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Prepared under Task No. SS12.2260

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List of Acronyms

a-Si	Amorphous silicon
BAPV	Building-applied photovoltaics
BIPV	Building-integrated photovoltaics
c-Si	Crystalline silicon
CF	Capacity factor
CIGS	Cadmium indium gallium diselenide
DOE	U.S. Department of Energy
GW	Gigawatt (1 billion watts)
IEA	International Energy Agency
LCOE	Levelized cost of energy
Pmpp	Power maximum power point
PV	Photovoltaics
SAM	System Advisor Model
WACC	Weighted average cost of capital
WVTR	Water vapor transmission rates
$\$/W_{p\ DC}$	U.S. (2010) dollars per peak watt of DC PV capacity

Executive Summary

For more than 30 years, there have been strong efforts to accelerate the deployment of solar-electric systems by developing photovoltaic (PV) products that are fully integrated with building materials. Despite these efforts and high stakeholder interest in building-integrated PV (BIPV), the deployment of PV systems that are partially or fully integrated with building materials is low compared with rack-mounted PV systems, accounting for about 1% of the installed capacity of distributed PV systems worldwide by the end of 2009. In this report, we examine the cost drivers and performance considerations related to BIPV for residential rooftops. We also briefly review the history of BIPV product development and examine market dynamics that have affected commercialization and deployment.

As with many renewable energy technologies, system prices—in terms of dollars per installed watt of direct-current peak power capacity ($\$/W_{p\ DC}$)—have a significant effect on PV deployment. In general, the installed prices of BIPV systems are higher than PV system prices, but the cause of these price premiums—higher costs, higher margins, or other considerations—and the potential for price reductions remain uncertain. Using a bottom-up analysis of components and installation labor costs, we explore the cost trade-offs that affect the prices of residential rooftop BIPV systems. We compare the prices of three hypothetical BIPV systems with the price of a rack-mounted crystalline silicon (c-Si) PV system, the "PV Reference Case," which is the most commonly installed residential system technology. One of the BIPV cases is a derivative of the c-Si PV case ("BIPV Derivative Case"), and the other two BIPV cases are based on an analysis of thin-film technologies (Table ES-1). In today's solar market, few BIPV products are fully integrated with building materials as envisioned in these BIPV cases; therefore, the cases should be seen as near-term possibilities. In contrast, the PV Reference Case represents a 2010 benchmark system price from an NREL study that uses the same methodology to assess objective system prices (Goodrich et al. 2011). Comparing the hypothetical near-term BIPV cases with the 2010 PV benchmark does not account for the continued advancements and cost reductions in rack-mounted PV systems. Thus, the potential cost advantages we have identified for BIPV installations are likely to change. Additionally, our analysis assumes that economies of scale and installer experience are equivalent for the PV Reference Case and the BIPV cases.

Table ES-1. Summary of Cases Used to Analyze Residential Rooftop PV System Prices

Scenario	Technology	Form	Efficiency	Module Area (m^2)
PV Reference Case	c-Si	Rigid	14.5%	1.28
BIPV Derivative Case	c-Si	Rigid	13.8%	0.58
BIPV Thin-film Case 1	CIGS	Rigid	11.2%	0.58
BIPV Thin-film Case 2	a-Si	Flexible	5.8%	0.58

a-Si—amorphous silicon; CIGS—$Cu(In,Ga)Se_2$; c-Si—crystalline silicon.

A summary of the analysis of PV and BIPV systems prices is shown below in Figure ES-1. The listed "effective prices" account for cost offsets due to an assumption that the BIPV cases replace traditional building materials; in this example, they replace asphalt shingles. Our findings suggest that BIPV has the potential to achieve system prices that are about 10% lower than rack-mounted PV system prices (i.e., the BIPV Derivative Case).The bulk of the BIPV cases' potential savings stem from eliminating the cost of module-mounting hardware—which rack-mounted PV systems need but BIPV systems do not—and from offsetting the cost of traditional building materials. BIPV labor savings result from the elimination of mounting hardware and our assumption of lower-cost roofing contractors in place of electricians. Some installation labor costs increase, however, due to the increased time that is required to install a greater number of smaller BIPV modules for a given area (i.e., more total electrical interconnections and wiring). Module costs and efficiencies are key factors that contribute to overall system prices across all of the cases, and we assume that the BIPV cases have lower efficiencies.

