The U.S. Investment Tax Credit for Solar Energy: Alternatives to the Anticipated 2017 Step-Down

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Abstract

The federal Investment Tax Credit (ITC) for solar installations is scheduled to step-down from 30% to 10% at the beginning of 2017 for corporate investors. This raises the question whether solar PV will be cost competitive post 2016 in the U.S. We examine the economics of solar PV for a sample of U.S. states and industry segments. Our model calculations indicate that for almost all of these settings the anticipated ITC step-down would render solar PV uncompetitive by early 2017, raising the specter of a 'cliff' for the solar industry. We identify and evaluate an alternative phase-down scenario that would reduce the ITC gradually and eliminate it completely by 2024. Provided the solar industry can maintain the pace of cost reductions demonstrated in past years, our projections indicated that solar PV would remain broadly competitive, even as federal tax support would be gradually diminished, and ultimately eliminated, under the alternative phase-down-scenario.

Keywords

Tax incentives

Solar energy systems

Cost competitiveness

Levelized cost

1 Introduction

Current legislation 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.[1] The ITC was initially created as part of the Energy Policy Act of 2005 and extended through the end of 2016 with the Emergency Economic Stabilization Act of 2008. In conjunction with the accelerated depreciation tax shield provided through the Modified Accelerated Cost-Reduction System, the ITC has spurred rapid growth in new solar installations for the U.S. To illustrate, 105 MW of photovoltaic (PV) installations were added at an average system price of $7.90 per Watt in 2006. In 2013, 4,776 MW of new PV capacity were installed an average system price of $2.93 per Watt. By 2014, new solar installations did account for more than one third of all newly installed capacity for electricity generation in the U.S. (GTM Research, 2014).

We assess the impact of the anticipated ITC step-down on the competitiveness of solar energy across different locations and different segments of the U.S. solar industry. As an alternative to the anticipated step-down, we then evaluate a gradual 'phase-down' scenario. We focus our analysis on five key states: California, Colorado, New Jersey, North Carolina and Texas. These states currently account for more than 65% of the cumulative solar installations in the U.S. They also exhibit considerable diversity in terms of solar energy market maturity, insolation rates, labor/material costs, and market structure. For each state, we distinguish three market segments: residential rooftop (< 10 kW capacity per installation), commercial-scale (10 kW – 1000 kW) and utility scale (>1 MW). For utility-scale systems, we consider two technology platforms: c-Si (crystalline silicon) and CdTe (thin film) solar cells.

Our main metric for assessing the cost competitiveness of solar PV under different policy regimes is the Levelized Cost of Electricity (LCOE). The LCOE identifies the break-even value that a power producer would need to obtain on average per 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 both the system price and the ap-

[1] See 26 USC §25D and 26 USC §48. Our analysis 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 early 2017.

plicable operations- and maintenance costs. The LCOE is assessed relative to a comparison price, given by the appropriate benchmark for a particular segment in a specific state. For commercial-scale installations in Colorado, for instance, the comparison price is determined by the rate charged per kWh to commercial users by energy service providers in Colorado.

At current (2014) costs, ignoring any state-level incentives, the following findings emerge with a 30% ITC : (i) utility scale installations are not yet 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, under the assumption that there are no restrictions on net energy metering.

To project cost declines in future years, we forecast the LCOE for different segments and states by applying a cost dynamic to each component of the solar PV system. For PV modules, we rely on a model of *economically sustainable prices* based on production cost fundamentals of the upstream manufactures. For inverters, balance of system (BOS) and operations and maintenance costs, we estimate individual exponential decay functions, 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.[2] The rate of change at which costs decrease is specific to the segment and geography – especially BOS – based on local market conditions (labor, materials, etc.) and competitiveness.

While the expected magnitude of further reductions in system prices for solar PV is quite significant, we nonetheless find that if the step-down to a 10% ITC were indeed to occur at the beginning of 2017, solar PV would become uncompetitive across the entire spectrum of segments and geographies considered in our study. The magnitude of the anticipated step-down in the ITC is likely to result in a 'cliff' for the U.S. solar industry in early 2017.

[2]Our cost reduction assumptions for PV modules are based on a standard learning-by-doing model in which cumulative production volume is the driving variable. However, since PV modules are a global commodity, the pace of future production volumes is arguably not affected materially by our analysis of alternative scenarios in the U.S., as the overall share of modules installed in the U.S. is less than 10% of the worldwide production volume.

At the same time, the sustained reduction in PV system costs demonstrated over the past decades suggests that solar energy will not require an indefinite continuation of the 10% ITC. A credible alternative to the current tax law therefore specifies a smoother glide path that could lead to a complete elimination of the federal tax incentives at some definitive future date. This feature would effectively introduce a *quid-pro-quo* element that could make alternative phase-down scenarios more acceptable politically.

For simplicity, we evaluate a policy scenario that involves only three distinct phases, starting at the beginning of 2017, 2021 and 2025, respectively. For the first two phases, the revised tax rules would be targeted so as to result in LCOEs that are in between those corresponding to the 10% and the 30% ITC benchmarks. The impact of gradually reduced tax incentives would be at least partially offset by the anticipated cost reductions during the previous phase. Because smaller residential systems tend to be the most expensive on a per Watt basis, the current solar ITC provides the largest support to residential PV systems in terms of dollars per Watt installed. More flexible and targeted tax breaks can be achieved by providing investors with a choice between alternative methods for calculating the ITC.

For the years 2017 – 2020, our phase-down scenario would offer a choice between a 20% ITC or a lump-sum ITC in the amount of 40 cents per Watt installed. The 40 cents figure is obtained by putting a price on the stream of future carbon emissions that would be avoided by generating power from solar cells rather than fossil fuel energy. Consistent with the overall concept of diminishing ITC support, the second phase would cut the previous parameters in half for the years 2021 – 2024. Investors would then have the choice between a 10% ITC or a lump-sum ITC in the amount of 20 cents per Watt.

Our simulation results show that the proposed alternative phase-down scenario would go a long way towards avoiding the cliff that is likely to result from the currently anticipated step-down in federal tax support. Residential installations would continue to opt for an ITC calculated as a percentage of the system price. The 20% ITC for the years 2017 – 2020 would be sufficient to keep the residential segment cost competitive in most of the five states we examine. Furthermore, the anticipated additional reductions in cost are projected to leave residential installations with an LCOE that is within 10 – 15% of the retail rates expected for the years 2021 – 2024.

Commercial and utility-scale systems would prefer the lump-sum ITC under our policy proposal. With this option, commercial-scale installations would be cost competitive in

California and Texas and close to break-even in the remaining three states of Colorado, New Jersey and North Carolina during the first phase. Without any ITC, commercial installations in California and Texas are projected to be competitive by 2025, at break-even in Colorado, and at a small disadvantage in New Jersey and North Carolina. Finally, the federal tax support we envision would leave utility-scale installations with LCOE values which at least match the projected wholesale electricity prices, starting in 2018. Importantly, utility-scale installations are projected to be fully cost competitive without any ITC by 2025. This pattern emerges for all of the states we consider, except New Jersey.

Taken together, our analysis identifies a gradual phase-down, rather than an abrupt step-down, of the federal Investment Tax Credit that would avoid a major disruption for the solar industry in early 2017. Relative to the current status quo, the phase-down scenario effectively shifts federal tax support to earlier years during which this relatively new electricity generation technology is poised to experience the most pronounced learning- and cost reduction effects.

The remainder of the paper proceeds as follows. The next section lays out our basic cost methodology and provides current cost estimates based on 2014 figures. Section 3 describes our model of future cost reductions in order to obtain a forecast of where the industry is likely to be in early 2017. These forecasts in turn allow us to evaluate the alternative ITC phase-down scenario in Section 4. We discuss our findings in Section 5 and conclude in Section 6. There are two appendices. Appendix A summarizes model input variables for each of the states and segments considered. Appendix B provides additional details for the levelized cost calculations. These appendices are provided as Supplementary Data to this article in conjunction with a spreadsheet model that underlies all our calculations.

2 Assessment of Current Levelized Costs

We seek to examine the economics of solar PV installations differentiated by location and segment. We focus our analysis on five key states: California, Colorado, New Jersey, North Carolina and Texas. Taken together these five sample states account for over 65% of all the solar installations currently in the U.S. In addition, these states were chosen for diversity in terms of insolation factors, labor/material rates, maturity of the local solar energy industry, and prevailing electricity prices. Within each state, the industry is classified into three

segments: residential rooftop (< 10 kW capacity per installation), commercial-scale (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. Our analysis thus covers 5 $\times$ 4 = 20 state/segment *solar applications*.

