
SC_t	System cost (residential) during period t	\$/W
m	Transaction margin (residential)	%
SP_t	System price during period t	\$/W
FMV_t	Fair market value of system during period t	\$/W
μ	Ratio of FMV_t/SP_t	#
c_t	Unit capacity cost during period t	\$/kWh
F_t	Fixed operation and maintenance cost during period t	\$/kW-yr
es	Operations and maintenance escalator	%
f_t	Average fixed operations and maintenance cost during period t	\$/kWh
w_t	Variable operations and maintenance cost during period t	\$/kWh
ρ_t	Consumer/rooftop "rental cost" during period t	\$/kWh
r_t	Weighted average cost of capital during period t	%
α	Effective corporate tax rate	%
Δ_t	Tax factor during period t	#
$LCOE_t$	Levelized cost of electricity during period t	\$/kWh
p_t	Comparison/competitive market price of electricity during period t	\$/kWh
i_t	Federal investment tax credit during period t	%
AEC_t	Avoided emissions cost during period t	\$/W

Appendix B: Details of the LCOE Formula

To assess the life cycle cost of producing electric power at a solar facility, we aggregate the upfront capacity investment, the sequence of electricity outputs generated by the facility over its useful life, the periodic operating costs required to deliver the electricity output in each period and any tax related cash flows that apply to this type of facility.

Table A2: Input Variables (2014 Values) to LCOE Model: Residential

Variable	Units	California	Colorado	New Jersey	North Carolina	Texas
DC-to-AC capacity factor, CF	%	18.21	18.32	15.7	16.6	17.1
System degradation factor, x_t	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	<i>years</i>	30	30	30	30	30
Panel price, PP_t	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP_t	\$/W	0.40	0.40	0.40	0.40	0.40
Balance of system cost, BOS_t	\$/W	2.04	1.72	2.42	1.47	1.32
System cost (residential), SC_t	\$/W	3.16	2.83	3.53	2.58	2.43
Transaction margin, m	%	10	25	10	30	25
System price, SP_t	\$/W	3.47	3.54	3.89	3.35	3.04
Fair market value of system, FMV_t	\$/W	4.68	4.64	4.18	4.42	3.60
Ratio of FMV_t/SP_t , μ	#	1.35	1.32	1.08	1.32	1.19
Fixed operation and maintenance cost, F_t	\$/kW-yr	20.16	18.65	22.18	17.36	16.72
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Weighted average cost of capital, r_t	%	9.5	9.5	9.5	9.5	9.5
Average fixed operations and maintenance cost, f_t	\$/kWh	0.017	0.016	0.022	0.016	0.015
Consumer/rooftop "rental cost", ρ_t	\$/kWh	0.025	0.025	0.025	0.025	0.025
Unit capacity cost, c_t	\$/kWh	0.236	0.188	0.274	0.193	0.176
Tax factor, Δ_t	#	0.361	0.423	0.647	0.416	0.567
Levelized cost of electricity, $LCOE_t$	\$/kWh	0.127	0.120	0.224	0.122	0.139

Table A3: Input Variables (2014 Values) to LCOE Model: Commercial

Variable	Units	California	Colorado	New Jersey	North Carolina	Texas
DC-to-AC capacity factor, CF	%	18.21	18.32	15.7	16.6	17.1
System degradation factor, x_t	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	<i>years</i>	30	30	30	30	30
Panel price, PP_t	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP_t	\$/W	0.21	0.21	0.21	0.21	0.21
Balance of system cost, BOS_t	\$/W	1.30	1.10	1.49	0.99	0.93
System price, SP_t	\$/W	2.22	2.02	2.42	1.91	1.84
Fixed operation and maintenance cost, F_t	\$/kW-yr	19.09	17.74	20.88	16.06	16.03
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Weighted average cost of capital, r_t	%	8.0	8.0	8.0	8.0	8.0
Average fixed operations and maintenance cost, f_t	\$/kWh	0.016	0.015	0.020	0.016	0.015
Unit capacity cost, c_t	\$/kWh	0.132	0.118	0.164	0.125	0.117
Tax factor, Δ_t	#	0.708	0.707	0.708	0.707	0.706
Levelized cost of electricity, $LCOE_t$	\$/kWh	0.110	0.098	0.137	0.104	0.097

Table A4: Input Variables (2014 Values) to LCOE Model: Utility, c-Si, 1-axis

Variable	Units	California	Colorado	New Jersey	North Carolina	Texas
DC-to-AC capacity factor, CF	%	24.08	23.88	19.73	20.68	21.59
System degradation factor, x_t	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	<i>years</i>	30	30	30	30	30
Panel price, PP_t	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP_t	\$/W	0.14	0.14	0.14	0.14	0.14
Balance of system cost, BOS_t	\$/W	1.11	1.01	1.19	0.92	0.89
System price, SP_t	\$/W	1.97	1.86	2.05	1.77	1.75
Fixed operation and maintenance cost, F_t	\$/kW-yr	16.83	15.65	18.39	14.65	14.15
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Weighted average cost of capital, r_t	%	8.0	8.0	8.0	8.0	8.0
Average fixed operations and maintenance cost, f_t	\$/kWh	0.011	0.010	0.014	0.011	0.10
Unit capacity cost, c_t	\$/kWh	0.089	0.083	0.111	0.093	0.088
Tax factor, Δ_t	#	0.708	0.707	0.708	0.707	0.706
Levelized cost of electricity, $LCOE_t$	\$/kWh	0.074	0.069	0.093	0.077	0.072

Since the LCOE formula yields an *output price* which leads equity investors to break-even, it is essential to specify the appropriate discount rate. A standard result in corporate finance is that if the project in question keeps the firm’s leverage ratio (debt over total assets) constant, then the appropriate discount rate is the Weighted Average Cost of Capital (WACC). In reference to the above quote in the MIT study, equity holders will receive “*an acceptable return*” and debt holders will receive “*accrued interest on initial project expenses*” provided the project achieves a zero Net-Present Value (NPV) when evaluated at the WACC. We denote this interest rate by r and denote the corresponding discount factor by $\gamma \equiv \frac{1}{1+r}$.⁵

For a simplified representation of the LCOE of a new power generating facility, suppose initially that there are no periodic operating costs and no corporate income taxes. The LCOE formula is then based on the following variables:

- T : the useful life of the power generating facility (in years)
- SP : the acquisition cost of capacity (in \$/kW)
- x_t : system degradation factor: the percentage of initial capacity that is still functional in year.

We abstract from any quantity discounts and scale economies that in practice can be obtained if the installed capacity reaches a certain threshold size. Thus, there will be no loss generality in normalizing the investment in power capacity to 1 kW. For solar photovoltaic installations, prices are commonly quoted as “dollars per peak Watt DC” (abbreviated as \$ per W_p).

The system degradation factor, x_t , refers to the possibility that some output generating capacity may be lost over time. In particular with solar photovoltaic cells it has been observed that their efficiency diminishes over time. The corresponding decay is usually represented as a constant percentage factor which varies with the particular PV technology and the location of the installation.⁶

⁵Our analysis ignores inflation. In an inflationary environment the LCOE would compound at the rate of inflation. Yet, provided that all production inputs are subject to the same, constant inflation rate, and this rate is also reflected in the nominal discount rate, the resulting (initial) LCOE will be unchanged. Thus our concept of the levelized cost is to be interpreted as a real, rather than a nominal output price.

⁶In contrast, for other renewable energy sources, for instance, biofuels, analysts typically anticipate yield improvements which would result in a sequence of x_t that is increasing over time. See, for instance, NREL (2009).

The power generating facility is theoretically available for $8760 = 365 \cdot 24$ hours, but due to technological, environmental and economic constraints, practical capacity is only a percentage of the theoretical capacity. This percentage is usually referred to as the capacity factor, CF . We define *the cost of capacity for one kilowatt hour* (kWh) as:

$$c = \frac{SP}{8760 \cdot CF \sum_{t=1}^T x_t \cdot \gamma^t}. \quad (5)$$

The expression in (1) reflects that the original investment yields a stream of output levels over T years, with $x_t \cdot 8760 \cdot CF$ kilowatt hours delivered in year t due to the potential loss of capacity over time. If the firm were to receive the amount c as the revenue per kilowatt-hour, then revenue in year t would be $c \cdot x_t \cdot 8760 \cdot CF$. Absent any tax effects and annual operating costs, the firm would then exactly break-even on its initial investment of SP over the T -year horizon.

Corporate income taxes affect the LCOE through depreciation tax shields and debt tax shields, since both interest payments on debt and depreciation charges reduce the firm's taxable income. As mentioned above, the debt related tax shield is already incorporated into the calculation of the WACC. The depreciation tax shield is determined jointly by the investment tax credit (ITC), the effective corporate income tax rate and the depreciation schedule that the IRS allows for the particular type of power generating facility. We represent these variables as:

- i : investment tax credit (in %),
- a : effective corporate income tax rate (in %),
- T^o : facility's useful life for tax purposes (in years),
- d_t : allowable tax depreciation charge in year t (in %).

For solar PV investments, the federal tax code allows for an *Investment Tax Credit*, calculated as a percentage of the initial investment. We denote this percentage by i . Under the Economic Stabilization Act of 2008, new solar installations receive a 30% tax credit, which means that the investor's corporate income tax liability is reduced by 30% of the initial investment. For most businesses, the investment tax credit thus becomes a direct cash subsidy by the government. The tax code specifies a useful life, T^o , dependent on the type of power generating facility. This assumed useful life is generally shorter than the

projected economic life and thus $T > T^0$ in our notation. The depreciation charge that the firm can deduct from its taxable income in year t is given by $d_t \cdot SP$, with $\sum_{t=1}^{T^0} d_t = 1$. However, if the investing party does take advantage of an investment tax credit in the amount of i % of the initial investment SP , the corresponding asset value for tax purposes is reduced by a factor $\delta \cdot i$. In other words, for tax purposes the investing firm can only capitalize the amount $SP \cdot (1 - \delta i)$. Under the Economic Stabilization Act of 2008, $\delta = .5$. For the purposes of calculating the Levelized Cost of Electricity, the overall effect of income taxes is then summarized by the following *tax factor*:

$$\Delta = \frac{1 - i - a \cdot (1 - \delta i) \cdot \sum_{t=1}^{T^0} d_t \cdot \gamma^t}{1 - a}. \quad (6)$$

Absent any investment tax credit, the tax factor amounts to a “mark-up” on the unit cost of capacity, c . Specifically, the tax factor Δ exceeds 1 but is bounded above by $\frac{1}{1-a}$ if $i = 0$. It is readily verified that Δ is increasing and convex in the tax rate a . Holding a constant, a more accelerated tax depreciation schedule tends to lower Δ closer to 1. In particular, Δ would be equal to 1 if $i = 0$ and the tax code were to allow for full expensing of the investment immediately (that is, $d_0 = 1$ and $d_t = 0$ for $t > 0$).

To complete the description of the LCOE model, let w_t denote the variable operating cost of power generation per kWh. Costs in this category include fuel, labor and other cash conversion costs. It will be convenient to define the following “average” variable cost per kWh:

$$w = \frac{\sum_{t=1}^T w_t \cdot 8760 \cdot CF \cdot x_t \cdot \gamma^t}{8760 \cdot CF \cdot \sum_{t=1}^T x_t \cdot \gamma^t} = \frac{\sum_{t=1}^T w_t \cdot x_t \cdot \gamma^t}{\sum_{t=1}^T x_t \cdot \gamma^t}. \quad (7)$$

For one kW of installed capacity, the numerator in (3) represents the discounted value of future variable costs, while the denominator (as in equation (1)) measures the discounted value of future kilowatt hours available from installing one kW of power. Finally, let F_t denote the periodic fixed costs per kilowatt of power installed. These costs comprise primarily operating and maintenance costs that are independent of the amount of energy generated by the facility. Since capacity is subject to systems degradation, it will again be convenient to define the following “average” fixed cost per kWh:

$$f = \frac{\sum_{t=1}^T F_t \cdot \gamma^t}{8760 \cdot CF \cdot \sum_{t=1}^T x_t \cdot \gamma^t}. \quad (8)$$

The numerator in (4) represents the present value of fixed operating costs associated with a capacity installation of one kW, while the denominator again represents the discounted value of the stream of future kilowatt hours available from the installed kW.

Appendix C: Research Proposal as submitted to DOE in 2013

Background

Current legislation (26 USC §25D and 26 USC §48) stipulates that the federal Investment Tax Credit (ITC) for solar installations will be reduced from its current 30% rate to 10% on January 1, 2017 for commercial and utility scale solar power systems. The ITC was initially created as part of the Energy Policy Act of 2005 (P.L. 109-58) and extended through December 31, 2016 with the Emergency Economic Stabilization Act of 2008 (P.L. 110-343). Since its inception, the solar ITC has been a significant federal mechanism to spur rapid growth in the deployment of solar installations. In conjunction with the depreciation tax shield provided through the Modified Accelerated Cost-Reduction System (MACRS), the ITC has played a significant role in promoting new investments in solar installations and in manufacturing capacity for solar systems, including panels and electric systems. The results have been considerable for the U.S. In 2006, 105 MW of photovoltaic (PV) installations were installed with an average installed PV system price of \$7.90/W. In 2012, there were 3,313 MW of new PV installations with an average installed PV system price of \$3.63/W.

Given this backdrop, an immediate question for policy makers and the business community is how the projected shift in ITC rate down to 10% would affect the trajectory of future solar deployments in the U.S.⁷

Project Objectives

The proposed study will address the following three central issues related to the anticipated ITC reduction:

- 1. Impact on the LCOE and market dynamics of solar PV as we move toward the phase-down of the ITC in 2017 and beyond*
- 2. Impact on future solar PV deployments*
- 3. Consideration of alternative and complementary scenarios to create a smooth “glide path” for the solar industry as the ITC is phased down*

The study will produce:

1. Forecasts for solar PV industry dynamics—both upstream (solar panel manufacturing) and downstream (solar PV installations)

⁷The proposed study would focus on the photovoltaic segment of the solar power industry.

2. Policy recommendations regarding the ITC phase-down including complementary mechanisms to support a smooth glide path.
3. Dissemination of findings to policy makers, the solar PV industry, NGOs and universities

Research Approach

A common metric for assessing the competitiveness of alternative energy sources is the Levelized Cost of Electricity (LCOE). Expressed in \$/MWh, this metric allows for a direct cost comparison between electricity generated by traditional fossil fuel sources and renewable energy sources, in particular wind and solar. The LCOE is to be interpreted as the minimum price per megawatt hour (MWh) that an investor in an electricity generation facility would have to obtain on average in order to break-even on his/her investment over the entire lifecycle of the facility, taking into account investor/industry hurdle rates across a diverse set of project structures and sizes. This break-even calculation essentially corresponds to a discounted cash-flow analysis which solves for the minimum output price required to obtain a net present value (NPV) of zero.

In highly simplified form, the LCOE can be represented as:

$$LCOE = f + c \cdot \Delta, \tag{9}$$

where

- f : time-averaged operating cost per MWh,
- c : *cost of capacity* per MWh, which is a function of operational life, system price, capacity factor, degradation factor and discount rate,
- Δ : *tax factor*, which is a function of ITC, useful life for tax purposes, effective corporate income tax rate and the schedule of allowable tax depreciation charges.

For solar PV, the annual operating costs, f , are negligible. This stands in contrast to natural gas power plants, where fuel costs are a substantial component of the overall LCOE. On a pre-tax basis, the cost competitiveness of solar PV is determined by the system price of solar panels and the so-called Balance of System Costs (BOS), both of which are reflected

in the capacity cost, c . The tax factor Δ is usually greater than one. For traditional fossil-fuel based electricity generation plants, that do not qualify for an investment tax credit and are depreciated in a conventional manner for tax purposes, the tax factor amounts to about $\Delta = 1.3$. In contrast, the combination of the 30% ITC and the MACRS depreciation rules currently in place for solar installations reduce the tax factor to about $\Delta = 0.7$. As argued in a recent article by Reichelstein and Yorston (“*Prospects for Cost Competitive Solar PV Power*,” *Energy Policy*, 2013), this significant reduction in the tax factor has been instrumental in leading many businesses in the southwestern United States to the conclusion that commercial-scale solar installations on the rooftops of their office buildings and warehouses are already profitable investments at current market prices. Specifically, these businesses recognize that investments in solar panels on their rooftops are preferable to paying the retail electricity rates charged to commercial customers.⁸

System prices for solar PV installations have fallen precipitously over the past three decades. By some estimates, utility scale solar projects are now facing an initial system price of \$2.00 per Watt, with a proportional impact on the unit capacity cost, c , per kWh. As a consequence, the benchmarks articulated in the DOE’s SunShot initiative now seem within reach in the foreseeable future. This dramatic reduction in prices is generally attributed to two major causes. First, crystalline silicon has demonstrated a remarkable confirmation of the so-called 80% experience (Learning-by-Doing) curve. As demonstrated by various studies in the literature, panel prices over the past 30 years have come down by approximately 20% with every doubling of the *cumulative* amount of solar cells produced. Secondly, the industry has seen massive entry of new solar cell manufacturers in China in the last couple of years. This addition of new manufacturing capacity is generally regarded as the main reason for prices having come down even faster than forecast by the 80% learning curve.

The preceding considerations will be key ingredients in addressing the three questions identified at the outset. In particular, we will focus on the dynamic link between (i) a higher tax factor –due to a lower ITC – (ii) a slower pace of new solar installations and (iii) a reduced speed in learning-by-doing with correspondingly slower future cost-and price reductions, taking into account, among other things, the US share in global PV deployment.

⁸For utility-scale projects, the analysis in Yorston and Reichelstein (2013) identifies a 30% gap between the cost of electricity generation by solar PV in comparison to natural gas power plants. The recent adoptions of utility-scale solar projects must therefore be attributed to both the federal tax subsidies and state-level initiatives like the Renewable Portfolio Standard in California.

The analysis in Reichelstein and Yorston (2013) projects that if the current federal tax subsidies were to be in place until about 2020, solar PV installations on a commercial scale would become cost competitive with electricity generated from fossil fuels, even if at that point both the ITC and the accelerated depreciation rules were to expire. These projections will be the starting point for the proposed study as we consider a range of alternative and complementary scenarios for the reduction and expiration of the ITC. The overarching goal of this analysis is to expand the existing industry models so as to predict how sensitive the trajectory of future solar PV deployments is to the timing of reductions in the federal ITC.

Project Management, Budget and Timeline

The project will be headed by Professor Stefan J. Reichelstein, William R. Timken Professor of Accounting, Stanford Graduate School of Business. Prof. Reichelstein will be the principal investigator (PI) for the duration of the work. The remainder of the project team will consist of faculty, research associates and graduate students from Stanford's Business, Law and Engineering Schools. Dan Reicher, Executive Director of Stanford's Center for Energy Policy and Finance, will work with Professor Reichelstein and help with project coordination with the Department of Energy.

Appendix D: State-Level Incentives

This appendix provides an overview of the incentives available to solar PV at the state-level. We divide those incentives into the following categories:

- tax credit and exemptions,
- grants
- rebates
- loans,
- industry support and performance-based incentives
- PACE programs
- net-metering

California

Partial sales- and use-tax exemption is provided for agricultural solar power facilities. The incentive is active today, but it requires that 50% or more of the electricity produced by the PV system be used at the farm (DSIRE, 2014a). Also, property-tax exclusion for solar energy systems is incorporated in Section 73 of the California Revenue and Taxation Code and applies to commercial, industrial, and residential entities. The incentive is currently active, but it is set to expire at the end of 2014 (DSIRE, 2014a).