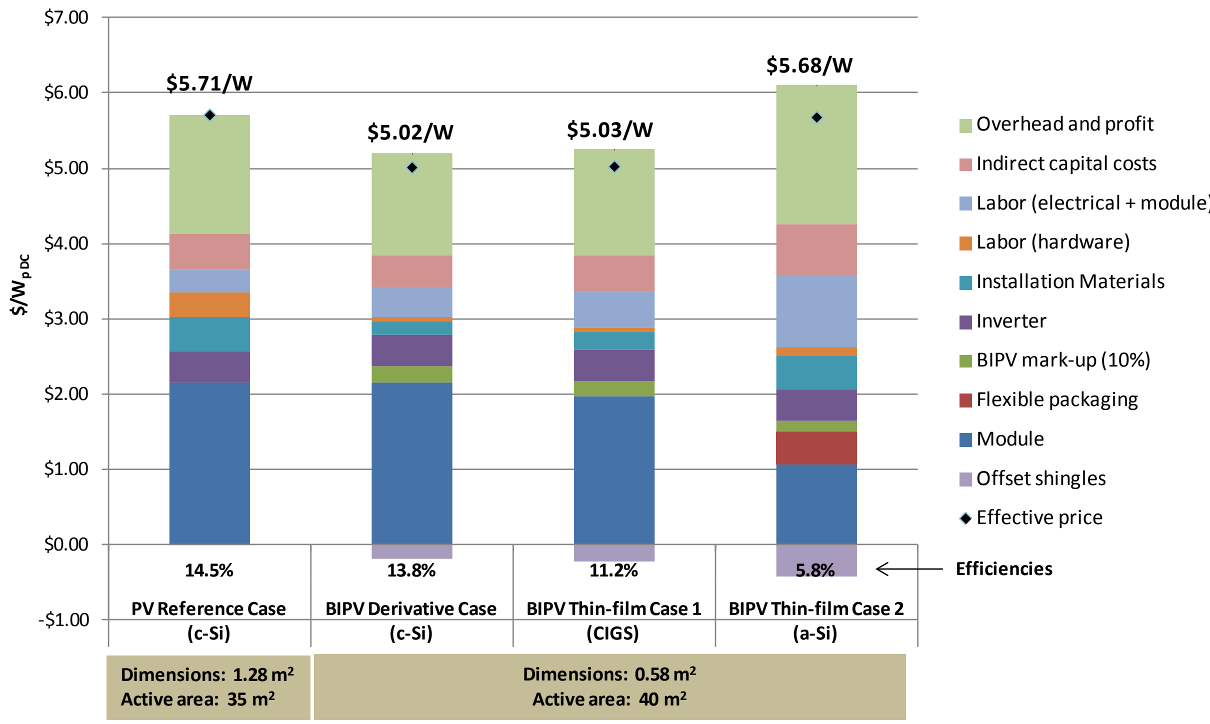
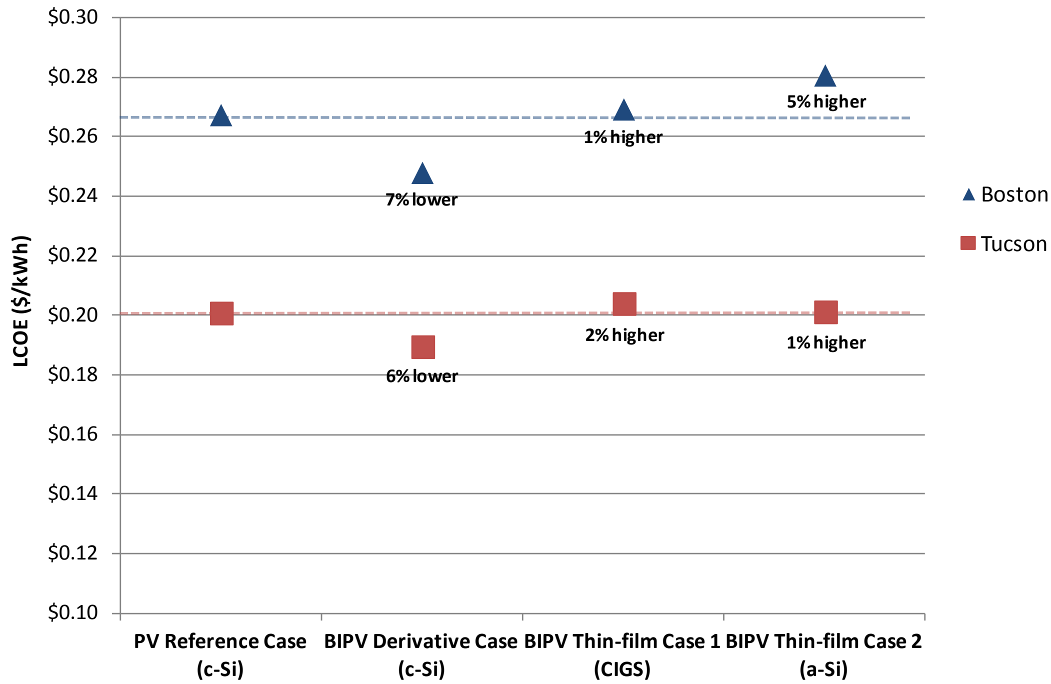


Figure ES-1. Comparison of residential rooftop prices for a rack-mounted the PV Reference Case and three BIPV cases.

Note: Listed BIPV prices include building-material cost offsets (shown as negative bars).

This report shows the potential for BIPV to achieve lower installed system prices than rack-mounted PV, but BIPV systems are likely to experience reduced performance (i.e., electricity generation) in comparison with PV systems. Unlike traditional PV systems that commonly include air spaces between the module and roof deck, BIPV systems are mounted directly on building surfaces, and this results in higher average operating temperatures in most environments. Resulting performance losses could affect the economic viability of BIPV projects. We assess comparative project economics by analyzing the unsubsidized levelized cost of energy (LCOE) for each case. Figure ES-2 summarizes the results of this LCOE analysis. The relative range of LCOE values differs from the relative range of installed system prices owing to differences in module efficiencies, degradation rates, and temperature coefficients.

These results show that c-Si BIPV shingles might achieve a lower LCOE than rack-mounted c-Si PV if installed system price advantages are fairly significant (i.e., greater than 5%). In cases where estimated BIPV cost advantages are small, expected performance losses may result in higher LCOE values, as shown in BIPV Thin-film Cases 1 and 2.



	PV Reference Case (c-Si)	BIPV Derivative Case (c-Si)	BIPV Thin-film Case 1 (CIGS)	BIPV Thin-film Case 2 (a-Si)
Efficiency	14.5%	13.8%	11.2%	5.8%
Installed Price	$5.71/W	$5.02/W	$5.03/W	5.68/W

Figure ES-2. Unsubsidized U.S. residential rooftop LCOE values for the BIPV shingle cases compared with the PV Reference Case.

Note: Listed percentages illustrate LCOE differences relative to the PV Reference Case.[1] The LCOE calculations are based on consistent system price and financing structure assumptions for both locations—Boston and Tucson—but account for differences in estimated system prices, efficiencies, temperature coefficients, and degradation rates. All systems are south-facing and tilted at 25 degrees.

