Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities

Alan Goodrich, Ted James, and Michael Woodhouse

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-6A20-53347
February 2012

Contract No. DE-AC36-08GO28308

Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities

Alan Goodrich, Ted James, and Michael Woodhouse

Prepared under Task No. SS12.2250

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401
303-275-3000 • www.nrel.gov

Technical Report
NREL/TP-6A20-53347
February 2012

Contract No. DE-AC36-08GO28308

NOTICE

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/help/ordermethods.aspx

Cover Photos: (left to right) PIX 16416, PIX 17423, PIX 16560, PIX 17613, PIX 17436, PIX 17721

Printed on paper containing at least 50% wastepaper, including 10% post consumer waste.

ANALYSIS DISCLAIMER AGREEMENT

These cost model results (“Data”) are provided by the National Renewable Energy Laboratory (“NREL”), which is operated by the Alliance for Sustainable Energy LLC (“Alliance”) for the U.S. Department of Energy (the “DOE”).

It is recognized that disclosure of these Data is provided under the following conditions and warnings: (1) these Data have been prepared for reference purposes only; (2) these Data consist of forecasts, estimates or assumptions made on a best-efforts basis, based upon present expectations; and (3) these Data were prepared with existing information and are subject to change without notice.

The names DOE/NREL/ALLIANCE shall not be used in any representation, advertising, publicity or other manner whatsoever to endorse or promote any entity that adopts or uses these Data. DOE/NREL/ALLIANCE shall not provide any support, consulting, training or assistance of any kind with regard to the use of these Data or any updates, revisions or new versions of these Data.

YOU AGREE TO INDEMNIFY DOE/NREL/ALLIANCE, AND ITS AFFILIATES, OFFICERS, AGENTS, AND EMPLOYEES AGAINST ANY CLAIM OR DEMAND, INCLUDING REASONABLE ATTORNEYS' FEES, RELATED TO YOUR USE, RELIANCE, OR ADOPTION OF THESE DATA FOR ANY PURPOSE WHATSOEVER. THESE DATA ARE PROVIDED BY DOE/NREL/ALLIANCE "AS IS" AND ANY EXPRESS OR IMPLIED WARRANTIES, INCLUDING BUT NOT LIMITED TO, THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE ARE EXPRESSLY DISCLAIMED. IN NO EVENT SHALL DOE/NREL/ALLIANCE BE LIABLE FOR ANY SPECIAL, INDIRECT OR CONSEQUENTIAL DAMAGES OR ANY DAMAGES WHATSOEVER, INCLUDING BUT NOT LIMITED TO CLAIMS ASSOCIATED WITH THE LOSS OF DATA OR PROFITS, WHICH MAY RESULT FROM AN ACTION IN CONTRACT, NEGLIGENCE OR OTHER TORTIOUS CLAIM THAT ARISES OUT OF OR IN CONNECTION WITH THE USE OR PERFORMANCE OF THESE DATA.

Executive Summary

The price of photovoltaic (PV) systems in the United States (i.e., the cost to the system owner) has dropped precipitously in recent years, led by substantial reductions in global PV module prices. However, system cost reductions are not necessarily realized or realized in a timely manner by many customers. Many reasons exist for the apparent disconnects between installation costs, component prices, and system prices; most notable is the impact of Fair Market Value considerations on system prices. To guide policy and research and development strategy decisions, it is necessary to develop a granular perspective on the factors that underlie PV system prices and to eliminate subjective pricing parameters. This report's analysis of the overnight capital costs (cash purchase) paid for PV systems attempts to establish an objective methodology that most closely approximates the book value of PV system assets.

The analysis shows the following benchmark 2010 U.S. PV system prices (cash purchase, before subsidy and considering reported target installer operating overhead and profit margins):[1]

- \$5.71/$W_{P\,DC}$ – 5 $kW_{P\,DC}$ residential rooftop
- \$4.59/$W_{P\,DC}$ – 217 $kW_{P\,DC}$ commercial rooftop
- \$3.80/$W_{P\,DC}$ – 187.5 $MW_{P\,DC}$ fixed-axis utility-scale ground mount
- \$4.40/$W_{P\,DC}$ – 187.5 $MW_{P\,DC}$ one-axis utility-scale ground mount.

Significant variation (standard deviations of 5%–8%) exists in these estimates due to regional and site-specific cost factors. Most notable is the impact that the wide range of U.S. labor rates and installer productivity (experience) factors can have on installation costs. This uncertainty analysis excluded the impact of system size, which can also play a significant role in determining installed system prices.

Although the cost structure of PV systems designed for use in each market segment are very different, module price and performance remains a significant opportunity for future cost reductions across all PV sectors. In addition to the expected evolutionary cost reductions at the module level (price and efficiency enhancement), advanced installation methods, such as unitized construction techniques, are expected to provide considerable installation labor and materials-related cost benefits by 2020. As the U.S. market matures, competition among installers, as well as improved supply chain and regulatory costs, will likely contribute to significant cost reductions by 2020. This dynamic has been observed in the German PV market. The analysis shows the following 2020 evolutionary PV system price estimates, which are compared with the price targets for 2020 set under the U.S. Department of Energy's SunShot Initiative:

- \$2.29/$W_{P\,DC}$ – 5 $kW_{P\,DC}$ residential rooftop
  (SunShot target: \$1.50/$W_{P\,DC}$)
- \$1.99/$W_{P\,DC}$ – 217 $kW_{P\,DC}$ commercial rooftop
  (SunShot target: \$1.25/$W_{P\,DC}$)

[1] $W_{P\,DC}$ = peak watt of direct-current capacity.

- $1.71/ $W_{P\ DC}$ – 187.5 $MW_{P\ DC}$ fixed-axis utility-scale ground mount (SunShot target: $1.00/$W_{P\ DC}$)
- $1.91/ $W_{P\ DC}$ – 187.5 $MW_{P\ DC}$ one-axis utility-scale ground mount (*modified*-SunShot target: $1.20/$W_{P\ DC}$).

As these results show, the evolutionary estimates of U.S. PV system prices fall short of the 2020 SunShot targets. This highlights the challenges that remain before solar energy can compete with incumbent electricity technologies without subsidy.

Table of Contents

List of Figures

List of Tables

1. Introduction

Unlike traditional energy-production technologies that have ongoing consumables costs, nearly all of the costs for photovoltaic (PV) systems must be paid at the beginning. Reducing those initial capital costs is crucial to reducing the cost of solar electricity. In addition to module price, many factors contribute to the price of a PV system, including installation labor, power electronics, permitting and other regulatory costs, and—in the case of ground-mount systems—site acquisition and preparation costs.

Under its SunShot Initiative, the U.S. Department of Energy (DOE) has established very aggressive system price targets for each of the three major PV market sectors: residential rooftop, commercial rooftop, and utility-scale ground mount. Achieving these targets will require total system cost reductions of approximately 75% by 2020. Industry stakeholders must understand the ever-changing PV system cost structure. As module prices continue to fall, the contribution of non-module costs to the cost of solar energy will increase. There are also critical relationships between system components, such as the relationship between module conversion efficiency and non-module area-related costs and the relationship between module configuration and installation methods. Research and development (R&D) managers, policymakers, system installers, and component manufacturers must understand the current cost of PV systems in adequate detail to allocate effectively the resources needed for further cost reductions and to design effective market policies. The resolution into PV system price drivers that is required for these decisions is difficult to attain from surveys of system prices, or by retrospective means. Results deviate based on regional, installer, and job-specific details, making accurate price comparisons between systems very difficult, unless conducted from the bottom up.

This report presents detailed, bottom-up 2010 benchmark system prices for residential and commercial rooftop systems and utility-scale ground-mount systems. These results are intended to depict the installed price[2] for U.S. PV systems in the second half of 2010, i.e., the unsubsidized cost (cash purchase) of the system from the owner's perspective. For each system type, the major cost drivers are identified, and the sensitivities to key assumptions (e.g., module efficiency, system scale) are presented.

Following the benchmark system price analysis, this report presents results of a bottom-up analysis of potential PV system price reductions through 2020, assuming an evolutionary path of technological and market improvement. These projections are compared with the 2020 system price targets established under the SunShot Initiative. The difference between the evolutionary projections and SunShot targets highlights the need for innovative system designs and installation methods to complement module-level cost reductions.

[2] Note: *installed system price* here refers to the overnight capital cost, or cash purchase price, for a system installed in the second half of 2010 (the period for which cost data underlying the model were provided).

2. PV System Price Metrics: Fair Market Value vs. Bottom-up Analysis

PV system prices are often characterized using Fair Market Value (*market price*), but this metric does not provide the resolution necessary for understanding system price drivers. Thus, the National Renewable Energy Laboratory (NREL) developed a bottom-up price analysis methodology—which is used to generate the results in this report—to provide the necessary resolution. The *market price* and bottom-up approaches are described below.

2.1. Fair Market Value

PV system prices reported to incentive programs, such as the California Solar Initiative (CSI), reflect the systems' Fair Market Value, which is subject to market dynamics. By definition—whether one relies on income, residual value, or some other methodology—Fair Market Value introduces subjectivity to the estimate, i.e., it depends on a customer's willingness to pay a certain price based on personal preferences and market dynamics.[3] Trends in system prices do not necessarily reflect trends in system costs, but rather the perception by willing and knowledgeable customers, who are under no compulsion to buy, of the value offered by a PV system.

The income-based Fair Market Value methodology, for example, establishes the value of a PV system based on the capitalization of the expected cash flows from that asset. The value of PV systems, as reported to many incentive programs and by Barbose et al. (2011), for example, generally reflects the difference between solar electricity costs and local offset electricity rates, net of any investment- or production-based incentives, state renewable energy credits (RECs), tax credits, and financial contracts (e.g., power purchase agreements [PPAs]). Progress in cost-reduction efforts does not necessarily impact the Fair Market Value of PV systems. In addition, a time lag between system cost reductions and system prices may exist owing to market dynamics.

Surveys of reported system prices show that the price of PV modules—the most expensive component in a PV system—has decreased sharply in recent years, but the total cost of systems has not fallen as quickly (Barbose et al. 2011). Between 2008 and 2010, the global price of PV modules decreased by approximately \$1.36 per peak watt of direct-current (DC) capacity ($W_{P\,DC}$; capacity-weighted average) (Mints 2010), while U.S. PV system (capacity weighted) prices fell by \$1.38/$W_{P\,DC}$ (Barbose et al. 2011). However, Barbose et al. (2011) also report that U.S. non-module system costs fell by \$0.60/$W_{P\,DC}$ during that same period. Therefore, nearly \$0.60/$W_{P\,DC}$ of global module price reduction does not appear to have impacted U.S. system prices.

Multiple factors may contribute to this apparent disconnect between module and total system price trends. Prices for modules and systems are largely based on different supply and demand dynamics. Module prices may be more dependent on global factors impacting manufacturing costs, while the remaining system costs depend on the regional installation experience base (i.e., installer productivity), wage rates, and regulatory costs.

[3] Fair market value (definition): value that an asset could be sold for (or an obligation discharged) in an orderly market, between willing buyers and sellers; often, but not always, it is current market value (Easton et al. 2010).

Delays in the supply chain may also contribute to a delay in module price declines being realized. Retail sales channels may include inventory changeover time at multiple distribution nodes in the supply chain. A reduction in the ex-factory gate module price, therefore, may not reach retail customers until other inventory has been sold, or written down. In utility markets, the construction period for large projects may be as long as three years. During this time, the price of modules may fall significantly. Typically, the engineering, procurement, and construction (EPC) entity will build into the project price a hedge against changing material costs. These derivative instruments mitigate, but do not eliminate, volatile price fluctuations in key materials, like modules. Over the course of the construction period, as module prices change, there may be only a limited pass through to the customer; installed module prices may lag current module prices by several months, depending on the rate of price decline and the terms of the procurement contract. Over the past two years, the rate of module price change has been rapid enough that a delay in delivery from factory to installer of only one quarter could be enough to account for, in some cases, nearly $0.34/W$_{P\ DC}$ at the installed system price (Mints 2010).

Throughout the remainder of this report, Fair Market Value PV system prices are referred to as *market prices* – a term that is intended to be synonymous with Fair Market Value.

2.2. Bottom-up Analysis

Because of the limited usefulness of *market price* for understanding PV system price drivers, this report uses a highly detailed and transparent bottom-up analysis of installed PV system prices developed by NREL, in collaboration with industry, relying on methods frequently employed by U.S. solar project developers. This methodology characterizes the unsubsidized cash purchase price of PV systems, an objective measure that most closely approximates the *book value* of an asset. The methodology includes all materials, labor, overhead and profit (O&P), land acquisition and preparation costs, and regulatory costs for a PV system up to the point of grid tie-in (e.g., for utility-scale PV, it includes substation but excludes transmission infrastructure). The detailed results can be used to guide R&D efforts aimed at reducing PV system prices and to understand the potential benefits of proposed technological improvements.

3. Bottom-up Installed System Price Analysis: 2010 Benchmark

The PV industry generally consists of three market segments: residential rooftop, commercial rooftop, and ground-mount utility-scale systems. The analyses in this report show price structures across the full spectrum of PV system sizes and complexities, from small (residential) rooftop systems to large (utility-scale) ground-mount systems. Section 3.1 discusses assumptions used in the analyses. Sections 3.2–3.4 show benchmark (2010) system prices for the three PV market segments, and Section 3.5 summarizes the benchmark prices for all market segments.

3.1. Analysis Assumptions

For each system, a bill of materials (BoM) was developed based on NREL's review of completed PV projects. The BoM informs not only material-related cost estimates, but also installation labor requirements. In some cases, material categories are presented in aggregate for illustration purposes. The category "wiring," for example, contains many subcomponents that range from wire and conduit to electrical connectors, excluding installation labor. Wiring materials may be further broken into two categories: DC and alternating-current (AC) materials. DC wiring consists of all components that make up the electrical pathway from the module up to, but excluding, the inverter. Wiring from the modules to the combiner box may be completed by general or carpentry labor. Beyond the combiner box—the handoff point—electrician labor is typically required. Skilled, electrician labor is generally required for AC wiring, which consists of all components and the electrical pathway that follows the inverter but excludes utility substation components. In this analysis, for utility-scale PV, the substation and grid tie-in costs are included as a component of "Permitting and Commissioning" costs.

A markup on the ex-factory gate price for module components is included for each of the three market sectors based on the typical installer supply chain costs and project overhead rates. The typical residential installer portrayed in this analysis purchases all materials through retail sales channels, incurring a 10% markup on ex-factory gate module prices. Larger commercial rooftop installations, which often use materials purchased through wholesale channels, incur a 5% markup. The utility-scale installer is modeled as if that company also acts as the EPC contractor for the project, as is becoming increasingly common in this market segment. As a result, no markup on ex-factory gate module price is assumed for utility-scale systems.

For simplicity, project overhead rates—which include interest during construction, inventory, and project-contingency costs—are rolled into a further markup on all materials, including modules. NREL has observed that these costs can vary widely from project to project, based on differences in regional and project-specific costs. Based on conversations with installers and a review of detailed project cost data, it is estimated that the typical residential installer passes through a markup of up to 30% on the retail price for all materials to cover the project-related costs described above. Owing to economies of scale and more efficient supply chains, commercial projects incur a 20% markup and utility-scale projects a 10% markup for the same materials and supply chain related costs.

All labor costs are calculated using U.S. national average wage rates and standard burden rates,[4] including payroll taxes, insurance and retirement benefits, and liability insurance as well as operating overhead costs that vary by market sector, installer size, and experience. The operating overhead rate in 2010 assumed for residential installers (54%) reflects not only the size of the firm, but also its experience in preparing and completing PV system designs and regulatory filings (e.g., building and electrical permits). As PV system design experience increases, installers likely will be able to prepare the necessary drawings and permits more efficiently. Moreover, as the size of the installer and number of PV jobs performed increases, certain overhead costs, such as the cost of trips to the permitting office, also will be reduced (i.e., amortized over more PV jobs).

Commercial rooftop installations may be completed by independent installers or vertically integrated companies. Owing to the size of these rooftop systems, the operating overhead costs incurred by the installer are typically less than for residential systems: approximately 32%, as reported to NREL by collaborating installers. Utility-scale installations generally have lower overhead costs than rooftop installations largely owing to economy-of-scale benefits as well as standardized ground-mount system designs. In 2010, the typical installer operating overhead rate for the utility-scale PV sector (22%), as observed by NREL, more closely approximates that of a mature U.S. electrical contractor (16%) whose annual billings exceed $4 million (RS Means 2010).

Because the levelized cost of energy (LCOE, in $/kWh) generated by the PV system is one of the most relevant competitive benchmarks, it is necessary to also include an estimate of the installer's profit margin, i.e., to calculate the price paid by the system owner, rather than simply the cost to install. Installers of residential systems tend to target a margin of 30%[5] on all installation labor services (costs), which is nearly triple the margin of contractor services in analogous, but more mature industries.[6] In addition to the significant impact of *market price* — the price a customer is willing to pay for solar energy—installer experience and market maturity (competition) can influence available margins heavily. A lack of residential installer competition in a geographic region may contribute to these higher-than-expected installer margins. Also, the accuracy with which rooftop systems are quoted can be limited by the installer's experience. Residential installers have reported to NREL that unexpected rooftop or building features, weather delays, and permitting delays often contribute to relatively large margins of error between a prepared quote and the realized project cost. To achieve an acceptable average gross margin, installers may account for these uncertainties by targeting higher margins. As a residential installer's experience and local competition both increase, it will benefit the installer to improve quotation accuracy and tighten the targeted profit margin. Installers of commercial rooftop PV systems target lower margins (approximately 20%) owing to differences in company and project size.

[4] A breakdown of burdened labor rates is as follows: worker's compensation insurance, 6.4%; federal and state unemployment insurance, 6.2%; Social Security taxes (FICA), 7.65%; builder's insurance, 0.44%; and public liability insurance, 2.02% (RSMeans 2010).

[5] Installer margin is considered a markup on labor costs only. Materials are marked up separately based on channel-to-market costs and project-related costs (contingency, inventory, interest during construction, etc.).

[6] The average U.S. electrical contractor (annual billings > $4 million) profit margin is 10% (RSMeans 2010).

The EPC entities for utility-scale PV systems tend to target a profit margin on installation labor that is more representative of mature contractor service industries (~10%). The difference in target profit margin between utility and residential market segments reflects not only a difference in system scale, but also competing electricity costs. Utility-scale systems are often installed to help a utility meet state renewable energy production goals. These goals, along with peak power demand (pricing) and project alternatives, contribute to the negotiated PPA price signed between a utility and the system owner. Depending on the specifics of this contract, the price that the system owner is willing to pay may vary, impacting the EPC entity's profit margin.

In the United States, utility-scale PV system EPC contractors, who are often the module manufacturers, may use a far more standardized installation system than is found in most residential rooftop applications. This standardization will lead to more favorable volumetric pricing for materials and improved installation (labor) efficiencies. SunPower, for example, has estimated that savings from the company's standardized Oasis Powerblock design may be as high as 25% over traditional one-off system designs (Campbell 2011a).