California has no grant programs, but it has multiple rebate programs. To start, California Solar Initiative (CSI), adopted by the California Public Utilities Commission (CPUC), provides more than \$2.3 billion to incentivize the installation of additional 1,940 MW in capacity by 2016. Launched in 2007, the program is intended to continue for 10 years or till funds are completely allocated. All three main utilities (PG&E, SCE, and SDG&E) have reached their budget limits for residential installations, and PG&E has reached its budget for non-residential as well (DSIRE, 2014a). As part of CSI, \$216 million has been allocated to help fund solar PV solar installations on low-income housing. The funding is divided equally between the Multi-Family Affordable Solar Housing (MASH) program (DSIRE, 2014a) and

the Single-Family Affordable Solar Housing (SASH) program (DSIRE, 2014a). Both programs are currently active, and they are planned to continue through 2021. That said, MASH is currently fully subscribed. New Solar Homes Partnership is another \$400 million program that provides rebates for solar PV on new home construction, but its scope is limited to customers of the three main utilities and Bear Valley Electric Service. The program was launched in 2007, is currently active, but expires at the end of 2016 (DSIRE, 2014a). In addition to state-wide rebates, California has had a total of 36 utility rebate programs. A quick review of those programs shows that 27 are currently active, many of which expire in 2016. The remaining programs are non-active because either they expired or their respective budgets were fully assigned (DSIRE, 2014a). Also, the Solar Energy Incentive Program by the City of San Francisco is a local rebate program that is currently active and whose benefits can be combined with those of CSI (DSIRE, 2014a).

In terms of loans, California Energy Commission has an active loan program for schools, local governments, and institutions. The loan is capped at \$3 million, and it must be repaid from energy cost savings within 15 years, including principal and interest (DSIRE, 2014a). A few other loan programs are available through local governments in the state. For industry support, the Sales and Use Tax Exclusion for Advanced Transportation and Alternative Energy Manufacturing Program has a \$100M/yr budget and is administered by the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA). The program is currently active and will continue through 2021 (DSIRE, 2014a).

Then we come to the performance-based incentives. Four programs are currently active: Renewable Market Adjusting Tariff (ReMAT) (DSIRE, 2014a), Palo Alto CLEAN (DSIRE, 2014a), LADWP Feed-in Tariff (DSIRE, 2014a), and Marin Clean Energy Feed-In Tariff (SDIRE15). All programs, except Palo Alto CLEAN, impose some limitations on the size of system, and contracts' lengths range from 10 to 20 yrs. Furthermore, California has enacted PACE enabling legislation. Despite the Federal Housing Financing Agency (FHFA) statement in 2010, a number of operational PACE programs are still active today (PACENow, 2014): CaliforniaFirst (in 17 counties), Clean Energy Sacramento, Figtree PACE Financing, Green Finance San Francisco, HERO Financing, Money for Property Owner Water and Energy Efficiency Retrofitting (mPOWER), Los Angeles County PACE Program, Palm Desert PACE Program, Sonoma County Energy Independence Program, and Yucaipa Energy Independence Program. Finally, net-metering is still alive in California, and its jurisdiction

includes all utilities except LADWP.

Colorado

The Renewable Energy Incentives Act authorizes counties and municipalities to offer property-tax or sales-tax rebates or credits to residential and commercial property owners who install renewable energy systems on their property. A pool of local incentives is currently active under the act, which expires in 2017 (DSIRE, 2014b). The state also has sales- and use-tax exemption for renewable energy equipment. This incentive was launched in July, 2009 and is planned to continue through July 1, 2017 (DSIRE, 2014b). A similar currently-active incentive is applicable for property taxes. To qualify for the exemption, the PV facility must be located on residential real property, used to produce energy primarily for residential improvements, and have a production capacity of no more than one hundred 100 kW (AC) (DSIRE, 2014b). Locally, the city of Boulder has its own active solar sales- and use-tax rebate program (DSIRE, 2014b). In addition, Colorado offers property tax exemption for community-solar gardens under H.B. 1101. This incentive applies for the tax years beginning on January 1, 2015 and ending before January 1, 2021 (DSIRE, 2014b).

Colorado has no state-wide rebate programs. However, there are a total of six active rebate programs offered by the following utilities: Colorado Springs Utilities, Holy Cross Energy, La Plata Electric Association, Poudre Valley REA, San Miguel Power Association, and United Power, all of which are currently active (DSIRE, 2014b). In addition, there are two active local programs. EnergySmart covers the city of Boulder. Energy Smart Colorado spans six counties: Eagle County, Gunnison County, Lake County, Roaring Fork Valley, and Summit County (DSIRE, 2014b). Local grants are also available in Colorado. Renewable Energy Mitigation Program (REMP) is available within the city of Aspen and Pitkin County (DSIRE, 2014b), and the Solar Grant Program is available within the city of Boulder (DSIRE, 2014b).

In terms of loans, the Direct Lending Revolving Loan Program is offered by Colorado Energy Office (CEO) for commercial, industrial, and nonprofit entities. The program is currently active but has an imposed minimum loan size of \$100k (DSIRE, 2014b). Green Colorado Credit Reserve is a loan loss reserve that was also created by CEO to incentivize private lenders to make small commercial loans. The program is currently active and is administered by the Colorado Housing Finance Authority (CHFA) on behalf of CEO (DSIRE,

2014b). The Renewable Energy and Energy Efficiency for Schools (REEES) Loan Program is another incentive, specifically for schools, launched in 2014 and currently active (DSIRE, 2014b). In addition to the aforementioned state-wide loan programs, Fort Collins Utilities has its own residential loan program (DSIRE, 2014b), and homes and businesses located in Boulder County or the City and County of Denver are eligible for the Elevations Energy Loan (DSIRE, 2014b). Energy Smart Colorado also offers loans (DSIRE, 2014b).

Furthermore, three performance-based incentives are currently active in Colorado. First, Black Hills Energy had the Solar Power Program, which provides payments for 10 years, but imposes limitations on the size of eligible systems system: between 0.5 kW and 120% of the building's most recent 12 month demand (DSIRE, 2014b). Xcel Energy offers two programs: Solar*Rewards Program with similar limitations on the PV system size, and Solar*Rewards Community Program with 2 MW maximum size for large RFP program (DSIRE, 2014b). Finally, Colorado has enacted PACE enabling legislation, but there is no active PACE programs, and net-metering is implemented in all utilities except municipal utilities with less than 5000 customers.

New Jersey

As stated in the Division of Taxation Publication S&U-6 (Sales Tax Exemption Administration), New Jersey offers a full exemption from the state's sales tax for all solar energy equipment. The exemption covers commercial, industrial, residential entities, and is currently active (DSIRE, 2014c). A similar active legislation also exempts PV solar systems used to meet on-site electricity, heating, cooling, or general energy needs from property taxes (DSIRE, 2014c). In addition, the state has special regulations for solar systems installed on farmland through legislation S.B. 1538 (DSIRE, 2014c).

In terms of grants, rebates, and loans, New Jersey has offered such incentives for multiple technologies but not for solar PV. The only exception is a utility program: PSE&G's Solar Loan Program, which is available to residential and commercial entities. It is currently on-hold due to reaching capacity, but it will re-open in February 2015 (DSIRE, 2014c).

Furthermore, New Jersey has two key programs for industrial support of PV solar, both of which are administered by the New Jersey Economic Development Authority (EDA). First, Edison Innovation Clean Energy Manufacturing Fund (CEMF) provides assistance for the manufacturing of energy efficient and renewable energy products. The fund provides grants

and loans for certain business development activities, and it is currently active with no set expiration date; applications are accepted on rolling basis (DSIRE, 2014c). Second, Edison Innovation Green Growth Fund (EIGGF) offers loans to for-profit companies. Launched in 2011, the fund is currently active but it is limited to fixed five-year term. (DSIRE, 2014c).

For performance-based incentives, solar PV projects under the SREC Registration Program are qualified for Solar Renewable Energy Certificates (SRECs). The incentive covers all sectors, is currently active, and its schedule extends till 2028. Although it imposes no limited on the PV system capacity, the system must be connected to distribution network and its annual output should not exceed annual on-site load (DSIRE, 2014c). New Jersey has also enacted PACE-enabling legislation (S.B. 1406) in January of 2012; the active legislation authorizes municipalities to develop local financing programs, subject to the approval of the Director of Local Government Services within the New Jersey Department of Community Affairs (DCA) (DSIRE, 2014c). Finally, net-metering has also been alive in New Jersey since its initiation in 2012 (DSIRE, 2014c).

North Carolina

North Carolina offers personal and corporate tax credit equal to 35% of the cost of eligible renewable energy property constructed, purchased or leased. The incentive is currently active under House Bill 512 till December 31, 2015 (DSIRE, 2014d). In addition, the state exempts 80% of the appraised value of a PV system from property tax. This exemption was initiated in 2008 and is currently active (DSIRE, 2014d).

While North Carolina offers no state-wide rebate programs, Duke Energy Progress offers incentives for residential customers to install PV through the SunSense Program. Although currently active, the program imposes some constraints, primarily requiring customers to surrender all their Renewable Energy Credits (RECs) to Duke Energy Progress for a period of five years (DSIRE, 2014d).

In terms of loans, North Carolina H.B. 1389 authorizes cities and counties to establish revolving loan programs to finance PV systems that are permanently attached to residential, commercial or other real property. Launched in 2009, the incentive is currently active (DSIRE, 2014d). In addition, Piedmont Electric Membership Corporation's (PEMC) offers the Energy Efficiency and Renewable Energy Loan Program which allows customers to finance solar PV (DSIRE, 2014d). Locally, the Town of Chapel Hill and the Town of Car-

rboro also offered the Worthwhile Investments Save Energy (WISE) Homes and Buildings rebate program which partly supported PV installations through the American Recovery and Reinvestment Act. The program ended, however, in 2013 (DSIRE, 2014d).

Then for performance-based incentives, NC GreenPower was launched in 2003 as a statewide green power program to encourage the use of renewable energy. It offers production payments for grid-tied electricity generated by solar and is currently active (DSIRE, 2014d). In addition, Tennessee Valley Authority (TVA) and participating power distributors of TVA power offer multiple programs, all of which are currently active. The Green Power Providers program was launched in 2012 and covers 0.5-50kW system installations for homeowners and businesses (DSIRE, 2014d). Mid-Sized Renewable Standard Offer Program was launched in 2010 and covers mid-sized 50kW-20MW renewable energy generators (DSIRE, 2014d). The Renewable Standard Offer program also includes Solar Solution Initiative Program, which offers additional financial incentives for 50kW-1MW PV projects and was launched in 2012 (DSIRE, 2014d).

Finally, North Carolina has enacted PACE enabling legislation, but there are currently no PACE programs operating or in development (PACENow, 2014). As for net-metering, North Carolina Utilities Commission (NCUC) established net-metering rules for the state's three investor-owned utilities (Duke Energy, Progress Energy, and Dominion North Carolina Power) in 2005. Though progressively amended through 2009, the rules are still active today.

Texas

Texas allows corporations to deduct the cost of installed solar PV from their franchise tax (DSIRE, 2014e). The state property tax code also allows 100% exemption of the appraised property value increase resulting from the installation or construction of a solar PV system used on-site. The exemption applies to commercial, industrial, and residential entities, and is currently active (DSIRE, 2014e). In addition to those state-wide tax incentives, the City of Houston allows partial tax abatement for U.S. Green Building Council Leadership in Energy and Environmental Design (LEED)-certified commercial buildings (that incorporates solar PV). The program is currently active but is set to expire in March 2016 (DSIRE, 2014e).

While Texas has no state-wide rebate programs, 11 utility-based active programs offer rebates for solar PV: SMART Source solar PV rebate program by AEP Texas Central Company and AEP Texas North Company, residential solar PV rebate program by Austin

Energy, distributed generation rebate program by City of San Marcos, solar energy rebate program by CoServ, solar energy rebate program by CPS Energy, GreenSense Solar Rebate Program by Denton Municipal Electric - GreenSense Solar Rebate Program, commercial and industrial rebate program by Oncor Electric Delivery, Solar Photovoltaic Standard Offer Program also by Oncor Electric Delivery, and Residential and Hard-to-Reach Standard Offer Program by Xcel Energy. The state has had two additional utility-based programs that are currently not active: renewable energy rebates offered by Guadalupe Valley Electric Cooperative and Solar PV Pilot Program by El Paso Electric Company (because all funds were fully subscribed) (DSIRE, 2014e). Locally, the City of Sunset Valley also offers a PV rebate program for residential customers (DSIRE, 2014e).

In terms of loans, the Texas LoanSTAR (Saving Taxes and Resources) is an active low-interest revolving loan program that finances solar PV as an energy-related cost reduction retrofit for state, public school, college, university, and non-profit hospital facilities (DSIRE, 2014e). In addition, Austin Energy offers a utility-scale a residential solar loan program (DSIRE, 2014e), and the City of Plano offers the local Smart Energy loan program for residents (DSIRE, 2014e). Both programs are currently active.

Texas also offers support for the solar PV industry, where companies engaged solely in the business of manufacturing, selling, or installing solar or wind energy devices are exempt from the franchise tax (DSIRE, 2014e). Additionally, while no state-wide performance-based incentives exist, Austin Energy utility offers such incentives to its commercial and institutional customers with PV system up to 200 kW (DSIRE, 2014e). Furthermore, Texas has passed a PACE-enabling legislation and is in the process of developing a PACE program (PACENow, 2014). Finally, for net-metering, Texas has no state-wide net-metering incentives. Nonetheless, a few utilities offer net-metering programs to their customers. Austin Energy allows net-metering for commercial system only up to 20 kW (DSIRE, 2014e); residential net-metering was substituted with Value of Solar Tariff rate-system (DSIRE, 2014e). The City of Brenham allows net-metering for systems up to 10 MW in all sectors (DSIRE, 2014e). El Paso Electric net-metering program is available for 50 kW systems or 100% of estimated/actual electricity consumption, whichever is less, and also covers all sectors (DSIRE, 2014e). Green Mountain Energy Renewable Rewards Program is buy-back program, similar in incentives to net-metering, with no size-limit on residential systems and 50 kW limit on commercial systems (DSIRE, 2014e).

Appendix E: Cost - and Price Dynamics of Solar PV Modules

Cost- and Price Dynamics of Solar PV Modules

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Cost- and Price Dynamics of Solar PV Modules

Abstract: For several decades, the prices for solar photovoltaic (PV) modules have adhered closely to an 80% learning curve. Yet recent price declines have been even steeper. Analysts have questioned whether these price declines reflect underlying reductions in production cost or excessive additions to manufacturing capacity. For a sample of solar PV manufacturers, we estimate production costs based on financial accounting statements. We use these cost estimates as data inputs in a dynamic model of competition to obtain equilibrium prices, termed *Economically Sustainable Prices (ESP)*. We find that, beginning in 2011, the ESPs significantly exceeded the observed average sales prices (ASP) for most quarters. At the same time, the observed dynamics of production costs point to reductions that are even faster than suggested by the 80% learning curve. Our estimates allow us to extrapolate a trajectory of future equilibrium prices to which ASPs should converge over time.

Keywords: Solar PV manufacturing, Industry dynamics, Economically Sustainable Price

JEL codes: D41, L11, L63, M21, Q42

1 Introduction

The solar photovoltaic (PV) industry has in recent years experienced rapid growth in the volume of output produced, sharp price declines for solar PV modules and a significant shift in the composition of module suppliers. To illustrate the growth dynamics, the 17 gigawatts (GW) of new solar PV power capacity installed worldwide in 2010 was equal to the total *cumulative* installations of solar PV power over the previous four decades. Increasingly, this demand has been met by Chinese firms. These companies added significant production capacity while many solar manufacturers in the U.S. and Europe exited the industry.¹

Swanson (2011) summarizes the price history through the end of 2010 and documents that this price trajectory conforms closely to the pattern of an 80% learning curve; see Figure 1. According to this constant elasticity curve, prices have dropped by 20% with every doubling of cumulative output.² The decline in average sales prices (ASP) for PV modules was even steeper between 2011 and 2013, as shown in Figure 2.³ Particularly noteworthy is the 40% price drop in 2011 alone and the rebound in prices for late 2013.

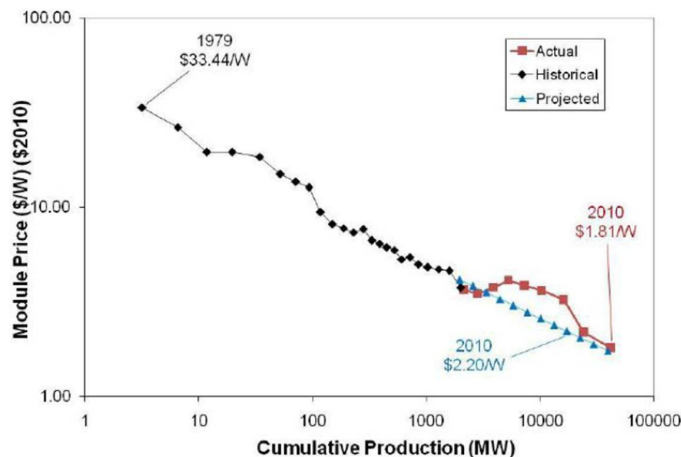


Figure 1: *Reproduction of plot from Swanson (2011)*

¹In 2008, firms headquartered in the U.S. and Europe held 28% of module manufacturing capacity, while firms headquartered in China held 46%. By 2013, these figures had moved to 18% and 56%, respectively (Lux Research, 2013).

²Timilsina, Kurdgelashvili, and Narbel (2011) regress average sales prices (ASPs) on cumulative production volume over the period 1979-2010 and obtain a learning rate of 81%.

³Figures 1 and 2 show that for the years 2008-2009, ASPs were distinctly above the trend line suggested by the 80% learning curve. Most industry observers attribute this discrepancy to an acute polysilicon shortage which temporarily increased the raw material cost of silicon wafers.

Industry analysts have pointed out that the steep price declines in recent years may not reflect proportionate cost reductions. The competing explanation is that prices declined ahead of production costs largely because the additions to industry-wide manufacturing capacity were excessive. If the latter explanation is valid, price forecasts based on mechanical extrapolations of recent price data could be misleading for manufacturers, solar power developers and policy makers. For example, the SunShot goals set by the U.S. Department of Energy (DOE) envision that a module price of \$0.50/W would allow solar power to be widely cost competitive. The anticipated timing with which this milestone will be reached may influence the duration of policies such as the 30% investment tax credit currently available in the U.S. to investors in solar electricity-generating facilities.

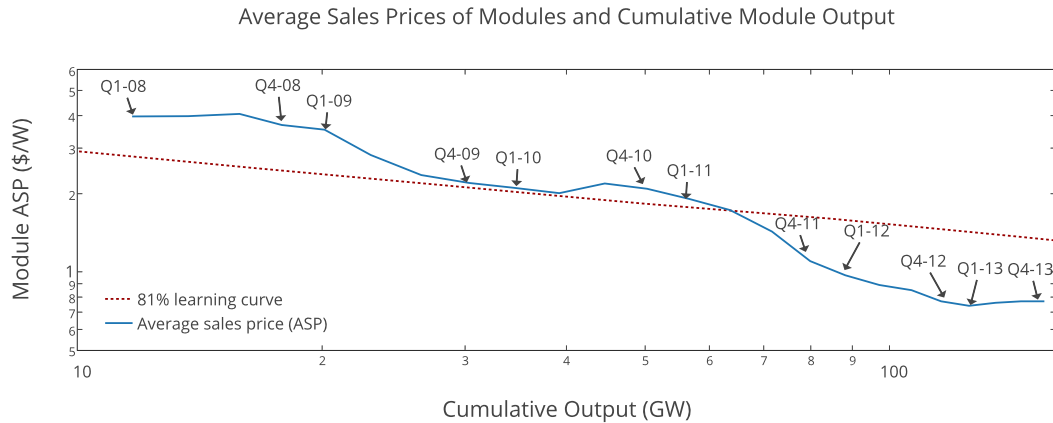


Figure 2: All prices are in 2013 U.S. dollars.

Our paper makes several contributions to the debate on solar PV module prices. We estimate the production costs of module manufacturers in order to back out prices that would have prevailed between 2008 and 2013, assuming the industry had been in equilibrium. To do so, we develop a method for deriving production costs from financial statements. The resulting estimated “equilibrium prices” can be compared to the actually observed ASPs to test whether the industry was out of equilibrium at different points in time. Finally, our analysis of the production cost incurred during the years 2008-2013 can be used to extrapolate a trajectory of future production costs and corresponding equilibrium prices. This trajectory represents our benchmark of the industry fundamentals and can be interpreted as a trend-line to which actual prices should converge over time.