Overall, findings in this report support the notion that BIPV prices could be lower than residential PV system prices, yet past market experiences suggest that realizing these cost-reductions can be very challenging. To capitalize on the opportunities to reduce residential solar system prices and attract new consumers with aesthetically pleasing designs, BIPV faces more complex product-development issues and market-adoption dynamics than rack-mounted PV. We briefly address these less-quantifiable issues. An evaluation of specific commercial products goes beyond the scope of this report.

[1] LCOE estimates do not include any federal, state, local, or utility incentives. They assume host ownership and that no taxes are paid on electricity. Mortgage payments are tax deductible.

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1 Introduction

Installations of solar photovoltaic (PV) technologies on building rooftops are common in some parts of the world. The vast majority of these systems are composed of modules that are mounted off the surfaces of roofs using different types of racking hardware. System designs are most influenced by PV performance considerations, and aesthetics are often secondary. But growing consumer interest in distributed PV technologies and industry competition to reduce installation costs are stimulating the development of multifunctional PV products that are integrated with building materials. This emerging solar market segment, known as building-integrated PV (BIPV), continues to attract the attention of many stakeholders, as evidenced by the mention of a rooftop solar shingle product in the President's 2011 State of the Union Address (White House 2011).[2] BIPV offers a number of potential benefits, and there have been efforts to develop cost-competitive products for more than 30 years. The deployment of BIPV systems, however, remains low compared to traditional PV systems. In this report, we examine the status of BIPV, with a focus on residential rooftop systems, and explore key opportunities and challenges in the marketplace.

A continuum of PV system designs exists with various levels of integration with building materials and architectural features (Figure 1); there is no consensus definition of BIPV. Many stakeholders describe BIPV as a multifunctional product—one that acts as both a building material and a device that generates electricity (e.g., a solar shingle). Incentive programs and market reports, however, sometimes include *partially* integrated PV systems—those that blend with the designs of building materials but are not multifunctional—in their descriptions of BIPV. In Europe, for instance, the rules to qualify for BIPV-specific incentives are sometimes vague and include semi-integrated PV products (PV News 2010).[3] In many cases, semi-integrated products are a combination of PV products and traditional buildings materials (EPIA 2010). These combined products do not replace traditional building materials, and some stakeholders have described them as building-applied PV (BAPV).[4] Photon International describes BIPV modules as products that are "specifically constructed for building integration," and, in their recent survey of more than 5,000 commercially available modules, less than 5% were listed as BIPV.[5] Photon adds, however, that standard modules can also be integrated into buildings using certain mounting systems, implying that semi-integrated systems can also be described as BIPV (Photon International 2011). Regardless of the specific definitions of BIPV, it is clear that there is a continuum of integration with building materials among a class of PV products suited for rooftop and façade applications.

[2] Luma Resources' solar shingle product, honored in the 2011 State of the Union Address, is composed of a polycrystalline PV module adhered to a metal shingle.

[3] Feed-in tariff (FIT) rates for small BIPV rooftop products in Italy exceed rates for rack-mounted PV by more than 10%. BIPV-specific FITs also have lower digression rates than PV technologies in some markets.

[4] BAPV is also referred to as building-adapted, -added, and -adhered PV (NanoMarkets 2010, Greentech Media 2010, Pike Research 2010, ASDReports 2010, EuPD Research 2009).

[5] Similarly, only 2% of modules eligible for California's solar-electric incentive programs are described as BIPV, and these include some partially integrated products (July 2011). The California Energy Commission's list of nearly 6,000 modules is available at: www.gosolarcalifornia.org/equipment/pv_modules.php

For this report, we consider BIPV to be a multifunctional product (not a combination of independent products) that generates electricity and replaces traditional building materials by serving as a significant weather barrier on residential building surfaces.[6] In other words, if the hypothetical BIPV cases we outline below were removed from rooftops, then repairs (e.g., waterproofing) would be required to ensure that buildings are protected from the environment. We call traditional, non-BIPV systems “rack-mounted PV”; these systems are intended to generate electricity only, are mounted on racks, and do not replace the function of building materials. The two photographs on the left in Figure 1 show examples of rack-mounted PV.

Least integrated (Open rack-mounted PV)	More integrated (Close roof rack-mounted PV)	Fully integrated (Direct-mounted BIPV, multifunctional)

Figure 1. Continuum of residential solar system designs showing increasing integration (from left to right) with building architecture and material

Source: Building Energy 2011, DOE 2011

The competitiveness of BIPV in the marketplace largely depends on its cost compared with PV. We examine this issue using a bottom-up analysis of installed PV and BIPV system prices for hypothetical rooftop cases and carry this forward to estimate levelized cost of energy (LCOE) values for each case. All cost values throughout this report are provided in 2010 U.S. dollars. We also examine less-quantifiable issues that affect the development and market adoption of BIPV products.

2 BIPV Characteristics and Growth Opportunities

As with many solar products, the market price of BIPV systems is a key factor that affects the demand for systems and resulting levels of deployment. An analysis of two California incentive programs showed that BIPV rooftop systems have been sold at higher market prices than rack-mounted PV systems. BIPV on new homes sold for about 8% more than competing PV, on average, from 2007 to 2010 (Barbose et al. 2011),[7] and the price disparity grew over the survey period, as illustrated in Figure 2. However, the prices reported in incentive program databases do not necessarily reflect downward trends in system *costs* because they are subject to a range of

[6] This definition is aligned with products that qualify for France’s highest BIPV “full integration” incentive, as well as a description of BIPV by the California Public Utilities Commission (CPUC 2010).

[7] These data were derived from information about systems funded through the California Solar Initiative (CSI) and New Solar Homes Partnership programs. System types (PV and BIPV) were determined using the CSI List of Eligible Modules, which lists some semi-integrated PV products as BIPV.

market dynamics.[8] Higher BIPV system prices may result from supply chain issues for products and services or consumers' willingness to pay premiums. Incentives may also influence the price disparities between rack-mounted PV and BIPV. In Section 4, we discuss the cost differentials between PV and BIPV in detail.