In the same way that standardization (i.e., economies-of-scale and experience-related cost reduction) has lowered the cost of module manufacturing, the opportunity associated with standardized systems is critical to future PV system cost reductions. For many years, the price of modules has followed a well-documented learning curve of a 20% reduction for every doubling of global module shipments (see Appendix C). A module manufacturer benefits from the shared knowledge and experience gained at all of its global factories (Nemet 2006). For example, First Solar has often touted the benefits of its Copy Smart production approach, which includes standard process and facility designs. In this approach, a manufacturing improvement developed at a facility in one country can more easily be implemented at a firm's other facilities, regardless of geographic proximity, because of standardized production methods and equipment. PV installations, on the other hand, generally require a system design customized to rooftop or ground-site features, local regulatory requirements, and customer preferences. This level of specialization, along with the more disaggregate nature of the PV installation business, results in very little sharing of knowledge across companies or geographies and limits experience-based cost-reduction opportunities. As the market matures, component manufacturers standardize system designs for utility-scale and rooftop applications, and installer best practices are shared, it is expected that immediate cost reductions similar in magnitude to the learning-curve benefits experienced by module manufacturers will be possible.

3.2. Residential Rooftop PV Systems: 2010 Benchmark Prices

Rooftop PV systems are often categorized into two discrete market segments—residential and commercial—based on the type of building on which they are installed. Generally, these markets are defined by electricity rates, PV system sizes, and rooftop slopes. In the United States, residential PV systems are generally 2–10 $kW_{P\ DC}$ and installed on sloped roofs, while commercial systems may be between 10 $kW_{P\ DC}$ and multi-megawatts and are most often installed on flat or low-slope roofs.

For the purposes of this comparison, NREL modeled a typical residential rooftop with 35 m^2 of total available space that is well suited for PV.[7] The baseline system includes 27 crystalline

[7] For background about PV-suitable spaces on residential rooftops, see Paidipati et al. (2008).

silicon (c-Si) modules (0.808 m × 1.580 m) installed in a portrait orientation using through-roof mounts and a standard rail mounting structure. The median c-Si module considered provides 14.5% conversion efficiency, producing approximately 185 $W_{P\,DC}$ per module, resulting in a system size of ~5 $kW_{P\,DC}$. The algorithms used by NREL to estimate racking, wiring, and wiring-subcomponent requirements are based on guidance from collaborating residential system installers and consider module orientation, row-to-row and module spacing, string size, and building code parameters.

For each material category, subcomponent price and installation labor requirements were estimated using a project cost estimation tool designed by NREL in cooperation with installers. The estimates of direct labor costs are sensitive to changes to independent variables such as module efficiency, module and string size, and other system design parameters. The general set of PV system components (depicted in Figure 1) can vary substantially depending on regional and local building or utility requirements; the variable number of AC/DC disconnects is one example (Coddington et al. 2008). In the baseline residential system design profiled here, there is one standalone AC disconnect in addition to the disconnect components that are integral to the inverter and breaker box components.

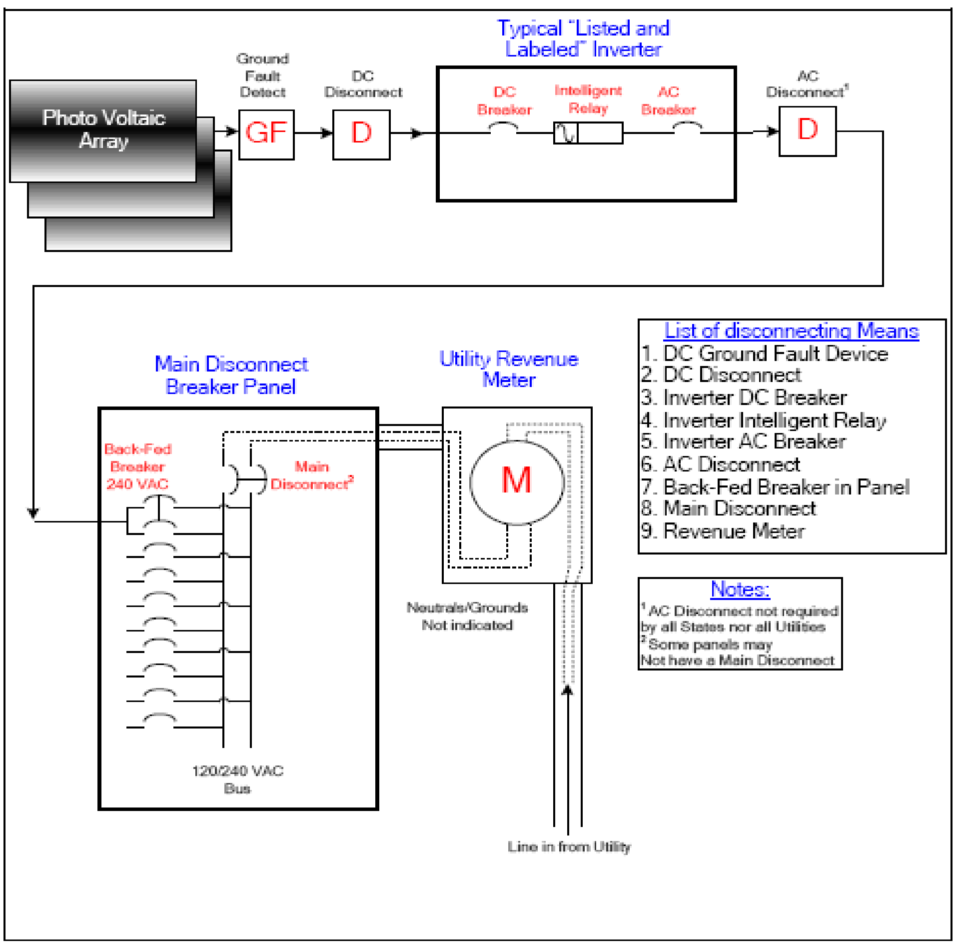

Figure 1. Schematic of a grid-connected rooftop PV system (Coddington et al. 2008).

It is assumed that nearly all non-mounting hardware components that constitute a residential PV system require skilled electrical labor, although this requirement may vary by region or state. The national average electrical contractor wage rate is $49.00/hr, before insurance and benefits, while the average wage rate for a roofer is approximately $33.00/hr (RS Means 2010). At these rates, and with the estimated labor requirements per unit, the cost to install a PV system's electrical components is estimated to be around $1,261 ($0.26/W$_{P\ DC}$). Despite a lower cost per hour for unskilled labor, and owing to the time required to install through-roof hardware, the cost to install the non-electrical (hardware) components is approximately $1,321 ($0.27/W$_{P\ DC}$). Table 1 shows the benchmark system parameters, including labor requirements by component.

Table 1. Benchmark 2010 Residential PV System Parameters (35 m^2 system area, 27 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[8] (per W$_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$2.15[9]	27	Modules	0.20	
Inverter	$0.42	1	Inverters	4.0	2.0
Wiring	$0.03	237[10]	Linear ft	0.05	
Other electrical[11]	$0. 19	1	Electrical subsystem	4.5	
Mounting hardware	$0.37	27	Modules		1.40
	$3.16				
Total Installation Labor Requirements (hr/system):				25.7	39.9

When markups for the applicable labor burden (22.7%), profit (30%) and operating overhead (54%) on labor are added to the base wage rates, the full cost of labor for this residential PV system is estimated to be $6,345 ($1.27/W$_{P\ DC}$). Installer profit and operating overhead rates contribute approximately $0.29/W$_{P\ DC}$ and $0.34/W$_{P\ DC}$ to this estimate, respectively. By reducing the profit and operating overhead rates to reflect those of a more mature service business, e.g., electrical contractor services, the total labor costs could be reduced from $1.27/W$_{P\ DC}$ to $0.81/W$_{P\ DC}$, and the total system price could be reduced by approximately 8%.[12]

[8] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[9] $1.95/W$_{P\ DC}$ ex-factory gate module price (Knoll and Siemer 2010) × (1 + 10% retail markup) = $2.15/W$_{P\ DC}$.
[10] Total wiring (237 linear ft) = home run wiring (77 ft) + row to combiner wiring (160 ft).
[11] Other electrical includes meter, system monitor, and disconnects.
[12] Assumes installer operating overhead (54%) and profit (30%) are reduced to 16% and 10%, respectively, according to the national average overhead and profit rates for electrical contractors (RSMeans 2010).

The project's "soft costs," which include local building and utility-mandated permit fees, are estimated to contribute around 3% to the total system price. The labor costs associated with permitting paperwork and regulatory filings are included in the installer operating overhead rate (54%) described previously. In some locations, it has been reported that utility "commissioning fees" may also apply to rooftop systems. These fees, which can range from $900 to $2,000 per system, may include upgrades to existing (building) electrical infrastructure or the addition of net-metering components.

The analysis results in a total installed price for a benchmark 2010 residential PV system of \$5.71/ $W_{P\,DC}$. Figure 2 shows the price breakdown by element. Modules contribute the most to the price (38%), followed by labor costs (22%, electrical and hardware labor plus installer O&P) and supply chain costs (17%).

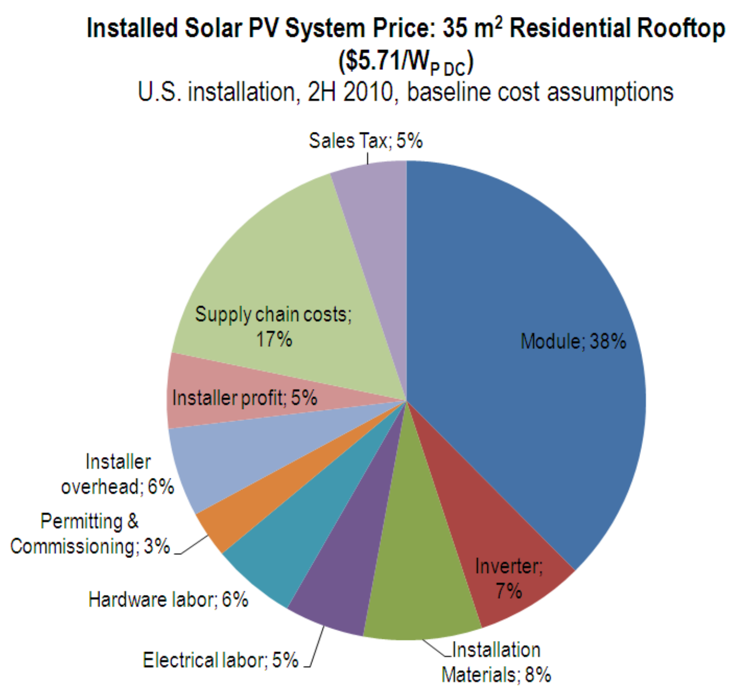

Figure 2. Benchmark 2010 residential PV system price: breakdown by element.

3.3. Commercial Rooftop PV Systems: 2010 Benchmark Prices

The design, and therefore cost, of PV systems for commercial rooftops varies significantly based on preexisting building features and roof materials. The commercial rooftop market segment includes one- to two-story warehouses and big-box stores, office buildings with more than two stories, skyscrapers, and architecturally unique buildings like churches. Commercial rooftops are most often low or no slope and use bitumen, standing-seamed metal, or ballasted-membrane surfaces. As in residential markets, commercial structures may have limited capacity for additional loads, particularly in the southern United States where snow fall is not a consideration. Another example of a region-specific system design requirement is the use of anchors for ballasted PV systems to satisfy municipal and county seismic-zone building requirements.

Building/roof characteristics and design requirements affect installation methods, system designs, and hardware requirements substantially.

The commercial rooftop PV system (914 c-Si modules, 0.992 m × 1.653 m, 14.5% efficiency) considered in this analysis is installed on a standing-seam metal roof without through-roof penetrations. Mounting hardware consists of four clips per module affixed directly to the roof's anchored roof seams.

Table 2 shows the benchmark system parameters, including labor requirements by component.

Table 2. Benchmark 2010 Commercial PV System Parameters (1,500 m^2 system area, 914 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[13] (per $W_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$2.05[14]	914	Modules	0.43	
Inverter	$0.37	1	Inverters	16.0	16.0
Wiring	$0.02	6,164[15]	Linear ft	0.08	
Other electrical[16]	$0. 74	1	Electrical subsystem	111	
Mounting hardware	$0.06	914	Modules		
Stage project	$0.00	1	None		36.6
	$3.21				
Total Installation Labor Requirements (hr/system):				1,010.1	52.6

An experienced crew of eight can install up to 150 modules per day using the direct-attach method available for standing metal seam rooftops. In contrast, the flashed points of penetration for through-roof systems are installed at a rate of 25 per day by an experienced eight-person crew. Depending on module size and design requirements (maximum span, cantilever, etc.), approximately 0.07 penetrations may be required per module. In addition to penetration hardware, the rate at which modules may be attached to the through-roof rail-type system is approximately 600 modules per day by an eight-person crew. In total, the approximate time

[13] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[14] \$1.95/$W_{P\ DC}$ ex-factory gate module price (Knoll and Siemer 2010) × (1 + 5% wholesale markup) = \$2.05/$W_{P\ DC}$.
[15] Total wiring (6,164 linear ft) = home run wiring (3,084 ft) + row to combiner wiring (3,080 ft).
[16] Other electrical includes conduit, switchboard, system monitor, combiner boxes (5), disconnects (4), and commissioning.

required to install a complete through-roof system is approximately 10%–15% faster than for the standing seam-attached system profiled in this report.

Ballasted mounting systems, which generally require no through-roof mounts, may be installed at a rate of approximately 1,000 modules per day by an experienced eight-person crew, depending on project-staging techniques and local and building requirements. The ballasted system may provide a 15%–20% labor savings over standing-seam mounting systems but is generally limited to no- or low-slope roof designs and membrane-type roofing materials.

In the commercial standing-seam system design considered in this analysis, approximately 77 module strings (12 c-Si modules per string) are connected to each of five combiner boxes. Conduit is installed between the three-story building's rooftop and the inverters/control and monitoring system located in the basement. The DC wiring passes through four disconnects located between the rooftop combiner boxes and the inverters. For redundancy, two inverters are included in the system architecture, along with one switchboard and one system monitor.

The cost of the system monitoring components can vary due to functionality, often as specified by a local utility. In some regions, utilities require that commercial systems greater than 1–3 $MW_{P\,DC}$ have advanced system monitoring and controls, which may include remote shut-off capabilities.

System overhead costs (i.e., "Permitting & Commissioning" costs) may include system design and engineering expenses, utility upgrades to the building, building permits, and delays caused by permit-related activities. In this case, design and engineering expenses are assumed to be approximately \$10,000, while commissioning fees (upgrade to the building's utility panel) are assumed to be approximately \$2,000. It has been reported to NREL that some locations charge a permit fee as high as 10% of projects costs.

The analysis results in a total installed price for a benchmark 2010 commercial PV system of \$4.59/ $W_{P\,DC}$. Figure 3 shows the price breakdown by element. Modules contribute the most to the price (45%), installation materials and supply chain costs each contribute 14%, and labor costs (electrical and hardware labor plus installer O&P) contribute 11%.

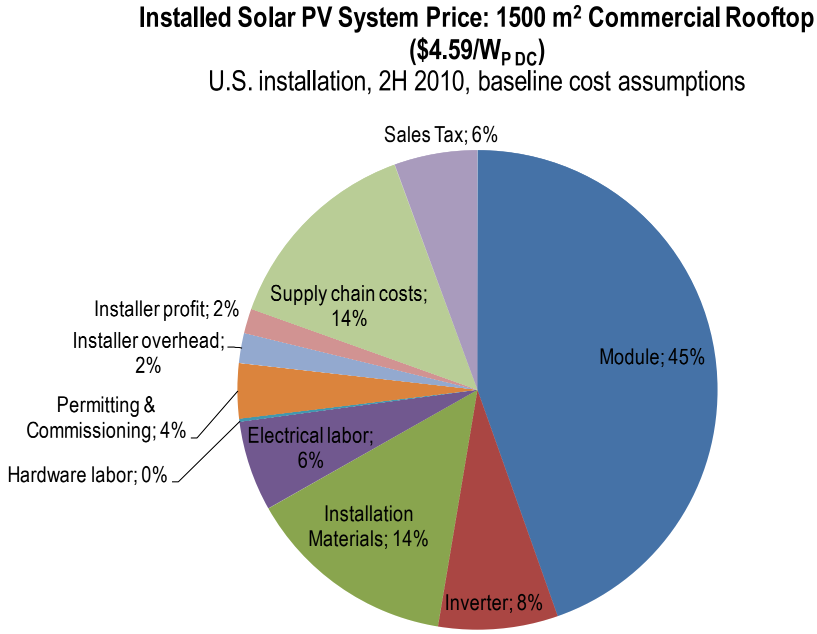

Figure 3. Benchmark 2010 commercial PV system price: breakdown by element.

3.4. Ground-Mount Utility-Scale Fixed- and One-Axis PV Systems: 2010 Benchmark Prices

The scale of individual ground-mount utility-scale PV systems installed in the United States has grown rapidly in recent months. Announcements such as SunPower's California Solar Valley Ranch (SunPower 2010b) and First Solar's Agua Caliente (First Solar 2010) installations represent a trend toward system sizes greater than 100 $MW_{P\ DC}$. At this size, the economy-of-scale benefits are clear, because the fixed costs for ground-mount systems—including permitting and regulatory costs, project transaction costs, and engineering design—are amortized over a greater system size. The scale of utility PV systems is also a significant factor that differentiates this sector from the residential rooftop market, because system size affects not only the configuration of system components, but also their installation methods, channels to market, and resulting system cost structure. Figure 4 shows the sensitivity of PV system price to system size for residential rooftop, commercial rooftop, and ground-mount utility-scale systems.