Our central cost measure is the long-run marginal cost of manufacturing and delivering

one unit of output. Following industry convention, our unit of output is the number of Watts (W) of solar power in a module. The long-run marginal cost comprises capacity related costs in connection with machinery and equipment, current manufacturing costs for materials, labor and overhead as well as periodic costs related to selling and administrative expenses. Our formulation allows for both the cost of capacity and the periodic operating costs to decrease over time due to exogenous technological progress and learning-by-doing effects.

We formulate a dynamic model of a competitive industry in which firms make a sequence of overlapping capacity investments and then choose their subsequent output levels in a competitive fashion, that is, taking market prices as given. While the long-run marginal cost contains components that are sunk in the short-run, the expected market prices will in equilibrium nonetheless be equal to the long-run marginal cost, precisely because firms are capacity constrained. Furthermore, firms will earn zero economic profits on their capacity investments if the expected market prices in future periods are equal to the long-run marginal cost in those future periods. Accordingly, we refer to the long-run marginal cost at a particular point in time as the *Economically Sustainable Price* (ESP).

To address the question of whether the dramatic price declines for solar modules in recent years can be attributed in significant part to underlying cost reductions, we compare the average sales prices (ASP) for solar modules with the ESPs for 24 quarterly observations between 2008 and 2013. Our calculations focus on ten major module manufacturers with a combined market share of 35%.⁴ All of these firms are listed on U.S. stock exchanges; therefore their financial statements have been prepared in accordance with U.S. accounting principles (GAAP). We infer the production costs for these firms from quarterly financial statements, including income- and cash flow statements as well as balance sheets. In addition, we obtain data on manufacturing capacity and shipments from analyst reports and industry associations.

Our findings show a relatively close match between average sales prices and economically sustainable prices for the years 2008 – 2010. While our calculations reveal a steady and significant decrease in costs and economically sustainable prices for the entire observation period, we also conclude that the dramatic decline in the observed ASPs for the years 2011-

⁴The solar PV industry satisfies the criteria of a competitive industry insofar as a large number of firms in the industry supply a relatively homogeneous product. To note, the median capacity market share of firms in this industry was 1% in 2012.

2013 is inconsistent with the industry having been in equilibrium during those years.⁵ In other words, for those years the drop in ASPs should in large part be attributed to excessive additions to manufacturing capacity rather than to cost reductions.⁶ For example, our estimates suggest an ESP of \$1.19/W at the end of 2012, but the ASP was about \$0.80/W.⁷

Despite our conclusion that observed prices were substantially below the ESP levels for at least some of the years, we also find that over our sample period the economically sustainable prices (the long-run marginal cost) declined even faster than suggested by the 80% learning curve. In particular, for production costs comprising materials, labor, and manufacturing overhead (excluding depreciation), we estimate a 74% learning curve. At the same time, we find that capacity related costs for machinery and equipment have fallen at a rate that also outperforms the 80% learning curve benchmark.

Our estimates of different learning parameters allow us to extrapolate the trajectory of future ESPs as a function of time and future production volumes. For the year 2014, we project a narrowing between the observed ASPs around \$0.80/W (after temporarily dropping to around \$0.75/W), and the inferred ESP of around \$0.90/W. Under the conservative assumption that the industry will continue to produce and install about 40 GW annually in the coming years, we obtain a fundamental trend-line to which we expect ASPs to converge. Projecting forward to 2017 and 2020, we estimate ESPs of about \$0.70/W and \$0.61/W, respectively. While these values would represent a first-order effect on lowering the cost of solar power, they are significantly above the \$0.50/W price target of the DOE Sunshot Initiative.

The methods we employ in this paper are applicable beyond the solar PV industry. The identification of the ESP as the cost-based price which represents a competitive equilibrium price relates our work to that by Spence (1981) and Dick (1991). Unlike these earlier studies, we consider the role of new capacity acquisitions, the cost of which is expected to decline over time. The inclusion of overlapping capacity investments builds on earlier models in

⁵Our conclusion is corroborated by the sharply negative earnings and declining share prices firms in our sample experienced during those two years.

⁶It is conceivable that these capacity additions reflected expectations about an expansion in demand that ultimately did not materialize.

⁷Our analysis allows us to conclude that, even in 2012, the observed ASPs covered those parts of the manufacturing costs that are typically considered “variable” or “avoidable” in the short-run. This observation speaks to antitrust and dumping disputes in which suppliers are frequently held to a pricing standard that requires prices to cover at least variable production costs.

Arrow (1964), Rogerson (2008), Rajan and Reichelstein (2009), and Rogerson (2011).

The cost inference method we employ to estimate the ESP provides an alternative to so-called “bottom-up” cost models, such as those in Powell et al. (2012), Powell et al. (2013), Goodrich et al. (2013a), and Goodrich et al. (2013b). These studies estimate costs by aggregating input requirements and prices as reported by various industry sources. Our approach based on reported accounting information can be viewed as a validation of the bottom-up cost models. In addition, our method yields equilibrium price predictions that account for anticipated future reductions in manufacturing costs. The work by Pillai and McLaughlin (2013) is closer in spirit to our analysis as it also applies firm-level accounting data to parametrize a model of competition in the solar manufacturing industry. However, as explained in more detail in Section 3 below, Pillai and McLaughlin rely on a measure of decision-relevant costs that differs fundamentally from the one in our paper.

The remainder of the paper is organized as follows. Section 2 formulates a dynamic model of a competitive industry with falling production costs. This framework allows us to identify Economically Sustainable Prices (ESP) in terms of production costs. Section 3 describes our data and inferential procedure. We then compare our ESP estimates to observed ASPs to test when the solar PV module industry was in equilibrium. Section 4 presents our econometric estimates of recent learning effects in manufacturing costs and applies these estimates to extrapolate a trajectory of future ESPs. Section 5 concludes. The appendix sections present proofs, data sources and adjustments used in our inference procedure, as well as robustness checks.

2 A Model of Economically Sustainable Prices

2.1 Base Model

The model framework we develop in this section allows us to identify economically sustainable prices in terms of production costs. We consider a dynamic model of an industry composed of a large number of suppliers who behave competitively. A key feature of the model is that firms are capacity constrained in the short-run. Each firm’s output supplied to the market in a particular period is limited to the overall capacity that the firm has installed in previous periods. Production capacity available at any given point in time therefore reflects the cumulative effect of past investments, as in Arrow (1964), Rogerson (2008), Rajan and

Reichelstein (2009), and Rogerson (2011).

In the base version of the model, all firms can accurately predict future demand. Let $P_t^o(Q_t)$ denote the aggregate willingness-to-pay (inverse demand) curve at time t , where Q_t denotes the aggregate quantity supplied at date t . Market demand is assumed to be decreasing in price and, in addition, we postulate that demand is expanding over time in the sense that:

$$P_{t+1}^o(Q) \geq P_t^o(Q), \tag{1}$$

for all $t \geq 1$ and all Q . The significance of this condition is that if firms make investments sufficient to meet demand in the short-run, they will not find themselves with excess capacity in future periods.⁸ Given the emphasis on renewable energy in many parts of the world, Condition 1 appears quite plausible in the context of the market for solar PV modules.⁹

In order to break-even on their capacity investments, firms must realize a stream of revenues that covers periodic operating costs in addition to investment expenditures. The concept of an economically sustainable price is cost-based and comprises capacity related costs, periodic operating costs, and costs related to income tax payments. At the initial date 0, the industry is assumed to have a certain stock of capacity in place. To acquire one unit of manufacturing capacity, i.e., the capacity to produce one Watt (W) of solar PV modules per year, firms must incur an investment expenditure of v at the initial date 0. We allow for technological progress resulting in lower capacity acquisition costs over time. For reasons of tractability, though, we confine attention to a single “technological progress parameter”, η , leading to a pattern of geometric declines such that $\eta^t \cdot v$ denotes the acquisition cost for one unit of capacity at time t , with $\eta \leq 1$.¹⁰ Accordingly, investment decisions and the subsequent level of aggregate capacity in the market are conditional on firms’ expectation of future decreases in capacity costs.

Investments in capacity represent a joint cost insofar as one unit of capacity acquired at time t will allow the firm to produce one unit of output in each of the next T periods.¹¹

⁸Rogerson (2008) and Rogerson (2011) refer to (1) as the No-Excess Capacity (NEC) condition.

⁹Indeed, cumulative installed capacity has increased monotonically from 1.2GW in 2005 to 39GW in 2013 (Bloomberg New Energy Finance, 2014).

¹⁰Decreases in capacity cost as a function of time can be attributed to improvements in manufacturing equipment and improved efficiency for the conversion of modules. Our formulation implicitly assumes that η is known with certainty.

¹¹For simplicity, we adopt the assumption that productive capacity remains constant over the useful life

To identify equilibrium prices in terms of costs, it will be useful to introduce the marginal cost of one unit of capacity *made available for one period of time*. As shown by Arrow (1964) and Rogerson (2008), this effectively amounts to “levelizing” the initial investment expenditure. To that end, let $\gamma = \frac{1}{1+r}$ denote the applicable discount factor. Practical capacity available in any period may only be a fraction of the theoretical capacity, and we denote the corresponding capacity factor by CF . The marginal cost of one unit of capacity available in period t then becomes:

$$c_t = \frac{\eta^t \cdot v}{CF \cdot \sum_{\tau=1}^T (\gamma \cdot \eta)^\tau}. \quad (2)$$

An intuitive way to verify this claim is to assume that firms in the industry can rent capacity services on a periodic basis. Assuming this rental market is competitive and capacity providers have the same cost of capital, it is readily verified that the capacity provider who invests in one unit of capacity at time t and then rents out that capacity in each of the next T periods for a price of $c_{t+\tau}$ would exactly break even on his initial investment of $\eta^t \cdot v$. Accordingly, Arrow (1964) refers to c_t as the *user cost of capacity*.¹²

In any given period, firms are assumed to incur fixed operating costs, e.g., maintenance, rent and insurance, in proportion to their capacity. Like past investment expenditures, these costs are assumed to be effectively “sunk” after date t because they are incurred regardless of capacity utilization. Formally, let f_t represent the fixed operating cost per unit of capacity available at time t , with $f_{t+1} \leq f_t$ for all $t \geq 1$. Finally, production of one unit of output entails a constant unit variable cost, w_t , which again is assumed to be weakly decreasing over time, that is, $w_{t+1} \leq w_t$ for all $t \geq 1$. In contrast to the fixed operating costs, variable costs are avoidable in the short-run if the firm decides not to utilize its available capacity.

Corporate income taxes affect the cost of production through depreciation tax shields and debt tax shields, as both interest payments on debt and depreciation charges reduce the firm’s taxable income. Following the standard approach in corporate finance, we ignore the

of a facility. In the regulation literature, this productivity pattern is frequently referred to as the “one-hoss shay” model; see, for instance, Rogerson (2008) and Nezlobin, Rajan, and Reichelstein (2012).

¹²For additional intuition, consider the case in which no capacity cost declines are expected. Then, $c = \frac{v}{CF \cdot \sum_{\tau=1}^T \gamma^\tau}$. When the industry anticipates decreases in the cost of capacity, the marginal cost of one unit of capacity available in period t is described by (2). The expression reflects the need for the capacity to compete with lower cost facilities that could come online in subsequent periods.

debt related tax shield provided the applicable discount rate, r , is interpreted as a weighted average cost of capital. The depreciation tax shield is determined by both the effective corporate income tax rate and the allowable depreciation schedule for the facility. These variables are represented as:

- α : the effective corporate income tax rate (in %),
- d_t : the allowable tax depreciation charge in year t , $1 \leq t \leq T$, as a percent of the initial asset value.

The assumed useful life of an asset for tax purposes is usually shorter than the asset's actual economic useful life, which we denote by T in our model. Accordingly, we set $d_t = 0$ for those periods that exceed the useful life of the asset for tax purposes. As shown below, the impact of income taxes on the long-run marginal cost can be summarized by a *tax factor* which amounts to a “mark-up” on the unit cost of capacity, c_t .

$$\Delta = \frac{1 - \alpha \cdot \sum_{t=1}^T d_t \cdot \gamma^t}{1 - \alpha}. \quad (3)$$

The tax factor Δ exceeds 1 but is bounded above by $\frac{1}{1-\alpha}$.¹³ It is readily verified that Δ is increasing and convex in the tax rate α . Holding α constant, a more accelerated tax depreciation schedule tends to lower Δ closer to 1. In particular, Δ would be equal to 1 if the tax code were to allow for full expensing of the investment immediately. We are now in a position to introduce the measure of long-run marginal cost:

$$ESP_t = w_t + f_t + c_t \cdot \Delta. \quad (4)$$

The label ESP_t on the left-hand side of (4) anticipates Finding 1 below, which shows that firms will break-even (achieve zero economic profits) over time if product prices are equal to ESP_t in each period. Given our assumption of a competitive fringe of suppliers, the investment and capacity levels of individual firms remain indeterminate. Denoting the aggregate industry-wide investment levels by I_t , the “one-hoss shay” assumption that productive assets

¹³To calibrate the magnitude of this factor, for a corporate income tax rate of 35%, and a tax depreciation schedule corresponding to a 150% declining balance rule over 20 years, the tax factor would approximately amount to $\Delta = 1.3$.

have undiminished productivity for T periods implies that the aggregate capacity at date t is given by:

$$K_t = I_{t-T} + I_{t-T+1} + \dots + I_{t-1} \quad (5)$$

Equation (5) holds only for $t > T$. If $t \leq T$, then $K_t = I_0 + I_1 + \dots + I_{t-1}$.

Firms choose their actual output in a manner that is consistent with competitive supply behavior. Since capacity related costs and fixed operating costs are sunk in any given period, firms will exhaust their entire capacity only if the market price covers at least the short-run marginal cost w_t . Conversely, firms would rather idle part of their capacity with the consequence that the market price will not drop below w_t . Given an aggregate capacity level, K_t , in period t , the resulting market price is therefore given by:

$$p_t(K_t, w_t) = \max\{w_t, P_t^o(K_t)\},$$

while the aggregate output level, $Q_t(K_t, w_t)$ satisfies $P_t^o(Q_t(K_t, w_t)) = p_t(K_t, w_t)$. We refer to the resulting output and price levels as *competitive supply behavior*.

Definition 1 $\{K_t^*\}_{t=1}^\infty$ is an equilibrium capacity trajectory if, given competitive supply behavior, the net present value of capacity investments at each point in time is zero.

Finding 1 The trajectory given by:

$$ESP_t = P_t^o(K_t^*) \quad (6)$$

is an equilibrium capacity trajectory.¹⁴

The equilibrium price characterization in Finding 1 reinforces the interpretation of the ESP_t as the long-run marginal cost of one unit of output.¹⁵ With additional assumptions, the capacity trajectory identified in Finding 1 is also the unique equilibrium capacity trajectory. This is readily seen if one assumes that capacity investments are reversible or, instead, that

¹⁴A formal proof of Finding 1 is presented in Appendix A. An implicit assumption underlying Finding 1 is that the aggregate capacity in place at the initial date 0 does not amount to excess capacity. Formally, we require $P_t^o(K_0) > ESP_1$.

¹⁵Our assumed competitive structure implies that no firm has a material impact on the probability of entry or exit by other firms. Thus, any mismatches between the predicted equilibrium prices and actual market prices stem from a market out of equilibrium rather than one with strategic predatory pricing as considered by, e.g., Besanko, Doraszelski, and Kryukov (2014).

capacity can be obtained on a rental basis for one period at a time, with all rental capacity providers obtaining zero economic profits. Competition would then force the market price for the product in question to be equal to ESP_t in each period.

In our model formulation, the unit variable costs, w_t , and the unit fixed cost, f_t , may decline over time, with the rate of decline taken as exogenous. We note that under conditions of atomistic competition, or that in which no firm can impact the prevailing market price through its own supply decision, the result in Finding 1 also extends to situations where the unit costs decline as a function of the *cumulative volume* of past output levels. One possible formulation is for $w_t = \beta(\sum Q_t) \cdot w$, where $\beta(\cdot) < 1$ is decreasing in its argument and $\sum Q_t \equiv \sum_{\tau \leq t} Q_\tau$.

To conclude this subsection, we note that our ESP concept is conceptually similar to the Levelized Cost of Electricity (LCOE) that is widely quoted in connection with the economics of different electricity generation platforms; see, for instance, Lazard (2009), Borenstein (2012), and Reichelstein and Yorston (2013). The LCOE yields a constant break-even price per kilowatt-hour that investors in a particular energy facility would need to receive *on average* in order to cover all costs and receive an adequate return on their initial investment. In contrast to our framework here, LCOE calculations are generally focused on the life-cycle of a single facility rather than on an infinite horizon setting with overlapping capacity investments which, per unit of capacity acquired, may become less expensive over time.

2.2 Demand Uncertainty

With one additional assumption, the characterization of equilibrium in Finding 1 can be extended to environments with price uncertainty. Suppose that given the aggregate supply quantity Q_t at date t , the price in period t is given by:

$$P_t(\epsilon_t, Q_t) = \epsilon_t \cdot P_t^o(Q_t),$$

where $\tilde{\epsilon}_t$ reflects volatility in the level of demand and is a random variable with mean 1. The support of $\tilde{\epsilon}_t$ is $[\underline{\epsilon}_t, \bar{\epsilon}_t]$, with $0 < \underline{\epsilon} < 1$. The noise terms $\{\tilde{\epsilon}_t\}_{t=1}^\infty$ are assumed to be serially uncorrelated, such that each $\tilde{\epsilon}_t$ is observed by all market participants at the beginning of period t . Competitive supply behavior then requires that:

$$p_t(\epsilon_t, w_t, K_t) = \begin{cases} \epsilon_t \cdot P_t^o(K_t) & \text{if } \epsilon_t \geq \epsilon_t(K_t, w_t) \\ w_t & \text{if } \epsilon_t < \epsilon_t(K_t, w_t) \end{cases}$$

where the threshold level of demand volatility is given by:

$$\epsilon_t(K_t, w_t) = \begin{cases} \bar{\epsilon}_t & \text{if } \bar{\epsilon}_t \cdot P_t^o(K_t) \leq w_t \\ \frac{w_t}{P_t^o(K_t)} & \text{if } \bar{\epsilon}_t \cdot P_t^o(K_t) > w_t > \underline{\epsilon}_t \cdot P_t^o(K_t) \\ \underline{\epsilon}_t & \text{if } \underline{\epsilon}_t \cdot P_t^o(K_t) \geq w_t \end{cases}$$

Given K_t and w_t , the expected market price in period t then becomes:

$$E[p_t(w_t, \tilde{\epsilon}_t, K_t)] \equiv \int_{\underline{\epsilon}}^{\epsilon(K_t, w_t)} w_t \cdot h_t(\epsilon_t) d\epsilon_t + \int_{\epsilon(K_t, w_t)}^{\bar{\epsilon}} \epsilon \cdot P_t^o(K_t) \cdot h_t(\epsilon_t) d\epsilon_t \quad (7)$$

With risk neutral firms, price volatility will not affect the capacity levels obtained in equilibrium provided firms anticipate that they will exhaust the available capacity even for unfavorable price shocks. To that end, we introduce a condition of *limited price volatility*:

$$\underline{\epsilon}_t \cdot ESP_t \geq w_t.$$

Holding the distributions $h_t(\cdot)$ of $\tilde{\epsilon}_t$ fixed, this condition will be satisfied if the short-run avoidable cost w_t constitutes a relatively small percentage of the long-run marginal cost, ESP_t . The implication of this condition is that even for unfavorable price fluctuations firms will still want to deploy their entire capacity.

Corollary to Finding 1 *If price volatility is limited, the trajectory identified in Finding 1 remains an equilibrium capacity trajectory. The expected market prices in equilibrium satisfy:*

$$ESP_t = E[p_t(w_t, \tilde{\epsilon}_t, K_t^*)]. \quad (8)$$

As will become clear from the cost analysis in the following sections, the limited price volatility condition appears to be descriptive in the context of the solar PV module industry. Our estimates suggest that the unit variable cost, w_t , accounts for less than 60% of the total product cost, as measured by ESP_t , for the observation period 2008-2013. In the context of our model this would amount to $\underline{\epsilon}_t \geq 0.6$. To be sure, there are indications that some firms idled part of their available capacity during that time period, but we attribute this observation to the industry having been out of equilibrium, at least in parts of 2011 and 2012, rather than to the occurrence of large price shocks.