The Levelized Cost of Electricity (LCOE) concept is commonly used in the energy literature to compare the cost competitiveness 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 life-cycle cost measure on a per kilowatt-hour (kWh) basis that must be covered as sales revenue in order to justify an investment in a particular power generation facility. As such, the LCOE reflects the time-value of money and identifies a break-even figure that must be attained as *average* revenue per kWh in order for equity investors and creditors to attain a zero-net-present value on their investments, and thereby a competitive return on their capital. Following the approach in Reichelstein and Yorston (2013), we represent the LCOE in the form:[3]

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

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 (in %).

As presented here, the LCOE does not account for the fact that electricity prices in the wholesale market and the rates paid by commercial customers can vary considerably across the hours of the day and across different seasons. In particular, 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 between solar power (Joskow, 2011) and real-time electricity rates. Recent work by Reichelstein and Sahoo (2015) identifies a multiplicative adjustment factor to the basic LCOE calculation. The adjustment factor captures

[3]For a full treatment of the basic LCOE, including definition of sub-elements, the reader is referred to Reichelstein and Yorston (2013). See also Appendix B in the Supplementary Data for modifications of the LCOE formula required for the current study.

any synergies that result from correlations between relatively high electricity prices and solar PV generation patterns at particular times of the day. For select locations in California, Reichelstein and Sahoo (2015) conclude that the effective LCOE of solar installations is about $10-15\%$ lower than suggested by a traditional LCOE analysis based only on broad averages.

Among the three components of the LCOE formula in equation (1), the unit cost of capacity, c, is derived primarily from the system price of the solar installation. The corresponding initial investment expenditure must be 'levelized' across the stream of future energy outputs derived from the system in order to arrive at a unit capacity cost per kWh. Following Reichelstein and Yorston (2013), the relationship between the unit cost of capacity and system price is given by:

$$c = \frac{SP}{8,760h/year \cdot CF \cdot \sum_{t=1}^{T} x_t \cdot \gamma^t}, \tag{2}$$

where 8760 refers to the number of hours per year and CF denotes the applicable capacity factor which varies with the application according to segment and to geographic location. By T we denote the useful life of the solar installation, which in all our calculations is fixed at 30 years. The parameters x_t represent the factor of the initial capacity that is still available in year t after accounting for systems degradation. Our calculations generally assume a constant 0.5 percent system degradation rate. Thus, $x_t = .95^{t-1}$. Finally, $\gamma = \frac{1}{1+r}$ denotes the discount factor based on the applicable cost of capital r.[4]

Since the LCOE concept takes an investor perspective, we employ a " bottom-up" cost approach to arrive at the *sales price* that a turnkey installer in a given state and segment would charge a would-be investor for a new solar energy system.[5] The three main components for the system price are the solar module, the inverter and the balance of system (BOS):

$$SP = PP + IP_i + BOS_{ij}, \tag{3}$$

[4]We interpret r as a weighted average cost of capital (WACC). Our analysis does not attempt a comprehensive assessment of the applicable cost of capital for the different solar PV applications we consider. For our baseline calculations, the cost of capital is held fixed at 8% for both commercial- and utility scale installations, while r is set at 9.5% for residential systems. Section 5 below reports some sensitivity tests that show the impact of changes in the assumed cost of capital.

[5]Our approach is similar to an engineering cost estimate approach, where the costs of individual system subcomponents are aggregated to arrive at the overall 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).

where

- PP denotes the solar PV module price (in \$ per Watt)
- IP_i denotes the inverter cost for segment i (in \$ per Watt)
- BOS_{ij} denotes the Balance of system cost for segment i in state j (in \$ per Watt).

Our study views solar modules as global commodities that are only subject to negligible cost differentiation across geographies and segments within the U.S. As such, on a \$/W basis, modules are taken to be of equal cost across all applications. Inverters are also viewed as commodities, though their costs may differ across segments. The remaining BOS component exhibits cost differentiation across segments and geography. BOS cost components are further classified into subcomponents including 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 based on current (2014) average sales prices. The estimates for current average inverter prices were determined through select interviews with industry observers and analyst reports (GTM Research, 2014; BNEF, 2014). National averages of BOS subcomponents by segment were determined through select practitioner interviews, coupled with analyst reports (Lux Research, 2013; GTM Research, 2014; NREL, 2014; SNL Financial, 2014).[6] 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.[7] For detailed information on initial variable values, the reader is referred to Appendix A in the Supplementary Data.

The tax factor, Δ, in equation 1 reflects the impact of corporate income taxes, depreciation tax shields and investment tax credits. Absent any ITC, the tax factor amounts to

[6]These national averages were then adjusted using the RSMeans City Cost Indexes (RSMeans, 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). Resulting geography-specific estimates of BOS subcomponents were verified for general accuracy with practitioners having local-market expertise.

[7]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.

a "mark-up" on the unit cost of capacity.[8] While the tax factor generally exceeds 1, it can be reduced below 1 through an ITC. Table 1 shows the impact of the ITC on Δ for two depreciation methods: the 150% declining balance method with an assumed 20-year useful asset life and the Modified Accelerated Cost-Reduction System (MACRS), that is applicable for solar generation assets.

Table 1: *The tax factor, Δ, at a blended tax rate of $\alpha = 40\%$, for different depreciation schedules and ITC values.*

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

Since the tax factor, Δ acts as a multiplier on the unit cost of capacity, c, we conclude that, compared to a 0% ITC, the introduction of a 30% ITC effectively amounts to a 37% reduction in the cost of capacity needed to generate one kWh of electricity. Furthermore, a 30% ITC effectively reduces the unit cost of capacity by 27% relative to a 10% ITC scenario.

Table 2 shows our LCOE estimates by segment and state for the year 2014. These estimates are contrasted with the appropriate *comparison price* (CP), given by the average residential, commercial or wholesale electricity prices, respectively, in a given state (EIA, 2014). We conclude that under current conditions, solar PV appears competitive for only a few of the applications we examine. These findings suggest that the widespread adoption of utility-scale solar projects in recent years, in particular in states like California, was enabled by additional state level incentive programs, such as Renewable Portfolio Standards, grants, and loan- and rebate programs[9] While portfolio standards will remain in effect for the future, the market value of the corresponding Renewable Energy Credits has fallen substantially in value. In addition, most state-level direct incentive programs are currently scheduled to expire by 2017.

[8]The detailed expression for the tax factor Δ is provided in Appendix B of the Supplementary Data.

[9]For the states considered in our study – California, Colorado, New Jersey, North Carolina and Texas – the reader is referred to (DSIRE, 2014a), (DSIRE, 2014b), (DSIRE, 2014c), (DSIRE, 2014d) and (DSIRE, 2014e), respectively.

Table 2: *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

3 Levelized Cost Dynamics

While solar PV has yet to reach 'grid-parity' broadly, the cost reductions achieved over the past five years have been significant. So while there may only be few instances of cost competitiveness now, the 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%. In addressing this question, we postulate a dynamic for the system price and operating- and maintenance costs in order to project future LCOE reductions.