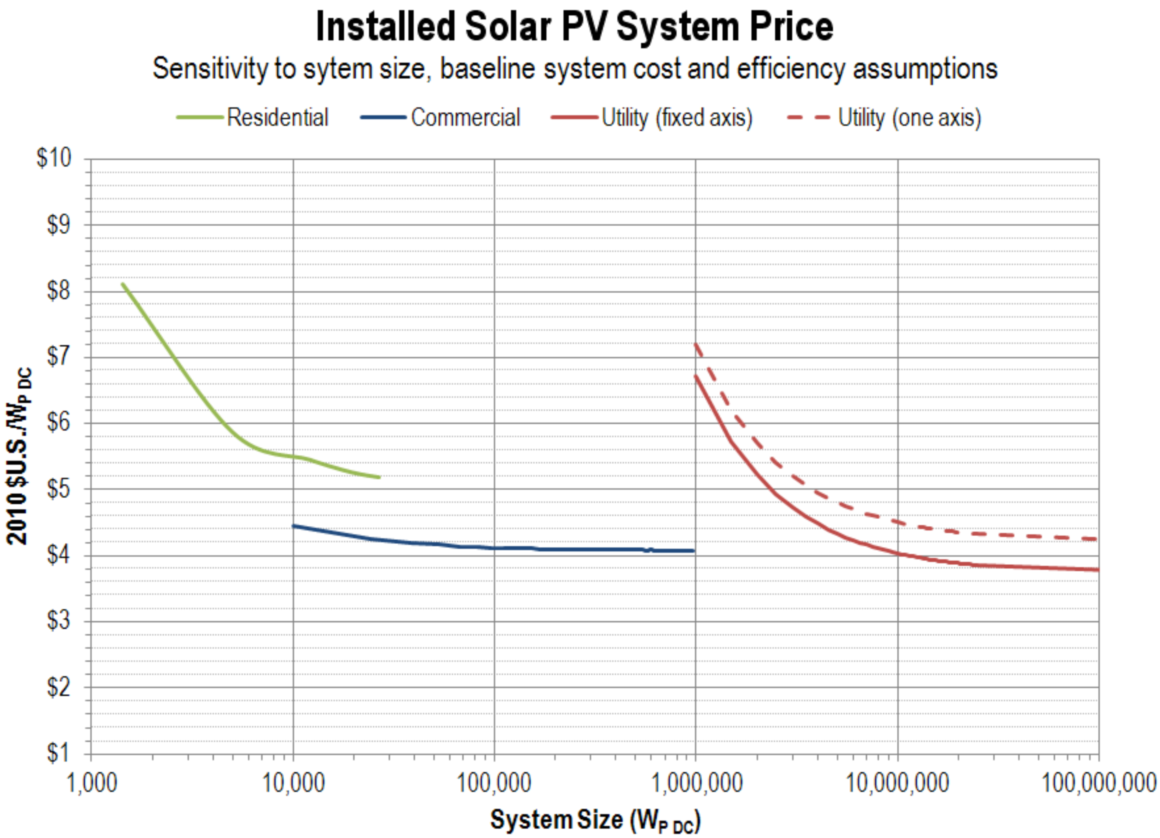

Figure 4. Economy-of-scale benefits: residential and commercial rooftop, ground-mount utility-scale PV.

Rather than a fixed-area (m^2) requirement, as in the rooftop analyses, the utility-scale systems are modeled based on a target system power of 187.5 $MW_{P\ DC}$ with an area dependent on module efficiency and system ground coverage ratio. Fixed-axis ground-mount systems based on 14%- to 15%-efficient c-Si modules typically require approximately 5 acres/$MW_{P\ DC}$, while systems based on the same modules using one-axis tracking require approximately 8 acres/$MW_{P\ DC}$ (Goodrich et al. 2011). System area requirements are based on row-to-row spacing as well as site features (e.g., size and unbuildable areas such as environmentally protected zones, rock formations, etc.) and the project's energy (kWh) production objectives. System installers may be obligated by a project's PPA contract, for example, to build a system that generates a minimum amount of energy per year. Installers may, therefore, purchase more land than is required by their initial design estimates to accommodate uncertainties in energy harvest estimates and to allow for possible project expansions.

Many c-Si module-based utility-scale systems installed in 2010 or planned for 2011 use one-axis tracking. Although the capital cost of one-axis tracking may add 10%–20% to the cost of a fixed-axis system, for c-Si modules the energy-production benefits (typically 25%–30% more kWh/kW per year in areas with high solar resources) often warrant the added capital costs (Campbell 2011a). NREL's analysis of utility-scale PV systems profiles fixed- and one-axis systems using the same standard c-Si modules designed for utility-scale applications (1.96 m^2 with 14.5%

efficiency). Across the range of module efficiencies and correlated module prices, lower-cost, lower-efficiency cadmium telluride (CdTe) modules were also considered for fixed-axis systems only (see Appendix A, simulation of fixed-axis system price-range assumptions).

The general component categories for a ground-mount utility-scale PV system are similar to those of a rooftop installation. The principal difference between rooftop and ground-mount systems is the lack of an existing structure on which the PV may be mounted; instead of a pre-existing structure and roof, the land for a site must be permitted, acquired, and prepared. The value of land used in PV installations is determined by its proximity to transmission infrastructure, available solar resources, subsurface conditions, zoning, and other factors likely to impact a site's PV energy generation and system construction costs. The demand for land that is well suited for PV has risen as the PV market has grown.[17] Speculators have contributed to the rising cost of PV-suitable land, often charging a premium for even small areas that enable large continuous swaths to be acquired for very large PV projects (Woody 2008). Of course, lower-efficiency modules increase the system land area requirements (and, therefore, overall costs) to achieve a desired system power output; the material and labor costs are also greater as fewer watts are being installed per component and per hour of labor. In 2010, the average cost of land best suited for PV in the United States was approximately $5,025 per acre (see Appendix B).

Generally, most PV sites will require clearing, leveling, grading, sediment control, hydrology work, and construction of access roads and fencing. Well-suited sites and low-impact system designs can minimize the site-preparation requirements; furthermore, low-impact site preparation increases the probability of a successful and timely environmental review. Average site-preparation costs have been observed to be approximately $25,000, although this can vary from $5,000–$25,000 per acre, depending on site specifics (see Appendix B).

The cost of permitting a site for PV also varies by region. Installers have reported the cost of environmental impact studies to be as low as $100,000, but also up to $5.0 million for more rigorous reviews, such as those required under the California Environmental Quality Act. These costs have the potential to be much higher based on the nearly unlimited litigation opportunities afforded to all stakeholders in the permitting process. Projects scoped by utilities to meet their state's renewable production standard goals avoid many of these "soft" costs by selecting pre-zoned sites that are collocated with existing energy generation or industrial infrastructure. Developers of so-called Greenfield projects are often willing to pay a premium for land that has been used for agricultural or industrial purposes because it may expedite the environmental review process. NREL has observed typical environmental review costs to be approximately $1.0 million for projects whose construction began in 2010 (see Appendix B).

This analysis considers the capital cost of a utility-scale PV system up to the point of grid tie-in (i.e., the costs of new transmission infrastructure or upgrades to existing transmission, grid interconnection studies, etc. are not considered in this report). The permitting and commissioning costs depicted here include the cost of the abovementioned environmental permitting and the cost of substation installation labor and materials. The cost of the substation and grid tie-in for

[17] The costs of new transmission, transmission upgrades, or interconnection (utility) studies were not considered in this analysis. It has been reported to NREL that these costs can quickly eliminate the cost feasibility of a project (costs are $20–$80 million for sites not situated near existing power generation).

the system is a function of the system's size. For the baseline utility-scale PV system (187.5 $MW_{P\ DC}$) described in this analysis, the cost of the commissioning can be \$1.0–\$10.0 million, depending on system size. In 2010, NREL observed typical substation costs to be approximately \$1.6 million (Goodrich et al. 2011). In total, site-related costs—including land acquisition, preparation, permitting, and commissioning—contribute less than 10% to the total utility-scale system price.

Because utility-scale ground-mount PV systems have no existing structure to use in their construction, the mounting structure requires footings that are often, but not always, driven into the ground and cemented. Strategies for these poles and foundations may also include non-penetrating cement feet. In this analysis, driven poles are considered; the pile driving is accomplished using a semi-automated machine and general construction labor. The racking components, to which the modules are affixed using clamps, are mounted atop these poles, also using general hardware or unskilled construction labor. Using modules that are less efficient than the 14%- to 15%-efficient modules modeled here would increase the amount of system area and mounting hardware required to achieve the desired system power, along with costs. One-axis trackers increase both the cost of the hardware as well as the total system area requirements because they must be separated by sufficient distance to avoid row-to-row shadowing; this also increases land, wiring material, and labor costs.

Table 3 shows the benchmark system parameters for fixed-axis utility-scale systems, including labor requirements by component. Table 4 shows the parameters for systems with one-axis tracking.

Table 3. Benchmark 2010 Fixed-Axis Utility-Scale Ground-Mount PV System (187.5 $MW_{P\ DC}$, 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), And Total Installation Labor Requirements.

Material Category	Component costs[18] (per $W_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$1.95[19]	659,747	Modules	0.45	
Inverter	$0.29	156	Inverters	40.0	8.0
Wiring	$0.15	3.8 million m^2	System area	0.19	
Other electrical[20]	$0.02	54,978	Module strings	0.52	
Mounting hardware	$0.23	1.3 million m^2	Active area		0.30
	$2.64				
Total Installation Labor Requirements (hr/system):				1,035,198	389,179

[18] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[19] $1.95/$W_{P\ DC}$ ex-factory gate module price (Knoll and Siemer 2010) – no supply chain markup.
[20] Other electrical includes meters, monitors, array disconnects, and other non-substation system components.

Table 4. Benchmark 2010 One-Axis Utility-Scale Ground-Mount PV system (187.5 $MW_{P\ DC}$, 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[18] (per $W_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	**Units**	**Electrical (hr/unit)**	**General (hr/unit)**
Module	$1.95[19]	659,747	Modules	0.45	
Inverter	$0.29	156	Inverters	40.0	8.0
Wiring	$0.25	6.0 million m^2	System area	0.19	
Other electrical[20]	$0.02	54,978	Module strings	0.52	
Mounting hardware *includes tracker*	$0.38	1.3 million m^2	Active area	0.10	0.30
	$2.88				
Total Installation Labor Requirements (hr/system):				1,523,164	389,179

The cost of wiring materials—including all wiring materials and subcomponents such as conduit, connectors, and grounding pathways as well as wiring-related installation labor—is a function of system area, module size, and module count. In this architecture, parallel strings of modules are connected in series to central inverters, which are then connected to a central grid tie-in location (substation). Wiring material costs, including material markups for a fixed-axis ground-mount system using 14%- to 15%-efficient c-Si modules are estimated to contribute approximately \$0.15–\$0.25/$W_{P\ DC}$, excluding installation labor. Systems that rely on one-axis mounting structures require additional wiring materials for the same power output, proportional to the larger system area requirements needed to avoid row-to-row shadowing losses.

Utility-scale inverters are often sized between 500–600 $kW_{P\ DC}$ per unit. NREL has observed that, for utility-scale PV systems, inverter pairs are most often housed in a storage shed, along with a single 34.5-kV medium-voltage transformer. These preassembled inverter-transformer systems, including switch gear, etc. weigh on the order of 6,700 kg and are installed in approximately 1 day (two workers) if proper site preparation is completed beforehand. Access roads are not always needed for their installation, depending on site specifics. The prices of utility-scale inverters have fallen considerably in recent years and are distributed over a relatively wide range. Recent prices observed by NREL have ranged from \$0.15–\$0.35/$W_{P\ DC}$, including the transformer and storage shed but excluding installation labor. A typical inverter-transformer assembly price for the period profiled in this analysis (second half of 2010) is \$0.29/$W_{P\ DC}$. Other electrical components include the meters and system monitors whose requirements depend on local regulations and customer preferences.

The analysis results in a total installed price for a benchmark 2010 fixed-axis ground-mount utility-scale PV system of \$3.80/ $W_{P\ DC}$. Figure 5 shows the price breakdown by element. Modules contribute the most to the price (51%), labor costs (electrical and hardware labor plus installer O&P) contribute 14%, and installation materials (including supply chain costs) contribute 17%.

The analysis results in a total installed price for a benchmark 2010 one-axis-tracking ground-mount utility-scale PV system of \$4.40/ $W_{P\ DC}$. Figure 6 shows the price breakdown by element. Modules contribute the most to the price (44%), labor costs (electrical and hardware labor plus installer O&P) contribute 18%, and installation materials (including supply chain costs) contribute 17%.

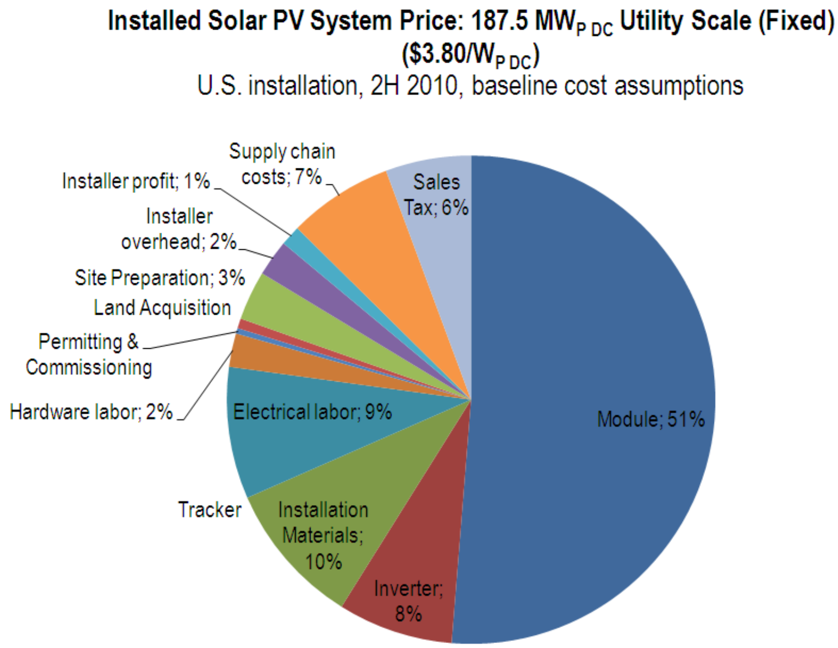

Figure 5. Benchmark 2010 fixed-axis utility-scale PV system price: breakdown by element.

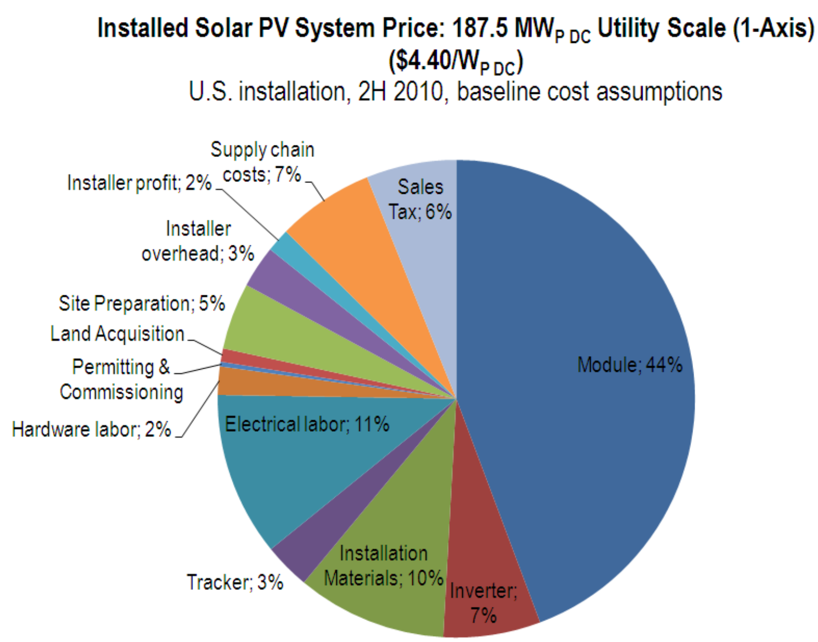

Figure 6. Benchmark 2010 one-axis-tracking utility-scale PV system price: breakdown by element.

3.5. Summary of 2010 Benchmark Prices

Figure 7 summarizes the 2010 benchmark price breakdowns by element for residential rooftop, commercial rooftop, and fixed- and one-axis utility-scale PV systems. The price of PV systems varies across market sectors based primarily on differences in system scale and installer channels to market. Excluding differences in system size, results may vary (as described in Appendix A) based on local labor and permitting costs, technology-selection decisions, installer productivity, and site-related costs. Regardless of these variations, system scale has a significant and beneficial impact on rooftop and ground-mount system prices. Large PV systems not only better amortize fixed project overhead expenses, but also improve installer efficiencies and drive more efficient supply chain strategies.

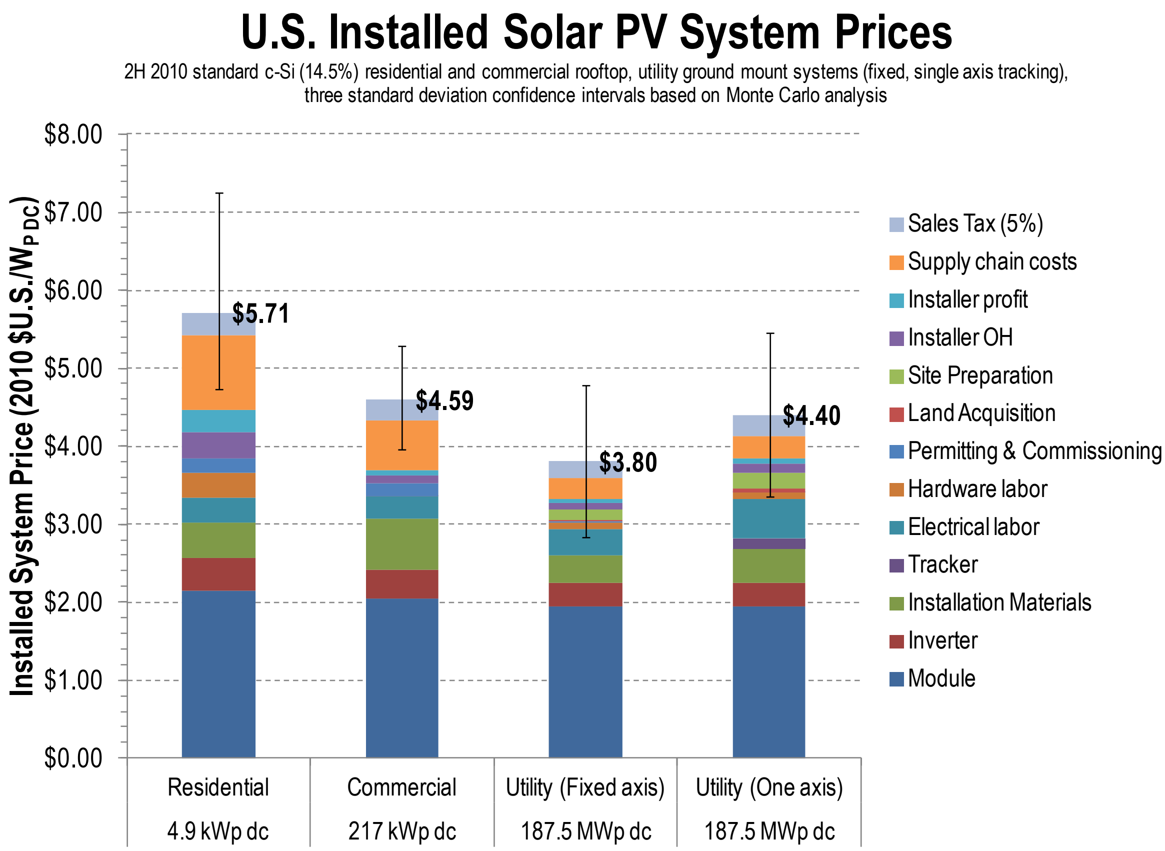

Figure 7. Benchmark 2010 PV system prices, all three sectors: breakdown by element.

Despite the recent precipitous drop in global PV module prices, these components continue to contribute a significant amount to total system price. In addition to module price, module selection decisions also impact conversion efficiencies, which are a critical price driver, especially for area-constrained rooftop systems (Figure 8).