Finally, we note that the analysis in Reichelstein and Rohlfig-Bastian (2014) has examined competitive equilibrium prices for settings where the limited price volatility condition

does not hold. Their model presumes a finite horizon setting with T periods. In equilibrium, all firms make a single investment at the initial date and then supply output in a sequentially optimal manner, given periodic fluctuations in market demand. The sequence of expected equilibrium market prices still corresponds to the long-run marginal cost. Yet, the aggregate capacity level will generally be higher than that emerging under limited price volatility if firms anticipate that with some probability the aggregate capacity of the industry will not be exhausted. The intuition for this result is that since market prices are bounded below by the short-run variable cost, significant price volatility essentially entails a call option in the firm's payoff structure. In order for the zero-profit condition to hold, the aggregate capacity level must, *ceteris paribus*, therefore increase .

3 Estimating Economically Sustainable Prices

This section presents our method for estimating the long-run marginal cost of production, the ESP, from financial accounting data. Our estimates for the cost of solar module production are on a per Watt basis. We begin by summarizing the main steps in the value chain of crystalline silicon PV modules. The major production steps consist of polysilicon, ingots, wafers, cells, and modules. The industry consensus is that opportunities for continued cost reductions remain at each step. Polysilicon is primarily produced via the so-called Siemens process, and the main cost reduction opportunities include improvements in energy efficiency and an increase in the scale of the Siemens chemical vapor depositor reactor.¹⁶

The polysilicon output is used to grow ingots. Two recent developments have potential to reduce production costs. The first is the production of larger ingots. The second is the use of quasicrystalline ingots, as these eliminate a downstream processing step in which active silicon material is discarded. Quasicrystalline ingot growth could deliver \$0.10/W savings, relative to the incumbent technique for monocrystalline growth (Lux Research, 2012b). Ingots are subsequently sliced into wafers. The bulk of silicon losses occur at this step, and the magnitude of losses depends on the thickness of the wire saws used. While smaller diameter wafer saws would reduce material loss during the process, these saws would

¹⁶Chemical vapor deposition is used to produce high purity materials. An alternative production method for polysilicon uses fluidized bed reactor (FBR) techniques. Though it can yield lower production costs, it presents operational challenges and requires a careful optimization of temperatures in the reactor (Goodrich et al., 2013a; Lux Research, 2012b).

be weaker and more likely to break.

The most capital and process intensive step of the module production process is the transition from wafers to cells. During this step, the wafers are etched and doped with impurities to achieve a desired level of electrical conductivity, metallized to facilitate the transfer of charges, and treated with an anti-reflective coating (Lux Research, 2012b). Finally, cells are strung together, enclosed, and appended with a junction box to build a solar module. Since module assembly requires only one essential piece of equipment, this last step has traditionally been labor intensive. Automation continues to reduce labor requirements substantially (Lux Research, 2012b).

We infer manufacturing costs from financial data released by Yingli Green Energy, Trina Solar, Suntech Power, Canadian Solar, LDK Solar, Hanwha SolarOne, JA Solar, ReneSolar, Jinko Solar, and China Sunergy.¹⁷ Almost 300 other firms supply the module market (Lux Research, 2012a), but we excluded manufacturers based on five criteria. In particular, we excluded those firms (i) with lower than 0.5% share of global capacity in 2012, (ii) without public financial data since 2010, (iii) privately held or embedded within large conglomerates, (iv) listed on exchanges outside of the U.S, and (v) manufacturing thin-film modules. The firms in our sample manufacture primarily in China, are at least partially integrated across the value chain, and have invested in capacity expansions over our study period.

Our data span 24 quarters from Q1 2008 to Q4 2013, and we use a time-index, $t \in \{1, \dots, 24\}$, to refer to quarters in our inference technique. Table 1 presents the variables of interest. For simplicity, we have dropped the index i referring to individual firms.

All the above variables are obtained directly from individual data sources, except for quarterly production levels and additions to finished goods inventory, that is, q_t and n_t . In addition to these two variables, we also need to infer the cost of goods manufactured ($COGM_t$). Following industry practice, all of the above Watt measures are stated in terms of distributed current, that is, they are calculated on a DC basis.

Our model framework in Section 2 conceptualizes the long-run marginal cost in each period as the sum of capacity related costs and current operating costs. Since we estimate these different cost components from firms' financial statements, we emphasize the basic distinc-

¹⁷We access financial data through the Bloomberg terminal system. Table 6 in Appendix B provides summary details about the firms. The U.S. based firm SunPower is notably absent from our analysis because its sizeable solar development business makes it difficult to infer manufacturing costs from reported financial information.

Variable	Description	Units
q_t	Production volume in period t	MW_p
s_t	Sales volume in period t	MW_p
n_t	Inventory volume in period t	MW_p
$Sales_t$	Sales of modules during period t	\$
$COGS_t$	Cost of goods sold during period t	\$
$COGM_t$	Cost of goods manufactured during period t	\$
Inv_t	Value of inventory held at end of period t	\$
D_t	Depreciation charge in period t	\$
GM_t	Gross margin during period t	\$
ASP_t	Average selling price in period t	$\$/W_p$
$CAPX_t$	Capital expenditures in period t	\$
RD_t	Research and development expenses in period t	\$
SGA_t	Sales, goods, and administrative expenses in period t	\$
K_t	Production capacity in period t	MW_p/year
I_t	Production capacity addition in period t	MW_p/year

Table 1: *Variables obtained from financial data or derived from our inference procedure.*

tion between *manufacturing* (inventoriable) costs and *period* costs. As the label suggests, the former pertain to factory related costs, including materials, labor, and manufacturing overhead inclusive of depreciation. These costs are reflected in the figures reported for cost of goods sold (COGS) as part of the gross margin. In contrast, *period costs* cover those related to selling as well as general and administrative (SG&A) expenses, including advertising and R&D. Conceptually, we think of w_t and f_t from Section 2 as having two components each: $w_t = w_t^+ + w_t^-$ and $f_t = f_t^+ + f_t^-$, with the “+” part referring to manufacturing (inventoriable) costs and the “-” part referring to period costs.

Sections 3.1 and 3.2 present our inference procedure for manufacturing and period costs, respectively. The first presents our method for identifying those components of the unit variable and the fixed operating costs that are incurred in the manufacturing process. In the latter section, we derive our estimators of the costs comprising period costs.

3.1 Manufacturing Costs

3.1.1 Core Manufacturing Costs

We use the label *core manufacturing costs* to refer to all manufacturing (inventoriable) costs other than depreciation. Firms' financial accounting data allow us to make inferences only about the aggregate core manufacturing costs in period t and not about their fixed and variable components:

$$m_{it} \equiv w_{it}^+ + f_{it}^+,$$

The key variable for gauging manufacturing cost is Cost of Goods Manufactured (COGM). It is calculated as the unit cost m_{it} times the quantity of modules produced in the current quarter plus current depreciation charges pertaining to equipment and facilities:

$$COGM_{it} = \text{Core Manufacturing Costs} + \text{Depreciation} \equiv m_{it} \cdot q_{it} + D_{it}. \quad (9)$$

For our estimation purposes, only the depreciation charge, D_{it} , is directly available.¹⁸ To estimate m_{it} in (9), we rely on several identities which connect production volume, sales, and inventory to infer the remaining variables, that is, $COGM_{it}$ and q_{it} . The quantity of units (modules on a per Watt basis) produced in period t equals the number of units sold plus the difference in inventory between the current and the prior period. Thus:

$$q_{it} = n_{it} - n_{it-1} + s_{it}. \quad (10)$$

Units sold in quarter t are sourced from both current period production and the inventory left from the prior period. Assuming that firms employ average costing for inventory valuation purposes, the average unit cost of firm i in period t is given by:

$$ac_{it} = \frac{Inv_{it-1} + COGM_{it}}{n_{it-1} + q_{it}}. \quad (11)$$

Here, ac_{it} is effectively the average cost per module available for sale by firm i at time t , taking the arithmetic mean between the beginning balance and the current period addition

¹⁸Depreciation charges are frequently reported only annually on the statement of cash flows. When quarterly depreciation figures are unavailable, we apportion annual depreciation charges equally across quarters. That approach is consistent with the use of straight-line depreciation for financial reporting purposes.

in both the numerator and the denominator. The left-hand-side of (11) can be inferred immediately from observations of cost of goods sold (COGS) and module shipments since:

$$COGS_{it} = s_{it} \cdot ac_{it}. \quad (12)$$

Finally, we make use of an expression yielding the ending inventory balance:

$$Inv_{it} = ac_{it} \cdot (n_{it-1} + q_{it} - s_{it}). \quad (13)$$

Adding this ending inventory balance to $COGS$, we obtain:

$$Inv_{it} + COGS_{it} = ac_{it} \cdot (n_{it-1} + q_{it} - s_{it}) + s_{it} \cdot ac_{it} = ac_{it} \cdot (n_{it-1} + q_{it}). \quad (14)$$

The right-hand side of (14) then allows us to infer $n_{it-1} + q_{it}$, which in turn yields $COGM_{it}$ in (9) via the fundamental identity in (10). In order to initialize the sequence of quarterly module production volumes, we infer an initial inventory level, n_{i0} by equating n_{i0} to $\frac{Inv_{i0}}{ac_{i0}}$.¹⁹ Our inventory measure comprises finished goods and work-in-progress, but not raw materials.²⁰

Finally, since firm-wide COGS and inventory apply to all products sold by the firm, we derive module-equivalent shipment levels.²¹ To do so, we modify shipment levels for intermediate products (i.e., wafers and cells) by multiplying them by the ratio of their average selling prices in a quarter to that for modules. In particular:

$$s_{it}^{ME} = \phi_{W_t} \cdot s_{it}^W + \phi_{C_t} \cdot s_{it}^C + \phi_{M_t} \cdot s_{it}^M, \quad (15)$$

where $\phi_{W_t} = \frac{ASP_{W_t}}{ASP_{M_t}}$, $\phi_{C_t} = \frac{ASP_{C_t}}{ASP_{M_t}}$, and $\phi_{M_t} = 1$. The Online Appendix lists the multipliers we use.²² To illustrate the equivalency concept with an example, consider a firm that ships 200MW of modules and 100MW of wafers in a given quarter. If ϕ_{W_t} were equal to 0.38, we

¹⁹We index one quarter in each firm's data series to $t = 0$. The initial period is Q4-07 for most firms. The exceptions are LDK Solar and Jinko Solar, for which the initial periods are Q1-09 and Q2-10, respectively.

²⁰Where quarterly breakdowns of inventory are unavailable, we assume that the split of inventory into finished and work-in-progress goods during the first, second, and third quarters is similar to the annual split observed in the previous and current years. Each quarter's split is a weighted combination of these two data points. The Q1, Q2, and Q3 estimates weight the previous year's annual data by 75%, 50%, and 25%, respectively.

²¹These resultant shipment levels thus account for the production and sale of other goods across the solar module value chain.

²²The Online Appendix is available at <http://stanford.io/1ov1kdQ>.

would record the firm’s module equivalent shipment quantity as $200 + 100 \cdot 0.38$ or 238MW. Upon doing so, we can use firm-wide COGS and inventory figures to estimate m_{it} .

Pillai and McLaughlin (2013) also use financial accounting data from solar PV manufacturers to infer production costs. However, our inference procedure differs markedly from theirs. First, Pillai and McLaughlin (2013) use Cost of Goods Sold (COGS) as their measure of variable cost of production. Since COGS includes depreciation charges and fixed operating costs, it will significantly exceed variable production costs. Secondly, Pillai and McLaughlin (2013) use the quotient of revenue to shipments in order to derive average selling prices (ASPs). Our inference procedure refines these estimates by adjusting shipments of wafers, cells, and modules in order to derive module-equivalent shipment measures.

3.1.2 Capacity Costs

For the purposes of calculating the long-run marginal cost of modules, we anchor the estimate of the capacity related costs to the baseline initial investment expenditure, v , required to manufacture one additional unit of output over the next T years. This expenditure is then “levelized” as shown in (2) in Section 2 to obtain the marginal cost of one unit of capacity made available at time t . Furthermore, this levelized cost must take into account the technological progress parameter η , which posits that the marginal cost of one unit of capacity made available at time t decreases geometrically with time.

Our analysis splits capacity related costs into two buckets: manufacturing equipment (e) and facilities (f). In accordance with (2), we obtain:

$$c_t = c_{et} + c_{ft} = \eta_e^t \cdot \frac{v_e}{CF \cdot \sum_{\tau=1}^T (\gamma \cdot \eta_e)^\tau} + \eta_f^t \cdot \frac{v_f}{CF \cdot \sum_{\tau=1}^T (\gamma \cdot \eta_f)^\tau}. \quad (16)$$

Ideally, we would use firm-level data on fixed assets, depreciation, capital expenditures, and total capacity available to construct a quarterly panel of capacity costs. However, the data available entail several complications. First, it is unclear whether investment expenditures were directed at capacity upgrades or capacity additions. Second, the proportion of expenditure applied to investments in facilities as opposed to equipment is ambiguous. Additional concerns relate to inter-temporal allocation issues. One of these is the need to specify the lag between capital expenditures and capacity additions coming online. Finally,

it is not clear how to split annual capital expenditure data into quarterly observations.²³ For these reasons, we estimate η by relying on data from an industry observer, GTM (2012).

We first turn to the estimation of facilities costs. Since these costs pertain primarily to the cost of buildings, we set $\eta_f = 1$. However, as the efficiency of solar cells increases, the same physical area of output contains a greater power capacity (in Watts) and therefore the capacity cost per Watt decreases. We adjust the capacity cost in each period to reflect increases in average module efficiency. Appendix B details these adjustments. The top line of Table 2 records the efficiency-adjusted and industry-wide estimate of v_f ; these numbers vary over time solely because of efficiency improvements. Our estimate of v_f is based on a bottom-up estimate of facility capacity costs for a known efficiency from Powell et al. (2013) and efficiency levels observed by Fraunhofer (2012) (see Table 7 in Appendix B). Powell et al. assume that a plant with an annual capacity of 395MW of 13.6% efficiency modules entails capacity costs of approximately \$53M, implying a v_f estimate of \$0.066/W.

Component	2009	2010	2011	2012	2013	2014	2015	2016
Facility	\$0.07	\$0.07	\$0.06	\$0.06	\$0.06			
Ingot	\$0.21	\$0.17	\$0.11	\$0.09	\$0.06	\$0.05	\$0.04	\$0.04
Wafer	\$0.24	\$0.20	\$0.16	\$0.13	\$0.08	\$0.07	\$0.06	\$0.06
Cell	\$0.45	\$0.30	\$0.20	\$0.16	\$0.10	\$0.08	\$0.08	\$0.07
Module	\$0.12	\$0.09	\$0.07	\$0.05	\$0.03	\$0.03	\$0.02	\$0.02
Total Equipment	\$1.02	\$0.76	\$0.54	\$0.43	\$0.27	\$0.23	\$0.20	\$0.19

Table 2: *All rows but the first provide estimates from GTM (2012) of crystalline silicon capital equipment cost per watt in China. The first row lists our facility capacity cost estimates. Since average efficiency levels for 2014 – 2016 are still unknown, these entries are left blank. The last row presents the total equipment-related costs, excluding the cost of capacity for the facility.*

Turning to equipment costs, we rely on data provided by an industry observer, GTM (2012), to estimate the parameter η_e . The industry-wide estimates regarding v_e for different baseline years are summarized in Table 2. While the table presents equipment capacity numbers for China, GTM also provides cost data for the U.S.; these costs are generally

²³A related challenge is that we observe changes in *total* capacity available, without being able to distinguish between additions to and retirements of capacity. This remains a challenge in our ultimate methodology. However, since the useful life of equipment is generally estimated to be between 7 and 10 years and since the firms in our sample had limited capacity before 2005, we do not believe that this issue introduces a significant source of bias.

higher. Indexing each year by t and setting 2009 as year 0, we estimate the technological progress parameter via a simple regression:

$$v_t = \eta^t \cdot v_0 + \xi_t,$$

where ξ_t is assumed to be a log-normally distributed error term with $E[\ln(\xi_t) | t] = 0$. Then, $\log \frac{v_t}{v_0} = t \cdot \ln(\eta_e) + \ln(\xi) \cdot t$. This regression estimate yields $\eta_e = 0.79$ (with a standard error of 0.02) for China and $\eta_e = 0.80$ (with a standard error of 0.02) for the U.S.

Since one of our goals is to derive a distribution of firm-specific ESP estimates with which to statistically test for a market in long-run equilibrium, we use our η_e estimate to derive firm-specific capacity costs. To align our capacity- and manufacturing cost estimates, we reset the index t to begin in 2007. We estimate equipment capacity costs for firm i , v_{ie} , as the quotient of cumulative capital expenditure, $CAPX$, between 2008 and 2013 to the change in module manufacturing capacity over that period. The technological progress parameter implies that in each subsequent year after 2007, the same capital expenditure yields more capacity per dollar. This prompts us to use the following adjusted measure of capital expenditures:

$$v_{ie} = v_{ie0} = \frac{\sum_{t=0}^6 CAPX_{it} \cdot \eta_e^{-t}}{K_{i2014} - K_{i2008}} \quad (17)$$

The η_e^{-t} term in the numerator “scales-up” capital expenditures after 2007 since such investments yielded more capacity per dollar.²⁴ The denominator, $K_{i2014} - K_{i2008}$, describes the change in manufacturing capacity.

Equation (17) is potentially prone to two erroneous inferences. First, our expression assumes that all capital expenditures were used to expand *integrated* module manufacturing capacity (i.e., capacity to produce ingots, wafers, cells, and modules). However, firms could have expanded their capacity to produce only some of these components. Second, firms’ financial statements do not specify the portion of their capital expenditures that were applied to facility improvements as opposed to investments in new production equipment.²⁵

²⁴Our approach thus yields estimates of the 2007 equipment capacity costs among the firms in our sample. Note that (17) assumes that capital expenses yield productive capacity within one year.

²⁵A potential third issue is that we observe changes in *net* capacity and must implicitly assume that no capacity has been taken offline. This is a reasonable assumption, given the ages of the firms in our sample. Though we may be unable to observe deletions of capacity, we observe a decrease in capacity from one quarter

We address the first issue by using an integrated module-equivalent (ME) level of capacity, K^{ME} , that “marks down” capacity additions that did not include all components of module manufacturing by the ratio of the capacity costs for the components actually installed to that for all components. Appendix B details our derivation of integrated module-equivalent capacity levels. The second issue leads us to define a factor β_t that measures the share of equipment capacity costs in total capacity costs:

$$\beta_t = \frac{v_e \cdot \eta_e^t}{v_e \cdot \eta_e^t + v_f}$$

The cost data in Table 2 allow us to calculate β_t on an annual basis. Since GTM does not provide capacity cost data for years preceding 2009, we backcast v_e for 2007 and 2008 by using our estimate $\eta_e = 0.79$. These two adjustments lead to the following modification of (17):

$$v_{ie} = \frac{\sum_{t=0}^6 \beta_t \cdot CAPX_{it} \cdot \eta_e^{-t}}{K_{i2014}^{ME} - K_{i2008}^{ME}}. \quad (18)$$

We obtain firm-specific facility capacity costs by substituting $1 - \beta_t$ for β_t in (18). In general, our sample includes capital expenditure data for each year between 2007 and 2013 and capacity levels from 2008 to 2014.²⁶ In accordance with our model framework in Section 2, we finally levelize the capacity acquisition costs to obtain a measure of cost per unit of output:

$$c_{iet} = \eta_e^t \cdot \frac{v_{ie}}{CF \cdot \sum_{\tau=1}^{10} (\eta_e \cdot \gamma)^\tau}, \quad (19)$$

and

$$c_{ift} = \frac{v_{if} \cdot \frac{eff_{ref}}{eff_t}}{CF \cdot \sum_{\tau=1}^{30} \gamma^\tau}. \quad (20)$$

to the next for only one firm and time period. If significant retirements actually occurred, our measure of v_{ie} would be biased upwards.

²⁶Table 3 notes exceptions. More specifically, 2009 serves as the base year for JKS capital expenditures and 2010 for capacity. For STP, 2011 serves as the end year for capital expenditures and 2012 for capacity. For LDK, 2012 serves as the end year for capital expenditures and 2013 for capacity.