To obtain a forecast for the evolution of PV module sales prices, we adopt the notion of *economically sustainable price* (ESP) in Reichelstein and Sahoo (2014). By construction, the ESP is the expected competitive market price for modules that would result in a long-run industry equilibrium. As such, the ESP incorporates all manufacturing costs and a competitive mark-up, which reflects the required return for module producers. For a sample of publicly listed module manufacturers, Reichelstein and Sahoo (2014) examine line items from income statements and balance sheets to infer manufacturing costs. In conjunction

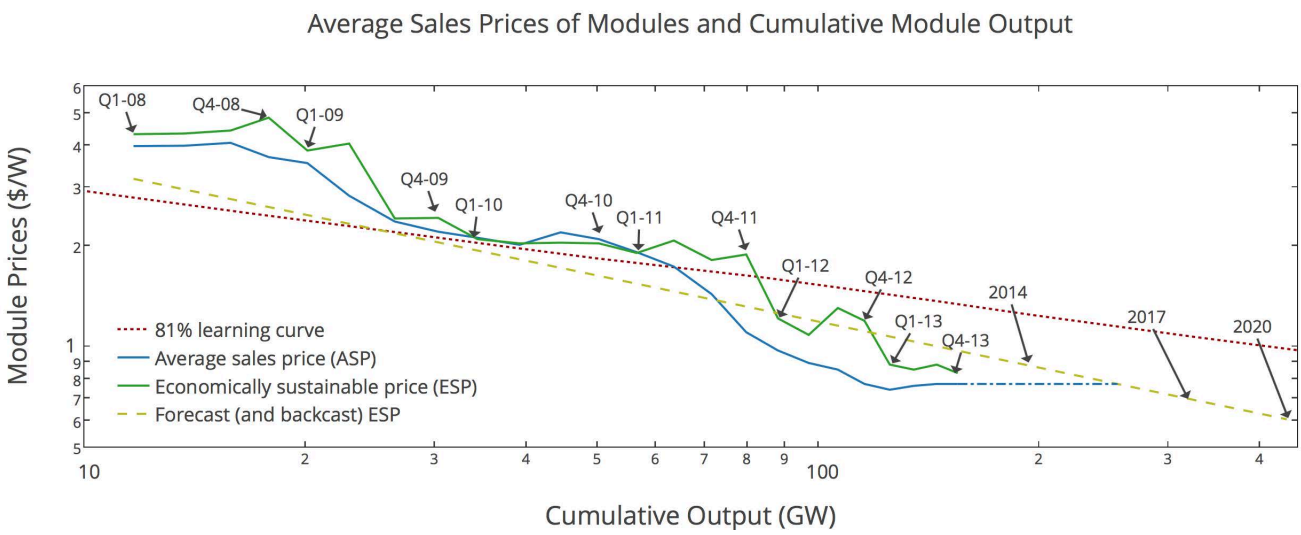


Figure 1: *Historical ASP and ESP for PV modules and forecast of future ESPs*

with industry-wide data on capacity additions and industry-wide production levels, their analysis derives an estimate for what prices should have prevailed if the industry had been in equilibrium. These estimates are shown in the green line in Figure 1 for the years 2008 – 2013. In contrast, the actual sales prices (ASP) are depicted in the blue line. While ESPs and ASPs were closely matched until early 2011, actual sales prices began to fall more quickly thereafter. That point in time also coincides with major additions to global manufacturing capacity, suggesting that the sharp drop in observed average sales prices must be attributed in part to excess capacity rather than intrinsic cost reductions.

The dashed yellow line in Figure 1 represents the fundamental trend line of regressed ESPs in Reichelstein and Sahoo (2014). We rely on these estimates to extrapolate a trajectory of future equilibrium prices to which ASPs should converge over time. Specifically, we assume that module prices will remain flat until 2017 when ESPs are projected to catch up with current ASPs. Our calculations assume that thereafter the industry will remain in equilibrium and therefore both ASPs and ESPs will decrease at the rate depicted by the dashed yellow line. We note that this line corresponds to a 78% constant elasticity learning curve which is slightly faster than the 80% learning curve identified for solar PV modules in the earlier work of Swanson (2011).[10]

For inverters and BOS costs, there is less empirical evidence that these cost components

[10]Our calculations are based on the the EIA's (2014) predictions regarding global production of modules. Given that trajectory, we can impute the ESPs of modules as a function of calendar time.

fall as a function of the cumulative number of units produced or the cumulative number of solar PV systems installed. Our analysis follows the modeling efforts by various industry analysts who assume that price reductions as a function of time. Specifically, an exponential decay function is used to capture the idea that these costs evolve at a rate proportional to their current value (Nemet, 2006; Neij, 2008; Ferioli and van der Zwaan, 2009). Thus, the assumed functional form specifying the cost evolution of BOS is:

$$BOS(t)_{ij} = BOS(0)_{ij} \cdot e^{-\lambda_{ij} \cdot t} \tag{4}$$

where:

- $BOS(0)_{ij}$ denotes the cost of component i in segment j state at $t = 0$ (i.e. 2014)
- $BOS(t)_{ij}$ denotes the cost of component i in segment j state and period t
- λ_{ij} represents the rate of cost reduction in each period.

To project future $BOS(t)$ costs, our calculations rely on a mix of industry expert opinions in addition to analyst reports from 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, analyst reports provided historical cost data. The arithmetic mean of each subcomponent cost per year, per segment was used to create a segment-specific national average set of BOS subcomponents.[11] An exponential decay function was applied to each $BOS(t)_{ij}$, thus enabling the estimation of the individual λ_{ij}. The functional form in (4) was then used to extrapolate $BOS(t)_{ij}$ for the entire period of analysis, that is the years 2014 – 2024. On average, these estimations resulted in annual cost reduction factors of $5-5.2\%, 4.2-4.4\%$ and $3.9-4\%$ for BOS in the residential, commercial and utility segments, respectively. For the initial values of $BOS(0)_{ij}$, the reader is referred to Tables A.2 – A.4 in Appendix A in the Supplementary Data.

Inverters are considered a commodity and therefore cost differences are assumed to occur across segments but not across states (i.e. these variables are only a function of i, not j). Postulating again exponential decay, we have:

$$IP(t)_i = IP(0)_i \cdot e^{-\lambda_i \cdot t}. \tag{5}$$

[11] In order to determine state-level averages, forecasted national average subcomponent costs were adjusted using the City Cost Indexes (RSMeans, 2014), as described for current costs in Section 2 above.

The same sources used in connection with BOS costs, led us to annual cost reduction estimates for inverters of $2.5\%, 2.3\%$ and 2% in the residential, commercial and utility segments, respectively. Taken together, the expression for the system price in equation (3) is therefore indexed to time according to:

$$SP(t) = ESP(t) + IP(t)_i + BOS(t)_{ij}. \tag{6}$$

Finally, operating and maintenance (O&M) costs constitute a relatively small component of the LCOE (approximately 13%). Based on analysts' reports, we assume that O&M costs decrease at an annual rate of 5% across all applications:

$$f(t)_{ij} = f(0)_{ij} \cdot 1.05^{-t}, \tag{7}$$

The preceding specifications describe the cost dynamic for the individual components of the solar system prices, which in turn determine the anticipated changes in the LCOE. One simplification of our model is that cost reductions are assumed to be a function of time only. As a consequence, our formulation ignores "endogeneity issues" that could potentially arise because different policy regimes would probably alter the path of solar deployments in the U.S. As noted in the Introduction, the literature on solar PV modules generally specifies learning curves that tie cost reductions at any point in time to the cumulative volume of production up to that point in time. Yet, because there is a global industry for solar modules and U.S. demand accounts for only a small share (less than 10%), changes in U.S. tax policy are unlikely to have a discernable effect on future module prices. For BOS costs, most existing studies have adopted an exponential decay form as a function of time, consistent with our formulation. Certain components of the BOS costs, e.g., permitting, will arguably decrease with cumulative experience in a particular region. For other components of the BOS costs, it seems plausible that there is innovation diffusion and firms will have access to global best practices, regardless of the rate of deployment in a particular location.

Table 3: *LCOE @30%, LCOE @10% in 2016 versus Comparison Price (CP).*

	Utility (c-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

Table 3 shows the projected LCOE values by the end of year 2016 next to the applicable comparison price as well as the LCOE that would be obtained at that point in time if the ITC were indeed to drop to 10%. The corresponding values are represented as $LCOE_{10}$. The main conclusion emerging from this table is that the anticipated cost reductions by the end of 2016 are nowhere near sufficient to compensate for the cost jump associated with the anticipated drop in the ITC. To witness, our calculations indicate that, based on a 10% ITC, solar PV would not be able to match the applicable comparison prices in any of the applications we have examined, with the exception of commercial installations in California. For most of the other applications, solar PV would in fact become distinctly uncompetitive.

We note that the magnitude of the percentage jump in LCOE is the most pronounced for the residential segment. Our explanation here is that ITC tax credits are based on the fair market value of the system installed. Determination of the fair-market value 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, however, 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 fair market value is generally larger than the full acquisition cost of the system, as incurred by the developer.[12] One can think of the difference as the profit margin for the investor/developer.[13] 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). Accordingly, a reduction in the magnitude of the ITC will lead, *ceteris paribus*, to a higher percentage increase in the LCOE for residential systems.