Across most PV technologies, the efficiency of commercially available PV modules varies from about 10% (for tandem microcrystalline-amorphous silicon) to 19.6% (for super monocrystalline silicon). By increasing the power/efficiency of each module installed, the area-related costs of the system may be reduced. This relationship is not linear, however, but offers diminishing returns. The asymptote for this relationship is defined by power-related costs, such as module and inverter components. Because cost structures vary by market sector, the value of module efficiency varies by market.[21]

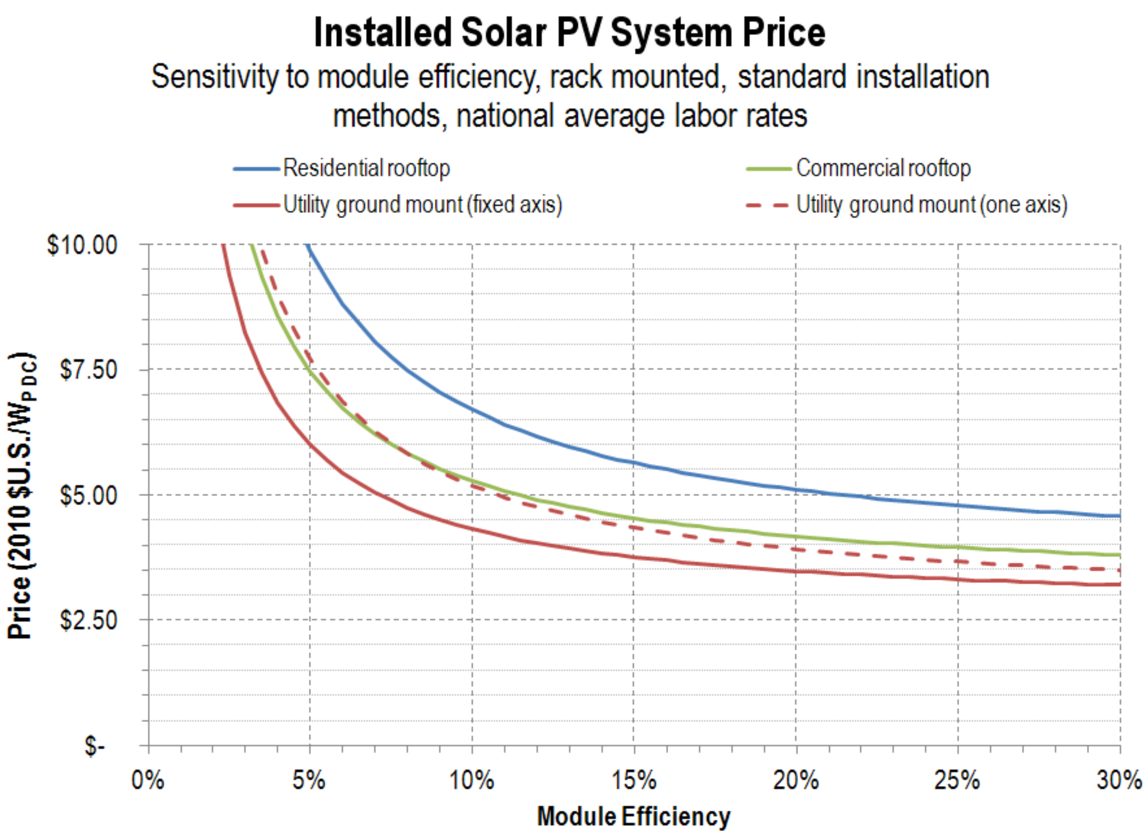

Figure 8. Sensitivity of 2010 benchmark installed PV system prices to module efficiency (module price is fixed).

For relatively mature PV module technologies like single-junction c-Si, which are approaching a practical module efficiency limit from a manufacturing perspective, the value of increased efficiency is low, relative to the value of improving the performance of lower-efficiency thin film modules such as those based on CdTe. For standard, 14.5%-efficient c-Si modules, the value of increased efficiency (per absolute point of efficiency) ranges from $0.07/$W_{P\ DC}$ (for utility-scale systems) to $0.14/$W_{P\ DC}$ (for residential rooftop systems).

The value of module efficiency improvements depends on the existing module efficiency, i.e., the starting point of the analysis. Improving the efficiency of a module used in residential applications from 10% to 11% provides $0.29/$W_{P\ DC}$ of system-level cost savings, while

[21] Rooftop systems were modeled as fixed areas (m^2); thus, their power varied by module efficiency. In contrast, utility-scale (i.e., ground-mount) systems were modeled as fixed (target) system power; thus, their area (m^2) varied to accommodate varying module efficiencies.

improving a module in the same market segment from 19% to 20% provides cost reductions of only \$0.08/$W_{P\ DC}$. Therefore, while module efficiency is an important system price driver, particularly for area-constrained applications such as residential rooftops, the value of pursuing ever-higher efficiencies is diminishing for many technologies, such as super monocrystalline-based modules. In contrast, while it is of diminishing value to pursue ever-increasing module efficiencies for high-performing technologies like super monocrystalline silicon, the cost penalty for technologies that are significantly less efficient is quite high.

4. Bottom-up 2020 Evolutionary PV System Price Projections vs. SunShot Targets

In collaboration with industry, NREL has developed detailed simulations of silicon module manufacturing costs (Goodrich et al. 2010). These tools provide a means of quantitatively evaluating alternative technical improvement pathways, including low cost polysilicon (PS) feedstock materials (e.g., produced via the fluidized bed reactor [FBR] process); ultra thin, kerfless wafers produced using diamond wire saws; and high-efficiency interdigitated back contact (IBC) cell architectures that eliminate front-side shadowing losses found in standard silicon cells.

Using these models, NREL has estimated that an evolutionary—or business-as-usual—development trajectory for PV modules will lead to industry median c-Si modules with an ex-factory gate price of about $\$1.01/W_{P\,DC}$ by 2020 (Figure 9, "Technology Group 2"). Importantly, it was estimated that this price could be achieved along with a substantial increase in median production module efficiency, to 21.5%—equivalent to a practical single-junction silicon cell efficiency limit of approximately 24% in high-volume production. Increasing module efficiency generally requires more advanced cell-processing techniques, resulting in higher module manufacturing costs. These added costs may, however, reduce many area-related system costs, providing a favorable cost tradeoff. Nevertheless, it is unlikely that these module improvements will be sufficient to meet the DOE SunShot Initiative targets and ensure that PV is competitive with incumbent energy sources without subsidy by 2020 in residential rooftop, commercial rooftop, or ground-mount utility-scale applications. Therefore, additional cost reductions will be required to meet the SunShot targets for each market sector.

The following sections describe the projected evolutionary pathways from the 2010 benchmarks described above through 2020 for residential rooftop, commercial rooftop, and ground-mount utility-scale PV systems. In addition, the system prices resulting from the evolutionary pathways are compared with the SunShot targets for each sector.

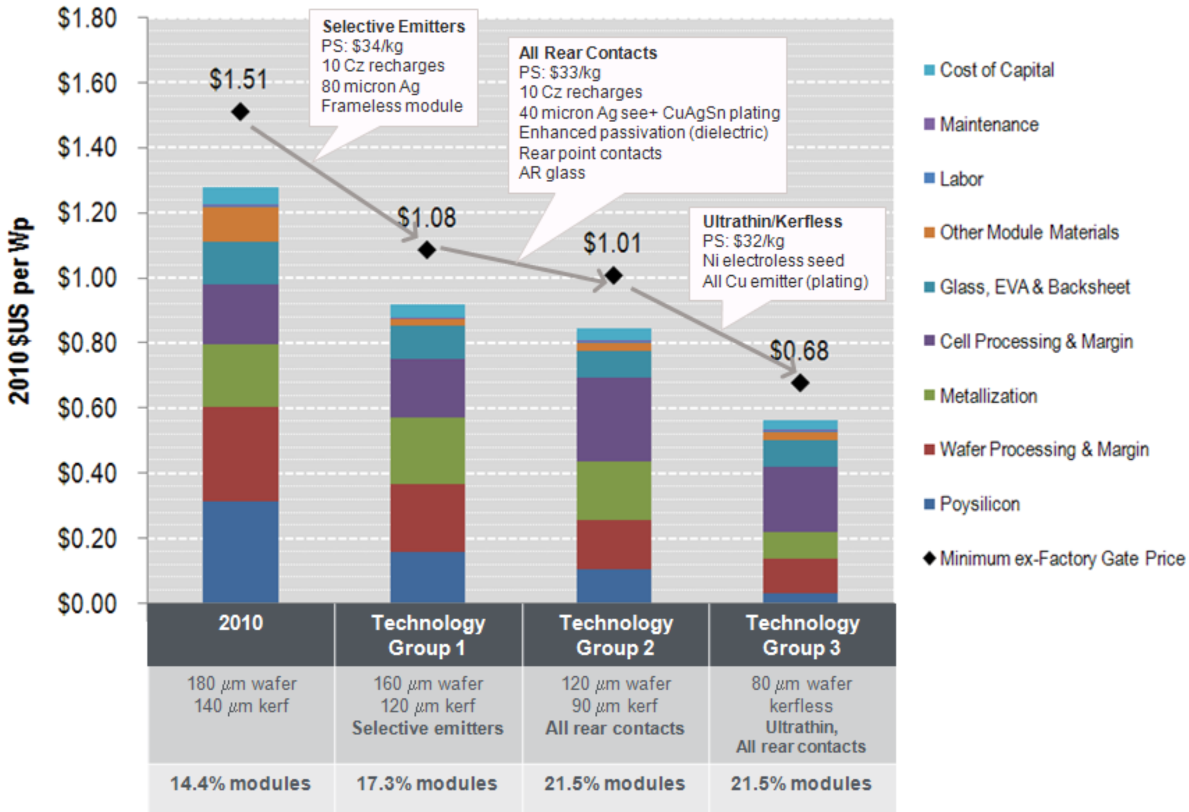

Figure 9. Current and projected single-junction wafer-based c-Si PV module costs and minimum sustainable prices.

(Goodrich 2010)

The Evolution of Non-Module Costs

As the U.S. market matures and installer experience increases, it is likely that non-module installation costs will be reduced. Cost elements like work productivity and supply chain costs (channels to market) are likely to approach those of more mature contractor services, like electrical contractors due to cumulative learning effects, reduced regulatory costs, and increased installer competition. The scale of these cost reduction opportunities is evidenced by comparing German installation prices† to the U.S. (Figure 10). Although direct and indirect labor costs in Germany are higher than in the U.S., installers there have also benefited from the experience that comes with having more than eight times the grid-connected PV capacity of the U.S.

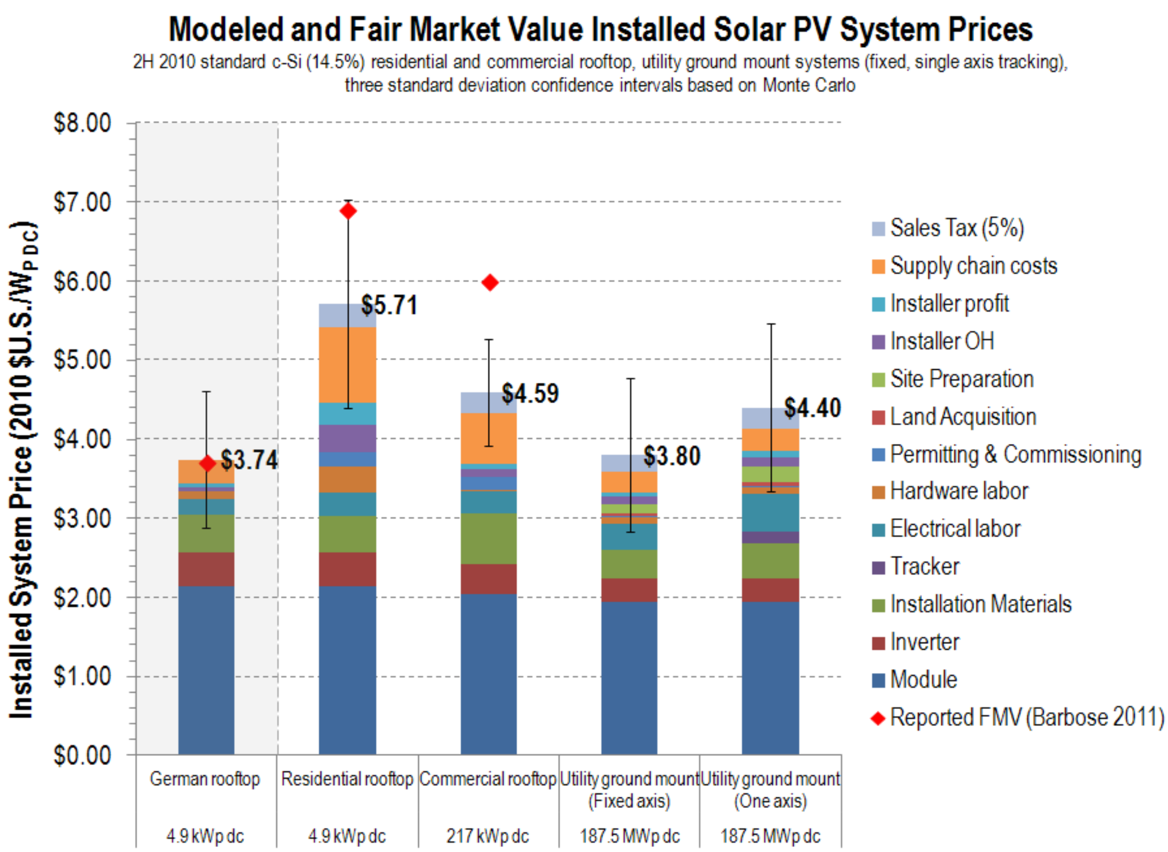

Figure 10. Benchmark 2010 U.S. and German PV system prices: breakdown by element, comparison to reported *market prices* (FMV) (Barbose 2011).

In contrast to the modeled U.S. results, the subjective prices for systems in Germany more closely approximate the estimate of the objective book value, due to a more competitive installer market and differences in demand-side incentive structures.

†Modeled German system price assumptions (differences relative to U.S. system costs): Supply chain (materials) markup reduced from 30% (U.S.) to 10%, Installer overhead rate reduced from 54% (U.S.) to 16%, Installer profit on labor reduced from 30% (U.S.) to 10%, Installation labor productivity improved by 50% relative to U.S. case, Installer electrician hourly wage rate raised from $49 (U.S.) to $68.11 (Germany), Installer carpenter hourly wage rate lowered from $33.10 (U.S.) to $20.85 (Germany), Sales (U.S.) or Value Added Tax (Germany), permitting and commissioning fees waived.

4.1. Residential Rooftop PV Systems

Figure 11 shows the evolutionary pathway for residential rooftop PV system prices from the benchmark of $5.71/$W_{P\ DC}$ in 2010 to $2.29/$W_{P\ DC}$ in 2020. It also shows the SunShot residential rooftop target of $1.50/$W_{P\ DC}$ for comparison.

A reduction in module price from the retail-2010 benchmark $2.15/$W_{P\ DC}$ (14.5% module) to the $1.01/$W_{P\ DC}$ (21.5% module) projected in 2020 contributes nearly $1.42/$W_{P\ DC}$ to residential system price reductions, net of supply chain markup and sales tax benefits. The projected increase in module efficiency would reduce system prices by an additional $0.71/$W_{P\ DC}$.

By 2020, the evolutionary residential system price estimate assumes that installation methods, installer experience (productivity), and supply chain costs will become more streamlined, bringing the PV industry more in line with other contractor service industries. Like central air conditioning systems, rooftop PV systems use standardized components for the construction of customized home systems. As the market for rooftop PV grows and matures, like the market and price for central air conditioning systems matured, system design and installation methods will likely become more standardized (Lacey 2011). These market maturity-related cost reductions have already been seen in the German PV market, where rooftop system prices are about 42% lower than NREL's estimate of U.S. residential system prices and 52% lower than the *market price* of comparable U.S. rooftop systems (Barbose et al. 2011).

Because components are generally fungible, and there does not appear to be a significant German labor-cost (wage rate or benefits on labor) advantage, it is reasonable to conclude that installer experience and competition, as well as supply chain efficiencies gained through the German market's rapid growth are the principal factors that explain these regional differences. In addition, broad German market acceptance of PV provides a considerable savings by reducing the high cost of onerous permitting processes. A lack of standard permit requirements and diversity of regulations among the many local jurisdictions in the United States contributes to the high (54%) markup for overhead expenses on labor for U.S. installers. NREL estimates that eliminating PV system permit fees could save the typical residential installation approximately $0.12/$W_{P\ DC}$ in direct costs and contribute to a reduction in operating expenses. As the industry matures, O&P rates could fall to those of more mature service industries, providing up to $0.19/$W_{P\ DC}$ in savings by 2020.

Unitized construction methods already have been shown to provide significant (30%) reductions in labor content by transferring assembly operations to more efficient factory settings (Koshmrl 2011). Further innovation related to installation methods and increased installer productivity are anticipated, which could contribute to a 50% reduction in installation labor content by 2020 and provide up to $0.45/$W_{P\ DC}$ in price reduction.

Materials-related cost savings may be attributed to more efficient channels to market for installers (i.e., reduced supply chain costs) and reduced material content/prices. By reducing the current residential markup on materials (30%) for "supply chain costs" (e.g., inventory and contingency costs) to 20%, system prices could be reduced by $0.20/$W_{P\ DC}$.

The price of residential inverters is expected to fall by nearly two thirds over the next decade, which would contribute approximately $0.20/$W_{P\ DC}$ to system price reductions. The prices of other system materials may be reduced through changes to system architecture, e.g., high-voltage strings that use smaller-gauge wiring. A savings of 50% in the area of "other materials" may contribute as much as $0.14/W_{P\ DC}$ to system price reductions by 2020.