The ratio of efficiencies in the latter equation reflects our adjustment for improvements in module efficiency over time (see Appendix B).

Since equipment and facility assets have different useful lives we employ separate tax factors, Δ_e and Δ_f , respectively. To calculate these, we apply a tax rate of $\alpha = 15\%$ and a (weighted average) cost of capital of $r = .13$. We set the useful life for equipment at 10 years and that for facilities at 20 years. These depreciation horizons are the minimum time horizons for equipment and buildings per Chinese law (PWC, 2012). Finally, we assume straight-line depreciation for tax purposes. These specifications are consistent with those in Goodrich et al. (2013b). Taken together, these inputs imply $\Delta_e = 1.08$ and $\Delta_f = 1.11$.²⁷

Table 3 presents our estimates of levelized capacity costs, c_f , c_{e2007} , and c_{e2013} . The bottom row adjusts these values to incorporate the tax factors, that is, $c_f \cdot \Delta_f$ and $c_{e2013} \cdot \Delta_e$. The penultimate row in Table 3 corresponds to weighted averages for v_e , v_f , c_e , and c_f . These weights of firm-specific measures are calculated in proportion to each firm's share of capacity added between 2007 and 2014, relative to the total additions in the sample. The summary statistics do not include data from LDK or SOL, since these firms had significant investments in polysilicon capacity that could bias our estimates.

We summarize our estimates regarding the change in capacity costs as:

Finding 2 *Our estimates of the 2013 facility and equipment capacity costs are \$0.01/W and \$0.10/W, respectively. We estimate the technological progress parameter for equipment capacity costs to be $\eta_e = 0.79$, implying a reduction in equipment capacity costs of 21% per year.*

In concluding this subsection, it should be noted that our procedure for inferring capacity acquisition costs yields estimates that are consistent with the data provided by GTM. In particular, we estimate a weighted average $v_e(2012)$ of \$0.42/W (not shown in Table 3), while the same figure from GTM equals \$0.43/W (see Table 2).

3.2 Period Costs

Having estimated the components w^+ and f^+ of the unit variable and fixed operating costs, w and f , this section develops estimates for the period costs, that is, the w^- and f^- com-

²⁷Since the facility lifetime exceeds that of equipment, Δ_f can be adjusted to reflect the depreciation tax shield remaining on the facility investment at the time of equipment obsolescence. We do not do so, since the capacity costs related to facilities are small.

Firm	$v_f,$ \$M/MW	$c_f,$ \$/W	$v_e(2007),$ \$M/MW	$c_{e2007},$ \$/W	$c_{e2013},$ \$/W	Notes
CSUN	0.07	0.01	1.12	0.53	0.07	
YGE	0.12	0.02	2.14	1.01	0.14	
TSL	0.05	0.01	1.00	0.47	0.07	
JKS	0.05	0.01	0.74	0.35	0.05	Uses 2009 as base year
CSIQ	0.07	0.01	1.32	0.62	0.09	
HSOL	0.11	0.02	1.96	0.92	0.13	
LDK	0.18	0.02	3.85	1.81	0.25	Uses 2013 as end year
JASO	0.08	0.01	1.40	0.66	0.09	
SOL	0.12	0.02	2.02	0.95	0.13	
STP	0.07	0.01	1.61	0.76	0.25	Uses 2012 as end year
Weighted Avg.	0.08	0.01	1.42	0.67	0.09	
With tax factor		0.01		0.72	0.10	

Table 3: *Estimated cost of capacity, facility and equipment for firms in our sample set. Weights in the weighted average estimate are based on the share of module-equivalent capacity additions from 2007 to 2014.*

ponents in our definition of ESP. As with our estimation of m_{it} in Section 3.1.1, we cannot identify w^- and f^- separately since we rely on financial accounting data. Period costs are primarily comprised of research and development (R&D) expenses and sales, general, and administrative (SG&A) costs. We treat R&D costs as an unavoidable fixed cost that provide the manufacturer an “entrance ticket” to internalize industry-wide cost reductions.²⁸ Selling expenses are an example of a variable period cost, while administrative and managerial costs are examples of fixed period costs.

We observe firms’ R&D and SG&A expenses directly from their income statements. To put these expenses on a per Watt basis, we divide each cost observation by the module-equivalent Watts of solar products produced by the firm in the given quarter. Referring back to the expression for the firm’s ESP in (4) where $ESP_{it} = w_{it} + f_{it} + c_{it} \cdot \Delta$, we thus obtain:

$$ESP_{it} = m_{it} + \frac{(R\&D)_{it}}{q_{it}} + \frac{(SG\&A)_{it}}{q_{it}} + c_{it} \cdot \Delta. \quad (21)$$

The straightforward inclusion of period costs in (21) reflects an implicit assumption that these cost components have not been subject to learning effects. Over the period 2008 – 2013,

²⁸In future work it would be desirable to examine the impact of firm-specific R&D expenditures on the pace of future cost reductions obtained by individual firms.

we find that firms had median R&D and SG&A costs ranging from \$0.01/W – \$0.05/W and \$0.09/W – \$0.20/W, respectively.

3.3 Implied Economically Sustainable Prices

The inference procedure described in Sections 3.1 and 3.2 yields estimates for all the manufacturing- and period cost components of the long-run marginal cost. We are now in a position to calculate the economically sustainable prices, ESP , for each firm and quarter in our sample. These values in turn imply an industry-wide figure, ESP_t , which we define as the weighted average of the firm-specific ESPs in that period:

$$ESP_t = \sum_i w_{it} \cdot ESP_{it} \quad (22)$$

The weights w_{it} in (22) are derived on the basis of firm i 's share of module-equivalent shipments in quarter t .

Figure 3 compares our ESP estimates with observed and in-sample ASPs, and we note three things.²⁹ First, before Q1-11, a casual inspection suggests that ASPs and ESPs generally stayed within a narrow band of each other. Second, the slope of the ESP and ASP curves match well until Q1-11, when the ASP curve decreases more steeply than the ESP curve. Third, the ESP and ASP measures appear to diverge after Q1-11. This latter period is one in which the market appears to have been out of equilibrium.

Statistical inference allows us to make a formal claim regarding the pattern shown in Figure 3. To the extent that firm-specific ESPs and ASPs can be interpreted as draws from a distribution around the “true” market-wide ESP and ASP, the weighted standard deviation serves as a measure of the standard error around our ESP and ASP estimates and permits a statistical test of their equality.³⁰ For a given quarter, our procedure tests the null hypothesis that $ASP_t = ESP_t$. We perform two-tailed hypothesis tests with the alternative

²⁹See Appendix B for details on the ASP series. The plot excludes the ESP estimate for SOL in Q4-08, given its value (\$57.92/W) far above any other in our estimation set. Though we exclude the point in the plot, we use it in hypothesis testing in this section.

³⁰Note that we only use firm-specific ASPs, which are defined as the ratio of firm-specific revenues to module-equivalent shipments (see Appendix B). The mean in-sample market-wide ASP and ESP measures are the weighted averages of the firm-specific ASPs and ESPs, respectively, with weights defined by the share of shipments by firm i . We do not use price index data because we do not observe the distribution of prices around the index price.

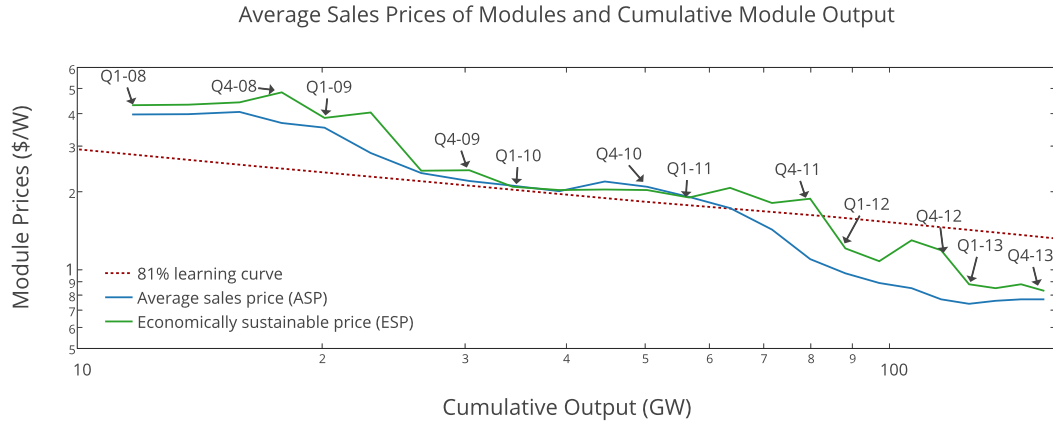


Figure 3: *ESPs generally track ASPs closely, though the two trajectories diverge beginning in Q1-11. All prices are in 2013 U.S. dollars.*

hypothesis being $ASP_t \neq ESP_t$.³¹

At the 10% significance level, we reject the equality of the ASP and ESP in Q1-12 ($p = 0.030$), Q3-12 ($p = .042$), Q1-13 ($p = .076$), and Q2-13 ($p = 0.093$).³² The Online Appendix details the weighted means, standard errors, and degrees of freedom used in our statistical tests. Our results support the claim that the market was out of equilibrium in 2012 and 2013. In addition, the statistical results suggest that, despite a tight polysilicon market in 2008, cost and price data from that year are consistent with a module market in equilibrium.³³ We summarize our inference regarding equilibrium in Finding 3.³⁴

Finding 3 *Our estimated ESP are statistically significantly different from the observed ASPs*

³¹Per standard econometric texts (e.g., Greene (2003)), the non-overlap of a confidence interval for a given significance level of a random variable with zero is equivalent to a formal parametric statistical test at the same level. Thus, the test suggested here can be implemented by comparing confidence intervals around our mean ESP and ASP measures. However, the direct comparison of confidence intervals increases the chance of a type II error. We use the analytic derivation by Afshartous and Preston (2010) to calculate confidence intervals around the ESP and ASP measures and perform the equivalent of a t-test of the null hypothesis.

³²With a more stringent 5% significance level, we reject the null hypothesis of equality between the ASP and ESP for Q1-12 and Q3-12.

³³A caveat is that our sample is smaller in the earlier period.

³⁴Inference using the simple average of ASPs and ESPs broadly agrees with our results and implies a market out of long-run equilibrium in 2012 and 2013. At the 5% level, tests with the simple averages reject the equality of the ASP and ESP in Q4-09, Q3-11, Q1-12, Q2-12, Q3-12, Q1-13, Q2-13, and Q4-13. At the 10% level, the test additionally rejects the null hypothesis in Q4-11, Q4-12, and Q3-13.

in Q1-12, Q3-12, Q1-13, and Q2-13. We thus infer that the solar PV module market was out of equilibrium during those periods.

Though our data are consistent with the suggestion of overcapacity in the PV module market, we also observe a fall in ESPs from \$1.82/W in Q1-11 to \$0.82/W in Q4-13. This suggests that “true” cost reductions also explain part of the price decreases observed over this period. In Section 4 we therefore estimate the size of learning effects within the industry in order to derive a trajectory of future equilibrium module prices.

To conclude this section, we relate our measure of production costs to the so-called “Minimum Sustainable Price” (MSP) estimates in Powell et al. (2013) and Goodrich et al. (2013a,b). The MSP is similar to our ESP concept insofar as the Minimum Sustainable Price also seeks to identify a cost-based sales price that provides an adequate return to investors. In contrast to our top-down approach based on firm-level financial data, Goodrich et al. (2013a,b) rely on a bottom-up cost model in which individual cost components are assessed in 2012 on the basis of various information sources available from industry observers. The MSP is then calculated as the derived manufacturing cost plus a profit mark-up.

We regard our top-down approach to the derivation of ESPs as complementary to the bottom-up cost models. The most important difference is that our formulation is inherently dynamic insofar as the long-run marginal cost (ESP) is assumed to change over time due to learning-by-doing and technological progress. These anticipated cost reductions apply both to core manufacturing costs and to capacity related costs and our notion of competition postulates that equilibrium prices incorporate these expected cost declines.

4 Forecasting Economically Sustainable Prices

A central motivation for the approach developed in this paper is to obtain a prediction model for future market prices that goes beyond a mere extrapolation of ASPs observed in the past. This section develops such a prediction model in the form a trajectory of future ESPs. The trajectory estimation requires projections both for capacity- and current manufacturing costs. Given our estimate of η_e from Section 3, the former is straightforward: for any time period, capacity costs are determined by the time elapsed since the period in which the baseline cost of capacity was calculated. We project future manufacturing costs by estimating a learning curve in Section 4.1. Section 4.2 combines our capacity cost decline

parameter and manufacturing cost learning curve estimates to project ESPs through 2020.

4.1 Projecting Core Manufacturing Costs

As indicated in Section 2, our model framework allows for the possibility that operating costs decline with cumulative production volume, as posited in traditional learning curve studies. The results reported in this section represent the first attempt to estimate the decline in module manufacturing costs, specifically the core manufacturing costs, m_{it} . Our estimation also offers a useful update to existing learning curve estimates, as the latter use data from a period during which large changes occurred on both the demand- and supply sides. Through the early 1980s, the demand-side was characterized by a monopsony, with governmental programs purchasing the majority of solar modules (Swanson, 2011). On the supply side, the industry has shifted to a diversified set of suppliers, with a large fringe of small producers. In addition, solar PV manufacturers have overtaken semiconductor manufacturers in their collective demand for polysilicon. This implies first that reductions in upstream polysilicon production can be at least partially attributed to increased demand by solar PV manufacturers and second that, during a supply crunch during the years 2007 – 2009, solar PV manufacturers faced large incentives to improve their production processes.

4.1.1 Econometric Specifications

Equation (23) presents our base specification, Specification 1. Following our approach in Section 3.1.1, our dependent variable is the aggregate core manufacturing cost, $m_{it} = w_{it}^+ + f_{it}^+$. We assume that m adheres to a constant elasticity learning curve.

$$m_{it} = m_{i1} \cdot \left(\frac{Q_t}{Q_1}\right)^{-b} \cdot e^{\varepsilon_{it}} \quad (23)$$

In (23), Q_t is the in-sample cumulative production level in time t , b is the learning elasticity, and ε_{it} is an idiosyncratic error term, with $E[\varepsilon_{it} | Q_t] = 0 \forall i, t$.³⁵ The slope of the constant elasticity learning curve, S , is given by $S = 2^b$ (Lieberman, 1984). Given a projected production level at time t and an original manufacturing cost, m_{i1} , we can use S to forecast the manufacturing cost at that time.

Though most empirical studies find that static scale economies are small in magnitude when compared to learning effects, we follow their lead in explicitly controlling for changes

³⁵The in-sample production includes production by the firms in our sample set only.

in the scale of manufacturing facilities. Specification 2 introduces scale effects by assuming that manufacturing costs change exponentially with the scale of plants.³⁶ In particular, and as seen in (24), we introduce a term, $\Delta Scale_{it}$, equal to the difference between scale at time t and in Q1-08, and a corresponding coefficient, b_{scale} . $Scale_{it}$ is measured in MW/year and is defined as the average capacity per manufacturing site operated by firm i .

$$m_{it} = m_{i1} \cdot \left(\frac{Q_t}{Q_1}\right)^{-b} \cdot e^{b_{scale}\Delta Scale_{it}} \cdot e^{\varepsilon_{it}} \quad (24)$$

Ideally, we would introduce time fixed effects or a trend in our specifications. However, as common in learning models, the correlation between time and cumulative output is high, and the inclusion of either time fixed effects or a temporal trend inflates standard errors to levels precluding statistical inference.³⁷ Time fixed-effects can capture the impact of changes in input prices that may account for changes in manufacturing costs marginal to learning effects. Polysilicon is a major input in module manufacturing, and Figure 4 documents changes in polysilicon prices during our sample period. In principle, one could use polysilicon price data to control for changes in this input price, but the temporal lag between polysilicon procurement and utilization is not obvious.³⁸

Instead, we exploit in Specifications 3 and 4 the variation in the slope of polysilicon prices. Though Specification 3 is structurally the same as Specification 2, it uses data only from the time periods over which polysilicon prices remained relatively constant; these are labeled as Pricing Regimes 2 and 4 on Figure 4.³⁹ Specification 4 adds a Pricing Regime 4 dummy term to Specification 3 and yields a learning curve slope estimate that can be interpreted as an upper bound. By including this dummy term, we effectively ‘remove’

³⁶We test an alternative form of Specification 2 with scale effects structurally similar to the learning effects. This follows specifications used by Lieberman (1984) and Stobaugh and Townsend (1975) but yields a poorer fit to the observed ESP data than does the one reported.

³⁷The correlation between time and cumulative production is 0.97. Cumulative production and scale have a smaller correlation of 0.65.

³⁸Using a solar grade polysilicon price index from Bloomberg New Energy Finance (2014), we test models including a linear polysilicon price term from (1) the current time period, (2) one lagged period, (3) two lagged periods, and (4) a weighted average of two lagged time periods, where the weights are defined by the share of production in each quarter. While we do not present the resulting estimates, we find that the statistical significance of polysilicon prices is sensitive to the assumed lag structure.

³⁹Pricing Regimes 1, 2, 3, and 4 include quarters Q1-08 through Q2-09, Q3-09 through Q4-10, Q1-11 through Q4-11, and Q1-12 through Q4-13, respectively. In our dataset, we include dummy terms for each regime that equal 1 for all records in the appropriate quarters.

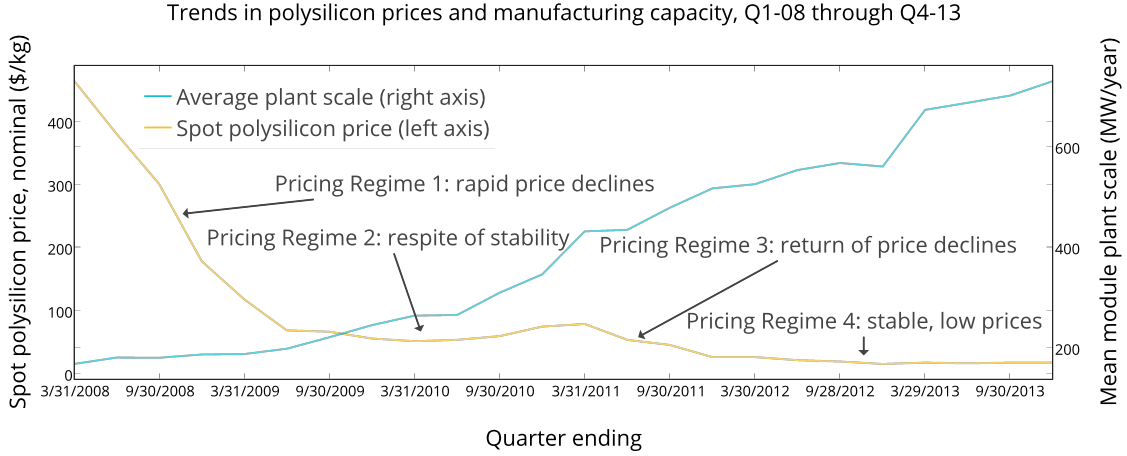


Figure 4: As cumulative production increased between 2008 and 2013, the average size of module manufacturing facilities increased and the price of polysilicon decreased.

all cost reductions between the end of Pricing Regime 2 and the start of Pricing Regime 4 from the estimate of the learning elasticity. If observed cost reductions were due only to polysilicon price decreases, we would expect the coefficient on cumulative output to be statistically indistinguishable from 0 in Specification 4.

While Specifications 3 and 4 compensate for our limited ability to include time fixed-effects, they do not substitute for temporal trends. The latter are important to the extent that the quality of output changed over time. Appendix C presents estimates in which we explicitly transform our cost data to a standard efficiency level. The only difference observed when estimating specifications with a standard efficiency level is that the learning curve slopes are slightly more gradual.