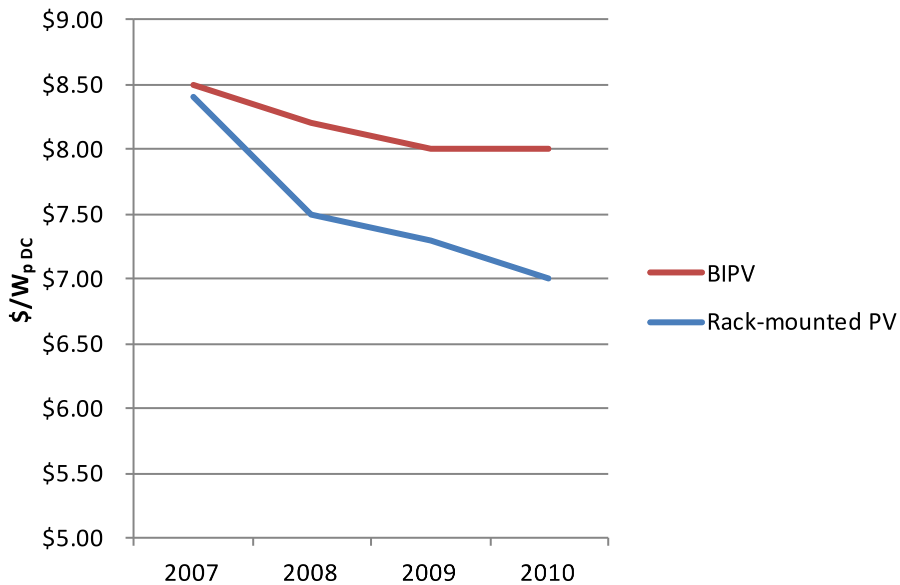

Figure 2. Average installed system prices of rooftop PV and BIPV systems (2- to 3-kW systems) on newly constructed homes in the United States[9]

Source: Barbose et al. 2011

BIPV may hold potential to increase PV-suitable space on buildings. One study of PV supply curves found that building rooftops in the United States could host about 660 GW of installed capacity, assuming the installation of rack-mounted PV with a 13.5% conversion efficiency (Denholm and Margolis 2008).[10] This assessment of PV-suitable rooftop areas accounted for shading, obstructions, and architectural designs that cannot accommodate traditional module form factors. Arguably, BIPV could increase these PV-suitable areas on buildings if products are lightweight or designed for specific building features. The International Energy Agency (IEA) estimated that incorporating BIPV on building façades could increase PV-suitable surfaces by about 35% (IEA 2002). Yet, there is considerable uncertainty about these findings, including how PV-suitable spaces are defined and how the lower energy generation potential of PV devices on vertical building surfaces reduces the economic viability of projects. Appendix E provides more information on these points.

[8] We consider "market price" to be synonymous with "fair market value" – the 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 the current market value (Easton 2010).

[9] These findings are from an analysis of about 3,000 residential rooftop PV and BIPV systems. The illustrated BIPV prices do not include any cost offsets for traditional roofing materials.

[10] Of the 660 GW, this study estimated that about 350 GW could be installed on residential rooftops and 310 GW on commercial building rooftops.

BIPV's aesthetic advantages over traditional PV could increase consumer appeal and provide growth opportunities. Additional considerations about BIPV market factors, such as industry interest and government support, are listed in Table 1.

Table 1. Potential Opportunities for BIPV Market Growth

Installation cost reductions	• Lower non-module costs – elimination of racking hardware, and greater use of traditional roofing labor and installation methods • Cost offsets for displacing traditional building materials • Lower supply chain costs – leverage more established channels to market
Improved aesthetics	• Consumer willingness to pay premiums in some markets • Broader appeal for residential solar product designs
Higher technical potential	• Increased PV-suitable space on buildings
Solar industry interest	• Showcase applications • High growth potential • Technology differentiation may help suppliers distinguish themselves • Possible cost reductions and new channels to market
Government support	• Maintain historic/cultural building designs • BIPV-specific incentives in select international markets

3 History and Status of BIPV Development and Deployment

In the late 1970s, the U.S. Department of Energy (DOE) began sponsoring projects to advance distributed PV systems, including collaborations with industry to integrate PV with building materials. By the 1980s, companies such as General Electric, Solarex, and Sanyo had developed PV shingle prototypes, but technical challenges and high costs slowed the commercialization of these products (SDA and NREL 1998).[11] As PV technologies became increasingly efficient and reliable in the years that followed, more stakeholders pursued the blending of PV devices with building materials. In 1993, DOE initiated a program called Building Opportunities in the United States for PV (PV:BONUS), which was designed, in part, to help commercialize innovative BIPV products (Thomas and Pierce 2001). Similar programs were established by groups in Europe and Japan around the same time (Arthur D. Little 1995).[12] Today, partnerships among PV manufacturers, architects, and building-materials suppliers intend to address barriers and bring new cost-competitive products to the market (Fraile et al. 2008).

Because BIPV has been known mostly for showcasing solar applications in sustainable building designs, it has been regarded as a niche product compared to rack-mounted PV products. One of

[11] BIPV system prototypes developed in 1979 and the early 1980s were evaluated at DOE-sponsored experiment stations in Massachusetts, Florida, and New Mexico.
[12] IEA PVPS Task 7. EPIA Sunrise Project (Europe). NEDO BIPV RD&D Program (Japan).

the first U.S. homes with BIPV was built in 1980 (Arthur D. Little 1995), and systems were later incorporated on commercial structures such as the 4 Times Square Building in New York City in 2001, where about 15-kW of amorphous silicon (a-Si) BIPV was installed (DOE 2001). Larger BIPV systems have been installed more recently, including a 6.5-$MW_{p\ DC}$ system on the Hongqiao Railway Station in China, completed prior to the 2010 Shanghai World Expo (IEA 2011). At the simplest level, BIPV systems are derivatives of common PV module designs and installation methods; early product designs were often highly customized for specific buildings and architectural features. Today, BIPV products have more standardized designs that are intended to integrate with many common building materials. Although the market prices for BIPV are still higher than for rack-mounted PV (see Section 2), new products offer lower costs and better performance than BIPV systems of the past.