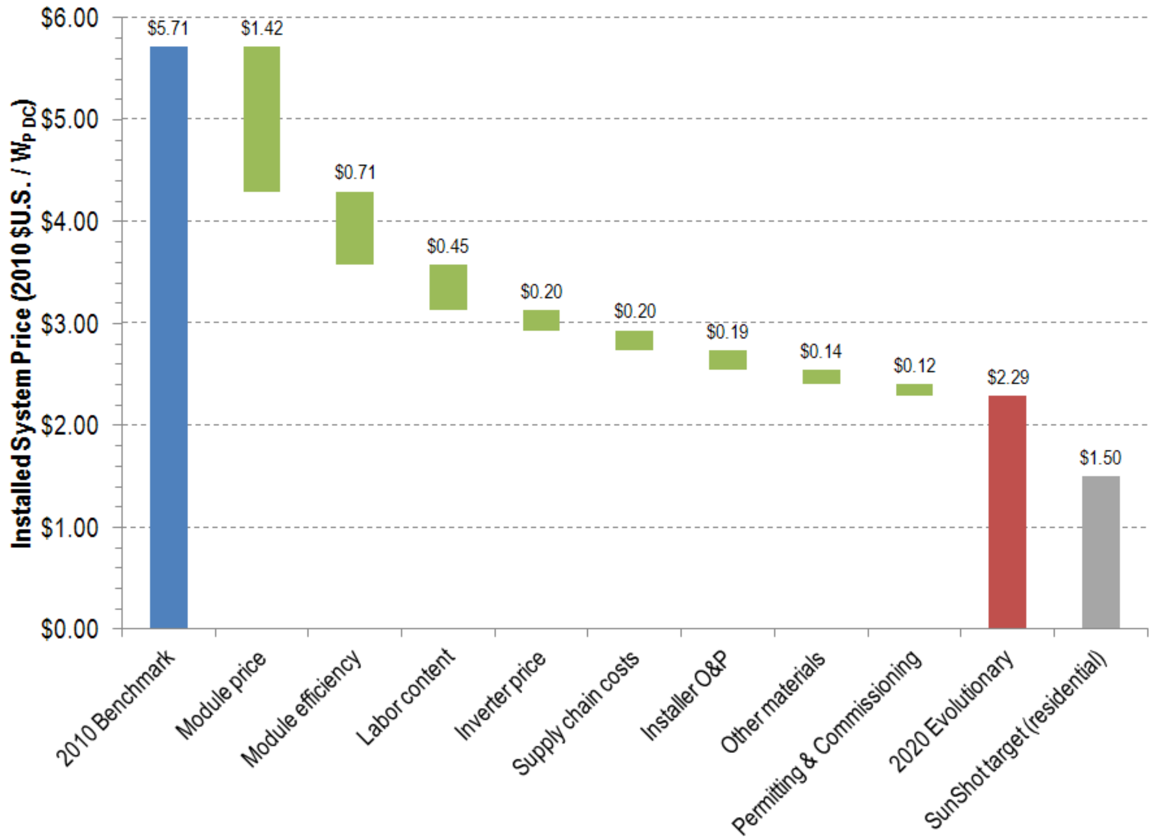

Figure 11. Evolutionary residential PV system price reductions and DOE SunShot target, 2010–2020.

NREL concludes from this analysis that the price of residential rooftop PV systems based on c-Si modules is likely to go below $2.30/W_{P\ DC}$ through a combination of anticipated market-driven cost reductions and evolutionary module and inverter technology advancements. Many factors will affect the rate of price reduction, but efforts and announcements by leading solar companies lead NREL to conclude that the proposed timeline in Figure 11 is plausible (Sunpower 2010a). The evolutionary price reduction falls about 34% short of the 2020 DOE SunShot target for residential systems.

4.2. Commercial Rooftop PV Systems

Figure 12 shows the evolutionary pathway for commercial rooftop PV system prices from the benchmark of \$4.59/$W_{P\ DC}$ in 2010 to \$1.99/$W_{P\ DC}$ in 2020. It also shows the SunShot commercial rooftop target of \$1.25/$W_{P\ DC}$ for comparison.

In absolute terms, the value of projected evolutionary c-Si module price trends is expected to contribute less to commercial rooftop system price reduction because of the lower materials-related markups (streamlined supply chain), relative to the residential rooftop sector. As a percentage, however, modules constitute a greater portion of current commercial rooftop system prices. By 2020, evolutionary module price reductions and efficiency enhancements are expected to reduce commercial rooftop PV system prices by 38%.

Other notable areas for improvements include the cost of non-module, non-inverter ("other") materials. By developing systems that operate at higher voltages (lower-gauge wire) and have fewer part counts (e.g., integrated wiring, eliminating some conduit materials), commercial system prices may be reduced by a further \$0.29/$W_{P\ DC}$.

Although the markups assumed for 2010 installer O&P margin are competitive with many mature industries, supply chain costs remain an area of cost-reduction potential. By reducing construction and permitting times, and by streamlining the supply chain for system materials, inventory and project contingency costs can be reduced. If the markup on materials can be reduced to that of mature industries, like electrical contractor services in other building sectors, then system prices may be reduced by \$0.18/$W_{P\ DC}$.

The trend towards unitized construction methods, including ballasted modules with installation labor requirements that can be less than half those for through-roof modules, is prominent in the commercial rooftop PV sector. Further innovation, in terms of product design and installation method, may further reduce the amount of labor required to install a commercial system by 50%, resulting in a price reduction of \$0.16/$W_{P\ DC}$.

NREL estimates that by 2020 the industry will achieve, through aggressive, but evolutionary cost reductions an installed system price for commercial rooftop PV of less than \$2.00/$W_{P\ DC}$, still about 37% short of the 2020 DOE SunShot target for this market sector (\$1.25/$W_{P\ DC}$).

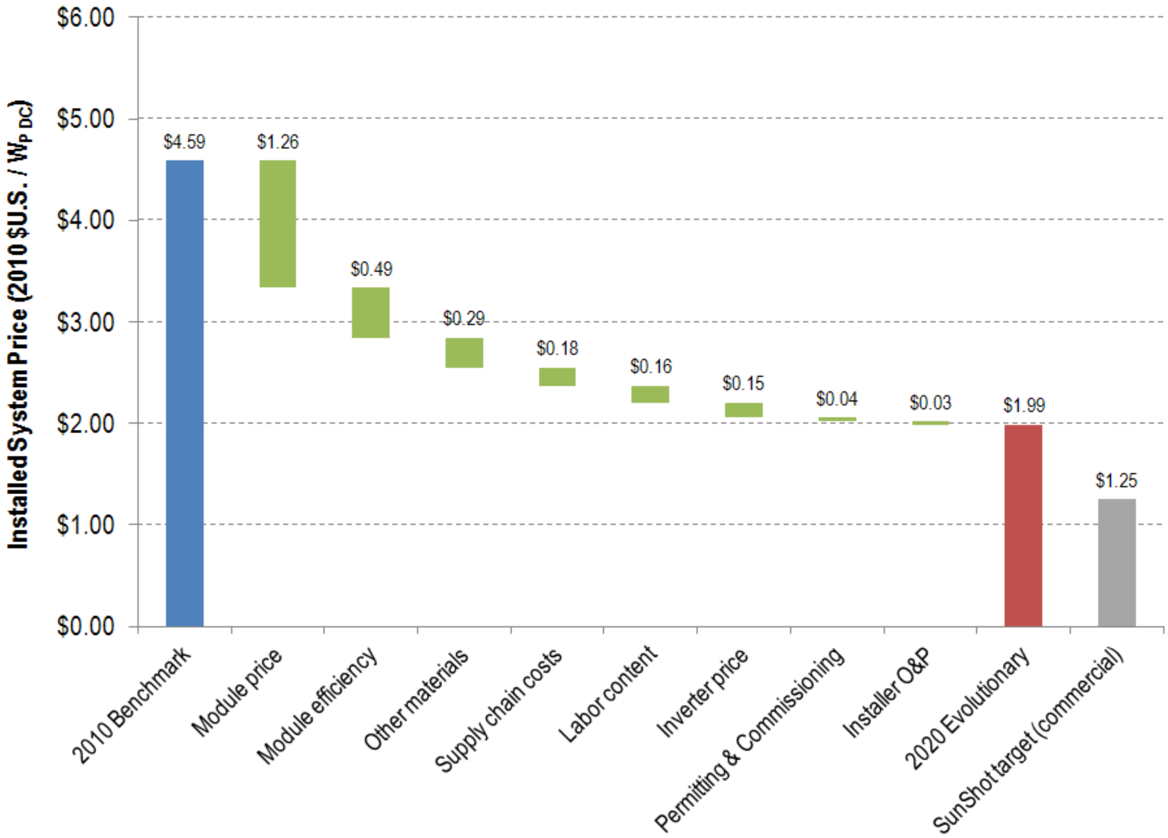

Figure 12. Evolutionary commercial PV system price reductions and DOE SunShot target, 2010–2020.

4.3. Ground-Mount Utility-Scale PV Systems

Figure 13 shows the evolutionary pathway for ground-mount, utility-scale, one-axis tracking PV system prices from the benchmark of $4.40/W$_{P\ DC}$ in 2010 to $1.91/W$_{P\ DC}$ in 2020. It also shows the SunShot utility-scale target of $1.00/W$_{P\ DC}$ for comparison.

As this report quantifies, the price structure of utility-scale PV systems with one-axis tracking is vastly different than that of rooftop systems; so too are the price reductions needed to compete with conventional electricity generation costs. The owner and operator of utility-scale PV systems must compete with the cost of generating electricity using traditional production technologies, rather than competing with the wholesale or industrial price of electricity as in the commercial market, or retail price of electricity as in the residential rooftop market.

Projected evolutionary module price reductions over the next decade contribute less to utility-scale system price reductions ($1.10/ W$_{P\ DC}$) than in residential or commercial applications due to differences in the supply chain costs (markups on material costs). Expected efficiency gains provide less benefit for utility-scale systems than for residential systems because of fewer restrictions and costs related to system area. Residential customers tend to be more bound to an absolute maximum system size (m^2), as defined by the size of the home and the PV-suitable area. Utility-scale developers can, in theory, purchase additional land to achieve a given system size (power output, peak W_{DC}) using less efficient modules. Nevertheless, NREL estimates that an improvement in module efficiency from ~14.5% to greater than 21% will provide \$0.57/$W_{P\,DC}$ in utility-scale system price reductions.

Future labor-cost reductions may be possible, for example through the integration of subcomponents in a factory setting (i.e., unitized construction methods). In a factory setting, economies of scale and automation can reduce electrical and hardware installation labor content (costs) for PV systems. NREL assumed, for the purposes of this illustrative analysis, that, by better integrating wiring subcomponents and preparing unitized sub-assemblies, the in-the-field electrical labor content may be reduced by half, thus decreasing system price by ~\$0.28/$W_{P\,DC}$.

Utility-scale inverter prices have fallen dramatically in recent years. It is anticipated that the price of a utility-scale inverter will approach \$0.10/$W_{P\,DC}$ by the end of the decade as the need for step-up transformers and switching gear is eliminated, and as input voltages for inverters are increased (i.e., increased module-to-inverter ratio). This projected reduction in inverter price (from \$0.29/$W_{P\,DC}$ to \$0.10/$W_{P\,DC}$) will provide up to \$0.22/$W_{P\,DC}$ in system price benefits, net of supply chain markups on materials and sales tax.

Improvements to the system's electrical architecture may also reduce the cost of 'other materials' (non-module, non-inverter components). Increasing the string size (up to, or greater than 1,000 V), for example, will reduce the gauge of electrical wiring. Integration of subcomponents as part of a unitized construction strategy may reduce or eliminate some conduit. As one-axis tracker technologies become more widely used, the cost of these components will continue to fall. NREL estimates that, by 2020, a 50% reduction in the cost of "other materials" used throughout the utility-scale PV system will lead to a price savings of \$0.23/$W_{P\,DC}$.

Low-impact system designs that require a minimal amount of site preparation (e.g., grading) may significantly lower the 2010 estimated cost of "site preparation" (reduce by 50%, from \$25,000 to \$12,500 per acre) and reduce system price by ~\$0.07/$W_{P\,DC}$.

Today's estimated utility-scale PV installer overhead (22%) may be lowered to minimally sustainable levels (i.e., to 16%) through increased competition and improved installation business practices (standardized system designs, streamlined permitting process, etc.). It is estimated that this improvement in installer operating costs may reduce the total system price by ~\$0.01/$W_{P\,DC}$. Although the cost of environmental permits can be high (estimated to be \$1.0 million in the benchmark scenario), at scales greater than 100 $MW_{P\,DC}$ the contribution of permit fees to system price is quite small. Therefore, reducing the permit fees by half will provide less than \$0.01/$W_{P\,DC}$ benefit to future system prices.

Figure 14 shows the evolutionary pathway for ground-mount, utility-scale, fixed-axis tracking PV system prices from the benchmark of \$3.80/$W_{P\,DC}$ in 2010 to \$1.71/$W_{P\,DC}$ in 2020. Overall, the evolutionary price reduction falls about 40%–48% short of the 2020 DOE SunShot target for utility-scale systems[22].

[22] The DOE SunShot goal for (fixed axis) utility-scale systems is \$1/$W_{P\,DC}$. Crystalline silicon modules mounted on one axis trackers may experience a capacity factor benefit of between 25-30% (Campbell 2010b) in high solar resource locations, although the capital (system) penalty may be between 10-20%. In the future (2020), as the price of (one-axis) trackers comes down (e.g.

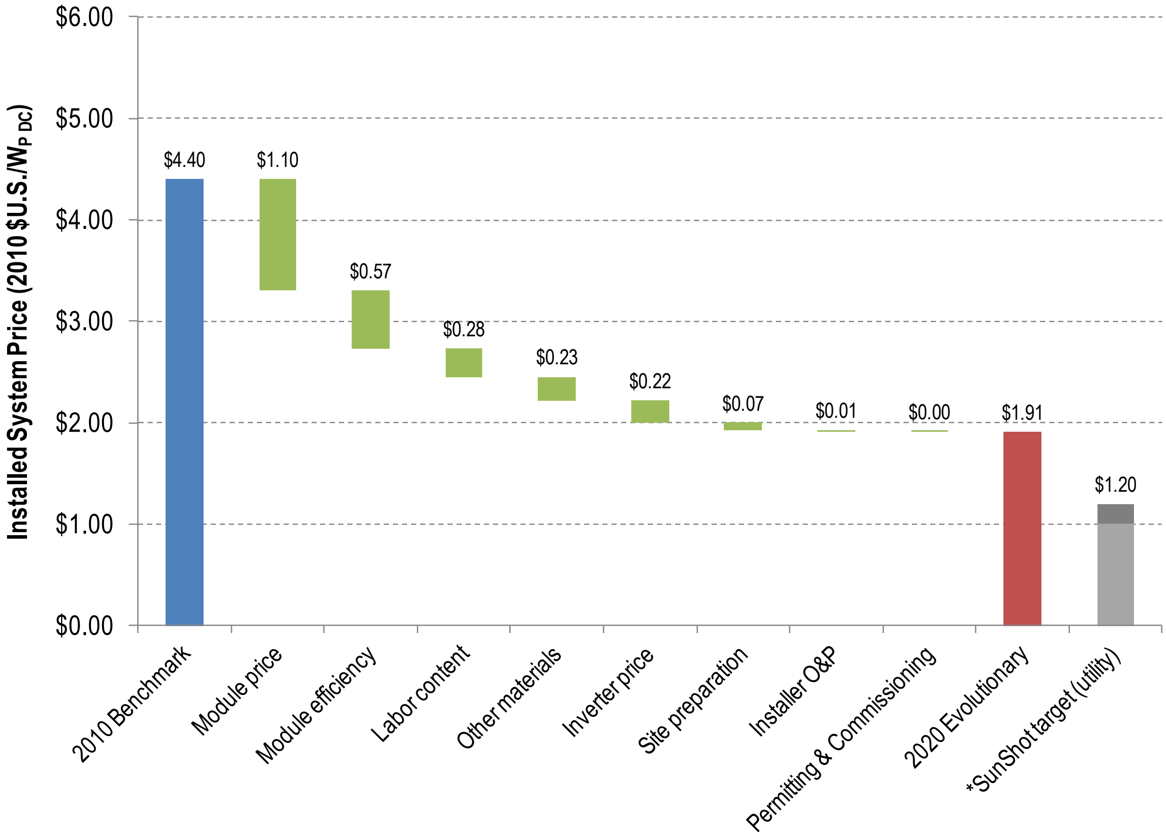

Figure 13. Evolutionary utility-scale (one-axis tracking) PV system price reductions and DOE SunShot target, 2010–2020.
***Single-axis utility scale PV SunShot target modified (20%) to account for enhanced capacity factor (25%; c-Si modules), less added system cost (5%; tracker).**

system cost penalty approaches 5%), the net-benefit of tracking c-Si modules in high resource areas may approach 20%. Because capacity factor and module efficiency are linearly correlated, the *modified* SunShot target for one-axis c-Si modules is estimated to be approximately $1.2/$W_{P\ DC}$; equivalent to the $1/$W_{P\ DC}$ fixed axis SunShot goal, when adjusted for tracking benefits and costs.

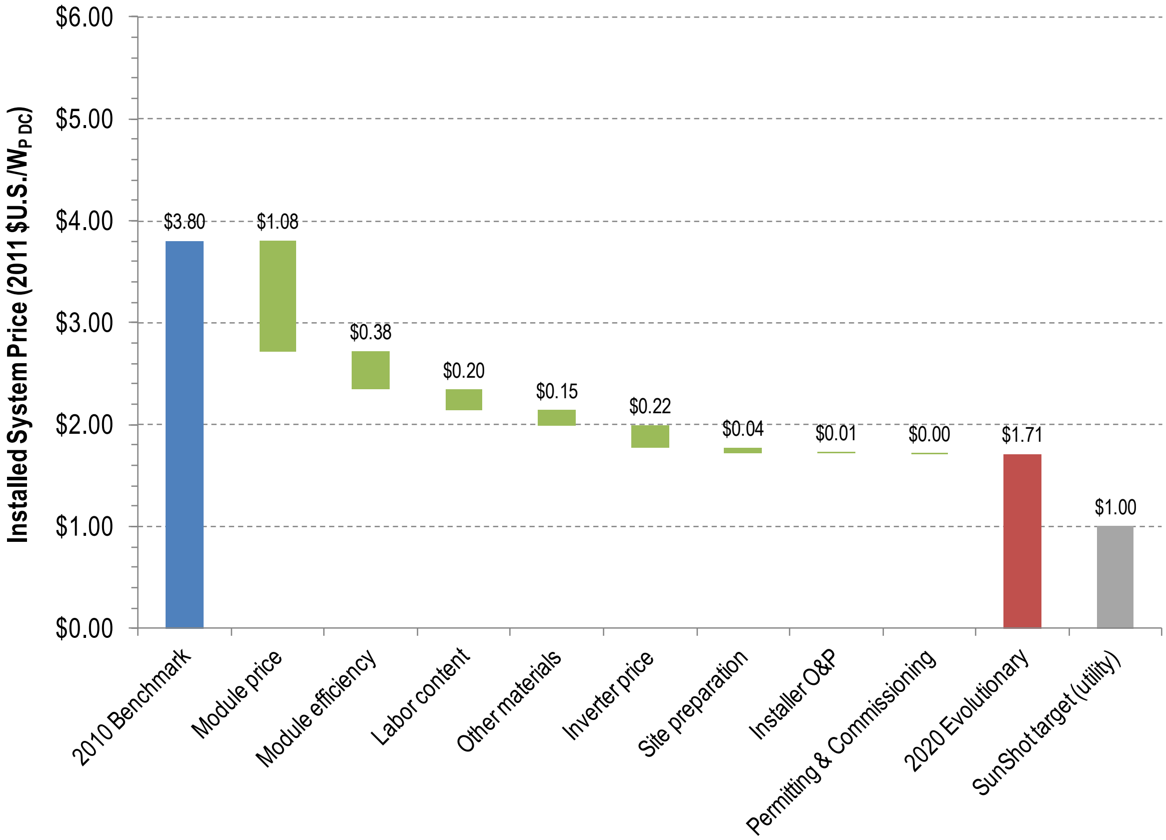

Figure 14. Evolutionary utility-scale (fixed-axis tracking) PV system price reductions and DOE SunShot target, 2010–2020.