To use standard linear panel data methods, we state the model in its linear in logarithms form; for example, we express Specification 2 as in (25):

$$\log(m_{it}) = \log(m_{i1}) - b \cdot \log\left(\frac{Q_t}{Q_1}\right) + b_{scale} \cdot \Delta Scale_{it} + \varepsilon_{it} \quad (25)$$

Across all specifications, we index observations from Q1-08 with $t = 1$.⁴⁰ Our cumulative

⁴⁰For two firms, JKS and LDK, our firm-specific production estimates do not cover Q1-08 since those firms did not release financial accounting data from these periods. To avoid dropping all observations in which those firms' data are unavailable, we use module production levels recorded in Lux Research (2014). For LDK, we use data from Lux Research (2014) for production observations between Q1-08 to Q1-09; for JKS, we use data from the same source for observations between Q1-08 and Q2-10.

output measure is based on the sum of estimated production across firms in our sample. We use firm-level plant scale data from Lux Research (2014), though we modify some records to reflect financial data and press reports. Across specifications, we assume the idiosyncratic error term has mean zero and is uncorrelated with the explanatory variables. Notably, we do not assume that $E[\varepsilon_{it}|m_{i1}] = 0$, and we accordingly use a fixed effect estimator.⁴¹

4.1.2 Details on Estimation and Inference

We make two sets of comments about our inference procedure that are relevant to the interpretation of our estimates. Our initial comments relate to the data themselves. First, we assume that measurement errors introduced by our cost inference procedure are normally distributed with mean zero and uncorrelated with our explanatory variables; this implies they are captured by the idiosyncratic error terms. Second, since we use data from firms listed on U.S. exchanges, our estimates are subject to sample selection bias. Despite this, we avoid making strong assumptions required to estimate a parametric Heckman model. Our estimates of learning effects should be interpreted as conditional on public listing on a U.S. exchange. If our intuition that firms with the highest propensity to learn will be publicly listed is correct, the estimated conditional learning curve slope estimate would be weakly steeper than the unconditional version.

The second set comments on adjustments of the standard errors and inference procedure. To account for departures from homoskedasticity, auto-correlation within firms and cross-sectional dependence across them, we report standard errors suggested by Driscoll and Kraay (1998) and implemented by Hoechle (2007).⁴² Finally, given the small size of our dataset, we correct the standard errors by scaling the asymptotic estimates by $\sqrt{\frac{N}{N-1} \cdot \frac{T-1}{T-k}}$, where N , T , and k are the number of firms, time periods, and coefficients, respectively. Moreover, our inference is based on a Student's t distribution with $(N-1)$ degrees of freedom, rather than a standard normal distribution, to account for our small sample size.

⁴¹This allows for unobserved variation across firms that can explain variation in manufacturing costs.

⁴²Although the calculation of these standard errors relies on large sample asymptotics, the Driscoll-Kraay errors have better small-sample properties than common alternatives, such as cluster robust variance estimators (CRVE), when cross-sectional dependence exists (Hoechle, 2007).

4.1.3 Econometric estimations and interpretation

Table 4 presents our estimates.⁴³ Across all specifications, the coefficient on cumulative output is significant, while that on scale is not.⁴⁴ Taken together, Specifications 1 through 4 imply that significant cost decreases occurred between 2008 and 2013 and that these were not solely attributable to decreases in polysilicon prices.

Specification	<i>Dependent variable: Log Manufacturing Cost/Watt</i>			
	1	2	3	4
Intercept	1.488*** (0.166)	1.440*** (0.166)	1.450*** (0.202)	0.767*** (0.170)
Cumulative Production (b)	-0.427*** (0.048)	-0.390*** (0.058)	-0.433*** (0.053)	-0.193** (0.060)
Firm Scale (b_s)	–	-0.000 (0.000)	-0.000 (0.000)	0.000 (0.000)
Dummy, PS Regime 4	–	–	–	-0.521*** (0.117)
Learning Curve Slope (S)	74.4% (15.6%)	76.3% (20.7%)	74.1% (16.9%)	87.5% (45.4%)
Adjusted R^2	0.7542	0.7593	0.7725	0.8157
N	213	213	125	125

Table 4: *Estimated coefficients for a constant elasticity learning curve. The intercept should be interpreted as the average of the logarithm of the Q1-08 core manufacturing cost across firms. Entries in parentheses are Driscoll-Kraay standard errors. Cumulative production is total output by firms in our sample.*

Key to statistical significance: ***: ≤ 0.001 ; **: ≤ 0.01 ; *: ≤ 0.05 .

Our preferred specification is Specification 3 because it accounts for possible unusual

⁴³The magnitude of estimated coefficients and standard errors on firm scale is indeed smaller than 0.000.

⁴⁴Our measure of cumulative output imputes production levels for Suntech Power (between Q2-12 and Q4-13) and LDK Solar (between Q1-13 and Q4-13). These firms were de-listed in Q2-12 and Q1-13, respectively, and we do not observe their subsequent production volumes. Our imputation assumes that these firms retain the 0.83% and 0.46% shares of global production, respectively, that we observe in the quarters for which we have financial accounting data. Without this imputation, our data would include a smaller increase in cumulative production than actually occurred, and we would estimate a coefficient on cumulative production that would be biased downwards. An estimation without imputed production from these two firms yields learning curve slopes that are 1% – 1.5% steeper than that reported in Table 4.

polysilicon pricing events in Pricing Regime 1 and controls for scale. Though Specification 4 does the same, we believe it is too conservative in excluding all cost reductions that occurred while polysilicon prices declined in Pricing Regime 3, especially since over 90% of demand for polysilicon is from the solar market. Nonetheless, if one believes that the upstream polysilicon market is unlikely to achieve future cost reductions at the same rate characterizing it from Q2-09 through Q4-13, Specification 4 provides the appropriate rate of cost declines for core manufacturing costs.

Finding 4 *Controlling for plant scale and excluding periods with substantial polysilicon price declines, we estimate a 74% learning curve for core manufacturing costs over the period 2008-2013.*

Table 4 indicates that the propagation of error from our scale coefficient estimate to our learning curve estimate implies a standard error of approximately 17% on our learning curve slope. We account for this uncertainty by providing a 95% prediction interval around our projected ESPs in Section 4.2. Appendix C provides details of robustness checks on our inference about decreases in manufacturing costs. We do not find any significant differences in estimates from those robustness checks.

4.2 ESP Projections

With our estimates of the technological progress parameter characterizing capacity cost dynamics and the learning curve slope applicable to core manufacturing costs, we are in a position to project future ESPs. Recall from Section 2 that we expect ASPs to converge to these ESPs as demand increases and both capacity- and core manufacturing costs decrease. The timing of convergence will depend on the trajectory of market demand. To illustrate the sensitivity of ESP projections to demand, we present ESP forecasts contingent on annual demand ranging from 40GW/year to 60GW/year. Our baseline forecast is based on a 40GW/year demand assumption, as it corresponds to observed demand in 2013.

To form our projections, we assume that a representative firm maintains the 35% share of global module production that the firms in our sample held in 2012. Accordingly, the increase in “within sample” cumulative production is $0.35 \cdot 40\text{GW}$, 50GW , or 60GW , depending on our demand assumption. Together with our estimated coefficient on cumulative production, we derive an expected core manufacturing cost for each year. Our projected capacity cost

for the representative firm reflects a weighted average of firms' projected capacity costs for each of the years between 2014 and 2020, with weights determined by a given firm's share of 2013 shipments. Finally, we add R&D and SG&A costs that are equal to the 2013 shipment-weighted average of firms' median R&D and SG&A costs from Q1-08 to Q4-13.

Figure 5 depicts the forecast trajectory of ESPs through 2020. This curve entails a 27% reduction in production costs with every doubling in industry-wide output. This reflects both the 74% learning curve on core manufacturing costs and the 78.5% annual geometric decline in capacity costs, which occurs faster than does a doubling in output. To reflect the error present in our estimates, Table 5 presents 95% prediction intervals for each year under each of the three demand scenarios.

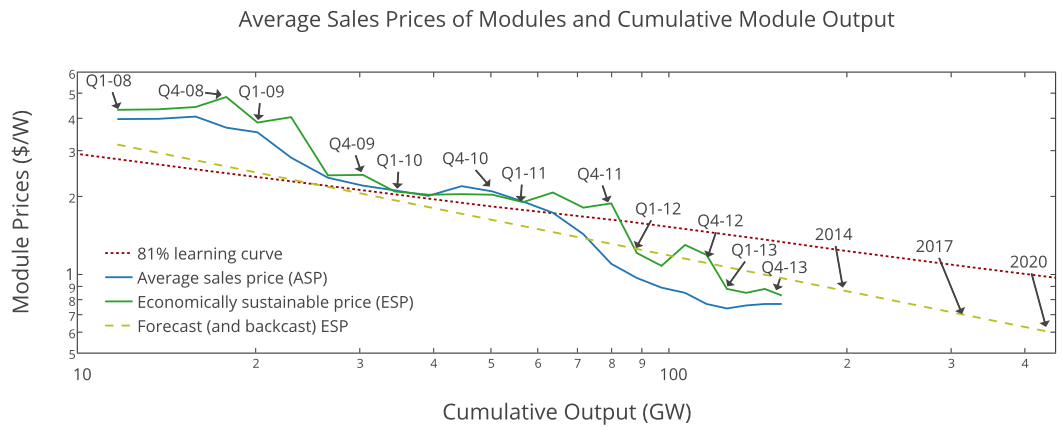


Figure 5: *Projected ESPs through 2020, assuming a constant yearly addition of 40GW. All prices are in 2013 U.S. dollars.*

Our ESP projections prompt three comments. First, even under our most aggressive assumptions about future demand, our ESP trajectory does not imply module production costs of \$0.50/W by 2020, as targeted by the SunShot goals of the U.S. Department of Energy. Nonetheless, the \$0.50/W cost target is covered by our 95% prediction interval by 2016 or 2017 in all three demand scenarios. Second, the lowest ASP we observe in our price data is \$0.74/W in Q1-13. Under our base assumptions about future demand (i.e., demand additions of 40GW per year), we do not project ESPs at that level until 2016. This agrees with our expectation that solar module prices will not decrease monotonically but instead converge to the ESP trajectory. Once such convergence has occurred, new capacity may enter the market and introduce a new generation of module manufacturing technology.

Third, our point estimates suggest that technological breakthroughs may be needed to push solar module prices toward SunShot goals.

Demand	2014 ESP			2017 ESP			2020 ESP		
	PE^-	PE	PE^+	PE^-	PE	PE^+	PE^-	PE	PE^+
40 GW	\$0.65	\$0.88	\$1.11	\$0.48	\$0.70	\$0.93	\$0.39	\$0.61	\$0.82
50 GW	\$0.64	\$0.87	\$1.10	\$0.46	\$0.68	\$0.90	\$0.37	\$0.58	\$0.79
60 GW	\$0.63	\$0.86	\$1.09	\$0.44	\$0.66	\$0.88	\$0.36	\$0.56	\$0.77

Table 5: *ESP projections, given assumptions about the yearly demand for solar PV modules. All figures are in 2013 dollars and are expressed per Watt. PE indicates “point estimate”, “ PE^+ ”, the upper bound of the prediction interval and “ PE^- ”, the lower bound of the prediction interval.*

5 Conclusion

Prices for solar PV modules have dropped consistently over the past four decades and have historically adhered to an 80% price-based “learning curve.” More dramatic price decreases between 2011 and 2013 caused analysts to ask whether market prices reflected “true” underlying cost decreases or excessive additions to industry-wide manufacturing capacity. This paper examines this issue by developing a method by which to study cost dynamics in a maturing industry such as the solar PV module sector. Our analysis also yields an estimate of the trajectory of module prices going forward.

The main conceptual contribution of our analysis is the derivation of the *Economically Sustainable Price* (ESP) measure. We demonstrate that the ESP can be interpreted both as the long-run marginal cost of manufacturing one unit of output and as the price that would emerge along a long-run equilibrium trajectory of manufacturing capacity additions. Accordingly, the ESP provides a benchmark against which observed prices could be compared to determine whether the market was in long-run equilibrium at different points in time. In the context of the solar module market, the ESP concept allows us to gauge to what extent the substantial large price reductions observed in recent years were matched by corresponding large cost reductions.

One obstacle in using the ESP concept is that the cost data needed to estimate it are usually unavailable to outside observers. To overcome this, we provide a cost inference

procedure to derive the ESP from publicly available financial accounting data. We apply this method to data from solar PV module manufacturers to infer quarterly ESPs and test whether observed ASPs were consistent with a market in long-run equilibrium. While ASPs and ESPs are statistically indistinguishable for most of our sample periods, they are significantly different in at least four quarters in 2012 and 2013, when module prices diverged most sharply from the 80% learning curve.⁴⁵ Accordingly, we conclude that the recently observed price reductions reflect a market dynamic driven partly by overcapacity rather than mere cost reductions.

Our assertion that the market was characterized by overcapacity might be interpreted as in support of claims that the Chinese firms that have invested in recent capacity expansions “dumped” their modules in the U.S. and European markets. However, our ESP estimates make this interpretation implausible. Our estimated core manufacturing costs are \$0.71/W and \$0.55/W in 2012 and 2013, respectively, suggesting that modules sold at prices above those benchmarks were unlikely to have been dumped into export markets.⁴⁶ Our comment on dumping allegations is corroborated by the minimum selling price of \$0.74/W for Chinese solar panels in the European Union that was set by Chinese and E.U. negotiators in the middle of 2013 (Kanter and Bradsher, 2013).

Our cost inferences also provide us with a panel of data with which to estimate how production costs for modules change as a function of time and experience. Using estimated cost decline parameters, we extrapolate a trajectory of future production costs. This path represents our benchmark of the economic industry fundamentals and is interpreted as a trend-line to which equilibrium prices should converge over time. Upon controlling for plant scale and periods in which polysilicon prices were declining steeply, cost data are consistent with a 74% learning curve for core manufacturing costs. Combined with capacity cost declines that occur yearly, we observe a net 73% cost reduction curve. We thus anticipate an ESP equal to 73% of its previous value with each doubling in cumulative production.

Though this rate of cost declines is faster than that embedded by the 80% price-based learning curve, our point estimates of future production costs suggest that module costs will

⁴⁵This holds with a 10% significance threshold. With a stricter cutoff at a 5% significance level, we reject the equality of the ASP and ESP in two of the periods, Q1-12 and Q3-12.

⁴⁶The annual ESP figures are weighted averages of quarterly core manufacturing costs in each year. For a given year, the measure weights each quarter’s observations by the share of annual shipments observed in that quarter.

not decrease to the \$0.50/W level targeted by the U.S. SunShot program for the year 2020. Even if demand were to equal 60GW/year, our point estimate of cost decreases implies that 2020 costs would remain at \$0.56/W. While the SunShot target is covered by 95% prediction intervals, our work suggests that the business-as-usual rate of technological progress may not itself deliver the cost targets envisioned by the SunShot program. The realization of these targets could require either technological advancements in module manufacturing or greater-than-expected reductions in downstream costs, which are collectively termed the “balance-of-system” (BOS) costs.

A Proof of Finding 1

We verify that the sequence of K_t^* given by:

$$P_t^o(K_t^*) = ESP_t \equiv c_t \cdot \Delta + w_t + f_t,$$

is indeed implementable by a sequence of non-negative investments I_t^* if

$$K_t = I_{t-T} + I_{t-T+1} + \dots + I_{t-1},$$

and $K_0 \leq K_1^*$. The non-negativity constraints are met if $K_{t+1}^* \geq K_t^*$ for $t \geq 1$. This follows from the observation:

$$P_{t+1}^o(K_{t+1}^*) = ESP_{t+1} < ESP_t = P_t^o(K_t^*),$$

combined with the NEC condition requiring that $P_{t+1}^o(K) > P_t^o(K)$ for all K .

It remains to verify that, given the aggregate capacity levels $\{K_t^*\}_{t=1}^\infty$, firms will break-even on their investments. Without loss of generality, assume that a particular firm invests in one unit of capacity at time t . The prevailing equilibrium market price in the next T periods is given by $P_{t+\tau}^o(K_{t+\tau}^*) = ESP_{t+\tau}$, with $\tau \in [1, T]$. The firm utilizes this capacity over the next T periods. The pre-tax cash flows of this investment are given by:

$$CFL_t = -v \cdot \eta^t,$$

and for $1 \leq \tau \leq T$,

$$CFL_{t+\tau} = ESP_{t+\tau} - w_{t+\tau} - f_{t+\tau}.$$

Taxable income in period $t + \tau$ becomes:

$$In_{t+\tau} = CFL_{t+\tau} - d_\tau \cdot v \cdot \eta^t.$$

Given a corporate income tax rate of α , the overall NPV of the investment is:

$$NPV = \sum_{\tau=1}^T [CFL_{t+\tau} - \alpha \cdot I_{t+\tau}] \gamma^\tau - \eta^t \cdot v \quad (26)$$

To show that the expression in (26) is indeed zero, we rewrite it as:

$$NPV = (1 - \alpha) \cdot \sum_{\tau=1}^T \Delta \cdot c_{t+\tau} \cdot \gamma^\tau + \alpha \cdot \sum_{\tau=1}^T d_\tau \cdot \eta^t \cdot v \cdot \gamma^\tau - \eta^t \cdot v, \quad (27)$$

where the tax-factor is as defined in the main text:

$$\Delta = \frac{1 - \alpha \cdot \sum_{\tau=1}^T d_\tau \cdot \gamma^\tau}{1 - \alpha}. \quad (28)$$

The second term on the right-hand side of (27) denotes the tax shield. Dividing (27) by $(1 - \alpha)$, we obtain:

$$\frac{1}{(1 - \alpha)} \cdot NPV = \Delta \left[\sum_{\tau=1}^T c_{t+\tau} \cdot \gamma^\tau - \eta^t \cdot v \right] = 0,$$

because

$$\sum_{\tau=1}^T c_{t+\tau} \cdot \gamma^\tau = \eta^t \cdot \sum_{\tau=1}^T c_\tau \cdot \gamma^\tau = \eta^t \cdot v.$$

■

B Data and adjustments for cost inferences

Firms in the study set

Firm	Ticker	2012 Capacity %	2012 Production %
Yingli Green Energy	NYSE: YGE	3.7	6.4
Trina Solar	NYSE: TSL	3.7	4.6
Suntech Power	NYSE: STP	4.0	5.9
Canadian Solar	NASDAQ: CSIQ	3.4	4.8
LDK Solar	NYSE: LDK	2.7	1.5
Hanwha Solar One	NASDAQ: HSOL	2.4	2.6
JA Solar	NASDAQ: JASO	3.3	3.6
ReneSola	NYSE: SOL	1.6	1.7
JinkoSolar	NYSE: JKS	1.9	2.7
China Sunergy	NASDAQ: CSUN	1.3	1.1

Table 6: *Firms included in the study set, including stock tickers, capacity, and production market share in 2012, as recorded by Lux Research (2013). We show 2012 shares since we do not observe the 2013 shares for Suntech Power and LDK Solar.*

Price data

Since prominent sources of module price data (i.e., Bloomberg New Energy Finance and pvXchange) began collecting price data no earlier than Q3-09, the average sales price (ASP) measure we use in our graphs is a composite of several indexes. The measure equally weighs our estimates of in-sample ASPs and a composite of price indexes that we obtain either from Swanson (2011) or the Bloomberg terminal system. For each firm and quarter, we derive firm-specific ASPs as the quotient of revenues and the sales volume (i.e., the module-equivalent shipment level; see Section 3.1.1):

$$ASP_{it}(firm - specific) = \frac{Revenue_{it}}{s_{it}^{ME}} \quad (29)$$

This implies a quarter-specific average in-sample ASP:

$$ASP_t(in - sample) = \sum_i w_{it} ASP_{it}, \quad (30)$$

where the weights in the above summation are in proportion to the firm's share of module-equivalent shipments across the firms in our sample in that quarter.

Our composite of indexes reflects the data available for a particular period. Prior to Q1-10, we use price data included in Swanson (2011). After Q4-10, we use a Bloomberg New Energy Finance index for multi-crystalline silicon module prices. To bridge the gap between the data from Swanson and that available from BNEF, we use the pvXchange Crystalline Modules China Price available from the Bloomberg terminal. We chose this index for Q1-10 through Q3-10 among those from PVXchange and PVinsights and accessible from the Bloomberg terminal system because it offered the best match with the BNEF multi-crystalline silicon module price index over the time periods in which we could observe both indexes. The ASPs on our graphs equal the simple average of our composite index and in-sample ASP measures and reflect an adjustment to 2013 dollars.