Overall, the global deployment of BIPV is small in comparison with the deployment of rack-mounted PV. By some estimates, the cumulative installed capacity of BIPV (and related semi-integrated PV products) worldwide was 250–300 MW by the end of 2009 (EuPD Research 2009, Pike Research 2010). This was about 1% of the cumulative installed capacity of distributed PV systems at that time (Mints and Donnelly 2011). Part of this limited market share can be attributed to the price premium of BIPV relative to rack-mounted PV, as well as qualitative factors we discuss in the following sections.

4 Residential System Price Analysis: BIPV Cases and 2010 PV System Benchmark

Our analysis approximates the cash purchase prices (or overnight capital costs) for three hypothetical BIPV systems and a typical rack-mounted PV system (2010 benchmark price) installed on residential rooftops in the United States. We develop a granular perspective on cost factors that underlie reported system prices, which may help guide strategic decisions by research and development managers and policymakers. This bottom-up method of estimating BIPV system prices disregards the pricing parameters determined by markets, focusing instead on objective inputs as a means to assess cost-reduction opportunities and challenges.

The National Renewable Energy Laboratory (NREL), in collaboration with industry, developed the methodology we use to analyze system costs. This method is similar to the approach used by many solar project developers to approximate the book value of solar assets, characterizing the unsubsidized cash purchase price for residential systems. Our analysis includes all of the materials, labor, regulatory costs, and overhead and profit (O&P) margins for installed residential systems. Costs are provided in terms of 2010 U.S. dollars per peak watt of DC PV capacity ($/W or $\$/W_{p\ DC}$).

4.1 Analysis Cases and Assumptions

We analyze the prices of a typical rack-mounted PV rooftop system and three BIPV rooftop systems (Table 2). The PV and BIPV cases do not represent specific commercial products. Assumptions are intended to represent typical system technologies and costs for 2010, unless otherwise noted. Efficiency assumptions are based on commercial modules and reasonable expectations about BIPV derate factors; we assume that residential BIPV systems have more inactive areas (i.e., areas that are not converting sunlight to electricity such as frames) than rack-mounted PV. Details about efficiency assumptions are provided in Appendix A.

Table 2. Summary of Cases Used to Analyze Residential Rooftop PV and BIPV System Prices

Scenario	Technology	Form	Efficiency	Module Area (m^2)
PV Reference Case	c-Si	Rigid	14.5%	1.28
BIPV Derivative Case	c-Si	Rigid	13.8%	0.58
BIPV Thin-film Case 1	CIGS	Rigid	11.2%	0.58
BIPV Thin-film Case 2	a-Si	Flexible	5.8%	0.58

a-Si—amorphous silicon; CIGS—Cu(In,Ga)Se_2; c-Si—crystalline silicon.

The PV Reference Case is based on the most commonly deployed PV technology in the world, crystalline silicon (c-Si) modules. The BIPV cases include a derivative of the PV Reference Case, as well as two examples using thin-film technologies. To assess the cost implications of flexible form factors, we consider that the cells of BIPV Thin-film Case 2 are packaged with flexible materials. The other cases have rigid form factors.

Module dimensions affect installation labor costs because of the time required to affix and wire systems. Smaller modules with the same form factor as larger modules generally result in higher labor costs for systems; the rate-determining step is often clamping and through-roof mounting. In our BIPV cases, we assume that the product dimensions for BIPV are smaller than those of traditional PV and more comparable to traditional roofing shingles. These dimensions allow for use of traditional roofing techniques (i.e., the BIPV installers may use nails and hammers; electricians are only needed to complete the wiring and interconnection). We assume the PV Reference Case modules are 1.28 m^2 (0.808 m × 1.580 m), typical of 2010 industry standards (Photon International 2011), and that electricians install the PV modules, in addition to completing the wiring and interconnection. It should be noted, however, that the share of installation labor from electricians varies widely across the United States, and it is not necessarily a BIPV-specific advantage to use general contractors to install modules. We also assume that all PV module surface area is exposed to the sun. We assume our BIPV shingles layer like traditional asphalt shingles so that some areas remain unexposed. We assume that only the exposed areas contain PV devices, and that this area is 0.58 m^2 (1.411 m × 0.411 m) per module. Including the layered areas, we assume the BIPV product's total area is about 0.80 m^2, which is between the sizes of traditional asphalt shingles and residential PV modules.[13] The dimensions of these BIPV shingles are also similar to the dimensions of today's BIPV products,[14] supporting the notion that they can be installed using traditional roofing methods.

For the purposes of cost modeling, solar system sizes are based on the following area constraints: 35 m^2 for the PV Reference Case and 40 m^2 for the BIPV cases. Area assumptions for the BIPV cases are slightly higher because smaller modules could potentially increase access to PV-suitable areas. According to these assumptions and the module efficiencies listed in Table 2, system capacities are about 5.0 kW for the PV Reference Case, 5.7 kW for the BIPV Derivative Case, 4.7 kW for the BIPV Thin-film Case 1, and 2.5 kW for the BIPV Thin-film Case 2. The

[13] Dimensions of the most common residential rooftop product (i.e., asphalt "strip shingles") are 0.29 m2 (National Roofing Contractors Association 2011 b).

[14] Luma Resources' c-Si solar shingle is 0.55 m^2 (Luma Resources 2010). SunPower's Suntile is 0.65–0.69 m^2 (SunPower 2010).

cost analysis is normalized in terms of $\$/W_{p\,DC}$, including an analysis of traditional building materials, to enable direct comparisons among the cases.