This analysis illustrates the need for technological advancements at the module (cost, efficiency) and non-module levels to achieve the aggressive SunShot targets. Under the evolutionary scenario described above, by 2020, non-module costs are expected to account for between \$0.70/$W_{P\,DC}$ (41%) and \$0.90/$W_{P\,DC}$ (47%) of utility-scale system price, for fixed- and one-axis tracking system architectures, respectively. If, more optimistically, the price of single-junction c-Si modules were to approach the longer-term \$0.68/$W_{P\,DC}$ price (see Appendix C), then the estimate for 2020 (fixed axis) system prices would be approximately \$1.38/$W_{P\,DC}$, still 28% short of the SunShot target. This highlights the need for innovative system designs and installation methods to compliment module-level cost reductions.

2011 Benchmark System Prices

The precipitous decline in global PV module prices has continued during the completion of this report. Since the last quarter of 2010, ex-factory gate c-Si module prices have reportedly fallen from \$1.95/$W_{P\ DC}$ to approximately \$1.10/$W_{P\ DC}$ (between \$1.05 and \$1.25/$W_{P\ DC}$), while industry-median conversion efficiency has increased from 14.5% to 14.8%. The pace of module manufacturing cost reductions has increased due largely to declines in polysilicon feedstock costs, but also due to competitive pressures from leading thin film technologies (e.g., CdTe-based modules). Manufacturer margins also have been compressed because of global overcapacity for cells and modules.

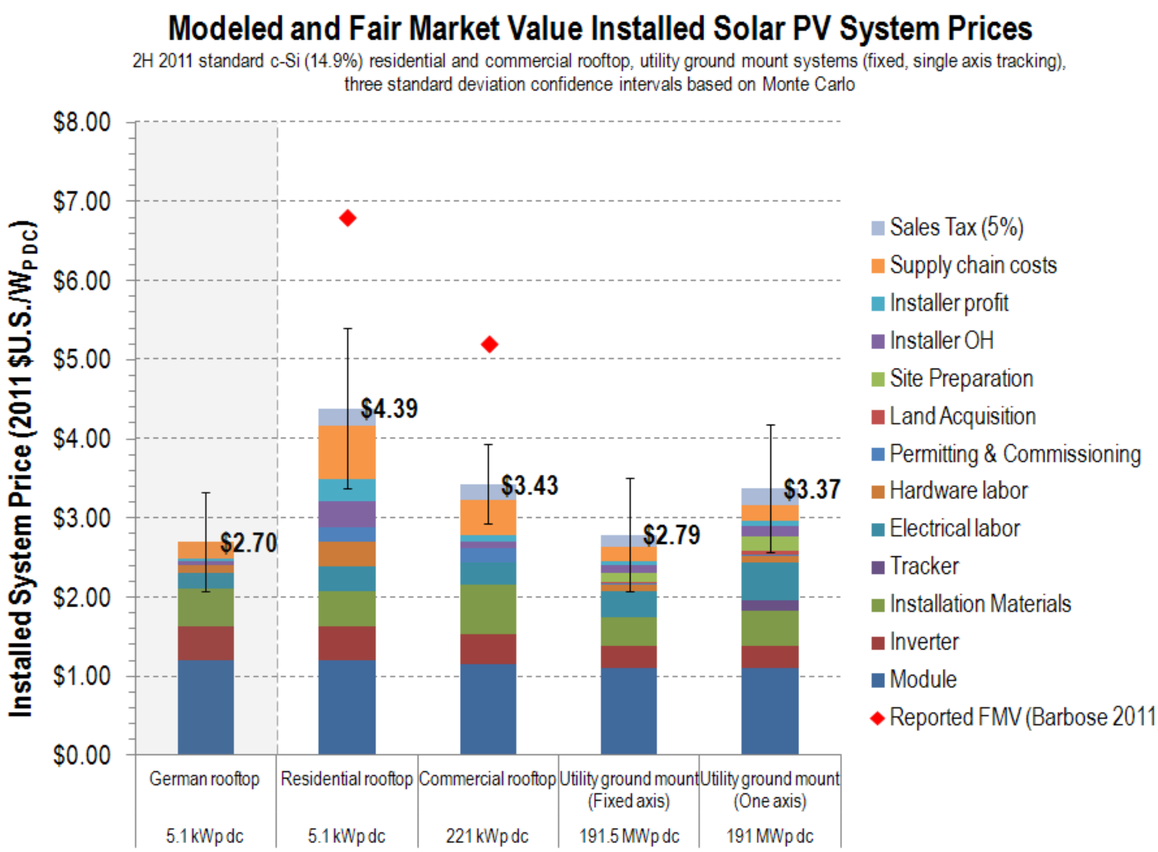

Figure 15. Benchmark 2011 PV system prices, all three sectors: breakdown by element. Note: Reported *market prices* (FMV) include only partial year 2011 (Barbose 2011).

The impact of reducing module prices by \$0.85/$W_{P\ DC}$ is magnified in the system price analysis the models' supply chain costs multiplier, which accounts for inventory and project contingency costs as a percentage of module price. As a result of module price declines that have occurred between the second half of 2010 and the second half of 2011, system prices have fallen by 23%–27% (Figure 15).

5. Conclusion: PV Price Reductions—the Road Ahead

Because of the rapid U.S. PV system cost reductions resulting from global module price declines, *market price* data have become insufficient for providing policy makers and industry stakeholders with an accurate and current understanding of system-price drivers. A time-lag effect and the dynamics of a nascent industry disconnect reported system prices from underlying system costs. This report shows an objective methodology for approximating the underlying costs of PV systems with the resolution necessary for understanding system price drivers. Comparing these objective values with *market price* data provides valuable insights into the U.S. PV market's inefficiencies, which may be useful for developing policies and practices that address these inefficiencies. Understanding the forces driving PV system price reductions—and their limitations—is also important.

The price of U.S. PV systems has fallen by nearly 30% since the second half of 2010, and further near-term price reductions are likely as the U.S. market matures. Most PV system components are based on commodities that have global prices. Thus, installation costs are largely responsible for the disparities in PV system prices among different countries and regions. The diffusion of installation knowledge and expertise throughout the U.S. market, increased local competition, and consolidation of U.S. installation companies should reduce these disparities substantially. Based on evidence from the more mature German PV market, factors such as improved installer productivity, reduced installer overhead and profit (due to competition), lower supply chain costs, and lower regulatory costs could reduce 2011 U.S. benchmark PV system prices by an additional 40%.

The tight polysilicon supply and high prices during 2007–2008 may also help reduce PV system prices in the near term. Polysilicon is the feedstock for the dominant c-Si PV technology. The recent price spike caused new entrants to build polysilicon production facilities, many of which are now coming online. The resulting overcapacity of polysilicon—along with weakening European demand for c-Si modules—has driven polysilicon contract prices down by more than half compared with contract prices in 2008. In addition, the 2007–2008 polysilicon shortage encouraged larger-scale production of thin film alternatives to c-Si PV, which also has contributed to lower global PV module prices. At the same time, the larger polysilicon production base has reduced the likelihood of another polysilicon shortage/price imbalance as severe as the one in 2007–2008.

The abovementioned factors likely will contribute to lower U.S. PV system prices in the coming years. This report provides detailed roadmaps to evolutionary c-Si PV system price reductions and performance improvements, including substantial reductions in module and non-module costs. By 2020, these roadmaps would enable U.S. PV systems to approach—but not meet—DOE's SunShot Initiative price targets. To accelerate PV price reduction toward meeting these aggressive targets, revolutionary improvements to module and non-module system components and installation methods are needed.

References

Barbose, G.; Darghouth, N.; Wiser, R.; Seel, J. (2011). "Tracking the Sun IV: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010." Berkeley, CA: Lawrence Berkeley National Laboratory.

Beck, G.; Hillman, M. (2009). "NASA/FPL Renewable Project: Space Coast Next Generation Solar Energy Center." Presentation at the Federal Utility Partnership Working Group meeting, Biloxi, MS, April 5-6, 2009. www.smartgridnews.com/artman/uploads/1/nasa_space_coast_solar.pdf.

Campbell, M. (2011a). "PV Power Plant Cost Trends." U.S. Department of Energy Balance of Systems (BoS) Workshop, SunPower presentation, January 13, 2011.

Campbell, M. (2011b). "Charting the Progress of PV Power Plant Energy Generating Costs to Unsubsidized Levels, Introducing the PV-LCOE Framework." European Photovoltaic Solar Energy Conference and Exhibition (EU PVSEC), proceedings, September 5-8, 2011.

Coddington, M.; Margolis, R.; Aabakken, J. (2008). "Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch." NREL/TP-581-42675. Golden, CO: National Renewable Energy Laboratory.

Easton, P.; Wild, J.; Halsey, R.; McNally, M. (2010). *Financial Accounting for MBAs.* 4th Edition. Cambridge Business Publishers.

First Solar. (2009). First Solar Analyst/Investor Meeting. Las Vegas, NV, June 24, 2009.

First Solar. (2010). Agua Caliente Solar Project website. www.aguacalientesolarproject.com, accessed 2010.

First Solar. (2011). *FS Series 2 Solar Module Datasheet*. First Solar website, www.firstsolar.com/en, accessed 2011.

Goodrich, A.; Woodhouse, M.; Hsu, D. (2010). "NREL Si PV Road Map. Presentation at the Silicon Workshop, August 2010.

Goodrich, A.; Woodhouse; M.; James, T. (2011). Private conversations with installers. Golden, CO: National Renewable Energy Laboratory.

Knoll, B.; Siemer, J. (2010). "Rippling Prices." *Photon International*, October 2010.

Koshmrl, M. (2011). "Installer Overcomes Blizzards with Preassembly." *Solar Today*. www.solartoday-digital.org/solartoday/201106/#pg66, accessed August 19, 2011.

Lacey, S. (2011). "Sungevity partners with Lowe's: Innovative business models are bringing solar to the general public." *Climate Progress*, May 17, 2011. http://climateprogress.org/2011/05/17/sungevity-lowes-innovative-business-models-are-bringing-solar-to-the-masses/, accessed September 2011.

Mints, P. (2006). *Photovoltaic Manufacturer Shipments 2005/2006*. Report NPS-Supply1. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Mints, P. (2010). *Photovoltaic Manufacturer Shipments, Capacity & Competitive Analysis 2009/2010*. Report NPS-Supply5. Palo Alto, CA: Navigant Consulting Photovoltaic Service Program.

Nemet, G. (2006). "Behind the learning curve: Quantifying the sources of cost reduction in photovoltaics." *Energy Policy* 34(17): 3218-3232.

Paidipati, J.; Frantzis, L.; Sawyer, H.; Kurrasch, A. (2008). *Rooftop Photovoltaic Market Penetration Scenarios*. NREL/SR-581-42306. Golden, CO: National Renewable Energy Laboratory.

RSMeans. (2010). *Building Construction Cost Data.* Norwell, MA: Reed Construction Data.

Strategies Unlimited. (2003). *Photovoltaic Manufacture Shipments and Profiles, 2001-2003*. Report SUMPM 53. Mountain View, CA: Strategies Unlimited.

SunPower. (2010a). "Roadmap to <$1.00/Watt panel (by 2014)." Slide 16, included in "Fourth Quarter 2009 Earnings Supplementary Slides," SunPower investor presentation, March 18, 2010.

SunPower. (2010b). "NRG Solar and SunPower Agree to Build 250-Megawatt California Valley Solar Ranch." SunPower press release, November 30, 2010. http://us.sunpowercorp.com/about/newsroom/press-releases/?relID=533634.

SunPower. (2011). *SunPower E18/400 Solar Panel Datasheet*. SunPower website, http://us.sunpowercorp.com, accessed 2011.

Woody, T. (2008). "The Southwest desert's real estate boom: From California to Arizona, demand for sites for solar power projects has ignited a land grab." *Fortune*, July 11, 2008. http://money.cnn.com/2008/07/07/technology/woody_solar.fortune/index.htm, accessed September 2011.

Appendix A: Uncertainty Analysis of PV System Prices

The analysis of PV system prices presented in this report relies on national average labor rates and frequently encountered system cost assumptions. Labor rates are a significant source of uncertainty in this analysis. Labor costs vary across U.S. states (wage rates) and from company to company (productivity), including operating O&P margin assumptions. Other areas of uncertainty include inverter prices, wiring materials content, supply chain costs (installer channel to market), and site-specific costs (land acquisition, preparation, permitting costs, etc.). For these reasons, it is very difficult to compare one project to another or to generalize the cost of PV systems without including a substantial error bar.

The following uncertainty analysis considered a reasonable range of values for major system parameters based on published data and installer-reported information. The values depicted in this analysis are benchmark 2010. Due to rapidly changing conditions, assumptions for parameters such as module prices may vary significantly from those presented here if the first quarter of 2011 were to be considered, for example.

Triangular distributions were assumed for all of the key variables. The most frequently reported values for each assumption ("mode") were provided by collaborating system installers or, in the case of wage rates, depict U.S. national average values (2010). However, much of the U.S. PV market has occurred, to date, in California, which has a wage rate higher than the national average. Therefore, the distribution function depicted in this analysis does not necessarily depict the distribution of prices that may be encountered or reported in the United States in 2010. The Monte Carlo analysis is intended to provide insights into those factors that most contribute to uncertainty in the price analysis results based on the assumptions presented above.

Figure 16 summarizes the results of the Monte Carlo analysis for residential, commercial, and utility-scale (fixed- and one-axis) systems. The following sections detail the analyses for each type of system.

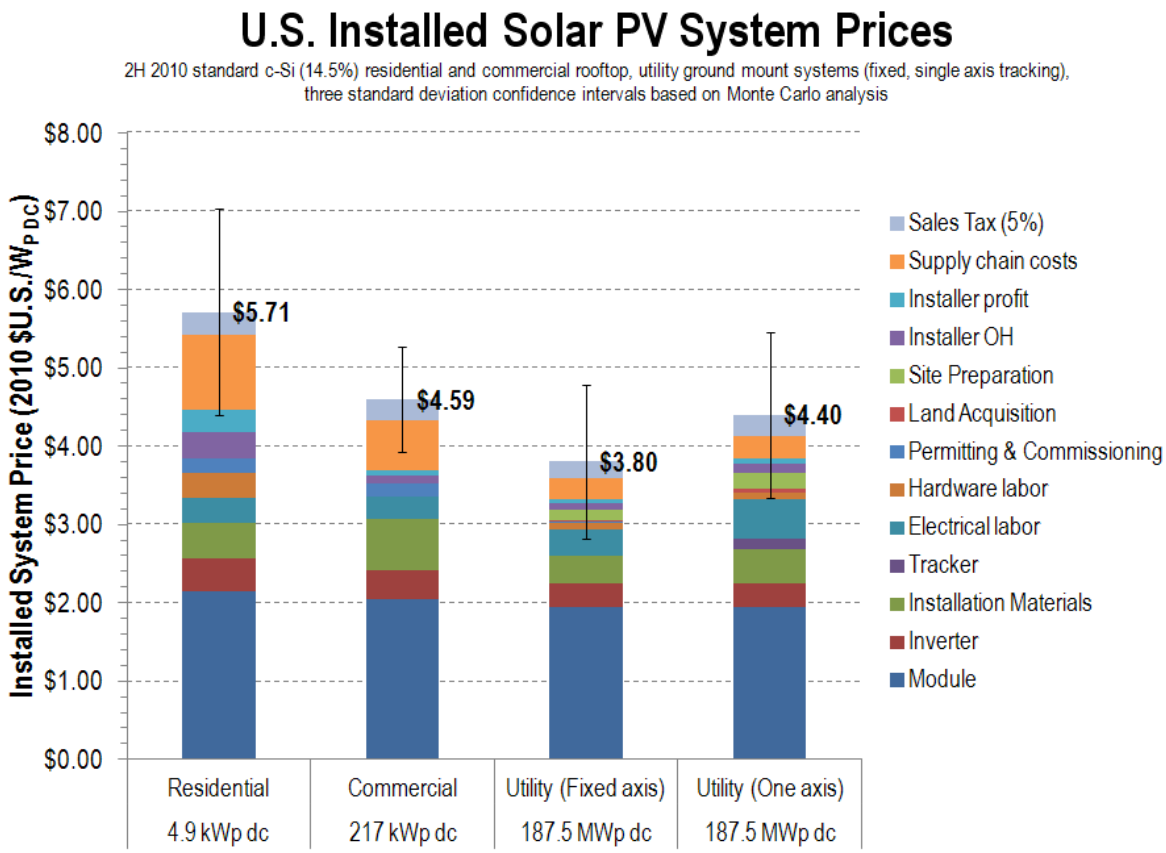

Figure 16. PV system price analysis: Monte Carlo analysis results.

Residential Rooftop PV Systems

The following Monte Carlo simulation of residential PV system prices resulted in a standard deviation of $0.44/$W_{P\ DC}$, or 7.7%. Based on a range of reasonable 2010 U.S. assumptions for the independent variables considered in Table 5, and considering a 35-m^2 system size, a reasonable range of residential PV system prices was found to be between $4.39 and $7.04 per $W_{P\ DC}$, before consideration of subjective values that influence customer perception of system value (price), such as incentives, local retail electricity rates, etc.

Table 5. Residential PV System Price Analysis: Monte Carlo Simulation Assumptions.

Residential PV System Price: Key Assumptions (Monte Carlo variables)				
Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	19.60%
[2] Module price	per $W_{P\,DC}$	$1.87	$2.15	$2.35
[3] Module size	m^2	1.28	1.28	1.64
Installation Labor				
[4] Electrical	$ per hour	$16.66	$49.00	$81.34
[4] General construction	$ per hour	$11.25	$33.10	$54.95
[5] Labor content (all types)	hours	48.5	64.7	80.9
[6] Operating overhead		25%	54%	65%
[7] Profit on labor		10%	30%	35%
Inverter				
[†] Inverter price	per $W_{P\,DC}$	$0.25	$0.42	$0.65
Installation Materials				
[†] Mounting hardware	per module	$52.29	$69.71	$89.25
[†] Wiring, conduit, connectors	per module	$3.60	$4.80	$6.14
[†] Supply chain costs	%-materials price	15%	30%	35%
Site work				
[†] Permitting		$0.00	$0.00	$500.00
[†] Grid Interconnect		$0.00	$900.00	$2,000.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

This range falls short of the ranges reported by the CSI for the same period (Barbose et al. 2011). An explanation of the deviation between NREL's expected system prices and CSI-reported data must include the following factors: system size (m^2), time lag between ex-factory gate module and retail prices, *market price* (impact of financing and incentive options), regional differences in labor and regulatory (permitting and commissioning) costs, and the potential for correlations between these factors. For example, high regulatory costs may correlate to high wage rate locations, such as the case in California. Figure 17 shows results of the Monte Carlo analysis for residential PV systems.