In contrast, our tests about whether the market is in long-run equilibrium in a given quarter use only the firm-specific ASP estimates. By using the firm-specific ASP estimates, we can compare a distribution of estimated ASPs and inferred ESPs across firms. Price indexes, on the other hand, provide us with only one quarterly price observation without any information about the spread of ASPs observed. We observe a relatively close match between our in-sample ASPs and the index price data; across the 24 quarters in our sample, we observe a median difference of 12% between the two numbers.

Adjusting facility capacity costs for physical efficiency gains

As the efficiency of solar cells increases, the same physical area of output contains a greater Watt capacity and therefore the capacity cost per Watt decreases. Recalling that $\eta_f = 1$, we modify c_{ft} from its form in (16) to:

$$c_{ft} = \frac{v_f \cdot \frac{eff_{ref}}{eff_t}}{\sum_{\tau=1}^T \gamma^\tau}.$$

Here, eff_t and eff_{ref} refer to average efficiency levels in the current and baseline periods, respectively. We use data from Fraunhofer (2012) and reported in Table 7 to adjust our capacity cost estimates.

Deriving module-equivalent capacity

In Section 3.1.2, we discuss two adjustments to the measure of firm-specific equipment capacity costs. One modification adjusts the level of capacity additions by firms. The naive approach implied by (17) assumes that a firm's capital expenditures on equipment are solely applied to the expansion of module manufacturing capacity. However, as we

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
12.0%	12.5%	12.5%	12.7%	13.0%	13.1%	13.1%	13.4%	14.5%	14.7%	15.5%

Table 7: *Average crystalline silicon module efficiency, from Fraunhofer (2012). The 2013 figure is an estimate, given reports by Fraunhofer that 2014 average efficiency levels had reached 16%.*

discuss in Section 3.1.2, firms could have expanded capacity for any of the four steps of module manufacturing or any combination thereof. In practice, firms have tended to invest in capacity either for only one of the four steps or for combinations of the four steps that are contiguous to each other and include all upstream steps. The latter observation implies that firms have invested in, for example, cell, wafer, and ingot capacity but not in only cell and ingot capacity. This practical reality implies that there are ten types of what we term *contiguous capacity investment bundles*.⁴⁷

Of course, it is not equally costly to expand each of the ten capacity bundles. To account for these differences, we use a module-equivalent (*ME*) level of capacity, K^{ME} :

$$K^{ME} = \sum_{l=1}^{l=10} K_j \cdot \chi_j \quad (31)$$

Here, the index j refers to the ten contiguous capacity investment bundles. We use quarterly firm-level capacity data from Lux Research (2014) across all steps of the value chain to derive K_j and K^{ME} .⁴⁸ We determine the expansion of a particular bundle by (1) taking the minimum of the capacity expansions for all constituent value chain steps and (2) subtracting the expansions recorded for more inclusive bundles. As an example, when calculating the capacity expansion in the “cells and modules” bundle, we know that this increase cannot

⁴⁷The ten bundles are investments in (1) ingots only, (2) wafers only, (3) cells only, (4) modules only, (5) wafers and ingots, (6) cells, wafers, and ingots, (7) cells and wafers, (8) modules, cells, wafers, and ingots, (9) modules, cells, wafers, and (10) modules and cells.

⁴⁸We make several amendments to the records in this dataset based on our findings from firms’ press releases and industry analysts. For Yingli, we use a 2014 module capacity of 2.45GW because we exclude tolling facilities to which the firm had access. For JA Solar, we added 150MW of module capacity in 2014 that stem from new capacity in South Africa but not included in the Lux Research dataset. For China Sunergy, we use an 1.155GW module capacity figure reported by Bloomberg New Energy Finance that matches with numbers released by the firm itself. Finally, we use 800MW for Hanwha SolarOne’s ingot capacity; while Lux Research (2014) does not include any ingot manufacturing capacity for this firm, previous versions of the same dataset record an ingot capacity of 800MW per year. In addition, the firm reports that it operates ingot manufacturing capacity.

exceed the observed expansion of either cell or module capacity (i.e., the constituent value chain steps). We thus calculate the minimum capacity expansion level observed across these two steps. To avoid double counting capacity expansions in cells and modules, we subtract the capacity expansion observed across the two more inclusive bundles, namely “modules, cells, wafers, and ingots” and “modules, cells, and wafers.”

χ_j is an adjustment factor that “marks down” the capacity additions for bundles that do not include all four components of the value chain. We define χ_j as the ratio of the capacity cost for bundle j to the capacity cost for the integrated module capacity investment. We estimate χ_j as the average of the ratios from 2009 to 2016 implied by Table 2.

C Learning curve estimation robustness checks

Accounting for physical efficiency gains

Since a time trend would have accounted for core manufacturing cost reductions due to improved quality, as measured by physical efficiency, we repeat Specifications 1 through 4 with data expressed on a dollar per square meter basis. Since $efficiency = \frac{power}{m^2}$, we convert manufacturing costs from dollars per watt to dollars per square meter by multiplying the former by efficiency. We use average module efficiency levels from Table 7 and change the scale and cumulative output measures to a square meter basis. Table 8 summarizes our estimates; each specification corresponds to the similarly numbered one in Table 4.

Specification	<i>Dependent variable: Log Manufacturing Cost/m²</i>			
	1SM	2SM	3SM	4SM
Intercept	-0.604*** (0.155)	-0.632*** (0.155)	-0.689*** (0.183)	-1.273*** (0.146)
Cumulative Production (<i>b</i>)	-0.391*** (0.044)	-0.367*** (0.053)	-0.395*** (0.048)	-0.188** (0.053)
Firm Scale (<i>b_s</i>)	–	-0.000 (0.000)	-0.000 (0.000)	0.000 (0.000)
Dummy, PS Regime 4	–	–	–	-0.431*** (0.106)
Learning Curve Slope (<i>S</i>)	76.3% (15.7%)	77.5% (20.0%)	76.1% (16.7%)	87.8% (41.2%)
Adjusted <i>R</i> ²	0.7273	0.7297	0.7337	0.7784
N	213	213	125	125

Table 8: *Estimated coefficients on a constant elasticity learning curve. Entries in parentheses are Driscoll-Kraay standard errors. The intercept should be interpreted as the average of the logarithm of the Q1-08 core manufacturing cost across firms.*

Key to statistical significance: ***: ≤ 0.001 ; **: ≤ 0.01 ; *: ≤ 0.05 .

Comparing Tables 4 and 8, we observe that the implied learning curve slopes are essentially the same across the two tables, with the slopes on a \$/Watt basis roughly up to 1 – 2% steeper than those on a \$/m² basis. The estimates suggest that our results are robust to the specification of output on an efficiency-adjusted basis.

Exclusion of firm-quarter pairs

Since some firms had a small share of modules in their output mix over some of the periods in our panel, we include four robustness checks in which we exclude observations for these firms from such periods. In the first, we drop data from CSUN between Q1-08 and Q3-10. The second drops data from JASO between Q1-08 and Q4-11, while the third drops data from SOL between Q1-08 and Q3-10. Finally, we drop all three sets of observations. We do not list the estimates derived upon dropping these observations, but we do not find any material differences between the learning curve slopes estimated from the full sample and those obtained when using the restricted samples. Though the standard errors change, they do not change in a systematic direction with these exclusions.

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Appendix F: Stanford GSB Case Study – SolarCity: Rapid Innovation



SOLARCITY

We only move into the space, into the market, if we can save the customer money.
—Lyndon Rive, SolarCity, CEO¹

The idea was conceived in the Nevada desert. Cousins Elon Musk and Lyndon Rive were headed to the 2004 Burning Man Festival when Musk suggested that Rive look into solar. A serial entrepreneur like Musk, Rive did just that and saw opportunity. Two years later, in 2006, Rive and brother Peter founded SolarCity, with cousin Elon Musk as chairman.

Lyndon Rive described SolarCity as an energy company, setting it apart from solar manufacturing. SolarCity bought solar photovoltaic panels, which it then installed for homeowners, schools, commercial entities, and governmental agencies to sell them energy. According to Rive, “We install solar systems for free, and we sell the electricity at a lower rate than you can buy it from the utility. So given the option of paying more for dirty power or paying less for clean power, what would you take?”²

Between 2010 and 2012, SolarCity experienced tremendous growth in an industry that was generally perceived to be struggling. Many other solar start-ups were failing—Solyndra, which

¹ Adam Lashinsky, “SolarCity CEO Talks the Future of Solar Power,” *Fortune*, March 4, 2013, <http://tech.fortune.cnn.com/2013/03/04/solarcity-ceo-talks-the-future-of-solar-power/> (May 1, 2014).

² Ibid.

Davina Drabkin and Professor Stefan Reichelstein prepared this case in conjunction with Don Wood, DFJ Partner and Stanford GSB lecturer as the basis for class discussion rather than to illustrate either effective or ineffective handling of an administrative situation. This case was developed based on information from the following sources unless otherwise noted: interview with Benjamin Cook, Structured Finance Vice President, Tim Newell, Vice President of Financial Products, West Owens, Director, Structured Finance, Leland Price, Associate Director, Structured Finance, May 29, 2014, and SolarCity Corporation, Form 10-K, 2013 SolarCity, <http://files.shareholder.com/downloads/AMDA-14LQRE/3026672994x0xS1193125-14-104447/1408356/filing.pdf> Special thanks to Jake Saper for his excellent research assistance and to Aaron Chew, Vice President of Investor Relations at SolarCity, and Philip Shen, Senior Research Analyst at Roth Capital Partners, for many helpful suggestions.

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had received a \$535M loan from the U.S. government, was the highest profile failure, declaring bankruptcy in September, 2011. Lyndon Rive noted, “Investors have been burned so badly from the solar sector. We’ve faced that stigma while selling our company to investors.”³ Despite that burn, however, SolarCity went forward with an initial public offering (IPO) in December of 2012 at an IPO price of \$8.00 per share. At the time, Draper, Fischer, Jurvetson (DFJ) was the largest venture capital investor in SolarCity. While low-cost solar panels from China were driving solar panel manufacturers out of business, SolarCity took advantage of the declining prices to ramp up installations. By end of the second quarter, 2014, SolarCity operated in 15 states and the District of Columbia and boasted 140,000 customers. It controlled 36 percent of the residential solar market but had never posted a profit—in 2013 it had a net loss of almost \$152 million. Yet, SolarCity’s growth drove the stock price up, hitting a high of \$86.14 in February 2014. CEO Rive explained how GAAP (Generally Accepted Accounting Principles) distorted the profitability picture for rapidly growing companies such as SolarCity:

The irony is as soon as we stop growing, our recurring revenue will start catching up to our operating cost, and then we’ll start showing a GAAP profit. In fact, if we have negative growth, we’ll show a GAAP profit in three years. So in a way, as soon as we start seeing positive GAAP profit, it means that we are slowing down in our growth. So for now, we want to grow as much as we possibly can.⁴

SOLARCITY’S BUSINESS MODEL

Touting itself as a full service solar provider, SolarCity developed an integrated approach to serving customers, overseeing every step in the relationship. The company built a regionally distributed field sales force that performed in-home consultations and created a large virtual sales force based at several call centers. Consultants also marketed solar installation to customers at store locations as part of partnerships with The Home Depot and Best Buy. In addition, SolarCity offered its services through retail electricity providers like Direct Energy and Viridian in deregulated markets and worked with more than 100 regional and national home builders to provide solar services for newly constructed homes. After an initial consultation with customers, SolarCity handled the system design and engineering, financing, and full installation. For homeowners, SolarCity’s in-house engineering team completed a structural analysis of the dwelling, submitted plans to the local city government, managed interactions with inspectors, and took responsibility for obtaining the necessary permits. SolarCity did the same for business and government clients, also identifying federal, state, and local financial incentives. The company had opened more than 50 regional “operations centers” to service customers.

Customers had the option to either purchase a solar system outright or apply for *SolarLease* or *SolarPPA* financing. A selling point with most customers was the option to switch to solar without incurring high upfront costs. Since SolarCity owned and operated most of the equipment, customers could install the system for free and then pay a monthly fee. They could put as little as \$0 down or prepay some or all of their electricity in advance to reduce or eliminate ongoing monthly payments. Under both financing options, SolarCity covered the full cost of

³ Maureen Farrell, “SolarCity IPO shines,” *The Buzz*, December 13, 2012, <http://buzz.money.cnn.com/2012/12/13/solarcity-ipo/> (June 2, 2014).

⁴ Adam Lashinsky, op. cit.

installing and maintaining the solar system and standard agreements were for 20-year terms. *SolarLease* offered homeowners a fixed monthly payment and a performance guarantee (a guaranteed minimum level of electricity output). Through *SolarPPA*, a power purchase agreement (PPA), the home or building owner agreed to buy the power produced at a fixed price per kilowatt hour (kWh).

Pioneering Financial Model

The introduction of solar lease financing and ownership of solar systems by a third party transformed the residential solar market. The idea behind lease financing was to leverage investor resources and tax equity by having investors purchase photovoltaic (PV) systems on behalf of residential homeowners. This made it possible for homeowners to install solar PV systems for little to no money up front while providing solar developers (i.e., SolarCity) with the means to finance the solar systems.⁵ Through complex tax equity structures, investors either became the sole owners of the PV systems or formed joint venture partnerships with the solar developer. These tax equity structures allowed investors to take advantage of federal tax benefits—a 30 percent tax credit and accelerated depreciation.⁶ According to The Motley Fool, one “thing that SolarCity currently does better than anyone else is tap into financing for residential and commercial solar installations.”⁷ By 2014, SolarCity had secured financing to fund more than \$4 billion in projects from a range of investors, including Credit Suisse, Google, Goldman Sachs, PG&E, U.S. Bancorp, First Solar, and DFJ.⁸

Vertical Integration

SolarCity pioneered the in-house solar leasing model, where one company operates all segments of the solar leasing value chain. From creating investor funds, to selling lease contracts, to overseeing its own installation crews, SolarCity had a deep understanding of its entire supply chain and could achieve unmatched economies of scale. Competitors took different approaches—SunRun, predominantly a financing company and SunPower, predominantly a manufacturer, on the other hand, focused on pieces of the upstream supply chain but worked with partners to install and then service those installations.

To achieve widespread residential adoption, solar developers aimed to bring down costs dramatically. While SolarCity took advantage of low cost solar panels from China on the manufacturing side, approximately half the costs in a residential solar PV system were downstream, including installation, maintenance, and monitoring. Tanguy Serra, SolarCity’s EVP of Operations, explained that to cut costs and gain scale, “you need to be vertically

⁵ Gabe Davis and Ben Peters, “Residential Solar Leasing,” *SolarPro*, Issue 6.2, February/March 2013, <http://solarprofessional.com/articles/finance-economics/the-evolution-of-residential-solar-leasing> (June 7, 2014).

⁶ Josh Lutton, “Tax Equity 101: Structures,” Woodlawn Associates, March 8, 2013, <http://www.woodlawnassociates.com/tax-equity-101/> (June 16, 2014).

⁷ Travis Hoium, “Read More About SolarCity’s Plans to Dominate the Solar Industry,” *The Motley Fool*, December 28, 2013, <http://www.fool.com/investing/general/2013/12/28/read-more-about-solarcitys-plans-to-dominate-the-s.aspx> (June 12, 2014).

⁸ Jonathan Bass, vice president, communications, Solar City, e-mail communication September 3, 2014.

integrated. ... We want to avoid margin stacking; we take it out everywhere that we can.”⁹ That drive spurred a number of acquisitions by SolarCity, notably Zep Solar in 2013 and then Silevo in 2014. Zep had invented interlocking frames and specialized components that greatly simplified installation of solar arrays. It allowed SolarCity crews to cut installation time down from a day or two to only four or five hours, doubling their daily rate. That, combined with identifying best practices and creating consistent internal processes, allowed SolarCity to jump from installing 40-80 kW per crew per month to 200-250 kW per crew per month. The acquisition of Silevo, a solar panel manufacturer, was intended to enable SolarCity to produce efficient, low-cost panels in sufficient quantities to ensure its supply. Chief Technology Officer, Peter Rive, commented that adding Silevo would make SolarCity “the most vertically integrated solar company in the world.”¹⁰

Vertical integration also allowed SolarCity to develop long-term relationships with its customers, providing them with a single point of contact and accountability for all products and services. SolarCity could directly educate its customers about new product offerings and lease renewals.

Brand Equity

Through its successful IPO and its system of integrated services with a single point of contact, SolarCity achieved wide name recognition. Other solar companies relied on a varied and complex network of financiers, installers, and maintenance crews, each with a different name. Unlike competitors Sunrun and Clean Power Finance, SolarCity operated its own fleet of trucks—those green trucks, all consistently sporting SolarCity’s sunshine logo, were one important element in building SolarCity’s brand equity. Travis Hoium of *The Motley Fool* summarized, “What SolarCity has done is build the largest and most efficient sales, installation, and financing network in the industry. It has a first mover advantage by building a strong brand name and customer loyalty.”¹¹

INDUSTRY RISKS AND OPPORTUNITIES

Cost of Equipment

Since its inception, SolarCity had benefitted from the downward pressure that Chinese manufacturers were putting on the price of solar panels. Regarding the acquisition of solar panel maker Silevo, Chairman Elon Musk said that SolarCity was at “risk of not having solar panels we need to expand our business in the long-term.”¹² He noted that while many basic panels were being produced, high efficiency cells were needed for the solar industry to lower costs and

⁹ James Montgomery, “SolarCity Buys Zep: Behold The Power of Vertical Integration,” RenewableEnergyWorld.com, October 10, 2013,

<http://www.renewableenergyworld.com/rea/news/article/2013/10/solarcity-buys-zep-behold-the-power-of-vertical-integration> (June 12, 2014).

¹⁰ Wendy Koch, “Elon Musk’s Solarcity to Acquire Panel Maker Silevo,” USA Today, June 17, 2014, <http://americasmarkets.usatoday.com/2014/06/17/elon-musks-solarcity-to-acquire-panel-maker-silevo/> (June 18, 2014).

¹¹ Travis Hoium, op. cit.

¹² Wendy Koch, op. cit.

compete with other sources of energy without government subsidies. Chief Technology Office, Peter Rive, commented that SolarCity had become “the most vertically integrated solar company in the world.”¹³

Federal Tax Incentives

As part of the 2009 Recovery and Reinvestment Act, the federal tax code adopted an Investment Tax Credit (ITC) in the amount of 30 on new solar investments (set to decline to 10 percent in 2017). Thus investors were eligible for a credit of 30 percent on their corporate income tax obligation. To establish their claims toward the IRS, SolarCity and competitors SunRun and Sungevity relied on independent appraisers to assess the “fair market value” of new installations. Nonetheless these companies were being investigated for possibly overstating the fair market value of their solar installations. Developers obviously benefited from higher reported values for the systems they had installed.¹⁴

State Level Incentives

As of 2013, 29 states plus the District of Columbia had enforceable Renewable Portfolio Standards (RPS) or other mandated renewable capacity policies while an additional 7 set voluntary goals for renewable generation. RPS policies required energy service providers to supply a specified minimum share of their electricity from designated renewable resources such as wind, solar and some forms of hydroelectricity. One way that obligated parties could satisfy RPS requirements was to purchase Renewable Energy Certificates (RECs) from renewable generators. As an illustration, a wind farm would earn one REC for every 1000 kWh of electricity produced. After certification by a designated agency, the wind farm routed the renewable energy to the commercial grid and then sold RECs to a third party company. By 2014, the value of one REC (1000kWh) had fallen to \$2 in California, though it was much higher in other states such as New Jersey.

Net Metering

When solar production was more than what the customer used, the excess energy was automatically sent through the electric meter into the grid. The meter recorded how much electricity was actually consumed and how much was pushed back into the grid, running backward as it captured the excess electricity and crediting the customer account.¹⁵ In 2014, 43 states plus the District of Columbia had net metering policies and regulations—utilities were required to credit consumers at the full retail rate and only bill for their “net” energy use.¹⁶ While some states limited the number of subscribers who could use net metering at any given

¹³ Wendy Koch, “Elon Musk’s SolarCity to Acquire Panel Maker Silevo,” USA Today, June 17, 2014, <http://americasmarkets.usatoday.com/2014/06/17/elon-musks-solarcity-to-acquire-panel-maker-silevo/> (June 18, 2014).