[12]In their reports to investors, companies like SolarCity explicitly discuss the magnitude of their own installation cost in comparison to the fair market value of the systems they install (SolarCity, 2014).

[13]The corresponding mark-up is reflected in our parameter $\mu > 1$ in Table A.1 in Appendix A (Supplementary Data). Further, Appendix B extends the LCOE formula to settings where the fair market value for tax purposes may differ from the system acquisition cost incurred by the developer/investor.

4 An Alternative ITC 'Phase-Down' Scenario

The findings reported in Table 3 strongly suggest that the magnitude of the anticipated step-down in the ITC is likely to result in a 'cliff' for the U.S. solar industry in early 2017. At the same time, the sustained reduction in PV system costs demonstrated over many years suggests that solar energy will not require an indefinite continuation of the 10% ITC. An alternative to the current tax law could therefore specify a smoother glide path that could entail a complete elimination of the federal tax incentives at some definitive future date. The latter feature introduces a *quid-pro-quo* element that could make alternative phase-down scenarios more acceptable politically.

For simplicity, we focus on a policy scenario with three distinct phases starting at the beginning of 2017, 2021 and 2025, respectively. For the first two phases, the revised tax rules would be targeted so as to result in LCOEs that are in between those corresponding to the 10%, and the 30% ITC benchmarks. The impact of gradually reduced tax incentives would be partially offset by the anticipated cost reductions during the previous phase. These qualitative features of our alternative phase-down scenario are illustrated in Figure 2. Consistent with the glide path LCOE* (in red), the proposal 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 well off than they would have been under the current 30% ITC for the years 2017 – 2020. The proposed policy would then, at the end of the first four years, reduce the ITC, causing a 'seesaw' effect, albeit more muted than the one projected in 2017 under current policy.[14] Finally, after another four years, the ITC would be reduced to zero in 2025.

One way to front-load federal support for solar PV relative to the current tax rules would be to offer a 20% ITC for the years 2017 – 2020, a 10% ITC for the years 2021 – 2024 and zero thereafter. Clearly this would be in keeping with the above ideas for a gradual phase-down as illustrated by the LCOE* path in Figure 2. An alternative policy would set the applicable ITC as a lump-sum dollar amount rather than a percentage of the system price. One argument in favor of a lump-sum amount is that because smaller residential systems tend to be the most expensive on a per Watt basis, the current solar ITC provides the largest support to residential PV systems in terms of dollars per Watt installed.

More flexible and targeted tax breaks can be achieved by providing investors with a

[14] Obviously, the magnitude of the seesaw effect could be muted further by more frequent adjustments to the ITC schedule.

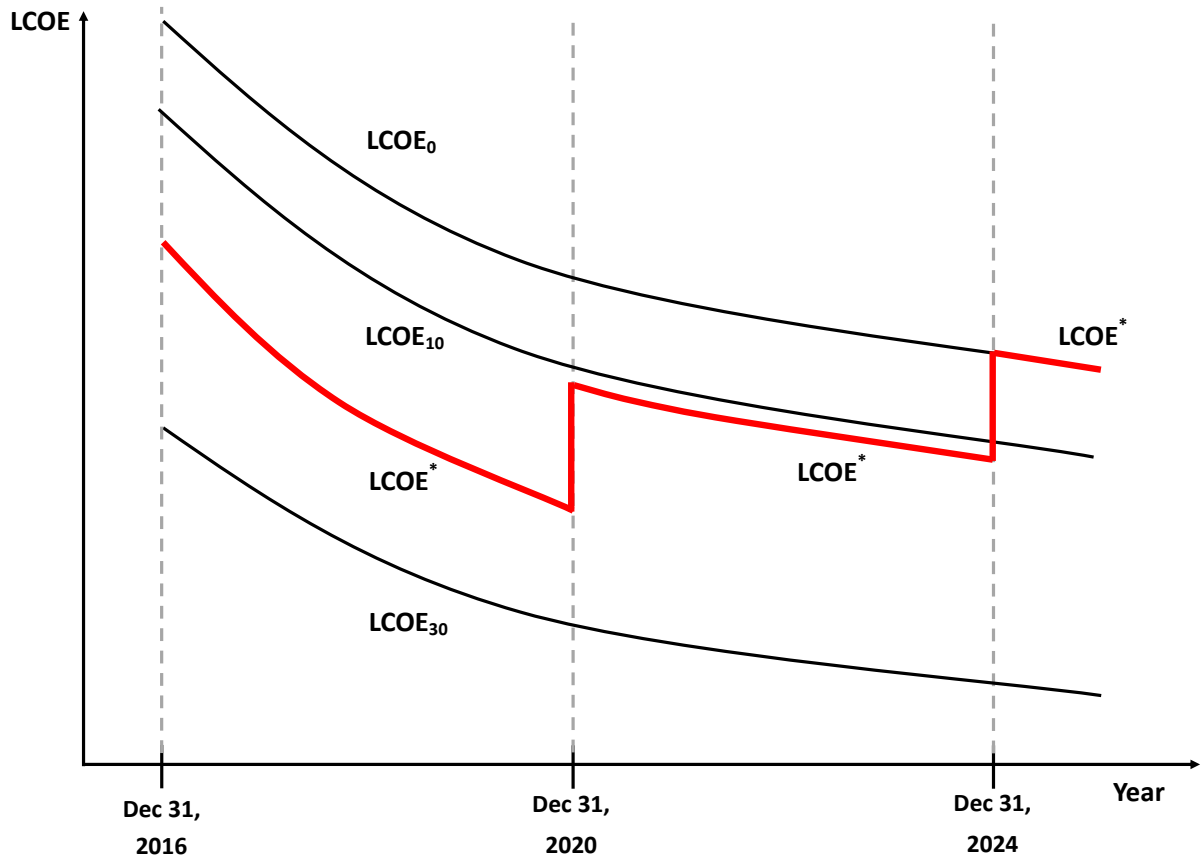


Figure 2: *Glide path with 'seesaw' pattern and ultimate reversal past 2024.*

choice. Specifically, our phase-down scenario would offer a choice between a 20% ITC or a lump-sum ITC in the amount of 40 cents per Watt installed for the years 2017 – 2020. Consistent with the overall concept of diminishing ITC support, the second phase would cut the previous parameters in half for the years 2021 – 2024. Investors in new facilities would then have the choice between a 10% ITC or a lump-sum ITC in the amount of 20 cents per Watt. We refer to this policy alternative as the *ITC Choice Scenario*.[15]

The 40 cents per Watt installed figure can be calibrated by putting a value on the stream of future carbon emissions that would be avoided by generating power from solar

[15] An additional consideration in determining how ITCs are calculated is that a percentage-based ITC amounts to cost sharing between the investor and the government. As a consequence, it provides only partial incentives to reduce costs, while a lump-sum ITC gives investors the full return on any cost reductions that the solar PV industry achieves.

rather than fossil fuel energy resources. For instance, modern combined cycle natural gas generation facilities have a CO_2 emissions rate of about 0.35 kg per kWh. If one multiplies this emission rate with a 'shadow price' for carbon emissions sent into the atmosphere, one obtains the cost of avoided carbon emissions associated with one Watt of solar power. Such a calculation must take into consideration the useful life of the facility, the number of hours per year and the capacity factor of the solar facility.[16] Combining these input variables, one arrives at the following lump-sum ITC (ITC_{LS}), calculated on a per Watt installed basis.

$$ITC_{LS} = 8,760\ h/year \cdot CF \cdot T \cdot AE \cdot CC, \tag{8}$$

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).

The initial 40¢/W installed figure underlying our ITC Choice scenario 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 CO_2 is \$40 per tonne[17]; and (iv) the avoided emissions are 0.35 kg per kWh, as discussed above in connection with natural gas power plants.[18] Interestingly, our results below show that offering investors an initial 40¢/W figure (20¢/W figure for the years 2021 – 2024) would be consistent with the idea of diminished tax support relative to the benchmark of a 30% ITC. In other words, the resulting levelized cost figures stay within the range envisioned for the LCOE* curve in Figure 2.

[16]Unlike the calculation for the unit capacity cost of solar installation in equation (2), we do not discount future avoided emissions because timing is almost inconsequential, as CO_2 emissions are projected to stay for orders-of-magnitude longer in the atmosphere than the operational life of the facility.