Residential-sector system costs vary owing to a number of factors, including channels to market, installer experience, and differences in regional labor rates, permitting fees, and taxes. A recently released technical report by NREL, which uses the same methodology as this report to estimate system book values, found a 2010 residential benchmark price of $\$5.71/W_{p\,DC}$ (Goodrich et al. 2011). Accounting for the regional factors that affect system costs, this 2010 benchmark price has a standard deviation of about 8%.

4.2 Major Cost Differential Categories

Product designs and intended functionality create inherent cost differences between PV and BIPV. BIPV devices often include additional materials such as flashing to ensure buildings are protected from a wide range of weather conditions. On the other hand, most BIPV products reduce installation costs by eliminating common PV mounting hardware such as struts, z-channels, and clips and associated labor costs. BIPV modules may also install more quickly than incumbent PV modules. Additionally, it is important to consider the potential cost benefits of offsetting the use of traditional building materials (e.g., asphalt shingles) in the areas where BIPV is installed.

4.2.1 Installation Costs

The installation cost differences between the rack-mounted PV benchmark case and BIPV cases are driven by the installation methods and materials requirements of each system. The most significant installation cost difference for the BIPV cases is from the elimination of racking hardware and associated labor costs. Racking components serve as the direct interface between PV modules and rooftop structures, and our BIPV cases eliminate the need for this robust material interface.

Secondly, we assume that BIPV's functionality as a roofing material, along with its smaller module size, would allow project developers to use lower-cost roofing contractors to install the products using traditional roofing methods.[15] In this regard, the BIPV cases have cost advantages because we assume that electricians are only needed for the final wiring steps and commissioning; we also assume that BIPV shingles would take 65% less time to install on a per-module basis. Because the BIPV modules are smaller, however, more total time is required to install the modules on a per-area basis.

We include overhead and profit (O&P) margins and sales taxes as part of the installation cost category, and these factors are determined as a percentage of total system costs. We assume that all of the cases have the same rates for O&P and taxes (54% overhead, 30% profit, and 5% sales tax). Yet, because system costs differ for each case, the resulting O&P and sales tax costs are not the same. We also assume that "indirect capital costs" such as permitting fees, which vary considerably across jurisdictions, are equivalent for all of the cases: $900 per system, based on interviews with U.S. industry stakeholders. The resulting proportion of indirect capital costs to

[15] We used electrical contractor wage rates of $101.29/hr for the PV Reference Case and roofing contractor wage rates of $68.42/hr for all BIPV cases (RSMeans 2010).

system costs is a function of system capacity, which differs for each case. Therefore, larger systems have smaller indirect capital costs in terms of $/W.

We approximate 2010 installation cost differences between comparable PV and BIPV residential systems. Quantifying prospective cost-reduction opportunities is beyond the scope of this analysis; however, we recognized that new installation methods and system designs may likely affect the cost differentials illustrated in our analysis. Cheaper mounting structures and faster installation methods for rack-mounted PV, for example, would reduce the installation cost advantages of the BIPV cases. It is also possible that novel and integrated circuitry could lower BIPV wiring costs in the future, yet it is uncertain whether the benefits would be specific to BIPV or diffuse across the sector, reducing PV system costs as well. As such, we limit our analysis to the costs of currently available technologies assuming that much of the bill-of-materials is the same across all cases. These materials include inverters, meters, system monitors, AC/DC disconnects, combiner boxes, fuses and holders, conduit, and wiring.

4.2.2 Module Costs

We assume that modules in the BIPV cases have the performance of roofing products in addition to the functionality of PV devices, and we assume that this is achieved by the use of more materials than are used in incumbent PV modules. We recognize that materials are highly specific to BIPV product designs, which may include novel framing, flashing, adhesives, and materials to mitigate heat gains. Different BIPV module designs can also lead to trade-offs between module costs and installation costs.

Because of the variability of BIPV module designs, we simplified the assumptions of the BIPV cases by adding 10% premiums to the costs of commercially available PV modules, adding about $0.15–$0.22/W depending on the technology. The BIPV module mark-up accounts for all materials (framing, flashing, etc.) that are necessary to enable safe rooftop installations, and it includes base layers installed directly onto roof decks and under BIPV modules. Felt paper barriers or wraps, for instance, are typically installed under asphalt shingles, although some BIPV products require more expensive materials made of polypropylene or elastomeric sheets. When purchased in volume, the installed prices of the higher-end materials are about $2.00–3.00/m^2 (RSMeans 2010), adding a cost of about $0.02/W, which we assume is part of the 10% premium. Given that the BIPV module premium is a rough estimate, we include a range of BIPV module costs in the uncertainty analysis, which is available in Appendix C**.**

4.2.3 Flexible Packaging Costs

There is on-going debate about the value of flexible PV and BIPV products, but it is clear that BIPV does not require flexible form factors. Among currently installed BIPV and semi-integrated PV designs, the most widely deployed products are rigid and use c-Si technologies (Ceron et al. 2010).[16] There may be specific opportunities for flexible BIPV products such as on commercial buildings, where roofing materials are often flexible, or for niche applications such as military tents or buildings with tensile fiberglass roofs (e.g., the Denver International Airport). Opportunities may also exist in the residential rooftop sector for non-planar products such as S-tiles. In all cases, the potential benefits of flexible form factors must be weighed against added costs and performance considerations.

[16] This is based on a study that assessed 238 integrated PV products produced by 109 different companies.

The thin-film technologies analyzed in this report (CIGS and a-Si) can be developed into flexible BIPV products, and there are some advantages: flexible modules tend to have lower weight than glass modules (up to 90% lighter), and they can have lower shipping and installation costs. Another advantage is that they may better accommodate building areas with limited structural support.[17] These potential advantages, however, may not compensate for the additional costs of flexible barrier materials or additional challenges involving long-term product safety, reliability, and durability. Different tolerances to long-term ultraviolet radiation exposure, for instance, can affect anti-soiling properties, transmissivity, and the adhesive stability of materials, which can significantly affect device performance (Kempe 2009).