¹⁴ Prior to the spring of 2013, the 1603 Treasury Program allowed solar and other renewable energy project developers to receive a direct federal grant in lieu of an ITC.

¹⁵ “Net Energy Metering in California,” Go Solar California, http://www.gosolarcalifornia.ca.gov/solar_basics/net_metering.php (May 12, 2014).

¹⁶ Tom Tanton, “Reforming Net Metering: Providing a Bright and Equitable Future,” American Legislative Exchange Council, March, 2014, <http://www.alec.org/publications/net-metering-reform/> (June 2, 2014).

time, almost all limited the eligible wattage (i.e., the 2014 limit in California was five percent of peak customer demand. As utilities approached those caps, however, the national trend was to redefine or expand caps).¹⁷ The reduction in utility bills that net metering yielded was an important benefit that developers such as SolarCity promoted to their customers.

The utility industry, however, was calling for changes to net metering. According to a report issued by the American Legislative Exchange Council (ALEC), the largest individual public-private membership association of state legislators in the U.S., “in many states where a utility is statutorily required by law to reimburse Direct Generation (DG) customers at the retail rate for their surplus electricity generated, DG customers are able to avoid paying for much of the electric grid infrastructure they use and other services provided by a utility.”¹⁸ Utilities had begun pushing to implement fees associated with net metering in several states.

Insolation and Electricity Rates

Solar insolation refers to the amount of solar radiation received in a particular location. Insolation is affected by factors such as atmospheric conditions, latitude, time of year, and time of day. Because SolarCity offered solar power at a discount relative to utility prices, electricity rates and insolation were two key components in determining which markets to enter. Lyndon Rive elaborated, “So we first look at the functional economics: What is our current cost of electricity? Then we look at how much sun does that market get, and then we look at any state incentives. The most important is what’s the cost of electricity because that’s our competition. We are competing against the local utility, and so we have to price below their price.”¹⁹ For example, although the retail price of electricity was relatively cheap in Arizona (12-13 cents per kWh), the high insolation rates allowed SolarCity to price below the utilities. In California, where insolation rates were lower, the price per kWh was higher around 16 cents, making the economics work.²⁰ **Exhibit 3** shows an example of savings attained by the residential customer, as advertised by SolarCity.

FINANCING

The three factors that most impacted competitiveness in the solar industry were: (1) low cost of customer acquisition, (2) inexpensive installation, and (3) low cost of capital. Due to the structure of federal incentives (i.e., 30 percent tax credit), SolarCity and other solar developers partnered with tax equity investors. While there were three primary financial arrangements for such financing, as of March 2013, SolarCity had used the “Partnership Flip” model for about two thirds of the funds that it raised.²¹

¹⁷ Customers could also “zero-out” their utility bills but most utilities did not disburse payment for net electricity production. “Understanding Net Metering,” SolarCity, <http://www.solarcity.com/learn/understanding-netmetering.aspx> (May 12, 2014).

¹⁸ Tom Tanton, op. cit.

¹⁹ Adam Lashinsky, op. cit.

²⁰ “Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector,” U.S. Energy Information Administration, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a (July 23, 2014).

²¹ Josh Lutton, op. cit. The two other main financial arrangements used were: sale-leaseback and inverted lease (also known as lease pass-through).

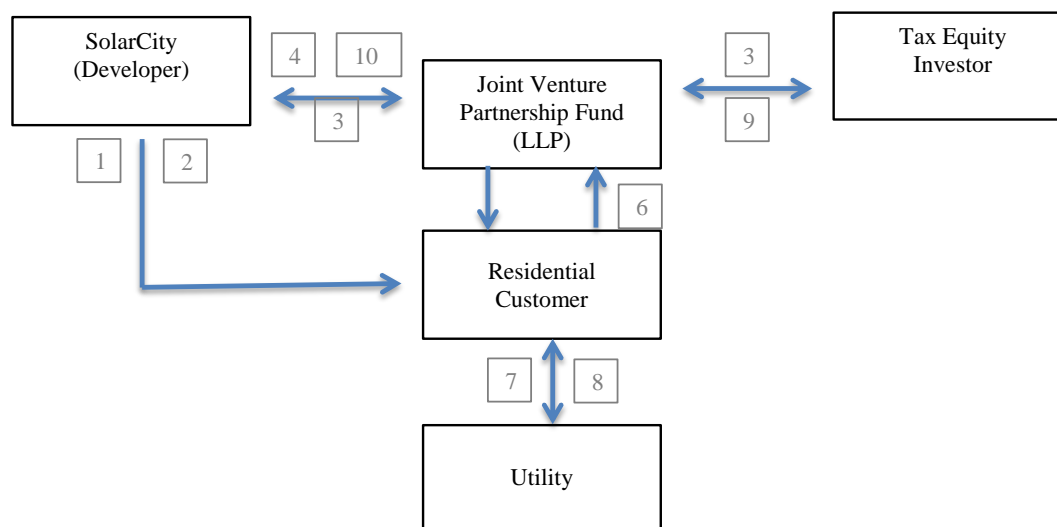
Partnership Flip²²

Under this arrangement, the developer (SolarCity) and tax equity investor created a joint venture partnership in which the distribution of cash flows and income “flipped” between the parties one or more times during the duration of the partnership. The partnership, from hereon called the “fund,” comprised a large number of solar installations. The developer (SolarCity) would “transfer” the systems to the fund and receive a buy-in payment from the tax equity investor. Subsequently, the fund would receive monthly payments from customers. In the first five years, the fund passed most of its income (usually 99 percent) to the tax equity investor while most of the fund’s income went to the developer in the remaining years (often 95 percent). One advantage of this model was that it was well understood due to long use in wind energy deals. Disadvantages included the developer investing some of its own scarce capital.

The Partnership Flip operated according to a general **timeline**:

- Stage 1: SolarCity acquires customer, establishes lease or PPA, completes installation, and secures net metering arrangement with utility.
- Stage 2 (first 5 years): Customer uses solar power and makes payments to the fund. For tax purposes, most of the income (99 percent) goes to the tax equity investor. Cash flows shared between tax equity investor and SolarCity.
- Stage 3 (years 6 – 20): Partnership flips. Customer continues to make payments to the fund and most cash flows and income go to SolarCity.
- Stage 4: End of contractual obligations after 20 years. Customer can purchase the solar system, ask SolarCity to remove it for free, upgrade to a new system with a new contract, or extend existing agreement in five-year increments.

The graphic below illustrates the main steps involved in the Partnership Flip model:



²² This section is in part is based on information from Josh Lutton, Ibid.

Main Steps:

1. SolarCity initiates relationship with customer
2. Customer agrees to lease or PPA
3. Fund is structured as a limited liability partnership (LLP)
4. SolarCity installs solar system and “transfers” the system to the fund
5. Tax equity investor makes buy-in cash payment to SolarCity
6. Customer makes lease or PPA payments to the fund
7. Net Metering: at times when solar system produces electricity in excess of consumer demand, excess is fed back into the grid. Utility credits consumer full retail cost per kWh for electricity fed back into the grid
8. When the solar system does not produce sufficient electricity to meet consumer demand, consumer purchases the additional required electricity from the utility.
9. In the first phase, fund passes 99 percent of its (taxable) income to tax equity investor, who can claim the ITC. Cash flows to the fund are shared between the parties according to contractual agreement.
10. After the flip, SolarCity receives 95 percent of the fund’s cash flows and income

Securitization

In 2013, SolarCity took a big step to increase its sources of capital. It sold almost \$55M of bonds that were secured by payment claims that SolarCity had through its solar installations. These bonds “bundled” claims across many different installations so as to make default rates quite predictable. In what was the first securitization of distributed solar payments, SolarCity offered a 4.8 percent interest rate. West Owens, Director of Structured Finance, explained that the company’s vertical integration and ownership of data from top to bottom of its supply chain were critical in valuing its assets and negotiating the terms.

Travis Hoiium of *The Motley Fool* commented on the significance of securitization: “In 2017, the investment tax credit will fall from 30 percent to 10 percent, and suddenly the tax equity financing portion won’t be so important. Instead, being able to quickly and efficiently finance solar installations will become more important and that’s why [SolarCity] offering securitization now [before 2017] and building a record with investors is so important.”²³ Noting that securitization lowered the cost of capital, thus lowering SolarCity’s cost per kWh produced, Hoiium stated, “If leasing solar equipment continues to be the dominant product for the residential industry, this low cost of capital will be key to success.”²⁴ In July 2014, SolarCity announced an even larger offering—\$201.5 million of asset-backed notes at a weighted yield of 4.32 percent.²⁵

THE PARTNERSHIP FLIP MODEL: AN EXAMPLE

The following example illustrates the basic mechanics of the partnership flip model. It also identifies the economic benefits and risks to the three principal players participating in a

²³ Travis Hoiium, op. cit.

²⁴ Ibid.

²⁵ Eric Wesoff, *greentechsolar*, July 25, 2014, <http://www.greentechmedia.com/articles/read/SolarCitys-New-201M-Securitized-Solar-Portfolio-Keeps-the-Capital-Flowing> (July 29, 2014).

transaction: the residential customer, SolarCity, and the tax equity investor. The following figures are intended to be illustrative and broadly applicable on average. This information can also be found in the Excel file, “**SolarCity-Template.**”

- An average installation was for 6 kilowatts of power. Assuming an initial capacity factor of about 16 percent, the system was expected produce 1,400 kWh of electricity in the first year, with an expected output reduction (degradation) of about 0.5 percent per year.
- In order to attract a **residential customer**, SolarCity anticipated that the customer would need to project at least \$10,000 of electricity savings over 20 years (undiscounted).
- The **residential customer** could buy or sell electricity from/to the local utility for 16 cents per kWh initially, with an expected annual escalation factor of 3.5 percent.
- Under the PPA arrangement, the **residential customer** would pay an initial price per kWh generated by the system. This price would then be escalated at a rate of 2.5 percent per year. The initial price to be calculated so as to meet the \$10,000 savings target.
- **SolarCity’s** direct full cost of installing the system was \$3.2 per watt. Once the system was fully connected, SolarCity would “transfer” it to a Limited Liability Partnership (“the **fund**”) in which SolarCity partnered with a **Tax Equity Investor (TEI)**. The tax equity investor would make an initial buy-in payment to SolarCity.
- PPA payments would go to the **fund** in subsequent years. The fund incurred annual maintenance costs of \$20 per kW installed, escalating at a rate of 1.5 percent per year. Taxable income of the fund to be “passed on” in the following proportions: 100 percent to **Tax Equity Investor (TEI)** in years 1-5²⁶, and 95 percent to **SolarCity** (5 percent to TEI) in years 6-20. The pre-tax cash flows of the fund were to be split in the following proportions: 30 percent to the **TEI** (70 percent to SolarCity) in years 1-5, and 95 percent to **SolarCity** (5 percent to TEI) in years 6-20.
 - Since the **TEI** received 100 percent of the fund’s income initially, it was entitled to the ITC in the amount of 30 percent of the initial fair market value.²⁷ The fair market value of the system was estimated at \$4.50. The **TEI** would also receive all the tax benefits associated with accelerated depreciation under MACRS in the first five years.
 - The **TEI’s** initial investment payment to SolarCity was calculated so as to provide the **TEI** with an internal rate of return of around 8-9 percent on its investment.

CONCLUSION

SolarCity was working hard to further improve its competitiveness and remain the industry leader going forward. Its vertical integration, aside from helping to provide a good customer experience, reduced customer acquisition costs. The recent purchase of Silevo was intended to secure a steady supply of quality solar panels and keep installation expenses low. And blazing a trail into securitization would diversify funding sources as well as lower the cost of capital. However, SolarCity’s continued lack of positive accounting earnings, yet impressive stock returns, left analysts and industry observers wondering: Was SolarCity already making money on installations like the partnership flip described above or was the company’s share price primarily a bet on the future with lower solar installations costs?

²⁶ Typically 99 percent but rounded up to 100 percent in this example for simplicity.

²⁷ The tax rules specify that if the 30 percent ITC is taken, then, for tax purposes, the initial book value of the system is only 85 percent of the fair market value.

Exhibit 1
Consolidated Balance Sheets
(In Thousands, Except Share Par Values)

	December 31,	
	2013	2012 (Restated)
Assets		
Current assets:		
Cash and cash equivalents	\$ 577,080	\$ 160,080
Restricted cash	19,182	7,516
Accounts receivable (net of allowances for doubtful accounts of \$955 and \$220 as of December 31, 2013 and 2012, respectively)	23,011	24,629
Rebates receivable	20,131	17,501
Inventories	111,394	87,087
Deferred income tax asset	9,845	5,623
Prepaid expenses and other current assets	27,020	11,502
Total current assets	787,663	313,938
Restricted cash	301	2,810
Solar energy systems, leased and to be leased – net	1,682,521	984,121
Property and equipment – net	22,407	18,635
Goodwill and intangible assets – net	278,169	626
Other assets	38,473	22,170
Total assets(1)	\$2,809,534	\$1,342,300
Liabilities and equity		
Current liabilities:		
Accounts payable	\$ 121,556	\$ 62,986
Distributions payable to noncontrolling interests and redeemable noncontrolling interests	20,390	12,028
Current portion of deferred U.S. Treasury grants income	15,340	11,376
Accrued and other current liabilities	72,157	53,233
Customer deposits	8,828	7,909
Current portion of deferred revenue	59,899	31,822
Current portion of long-term debt	7,422	20,613
Current portion of solar asset-backed notes	3,155	—
Current portion of lease pass-through financing obligation	29,041	13,622
Current portion of sale-leaseback financing obligation	418	389
Total current liabilities	338,206	213,978
Deferred revenue, net of current portion	410,161	204,396
Long-term debt, net of current portion	238,612	83,533
Convertible senior notes	230,000	—
Solar asset-backed notes, net of current portion	49,780	—
Long-term deferred tax liability	9,238	5,643
Lease pass-through financing obligation, net of current portion	64,167	125,884
Sale-leaseback financing obligation, net of current portion	14,338	14,755
Deferred U.S. Treasury grants income, net of current portion	412,469	286,884
Other liabilities and deferred credits	193,439	114,006
Total liabilities(1)	1,960,410	1,049,079
Commitments and contingencies (Note 25)		
Redeemable noncontrolling interests in subsidiaries	44,709	12,827
Stockholders' equity:		
Common stock, \$0.0001 par value – authorized, 1,000,000 shares as of December 31, 2013 and 2012; issued and outstanding, 91,009 and 74,913 shares as of December 31, 2013 and 2012, respectively	10	7
Additional paid-in capital	819,914	330,130
Accumulated deficit	(202,326)	(146,536)
Total stockholders' equity	617,598	183,601
Noncontrolling interests in subsidiaries	186,817	96,793
Total equity	804,415	280,394
Total liabilities and equity	\$2,809,534	\$1,342,300

Source: 2013 Annual Report, SolarCity, <http://investors.solarcity.com/secfiling.cfm?filingID=1193125-14-104447&CIK=1408356>, p. 76.

Exhibit 2
Consolidated Statements of Operations
(In Thousands, Except Share and Per Share Amounts)

	Year Ended December 31,		
	2013	2012 (Restated)	2011
Revenue:			
Operating leases and solar energy systems incentives	\$ 82,856	\$ 46,098	\$ 23,145
Solar energy systems sales	80,981	80,810	36,406
Total revenue	163,837	126,908	59,551
Cost of revenue:			
Operating leases and solar energy systems incentives	32,745	14,596	5,718
Solar energy systems sales	91,723	84,856	41,418
Total cost of revenue	124,468	99,452	47,136
Gross profit	39,369	27,456	12,415
Operating expenses:			
Sales and marketing	97,426	69,392	42,004
General and administrative	91,321	49,075	31,664
Total operating expenses	188,747	118,467	73,668
Loss from operations	(149,378)	(91,011)	(61,253)
Interest expense – net	25,738	20,142	9,272
Other expense – net	1,441	2,519	3,097
Loss before income taxes	(176,557)	(113,672)	(73,622)
Income tax benefit (provision)	24,799	(54)	(92)
Net loss	(151,758)	(113,726)	(73,714)
Net loss attributable to noncontrolling interests and redeemable noncontrolling interests	(95,968)	(14,391)	(117,230)
Net (loss) income attributable to stockholders	\$ (55,790)	\$ (99,335)	\$ 43,516
<i>Net (loss) income attributable to common stockholders</i>			
Basic	\$ (55,790)	\$ (109,426)	\$ 8,225
Diluted	\$ (55,790)	\$ (109,703)	\$ 10,989
<i>Net (loss) income per share attributable to common stockholders</i>			
Basic	\$ (0.70)	\$ (7.68)	\$ 0.82
Diluted	\$ (0.70)	\$ (7.69)	\$ 0.76
<i>Weighted average shares used to compute net (loss) income per share attributable to common stockholders</i>			
Basic	79,781,976	14,240,187	9,977,646
Diluted	79,781,976	14,267,767	14,523,734

Source: 2013 Annual Report, SolarCity, <http://investors.solarcity.com/secfiling.cfm?filingID=1193125-14-104447&CIK=1408356>, p. 78.

Exhibit 3 Solar PPA Sample Customer Savings

ANNUAL ENERGY SAVINGS						
Year	Electric Bill Without Solar	Electric Bill With Solar	Savings on Electric Bill	Annual Payments	Overall Savings	Cumulative Cash Flow
0						
1	\$2,293	(\$735)	\$1,559	(\$1,163)	\$396	\$396
2	\$2,403	(\$778)	\$1,625	(\$1,191)	\$435	\$830
3	\$2,519	(\$824)	\$1,695	(\$1,219)	\$476	\$1,306
4	\$2,640	(\$872)	\$1,767	(\$1,248)	\$519	\$1,825
5	\$2,766	(\$924)	\$1,843	(\$1,278)	\$565	\$2,390
6	\$2,899	(\$978)	\$1,922	(\$1,308)	\$613	\$3,003
7	\$3,038	(\$1,035)	\$2,004	(\$1,340)	\$664	\$3,667
8	\$3,184	(\$1,095)	\$2,089	(\$1,372)	\$718	\$4,385
9	\$3,337	(\$1,158)	\$2,179	(\$1,404)	\$774	\$5,159
10	\$3,497	(\$1,225)	\$2,272	(\$1,438)	\$834	\$5,993
11	\$3,665	(\$1,296)	\$2,369	(\$1,472)	\$897	\$6,890
12	\$3,841	(\$1,371)	\$2,470	(\$1,507)	\$963	\$7,854
13	\$4,025	(\$1,449)	\$2,576	(\$1,543)	\$1,033	\$8,886
14	\$4,219	(\$1,532)	\$2,686	(\$1,580)	\$1,106	\$9,992
15	\$4,421	(\$1,620)	\$2,801	(\$1,618)	\$1,183	\$11,176
16	\$4,633	(\$1,713)	\$2,921	(\$1,656)	\$1,265	\$12,440
17	\$4,856	(\$1,810)	\$3,046	(\$1,696)	\$1,350	\$13,790
18	\$5,089	(\$1,913)	\$3,176	(\$1,736)	\$1,440	\$15,230
19	\$5,333	(\$2,021)	\$3,312	(\$1,778)	\$1,534	\$16,764
20	\$5,589	(\$2,136)	\$3,453	(\$1,820)	\$1,633	\$18,397
20-year Sum	\$74,248	(\$26,485)	\$47,764	(\$29,366)	\$18,397	

* Please note this proposal is an estimate and does not guarantee actual system production or savings. The system design may change based on a detailed engineering site audit. Actual system production and savings will vary based on the final system size, design, configuration, utility rates, applicable rebates and your family's energy usage. The electricity rates or lease payments set forth in this proposal are set by SolarCity. Utility annual increases are estimated. Actual rate increases may be higher or lower than indicated in this proposal. Utility rates, charges and fee structures imposed by your local utility are not affected by this proposal or any contract you may sign with SolarCity and are subject to change in the future at the discretion of the authority or entity that regulates or governs your local utility. © 2014 SolarCity Corporation. All rights reserved. OO EC 8041

Source: SolarCity. Reprinted with permission.

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