[17]According to the EPA and various integrated assessment models, the \$40 per tonne figure is in the mid-range of various estimates of the social cost of one tonne of carbon dioxide emitted into the atmosphere (Interagency Working Group on Social Cost of Carbon, United States Government, 2013).

[18]One may ask why our phase-down scenario calls for a lump-sum that ITC that is decreasing over time, even though the avoided cost of carbon arguably is not. 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. We also believe that it is plausible that by 2021 there will be some federal carbon pricing policy in place for the U.S. (Leiserowitz et al., 2014).

Tables 4 – 7 display our results. As indicated in the captions to the tables, we project the levelized cost of new solar installations for a 30% and a 10% ITC with the red and blue bars, respectively. The results for our *ITC Choice Scenario* are shown in purple bars. For direct comparison, we also show in green bars the findings that would obtain for a simpler ITC phase-down policy that would not allow for a lump-sum choice but simply offer fixed percentages of 20% starting in 2017, 10% starting in 2021 and zero thereafter. This scenario is referred to as the *20/10/0 Scenario*. By construction, the purple bars can never exceed the green ones and a positive difference indicates that the investing party would be better off with a lump-sum ITC.

Table 4 summarizes the findings for the commercial-scale segment. In all of the states considered, the *ITC Choice Scenario* is the more attractive alternative as evidenced by the fact the purple bars are generally below the green ones. Because system prices for commercial-sized installations tend to be smaller in comparison to residential-sized systems, commercial investors would prefer 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.

The results for the utility-scale segment are displayed in Table 5 (c-Si) and Table 6 (CdTe). Like the commercial segment, the *ITC Choice Scenario* 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 be on par with wholesale electricity prices 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 prices, that is, the average wholesale price in the state, are expected to rise in real terms for all geographies considered.

Finally, our findings for the residential segment are summarized in Table 7. Because this segment has the highest system prices per Watt installed, we find that investors 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 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 LCOEs that are within 10 – 15% of the applicable retail rate in all of the states except for New Jersey. Beyond 2024, however, residential solar installations are projected to face "head-winds" in all of the five sample states, provided the federal ITC support were indeed to be eliminated entirely by the end of 2024 and no new state programs were to be enacted. This prediction is in large part a consequence of the EIA's (2014) report which, in contrast to the forecast for wholesale prices, predicts that residential retail rates will either stay constant or decrease in real terms (2014 dollars) over the next decade.