We only examine the costs of flexible cell packaging in the a-Si BIPV case (Thin Film Case 2). We assume that a-Si requires top sheets with water vapor transmission rates (WVTRs) of about 10^{-2} g/m²/day, which are available for about $10/m^2. This would add about $0.40/W compared to standard glass-glass packaging. BIPV Thin-film Case 1 (CIGS) is modeled as a rigid product, although CIGS can be developed into flexible form factors. CIGS is highly sensitive to water, and it requires higher performing barriers than a-Si technologies with WVTRs of less than 10^{-4} g/m²/day (Leffew et al. 2011). The prices of these barriers are expected to decrease substantially with industry scale-up; however, they are costly today at $40–$80/m^2. Assuming a $40/m^2 top sheet barrier film and $20/m^2 back sheet, we estimate that flexible CIGS modules are about $0.60/W more expensive than glass-glass CIGS modules. Our analysis only models CIGS BIPV as a rigid product, so this packaging premium does not appear in the results.

4.2.4 Building Material Cost Offsets

If BIPV products completely replace traditional building materials, overall system costs should reflect a commensurate cost offset. Developing multifunctional products is a central challenge for BIPV product designers because building materials often require higher durability than PV devices, and BIPV must meet codes and standards for both PV and building products. [18] We assume these challenges have been overcome for the BIPV cases in this paper.

The costs and performance of standard roofing materials vary. Asphalt shingles are the most common product installed on U.S. residential rooftops; they account for more than 50% of U.S. residential sector market share (National Roofing Contractors Association 2011 b). For most conditions, asphalt shingles last about 17–20 years, and installed costs are between $18–$32/m^2 (RSMeans 2010). More expensive rooftop products such as clay tiles may last more than 50 years and often provide better insulation and fire protection than less costly products. Figure 3 illustrates the range of retail prices for fully installed products in 2008–2009.

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[17] A survey of more than 200 BAPV/BIPV products found that the majority, many of which were rigid products, weigh less than 20 kg/m^2. About 10% of the products weighed more than 30 kg/m^2, and these heavy systems may require that rooftops have additional structural support (Ceron et al. 2010).

[18] PV and rooftop building material requirements may include: IEC TC82 (WG3), FM global, ICC-ES, AC-07, FM 4470, IBC, ASCE, BOCA, SBCCI, and SFBC codes (Sharma and Herron 2011).

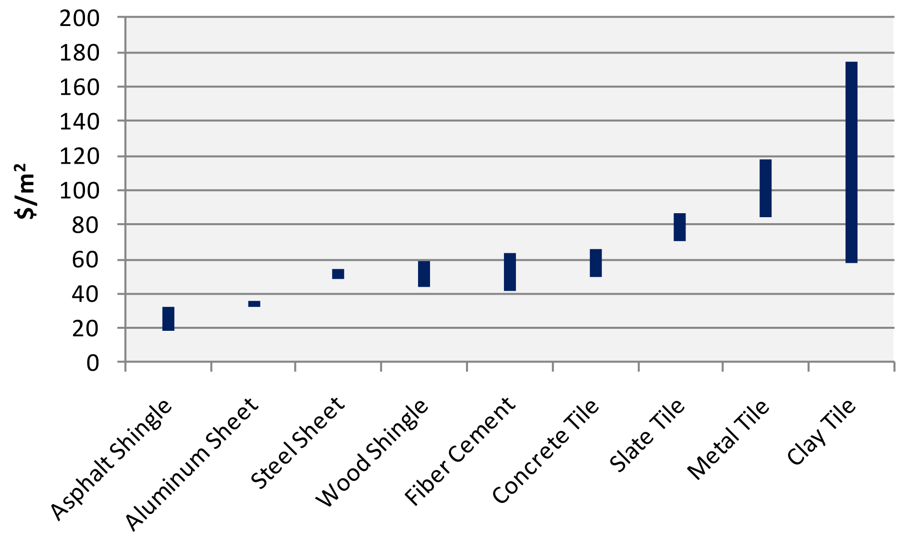

Figure 3. Installed retail prices of residential roofing products in the United States, 2008–2009

Source: RSMeans 2010

To estimate the value of potential offsets for BIPV, we converted roofing product prices from $\$/m^2$ to $/W, accounting for module dimensions and efficiencies.

Table 3 lists the values for several roofing materials to illustrate general cost trends. Later, we estimate asphalt shingle offset values according to the technology characteristics of each BIPV case (Section 4.3.2).

Table 3. Average Installed Retail Prices for Traditional Residential Roofing Materials, Converted to $/W Based on the BIPV Derivative Case (13.8%-efficient, 0.58 m^2)

Roofing Product	$\$/m^2$	$/W
Asphalt shingle	$25.08	$0.18
Wood shingle	$51.13	$0.37
Concrete tile	$57.86	$0.42
Slate tile	$78.58	$0.57
Metal tile	$101.45	$0.74
Clay tile	$116.52	$0.85

PV products have a range of efficiencies, and lower-efficiency products require more space than higher-efficiency products for equivalent system power capacities. Similarly, lower-efficiency BIPV technologies require more space and displace more traditional products than higher-efficiency BIPV technologies; thus, in terms of $/W, offsets are inversely related to PV efficiencies: a 6.3%-efficient device has more than double the offset value of a 14.5%-efficient device for an equivalent roofing product. Table 4 lists the approximate offset values for selected technologies and building materials, illustrating the possible range of residential offset values by highlighting a low-case offset (shingles) and a high-case offset (clay tiles).