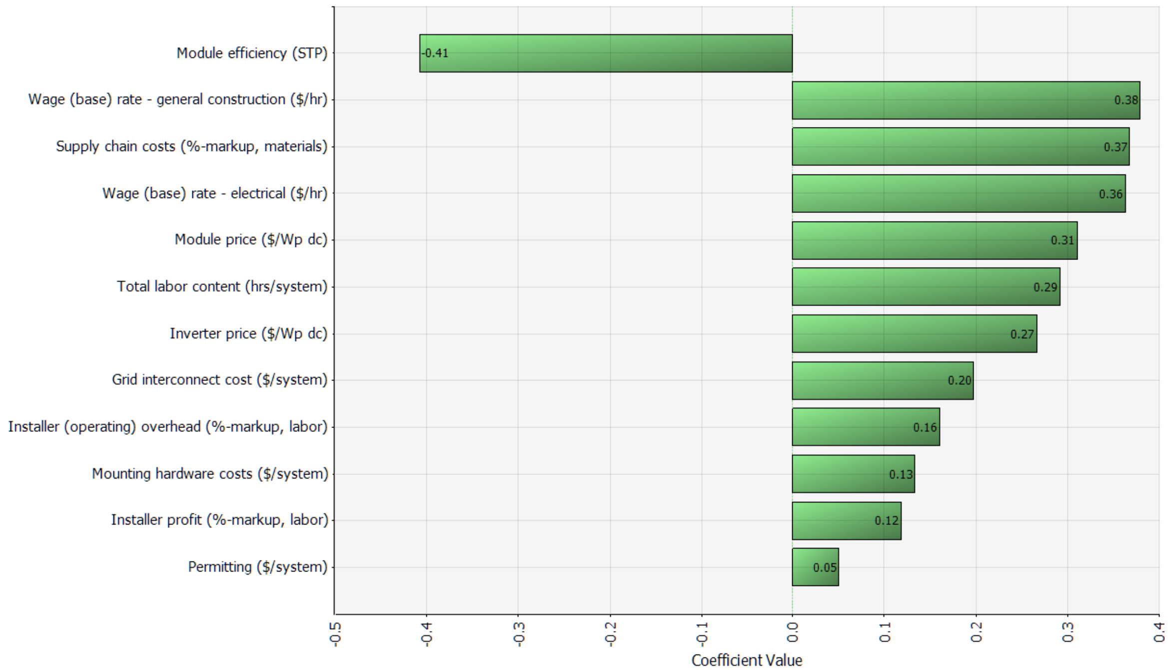

Figure 17. Residential PV system price analysis: Monte Carlo analysis results, regression coefficients (key variables).

The value of module efficiency is greatest in area-constrained (e.g., rooftop) PV systems. In residential rooftop systems, module efficiency is critical because many of the project overhead, hardware, and labor costs are either area related or fixed, making system size critical to a low $/W system price.

Labor and supply chain (material) costs contribute significantly (coefficients greater than 0.35) to the uncertainty in NREL's estimate of 2010 residential PV system prices. This is due to the large standard deviation observed in U.S. wage rates (regional) in 2010 and the relatively high contribution of material prices to system price.

Commercial Rooftop PV Systems

PV systems installed on commercial buildings (rooftops) tend to use c-Si modules due to the high value of module efficiency in area-constrained rooftop applications. Module efficiency and price assumptions were based on the range of data collected by NREL in the second half of 2010, which included standard multicrystalline through nonstandard monocrystalline modules. Relative to residential rooftop systems, module efficiency has less effect on the commercial rooftop price uncertainty analysis. This is primarily due to the reduced relative contribution of labor (O&P) and materials (supply chain) related cost multipliers. As the cost of labor and area-related hardware is reduced, the value of efficiency gains is diminished.

With regard to installer overhead, including operating overhead and installer-margin rates, the commercial rooftop PV sector lies somewhere between a residential system (high overhead costs) and a utility installation performed by a vertically integrated module manufacturer/installer. The markup of burdened labor costs to account for overhead rate (mode = 32%) and profit margin (mode = 20%) are based on the rates observed by NREL during 2010. While these costs are lower than the rates observed in the residential sector, they are still higher than in a mature industry, such as electrical contractor services. The markup on materials (mode = 20%) related to supply chain costs, like inventory and contingency, reflects the more streamlined channels to market that commercial rooftop system installers rely on, relative to residential installers. These wholesale distribution channels afford commercial installers lower-cost materials.

The commercial rooftop PV system was found to have a standard deviation of $0.224/$W_{P\ DC}$, or 4.9%. Based on the range of assumptions considered here (Table 6), in 2010 a reasonable objective system price for commercial rooftop systems was found to be between $3.92/$W_{P\ DC}$ and $5.27/$W_{P\ DC}$ for a 217-k$W_{P\ DC}$ U.S. commercial PV system, cash purchase, before subsidy.

Figure 18 shows results of the Monte Carlo analysis for commercial PV systems. In addition to the relative contribution of module efficiency to both the residential and commercial rooftop sectors, the impact of module size is a notable variable to contrast, in terms of its impact on system price. In residential systems, module size (m^2) did not have a significant effect on system price. However, as the rooftop system size is increased from 5 kW to 217 kW, the contribution of module size (m^2) becomes more prominent. That is, the relative contribution of module installation time (hours per module × number of modules) and labor costs is greater as a percentage of project costs for commercial systems than it is for residential systems.

Table 6. Commercial PV System Price Analysis: Monte Carlo Simulation Assumptions.

Commercial PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	19.60%
[2] Module price	per W_{PDC}	$1.79	$2.05	$2.25
[3] Module size	m^2	1.28	1.64	1.64
Installation Labor				
[4] Electrical	$ per hour	$16.66	$49.00	$81.34
[5] General construction	$ per hour	$11.25	$33.10	$54.95
[6] Operating overhead		16%	32%	54%
[7] Profit on labor		10%	20%	30%
Inverter				
[†] Inverter price	per W_{PDC}	$0.20	$0.37	$0.55
Installation Materials				
[†] Mounting hardware	per module	$52.29	$69.71	$87.14
[†] Wiring, conduit, connectors	per module	$3.60	$4.80	$6.00
[†] Supply chain costs	%-materials price	10%	20%	30%
Site work				
[†] Permitting		$0.00	$10,000.00	$50,000.00
[†] Grid Interconnect		$0.00	$2,000.00	$2,000.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

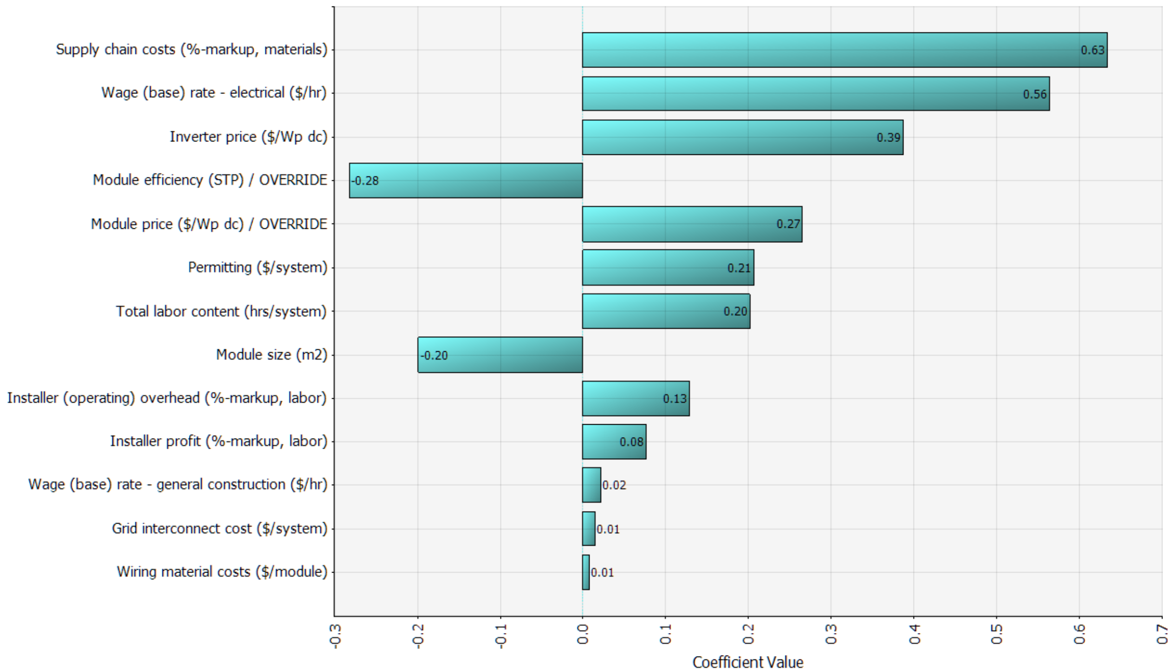

Figure 18. Commercial PV system price analysis: Monte Carlo analysis results, regression coefficients (key variables).

Ground-Mount Utility-Scale PV Systems

Utility-scale PV systems that use one-axis tracking tend to rely on c-Si PV modules. For one-axis systems, the range of module prices and correlated efficiencies, both of which are important to system price estimates, are based on commercially available c-Si modules only. For fixed-axis utility-scale systems, CdTe modules were also considered (module price, efficiency, area per module).

Labor cost assumptions were based on national average wage rates. All other independent variables included in the Monte Carlo analysis were based on ranges commonly encountered by collaborating installers of utility-scale systems in 2010.

The price estimate for one-axis, ground-mount, utility-scale PV systems was found to have a standard deviation of \$0.352, or 8.0%. Based on the range of assumptions considered (Table 7), in 2010 a reasonable objective system price was found to be between \$3.35/$W_{P\,DC}$ and \$5.46/$W_{P\,DC}$ for a 187.5-$MW_{P\,DC}$ U.S.-based, one-axis, utility-scale, ground-mount PV system, cash purchase, before subsidy.

Figure 19 shows results of the Monte Carlo analysis for one-axis utility-scale PV systems. The most significant factor affecting price was found to be electrician wage rate, followed by land use. Land use drives many system-related price factors, such as site preparation, wiring materials, and wiring-related labor. Land-acquisition cost is a relatively small contributor to system price. The wide range of U.S. wage rates for electricians has a significant impact on system price estimates. Although average U.S. wage rates were considered in the baseline analysis, many installations have been constructed in California, where wage rates tend to be higher than the national average.

Module size also had a major effect on system price owing to a fixed module installation time (hr/module) and short wiring requirements (materials and labor). As long as larger modules do not require special installation equipment (such as cranes, etc.), then there is a beneficial economy of scale for large modules. CdTe modules, such as those sold by First Solar, are available in 0.72-m^2 sizes, while a module from SunPower for utility applications is available in a size of 2.16 m^2 (First Solar 2011, SunPower 2011).

One-axis systems were found to be approximately 15%–20% more expensive than fixed-axis systems. Fixed-axis systems were found to have a standard deviation of approximately \$0.34/$W_{P\ DC}$ (7.7%). Many of the factors that affect fixed-axis systems price are similar to those described above for the one-axis system, including module size, electrician wage rate, and land use. Module price, however, had more effect on fixed-axis than on one-axis systems because CdTe modules were excluded from the one-axis system analysis but included for the fixed-axis analysis. Thus, the range of module prices was narrower for the one-axis systems, thereby reducing the impact of module price on system price uncertainty. Table 8 shows the assumptions considered for fixed-axis utility-scale PV systems, and Figure 20 shows the corresponding Monte Carlo analysis results.

Table 7. One-Axis Utility-Scale PV System Price Analysis: Monte Carlo Simulation Assumptions.

Utility (1-Axis) PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	18.50%
[2] Module price	per W_{PDC}	$1.70	$1.95	$2.14
[3] Module size	m^2	1.28	1.96	2.16
Installation Labor				
[4] Electrical wage	$ per hour	$16.66	$49.00	$81.34
[5] Electrical labor content	hours/kW_{PDC}	0.633	0.844	1.055
[4] General construction wage	$ per hour	$11.25	$33.10	$54.95
[5] General construction labor content	hours/kW_{PDC}	0.139	0.185	0.231
[6] General overhead		22.70%	22.70%	22.70%
[6] Operating overhead		16%	22%	28%
[7] Profit on labor		10%	10%	30%
Inverter				
[†] Inverter price	per W_{PDC}	$0.15	$0.29	$0.35
Installation Materials				
[†] Tracker	per m^2 (active area)	$7.5	$10	$80
[†] Other mounting hardware	per m^2 (active area)	$20	$30	$40
[†] Wiring, conduit	per m^2 (system area)	$3.3	$6.5	$9.8
[†] Supply chain costs	%-materials price	5%	10%	15%
Site work				
[†] Land requirements	acres/MW_{PDC}	5.0	8.0	12.0
[†] Land acquisition	per acre	$500.0	$5,025	$10,000
[†] Site preparation	per acre	$5,000	$25,000	$60,000
[†] Environmental permitting	$ millions	$0.10	$1.00	$5.00
[†] Grid Interconnect		$1.00	$1.60	$10.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

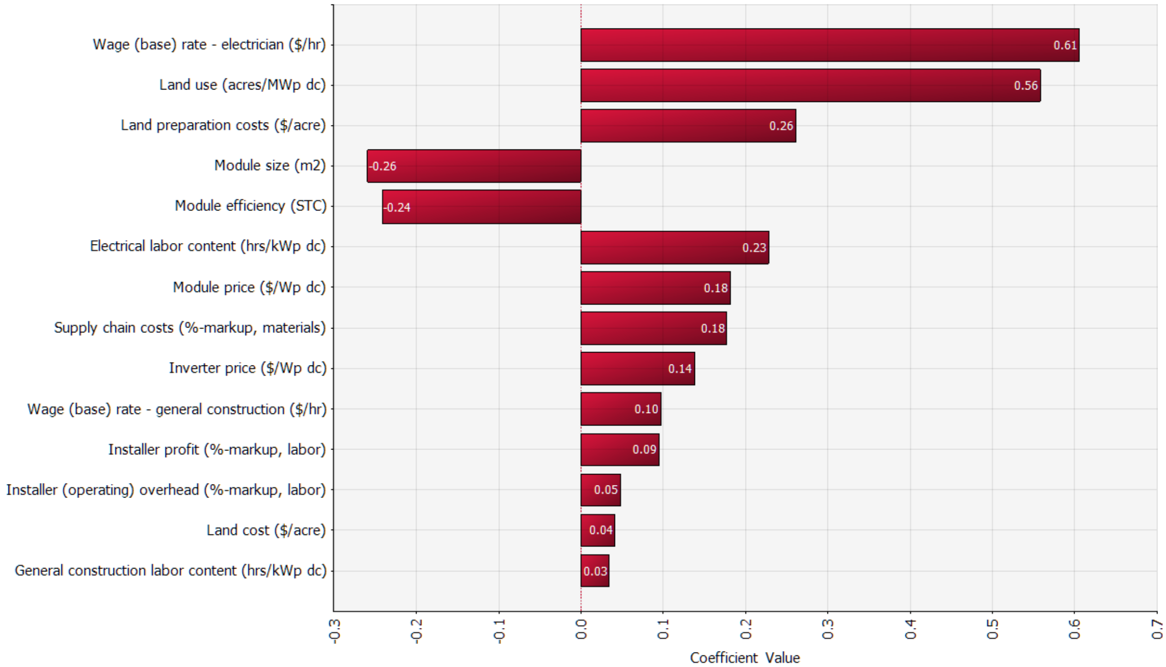

Figure 19. One-axis utility-scale PV system price: Monte Carlo analysis results, regression coefficients (key variables).

Table 8. Fixed-Axis Utility-Scale PV System Price Analysis: Monte Carlo Simulation Assumptions.

Utility (Fixed) PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	11.6%	14.5%	18.50%
[2] Module price	per $W_{P\,DC}$	$1.29	$1.95	$2.14
[3] Module size	m^2	0.72	1.96	2.16
Installation Labor				
[4] Electrical wage	$ per hour	$16.66	$49.00	$81.34
[5] Electrical labor content	hours/$kW_{P\,DC}$	0.633	0.844	1.055
[4] General construction wage	$ per hour	$11.25	$33.10	$54.95
[5] General construction labor content	hours/$kW_{P\,DC}$	0.139	0.185	0.231
[6] General overhead		22.70%	22.70%	22.70%
[6] Operating overhead		16%	22%	28%
[7] Profit on labor		10%	10%	30%
Inverter				
[†] Inverter price	per $W_{P\,DC}$	$0.15	$0.29	$0.35
Installation Materials				
[†] Other mounting hardware	per m^2 (active area)	$20	$30	$40
[†] Wiring, conduit	per m^2 (system area)	$3.3	$6.5	$9.8
[†] Supply chain costs	% -materials price	5%	10%	15%
Site work				
[†] Land requirements	acres/$MW_{P\,DC}$	3.0	5.0	8.0
[†] Land acquisition	per acre	$500.0	$5,025	$10,000
[†] Site preparation	per acre	$5,000	$25,000	$60,000
[†] Environmental permitting	$ millions	$0.10	$1.00	$5.00
[†] Grid Interconnect		$1.00	$1.60	$10.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)*, Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)*, Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

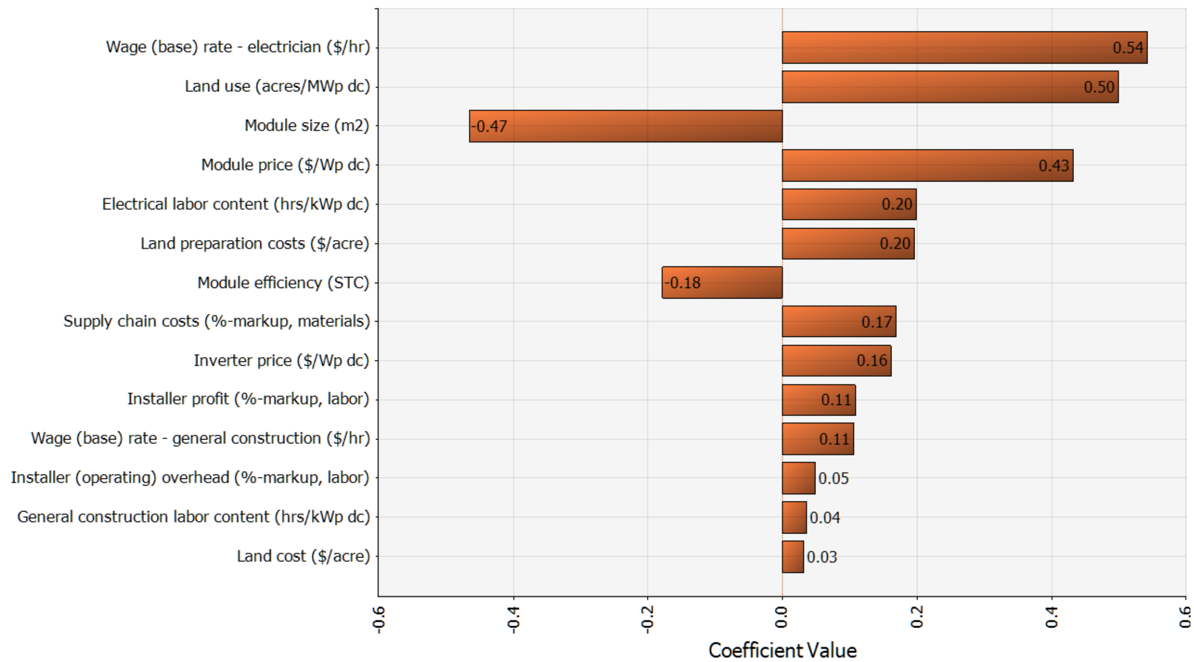

Figure 20. Fixed-axis utility-scale PV system price: Monte Carlo analysis results, regression coefficients (key variables).