Table 4: *Alternative ITC Phase Down: Commercial Segment.*

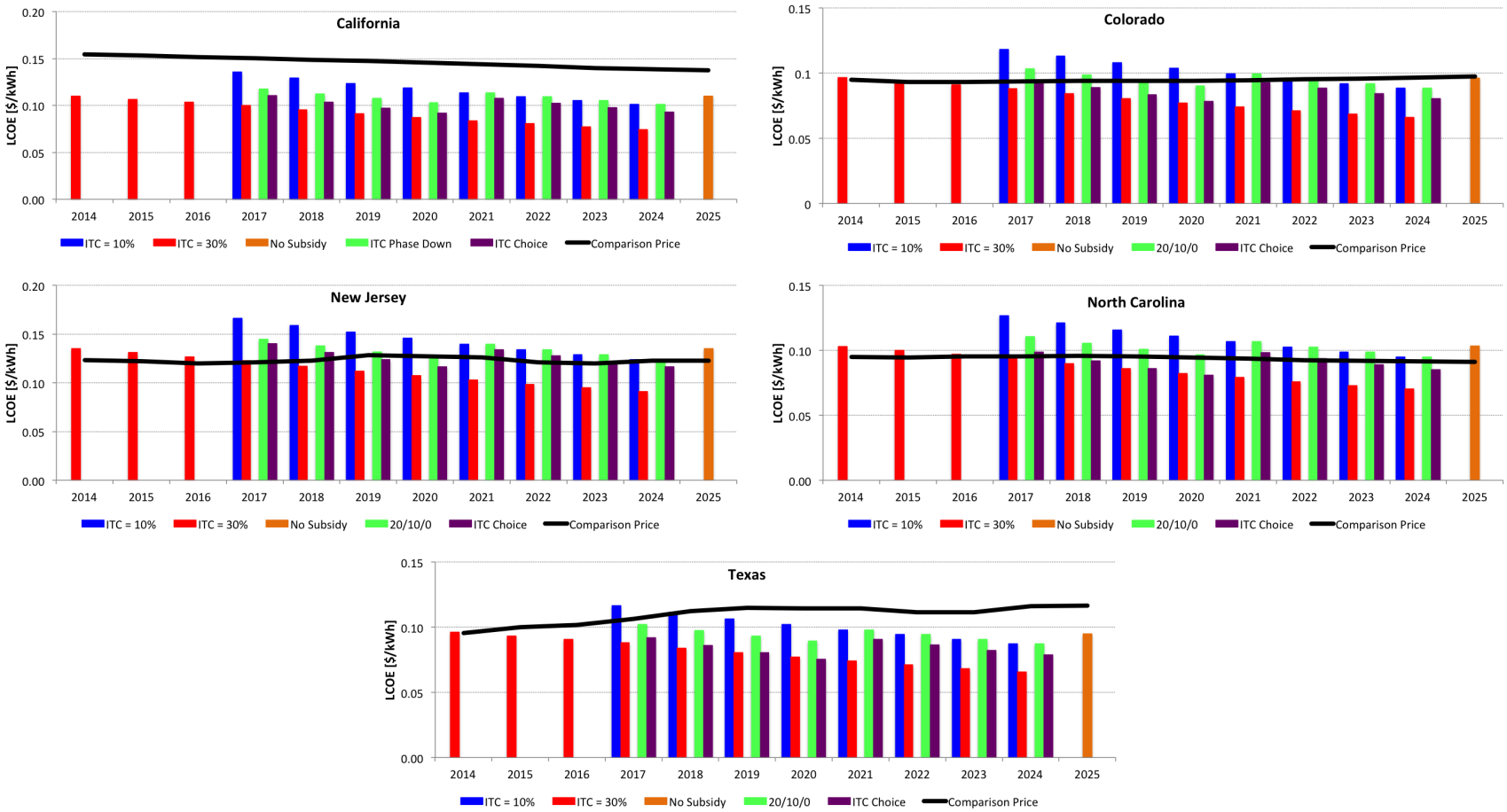


Table 5: *Alternative ITC Phase Down: Utility (1-axis, c-Si) Segment.*

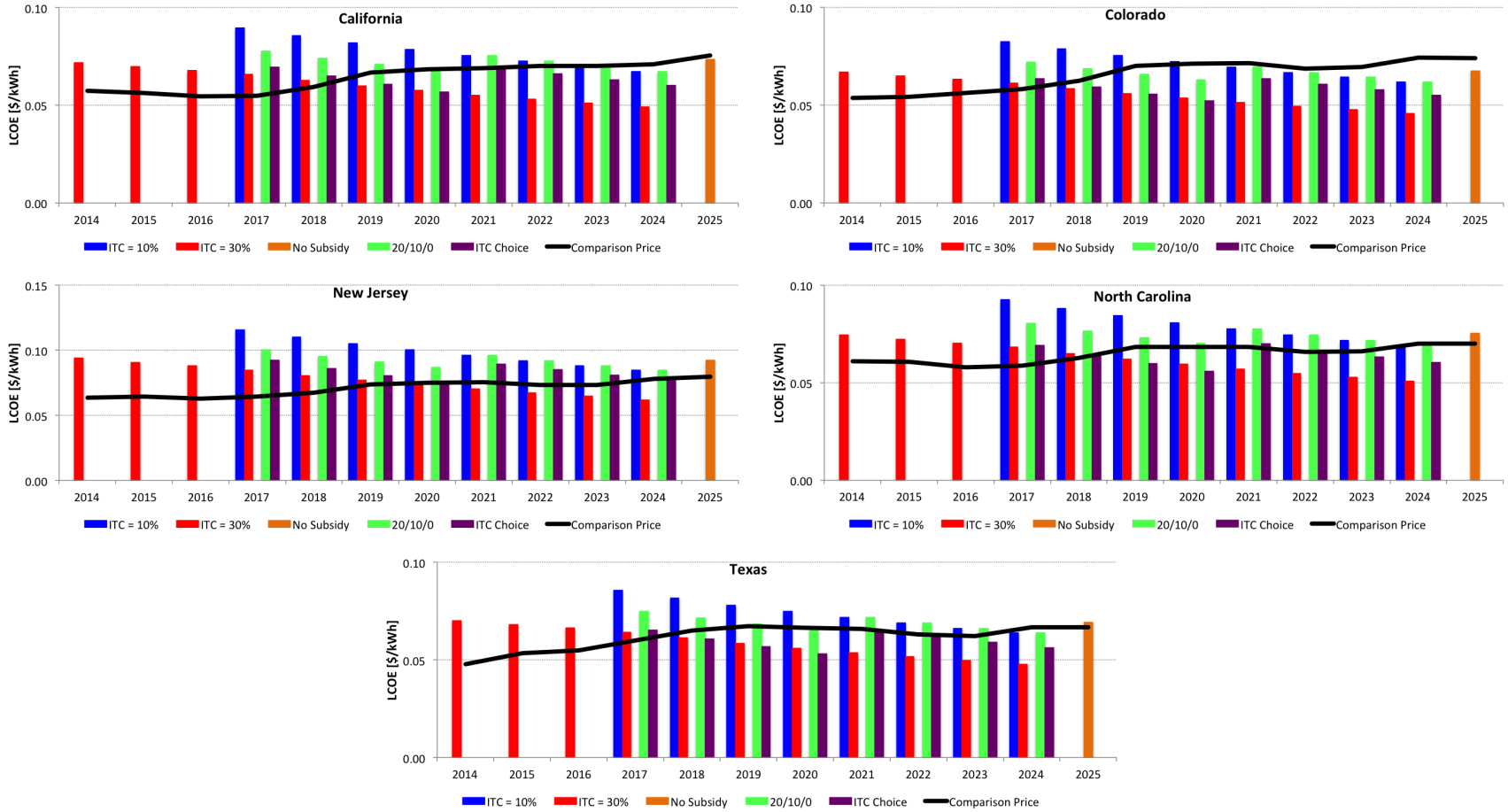


Table 6: *Alternative ITC Phase Down: Utility (1-axis, CdTe) Segment.*

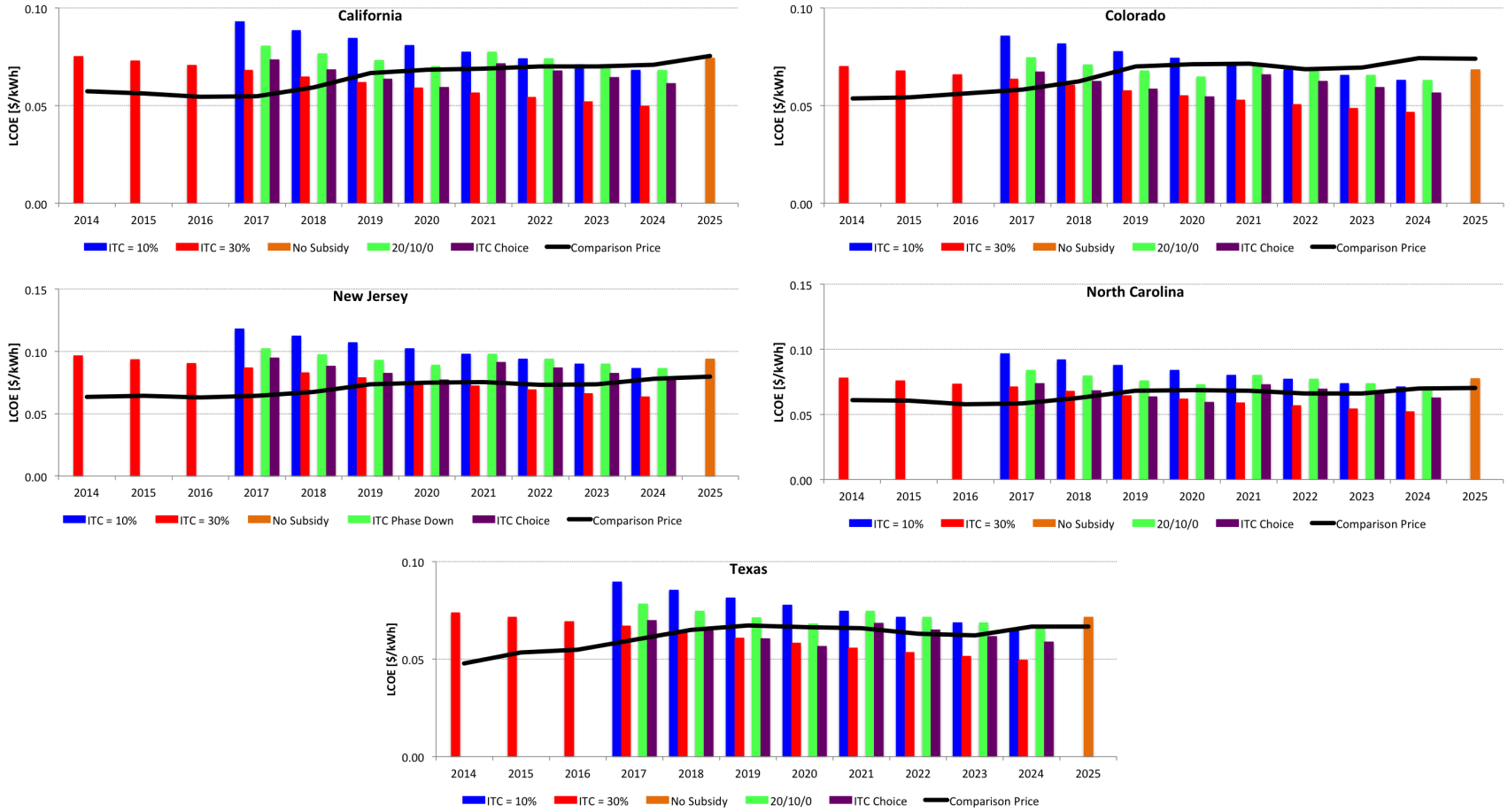
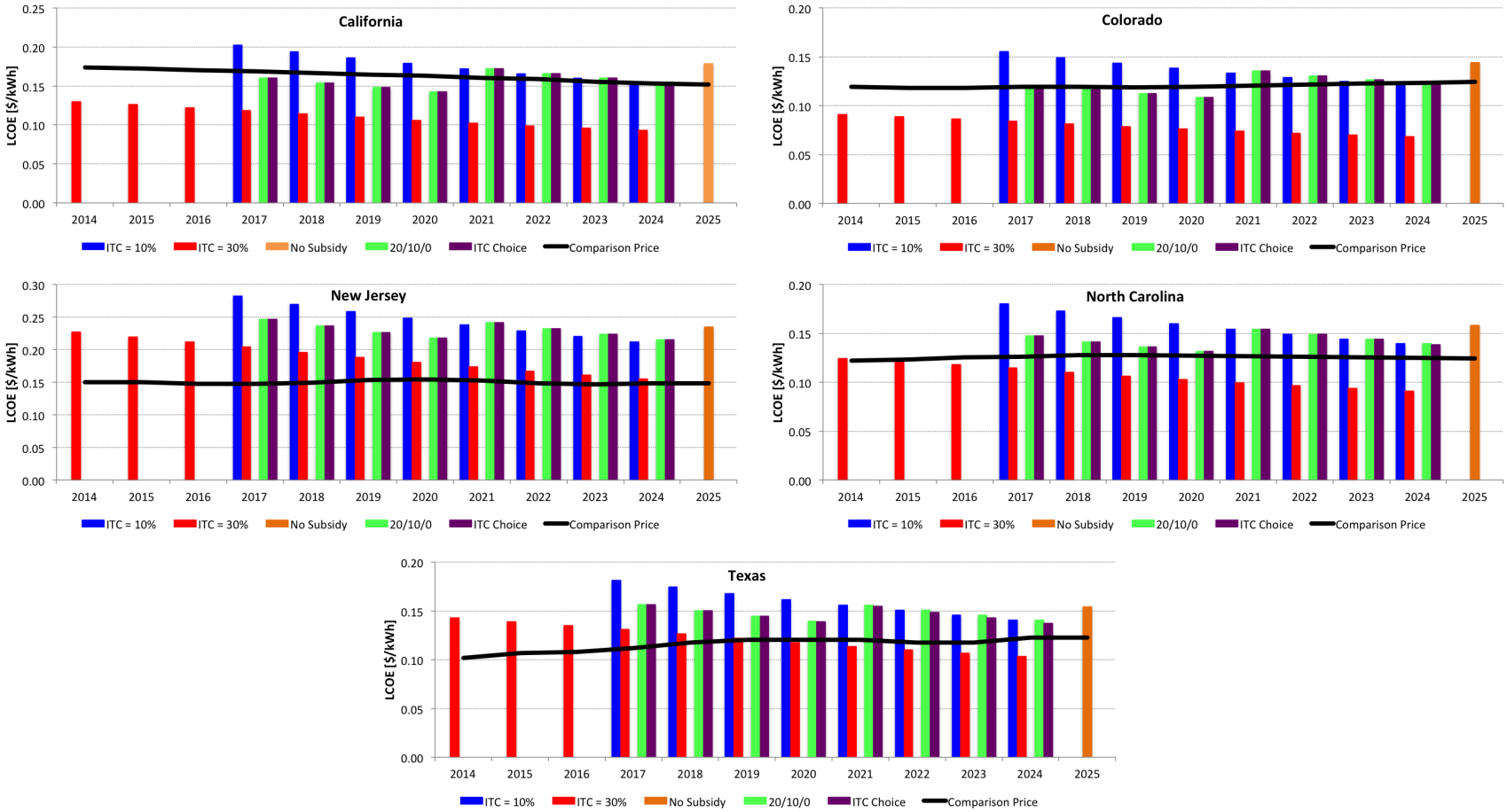


Table 7: *Alternative ITC Phase Down: Residential Segment.*



5 Sensitivity Analysis

Our analysis has derived a set of "point estimates" regarding the effectiveness of an alternative ITC policy, based on several working assumptions regarding the future progression of the solar PV industry. In this section, we conduct a partial sensitivity analysis focused on two key variables: the rate of improvement in the price of solar PV systems and the applicable cost of capital. By accessing the spreadsheet model, included as part of the Supplementary Data, the reader can perform additional robustness checks for other key variables in the model.

As demonstrated in Sections 2 – 4, the system price is by far the dominant LCOE component. Figure 3 examines the sensitivity of the LCOE to the assumed improvement rate for system prices. Assuming further the anticipated step-down in the ITC from 30% to 10% in early 2017, the plots in Figure 3 show the LCOE trajectory for three representative state/segment combinations. From left to right, the plots relate to Colorado residential, North Carolina commercial and California utility solar energy systems. In each plot, the baseline LCOE trajectory is compared to the LCOE trajectories that are obtained when the overall average annual system price reduction rates are set either more conservatively (red line) or more aggressively (green line). The conservative scenario assumes a rate of improvement that is one percent less than baseline, while the more favorable green line assumes a one percent higher than the baseline improvement rate.

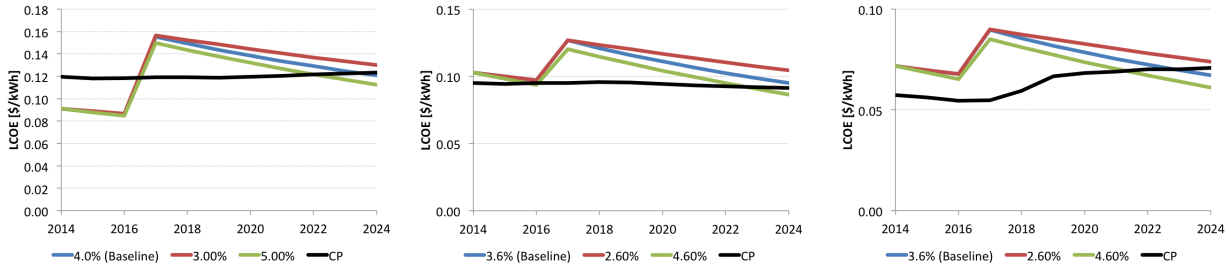


Figure 3: *Sensitivity of LCOE to improvement rate in system price. Current incentive policy shown for representative state/segments. From left to right: Colorado residential, North Carolina commercial, California utility scale.*

Due to compounding, the difference between the corresponding LCOE figures must widen over time. Nonetheless, the examples show that a 1% difference in the annual cost reduction

rate in the system price leads approximately to a cumulative 7 – 10% change in the LCOE over the entire decade. From that perspective, our policy conclusions appear fairly robust with regard to the rate of expected cost improvements. Similar results emerge for the other state/segment combinations considered in our analysis.

Figure 4 confirms that the LCOEs for solar installations are quite sensitive to the assumed cost of capital, owing to the fact that upfront capital expenditures account for a large share of the overall cost (Ardani et al., 2013; Lazard, 2014; BNEF, 2015). For instance, the LCOE for utility scale installations in California decreases from 7.18 to 6.52 ¢/kWh in 2014, as the assumed cost of capital drops from 8 to 7%. As a general rule, a 10% increase in the cost of capital triggers approximately a 8% increase in LCOE.

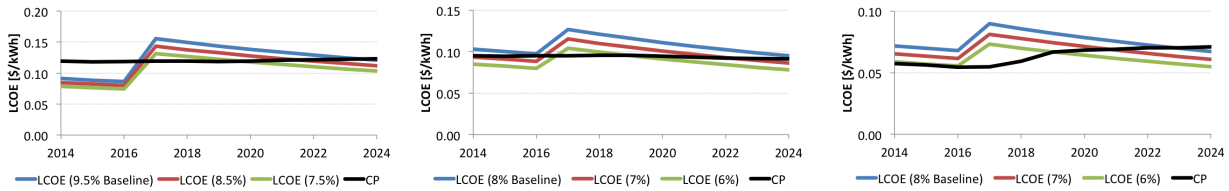


Figure 4: *Sensitivity of LCOE to assumed cost of capital. Current incentive policy shown for representative state/segments. From left to right: Colorado residential, North Carolina commercial, California utility scale.*

With regard to the overall conclusion of our study, Figure 4 indicates that even with a substantially lower cost of capital the anticipated step down in the ITC at the end of 2016 would make solar PV at least temporarily uncompetitive for the sample applications considered here. With a lower cost of capital, the alternative phase-down scenario described above would even be more effective in keeping solar PV at least close to competitive levels.

For the residential segment, our calculations were based on relatively high developer margins for certain states (North Carolina, Colorado and Texas). We recall that these margins (reflected in the parameter μ in Appendix B) reflect the markup from system cost to system price, which signifies what a third-party installer would need to charge if it were to sell a residential solar energy system. In this study, we have assumed constant margins over time. However, there is reason to believe that with the maturation of the residential solar market these margins will decrease over time similar to more competitive rates, such as those observed in California (Gillingham et al., 2014; Fthenakis, Mason, and Zweibel, 2009). Finally, there is an expectation amongst analysts that the cost of capital for residential

applications will decrease in the future as new financing mechanisms broaden the base of potential investors (Goodrich, James, and Woodhouse, 2012; Lux Research, 2013; Lazard, 2014).

6 Concluding Remarks

Current federal tax policy stipulates that at the beginning of 2017 the ITC for solar energy systems in the U.S. will drop from 30% to 10%, and remain at that level indefinitely. Our analysis has identified and evaluated an alternative policy scenario that would front-load federal tax support to the years 2017 – 2024, but in return eliminate the ITC for solar energy in its entirety post 2024. The main rationale for our alternative policy scenario is that the global solar PV industry continues to experience significant cost reductions and is poised to achieve "grid parity" within a decade. A sharp 20% decline in the ITC would likely result in a cliff at the beginning of 2017, yet federal tax support would continue indefinitely in years when it probably would no longer be needed.

Our analysis has evaluated the cost-competitiveness of solar energy systems across the three major segments of the solar PV industry in five sample states which collectively account for more than 65% of all solar capacity installations in the U.S. To project the impact of alternative tax policies, we have specified a dynamic that forecasts the reductions in solar system prices as a function of time. While our calculations are based on the assumption of continued and significant reductions in system prices and corresponding LCOE figures, we nonetheless conclude that an ITC step-down to 10% by early 2017 would render solar PV uncompetitive across the entire spectrum of applications considered in our study.

The alternative phase-down scenario examined in this paper would provide investors with a choice between an ITC calculated as either 20% of the system price or a lump-sum 40 cents per Watt for the years 2017-2020. This flexibility allows for more targeted incentives, as residential systems are likely to opt for the percentage-based ITC, while commercial- and utility-scale projects are likely to prefer the lump-sum tax credit. By phasing these incentives down to 10% and 20 cents per Watt, respectively, for the years 2021 – 2024, the resulting schedule of tax credits leads to LCOE figures that are in between those corresponding to the 10% and 30% ITC benchmarks.