Appendix B: PV System Land Costs

In collaboration with industry stakeholders, NREL has developed detailed models to quantify residential rooftop, commercial rooftop, and ground-mount utility-scale PV system installation prices. A number of assumptions used in this bottom-up cost and price analysis contribute to the uncertainty levels for ground-mount utility-scale systems (mean system price, fixed-axis utility: $3.80/$W_{P\ DC}$, standard deviation = $0.33/$W_{P\ DC}$). A particularly wide range of U.S. land costs has been observed over the past two years, from $500 to $105,000 per acre.

This appendix summarizes NREL's research of the factors that drive land costs for solar farms and their impact on installed system prices. Public and private information sources were used in this analysis. Data from third-party collaborators have been aggregated to ensure the protection of potentially business-sensitive data.

The cost of land for ground-mount utility-scale PV farms generally varies by region. More specifically, the cost varies by the following eight site-evaluation criteria (listed in order of importance by impact on land costs, according to system developers interviewed for this report).

1. **Available solar resources**
   Developers of solar projects first evaluate potential locations based on each site's available solar irradiance. If the level of solar resources is not acceptable, a site is not considered. If a site is considered to have suitable solar resources, the estimated amount of energy that can be produced from the site affects a developer's land-cost estimate.
2. **Proximity to transmission infrastructure**
   The proximity of a potential site to buildable transmission infrastructure can make or break a project, in terms of costs. It has been estimated that grid interconnection costs (substation materials and labor, commissioning) range, depending on project size, from $1.0 million (69 kV) to $3.0 million (230 kV). The cost of constructing new transmission infrastructure or adding capacity to existing transmission lines can be $20–$80 million for a 20-MW system ($1/W–$4/W). In most cases, the high end of this estimated range would be prohibitive for project developers.
3. **Expected permit fees and delays ("permit-ability")**
   The cost of permitting a prospective site depends greatly on local requirements as well as current zoning for the location and its estimated population of endangered species. Sites that have been used in the past for industrial or agricultural purposes ("previously disturbed") may be more easily developed than virgin land, which desert tortoises or other protected species may inhabit.
4. **Topography (site-preparation requirements)**
   In terms of preferred PV site topography, the "flatter the better." Nevertheless, PV's requirement for leveling is far less than would be required for solar thermal towers, for example. If a site is relatively flat, then a PV developer may only have to complete a minimal amount of leveling for construction. Reducing the amount of grading and leveling that must be performed not only reduces costs, but it can also speed up the community acceptance of a project and the site-permitting processes.

In addition to the cost of the land itself, site-preparation costs can range from $5,000 to $25,000 per acre, which includes leveling, sediment control, hydrology, road construction, and vegetation removal.

5. **Size (continuous acreage)**
   For large PV farms, a continuous tract of suitable land can be difficult to acquire. In some cases, oddly shaped parcels of land can increase construction costs. It is estimated that 5–8 acres are required per MW of capacity, depending on efficiency and mounting configuration (fixed-axis systems are typically at the lower end of the range, one-axis tracking systems are typically at the higher end). However, it has been observed that initial land purchases can be up to 1.8–2.0 times greater than these figures. For large projects, it reportedly adds little to no cost to negotiate with multiple land owners.
6. **Availability of water for construction**
   Water is required during construction of a solar farm for the purpose of dust control. Transporting water can increase construction costs.
7. **Community acceptance of PV**
   Communities that oppose the construction of a PV farm can add permitting and litigation costs to a project and contribute to project delays. The project delay period due to permitting is 1 year (minimum) and up to 2–3 years in most cases, including interconnection and transmission permitting.

   In California, for example, the Solar Environmental Quality Act (SEQA) can add approximately $1 million to a project that targets construction in a community that is relatively "accepting." The SEQA process affords opponents of a project the opportunity to add significant delays to the construction of a PV farm, via the following steps: 1) Scoping meeting—developer and county planning agencies explain project to public; 2) Conditional use permit is requested by developer; 3) Interveners have the opportunity to raise objections, draft impact statements; 4) Interveners can appeal decisions regarding their objections; 5) Finally, if appeals fail, interveners can sue the developer.
8. **Subsurface conditions**
   A site's subsurface conditions can impact a project's hardware and site-preparation costs. If, for example, a desert location has dry, cracked soil, a polymer-based emulsion such as Gorilla Snot may be required to treat the surface prior to construction. Unstable subsurface conditions may require additional footings for ground-mount hardware.

According to industry stakeholders interviewed by NREL, most "prime land is tied up" by speculators or system developers. This includes not only private land, but also parcels owned by the Bureau of Land Management (BLM). Stakeholders interviewed for this analysis also recommended a streamlined permitting process for standardized system designs. Specifically, they said state and municipal permitting agencies should be encouraged to accept standard system designs that have been pre-approved, which should fast track standard systems.

Based on the above criteria that system developers and installers use to identify "suitable" land for PV projects, the cost of land (purchase price) is generally about twice the *market price*. Speculators and the demand for sites that are well suited to PV has created a "land rush" and driven up the price for PV lands in many areas (Woody 2008).

Installers have generally estimated the cost of privately owned solar-suitable land to be $5,000 –$10,000 per acre (statistical mode) but as low as $500 per acre and as high as $105,000 per acre, in extreme cases (Beck and Hillman 2009). A land lease generally costs 10% of the estimated land purchase price per acre per year. Land owned by the BLM is often double these market figures, in terms of equivalent lease costs ($800–$1,200 per acre per year). Projects developed on leased land have lower upfront capital costs but are subject to additional operating costs. Because land leases are currently a popular choice for acquiring land for solar projects, it is important that all analyses pertaining to the capital cost of solar projects note this variation.

The land requirements for PV systems vary depending on each project's module technology (efficiency) and mounting structure (tracking or fixed). It has been estimated that standard (industry median) c-Si modules (14%–15% efficiency) require 5 acres/MW for fixed-axis and 8 acres/MW for one-axis tracking configurations. For one-axis tracking systems, the space between rows must be greater to allow for larger shadow lengths (avoid shadowing losses). The land requirement for lower-efficiency (e.g., 11%-efficient thin film) modules on fixed-axis mounting structures is estimated to be about 7 acres/MW.

The above estimates for land use may differ somewhat from reported land purchases and project sizes due to two factors. First, developers often purchase additional land that may be used if a site has limiting features, such as wetlands, difficult topography, or protected areas. Second, developers often purchase more land than is required to ensure that they can meet minimum power production guarantees issued under PPAs and other contractual agreements.

The cost of land for ground-mount PV is typically less than 1% of the system price. Nevertheless, a poorly chosen site can add more than 100% to an installed system price due to transmission costs. For the purpose of this report, mean site-preparation ($25,000/acre) and land-acquisition costs ($5,025/acre) were considered.

The cost of permitting a site ($1,000,000) also includes project delays, which NREL chose to capture both in terms of materials markup (10%, reflecting the cost of materials inventory and project contingencies) and installer overhead rates (16%, reflecting the cost of filing permits). Materials markup, labor overhead, and installer profit are captured in "installer overhead and profit."

Appendix C: Long Term Module Price Trajectories

NREL has constructed detailed manufacturing cost models for wafer-based c-Si PV and other PV technologies. As discussed in the body of the paper, NREL used these models to estimate that an evolutionary development trajectory for PV modules will lead to industry median c-Si modules with an ex-factory gate price of about $1.01/$W_{P\ DC}$ by 2020. Further, it is estimated that these costs could be achieved along with an average production module efficiency of 21.5%—equivalent to a production cell efficiency of approximately 24%. As shown in Figure 9, under a more optimistic set of model assumptions, 21.5%-efficient, single-junction, wafer-based c-Si PV could reach a direct manufacturing cost of $0.58/$W_{P\ DC}$ and a minimally sustainable average selling price of $0.68/$W_{P\ DC}$. While these levels of cost reductions and technological improvements would represent substantial progress, they are not sufficient to achieve the SunShot Initiative's overall installed system target of $1/W. This appendix explores the trajectories required for achieving substantial module price reductions as the PV industry grows over time.

The rate at which manufacturers of c-Si modules can achieve the cumulative production experience that is needed to reach ambitious cost and performance targets is highly uncertain. Learning curves for c-Si and CdTe are shown in Figure 21. A learning curve is a log-log plot of the cost or price of a product versus the cumulative production volume of that product.[23] Studies of historical data from multiple industries indicate there is typically a constant reduction in cost or price for every doubling of cumulative production volume. This is termed the progress ratio. For PV modules, data going back about 30 years have shown that the learning curve yields an approximate 20% reduction in cost for every doubling of cumulative volume. Two aspects of learning curves should be stressed, however. One is that the historical cost reductions represent many different factors in scale and innovation; in other words, "learning" does not just happen but is the result of specific actions and investments. The second aspect is that continued progress is not guaranteed and that over time a learning curve may flatten out. That being said, learning curves have been used to set benchmarks for and to project future cost reductions.

Using the historical PV learning curve to project future cost reductions suggests that, if historic learning trends continue, the cumulative installed c-Si capacity would need to reach about 4 TW in order to achieve a module average selling price (ASP) of $0.68/$W_{P\ DC}$. For comparison, total global installed electricity generating capacity was 4.4 TW in 2007 and is projected to grow to about 7 TW by 2035 (International Energy Agency 2010).

Single-junction PV modules based on CdTe materials have similar first principle constraints that limit the extent to which efficiency can be increased and costs reduced. First Solar is the largest manufacturer of these devices and has provided investors with guidance on the cost and performance roadmap for their modules, including a 2014 cost target of $0.52/$W_{P\ DC}$ and module efficiency of 14.4% (First Solar 2009). Assuming these targets are met, and further assuming that single-junction CdTe modules can achieve a module efficiency of 18% at no added ($/$m^2$) cost, then a manufacturing cost of $0.39/$W_{P\ DC}$ could be reached.[24] This corresponds to a minimum

[23] Learning curves can be based on either cost or price, although learning curves using price can be distorted due to changes in margins over time.
[24] It is estimated by NREL that the pathway to 18%-efficient CdTe modules will incur added costs per square meter, including, for example, the cost of low-iron glass and reduced process throughputs. Here, the net zero cost impact

module selling price of $\$0.49/W_{P\ DC}$. The CdTe-based learning curve shown in Figure 21 suggests that, if the historical learning rates can be maintained, then a cumulative installed CdTe capacity of 100 GW would need to be reached to achieve a module ASP of $\$0.49/W_{P\ DC}$.

Having estimated the best practical manufacturing costs and device efficiencies (experience curve asymptotes), it is possible to forecast the time required to reach these targets using historical learning rates and a range of global PV market growth projections. In order to bracket the uncertainty in this analysis, two cases were considered: Case 1 (10% of electricity from PV by 2050) and Case 2 (20% of electricity from PV by 2050). Both cases assume that the global demand growth rate for PV installations will, at some point, saturate and diminish to a mature rate that is representative or equal to the growing demand for all electric energy. In these scenarios, it is assumed that the demand for PV grows to approximately 10% or 20% of global energy production by 2050 and that current c-Si and CdTe device market shares remain constant at 88% and 12%, respectively.

As shown in Figure 22, projecting module selling prices based on historical learning rates using the 10% and 20% growth trajectories implies that c-Si will reach its lower bound price of $\$0.68/W_{P\ DC}$ around 2040 or later, and CdTe will asymptote at $\$0.49/W_{P\ DC}$ around 2020 or later. In order to assess how these module prices relate to achieving a total installed system price of \$1/W, they need to be combined with non-module system costs and installer margins.

---

assumes that these added costs will be offset by further manufacturing efficiency and economies of scale benefits. This is an optimistic set of assumptions, given the aggressive module performance assumed.

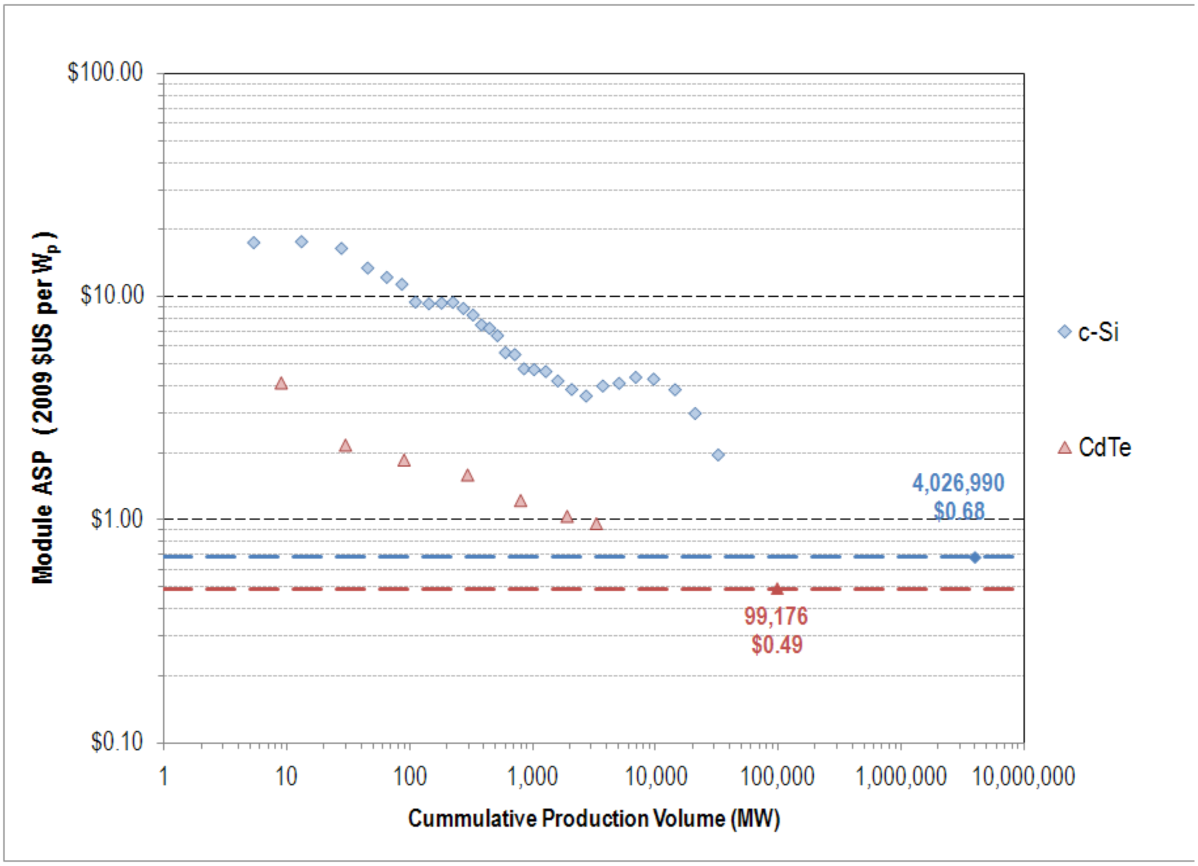

Figure 21. Single-junction c-Si and CdTe PV module experience learning curves
Source: First Solar (2009), Mints (2006), Mints (2010), Strategies Unlimited (2003), NREL internal cost models.

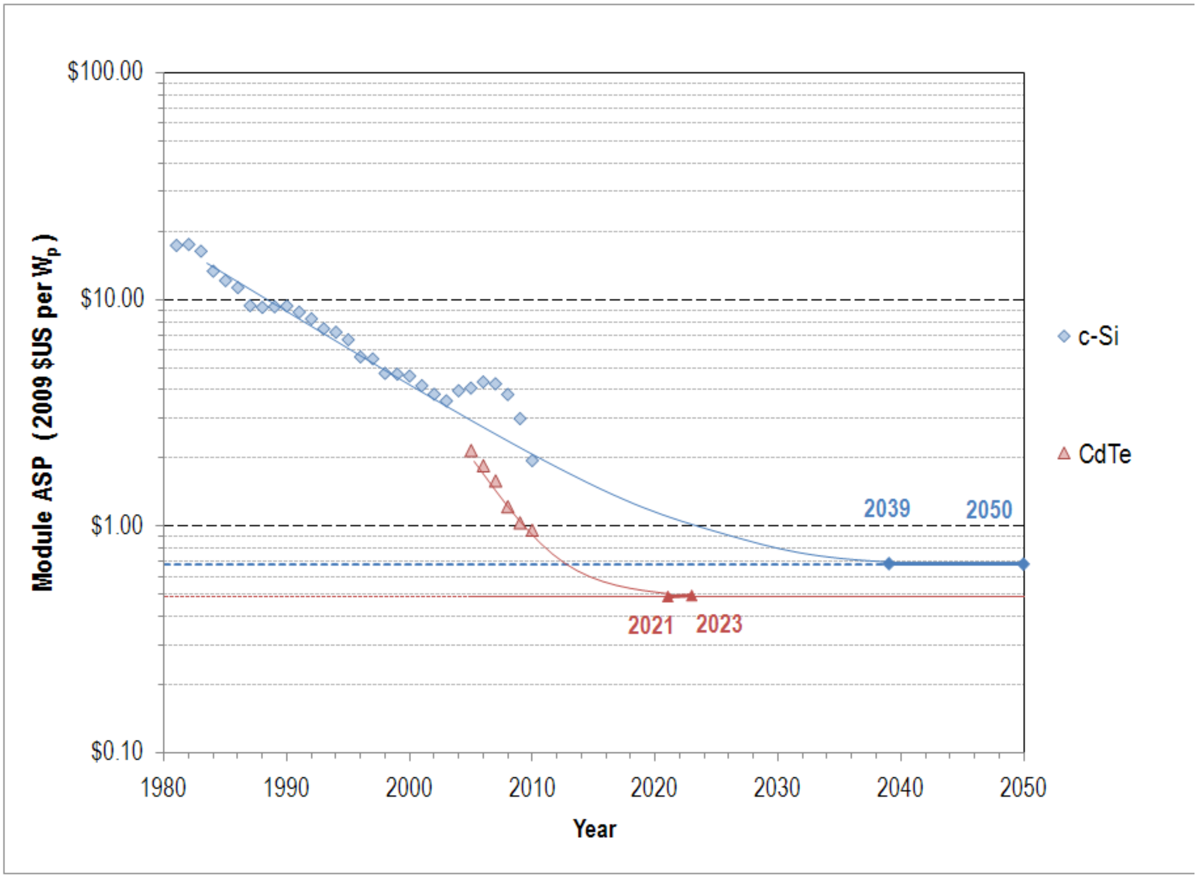

Figure 22. Historical and projected c-Si and CdTe module average selling prices (ASPs) Source: First Solar (2009), Mints (2006), Mints (2010), Strategies Unlimited (2003), NREL internal cost models.