Our findings indicate that for most of the applications considered here the diminishing ITC support would be just sufficient – with little or no margin to spare – to sustain the cost

competitiveness and current momentum of the solar industry. Furthermore, our numbers project that for most segments and locations the industry would be well positioned past 2024, even though our proposal envisions the complete elimination of the ITC in exchange for stronger incentives during the early phase from 2017 – 2020.

There are several promising avenues for extending the analysis in this paper. As noted in Section 2, the basic LCOE concept does not account for synergies between real-time electricity prices and the daily pattern of power generation by solar systems. Building on existing frameworks, it would be useful to quantify the magnitude of any synergistic effects for different locations. In future work, it would also be useful to refine the dynamic of future reductions in solar PV system prices, taking particularly into consideration that some components of the BOS costs are likely to change not only as a function of time but also the actual trajectory of new deployments in a particular location. Finally, our analysis has not attempted to "score" the alternative phase-down proposal in terms of tax revenues foregone by the U.S. Treasury. The general tradeoff here will be between lower tax revenues up to 2024 in exchange for permanent savings thereafter.

Appendix

Appendix A: Model Input Variables

Table A.1: *Comprehenisve 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	Panel price (DC)	\$/W
IP_i	Inverter price (DC) for segment i	\$/W
BOS_{ij}	Balance of system cost for segment i, US state j	\$/W
SC	System cost (residential)	\$/W
m	Transaction margin (residential)	%
SP	System price	\$/W
FMV	Fair market value of system	\$/W
μ	Ratio of FMV/SP	#
c	Unit capacity cost during	\$/kWh
F	Fixed operation and maintenance cost	\$/kW-yr
es	Operations and maintenance escalator	%
f	Average fixed operations and maintenance cost	\$/kWh
w	Variable operations and maintenance cost	\$/kWh
ρ	Consumer/rooftop"rental cost"	\$/kWh
r	Weighted average cost of capital	%
α	Effective corporate tax rate	%
Δ	Tax factor	#
p	Comparison/competitive market price of electricity	\$/kWh
i	Federal investment tax credit	%
ITC_{LS}	Lump-sum federal investment tax credit	\$/W

Tables A.2, A.3 and A.4 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 A.2: *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	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	*years*	30	30	30	30	30
Panel price, PP	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP	\$/W	0.40	0.40	0.40	0.40	0.40
Balance of system cost, BOS	\$/W	2.04	1.72	2.42	1.47	1.32
System cost (residential), SC	\$/W	3.16	2.83	3.53	2.58	2.43
Transaction margin, m	%	10	25	10	30	25
System price, SP	\$/W	3.47	3.54	3.89	3.35	3.04
Fair market value of system, FMV	\$/W	4.68	4.64	4.18	4.42	3.60
Ratio of FMV/SP, μ	#	1.35	1.32	1.08	1.32	1.19
Fixed operation and maintenance cost, F	\$/kW-yr	20.16	18.65	22.18	17.36	16.72
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Cost of capital, r	%	9.5	9.5	9.5	9.5	9.5
Average fixed operations and maintenance cost, f	\$/kWh	0.017	0.016	0.022	0.016	0.015
Consumer/rooftop "rental cost", ρ	\$/kWh	0.025	0.025	0.025	0.025	0.025
Unit capacity cost, c	\$/kWh	0.236	0.188	0.274	0.193	0.176
Tax factor, Δ	#	0.361	0.423	0.647	0.416	0.567
Levelized cost of electricity, $LCOE$	\$/kWh	0.127	0.120	0.224	0.122	0.139

Table A.3: *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	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	$years$	30	30	30	30	30
Panel price, PP	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP	\$/W	0.21	0.21	0.21	0.21	0.21
Balance of system cost, BOS	\$/W	1.30	1.10	1.49	0.99	0.93
System price, SP	\$/W	2.22	2.02	2.42	1.91	1.84
Fixed operation and maintenance cost, F	\$/kW-yr	19.09	17.74	20.88	16.06	16.03
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Cost of capital, r	%	8.0	8.0	8.0	8.0	8.0
Average fixed operations and maintenance cost, f	\$/kWh	0.016	0.015	0.020	0.016	0.015
Unit capacity cost, c	\$/kWh	0.132	0.118	0.164	0.125	0.117
Tax factor, Δ	#	0.708	0.707	0.708	0.707	0.706
Levelized cost of electricity, $LCOE$	\$/kWh	0.110	0.098	0.137	0.104	0.097

Table A.4: *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	%	99.3	99.5	99.5	99.3	99.3
Useful economic life, T	$years$	30	30	30	30	30
Panel price, PP	\$/W	0.71	0.71	0.71	0.71	0.71
Inverter price, IP	\$/W	0.14	0.14	0.14	0.14	0.14
Balance of system cost, BOS	\$/W	1.11	1.01	1.19	0.92	0.89
System price, SP	\$/W	1.97	1.86	2.05	1.77	1.75
Fixed operation and maintenance cost, F	\$/kW-yr	16.83	15.65	18.39	14.65	14.15
Effective corporate tax rate, α	%	43.8	39.6	44	41	35
Cost of capital, r	%	8.0	8.0	8.0	8.0	8.0
Average fixed operations and maintenance cost, f	\$/kWh	0.011	0.010	0.014	0.011	0.10
Unit capacity cost, c	\$/kWh	0.089	0.083	0.111	0.093	0.088
Tax factor, Δ	#	0.708	0.707	0.708	0.707	0.706
Levelized cost of electricity, $LCOE$	\$/kWh	0.074	0.069	0.093	0.077	0.072

Appendix B: LCOE for Residential Installations

LCOE is defined as the average revenue per kWh that must be obtained in order to break-even on a new energy system. Therefore, the tax factor, Δ, in equation (1) can be expressed as:[19]

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

where

- i : investment tax credit (in %),
- α : 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 %),
- δ: "capitalization discount", equal to 0.5 under current federal tax rules.[20]

We now present two modifications to the LCOE calculation in (1) and (2). Both modifications apply only to the LCOE for the residential installations, owing to the fact that the majority of residential solar energy systems are installed by developers who are also the principal investors in the project. From this perspective, the homeowner effectively rents out the space on his rooftop in return for a fee. For an investor/developer the system price (SP) represents the acquisition cost of the system which is generally below the fair market value (FMV) as assessed by independent appraisers. This difference arises because the appraiser may apply an income approach, rather than a cost approach, to valuing the energy system. One may view the difference between the two figures as the profit margin of the developer/investor.[21] Accordingly, we define:

$$FMV \equiv \mu \cdot SP,$$

[19]See Reichelstein and Yorston (2013) for a detailed derivation.

[20]The tax code effectively stipulates that if an investor claims a 30% ITC, then for depreciation purposes only 85% (=[1 − 30%] · 0.5) of the system price can be capitalized for tax purposes.

[21]See SolarCity (2014) for further elaboration on this point.

with $\mu > 1$. Since the federal tax code allows the ITC and subsequent depreciation tax shields to be calculated based on the FMV, the tax factor in (6) for residential systems becomes:

$$\Delta_{res} = \frac{1 - \mu\Big(i - \alpha \cdot (1 - \delta \cdot i) \cdot \sum_{t=1}^{T^0} d_t \cdot \gamma^t\Big)}{1 - \alpha},$$

We note that since $\mu > 1$, the resulting tax factor will be more sensitive to a drop in i, which denotes the ITC percentage. In particular, as noted in Section 2, the LCOE of residential systems will *ceteris paribus* increase by a higher percentage when the ITC decreases from 30% to 10%.

The second modification of the LCOE formula in connection with residential systems relates to the compensation paid to homeowners on whose roof the system is installed. If the homeowners enters a power purchasing agreement (or leasing arrangement) with the investor/developer at some rate, and via net metering effectively sells electricity to the utility at a higher retail rate, the difference between the two rates effectively becomes the rooftop rental cost that the investor/developer pays to the homeowner. Accordingly, the expression for the LCOE in (1) is modified

$$LCOE_{res} = f + c \cdot \Delta_{res} + \rho,$$

where ρ denotes the rooftop "rental cost" (in \$ per kWh).

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