Table 4. Estimated Offset Values for the Residential BIPV Cases

Technology	PV metrics		Residential Material Offsets ($/W)	
	Efficiency	W_p/m^2	Asphalt Shingle	Clay Tile
a-Si	5.8%	58	$0.43	$2.01
CIGS	11.2%	113	$0.22	$1.03
c-Si	13.8%	138	$0.18	$0.85

4.3 Installed System Price Results

The following sections summarize the installed system price estimates for the BIPV cases compared with the PV Reference Case. Installed system prices account for all component costs, installation labor costs, indirect capital costs, sales taxes, and margins. Operations and maintenance costs are not included. Offsets for BIPV cases are denoted as "Offset shingles." The listed "Effective price" values include the relative offsets for asphalt shingles in the BIPV cases.

4.3.1 Detailed Results for PV Reference Case vs. BIPV Derivative Case

Cost gaps between the PV Reference Case and BIPV Derivative Case are mostly from differences in module costs and installation costs, as well as the value of offsets from traditional building materials. These cost differentials also impact channel costs, as illustrated in Figure 7.

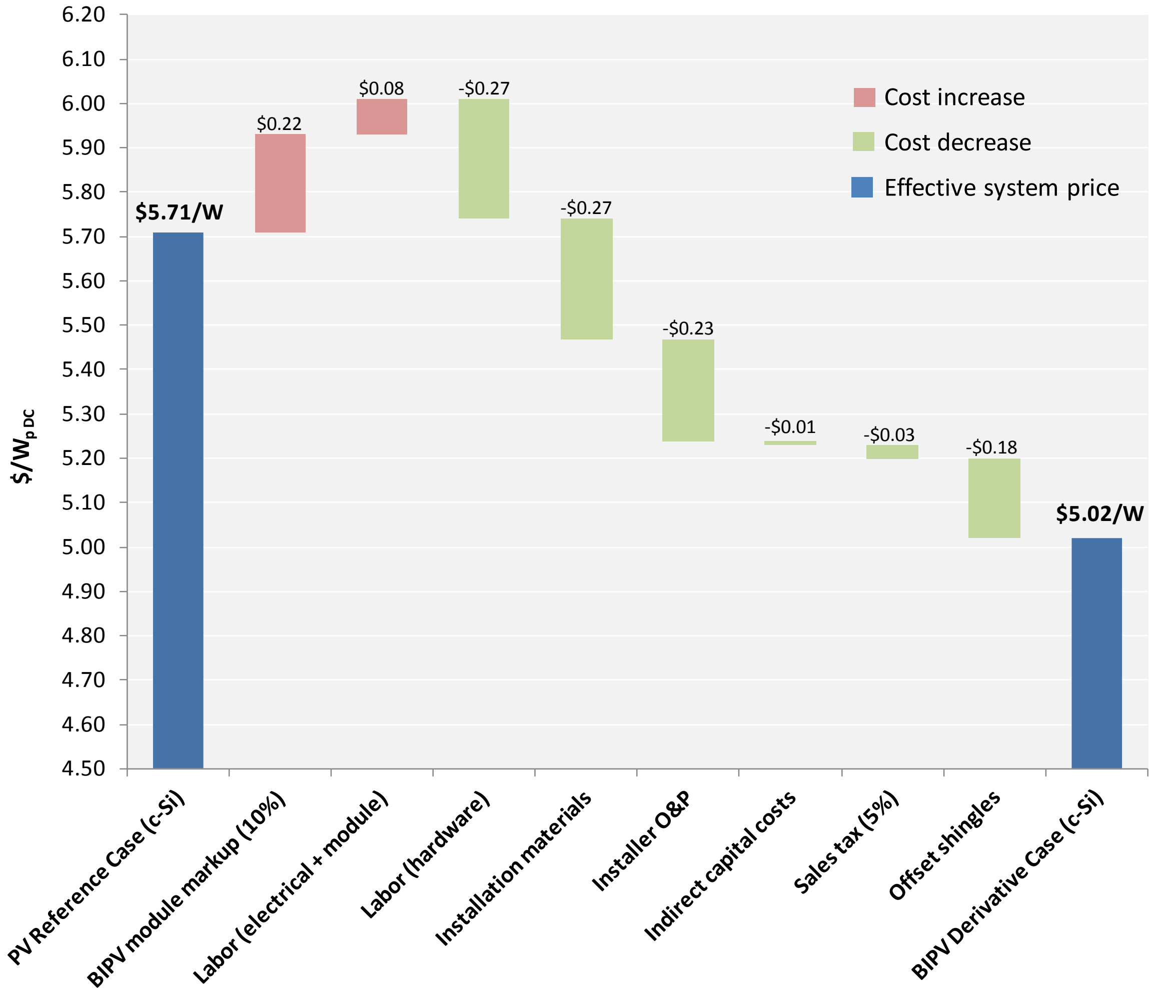

Figure 4. Price differences between the PV Reference Case (c-Si, 14.5% efficiency, 2010 benchmark price) and the BIPV Derivative Case (c-Si, 13.8% efficiency)[19]

Our analysis shows that the effective price of the BIPV Derivative Case is $0.69/W lower than the price of the PV Reference Case, a difference of more than 10%. An offset of $0.18/W was included because we assume the BIPV case replaces asphalt shingles. Elimination of racking hardware and associated labor is estimated to reduce total BIPV costs by $0.55/W ($0.27/W for labor and $0.27/W for materials). Not all differences reduce the BIPV case's costs, however. The smaller module dimensions for the BIPV case result in $0.08/W higher total module-related installation labor costs (despite non-electrician labor rates), and the 10% BIPV module mark-up adds $0.22/W. However, even with these increases, net installation costs are less for the BIPV Derivative Case. These lower costs help to reduce the costs of O&P and sales taxes. Indirect capital costs are also slightly lower in the BIPV Derivative Case because its system capacity (5.7

[19] Sources: Goodrich et al. 2011, Photon International 2011, SEIA and GTM Research 2010.

kW) is larger than the PV Reference Case (5.0 kW).[20] Figure 5 shows all of the major cost categories for the two c-Si cases.

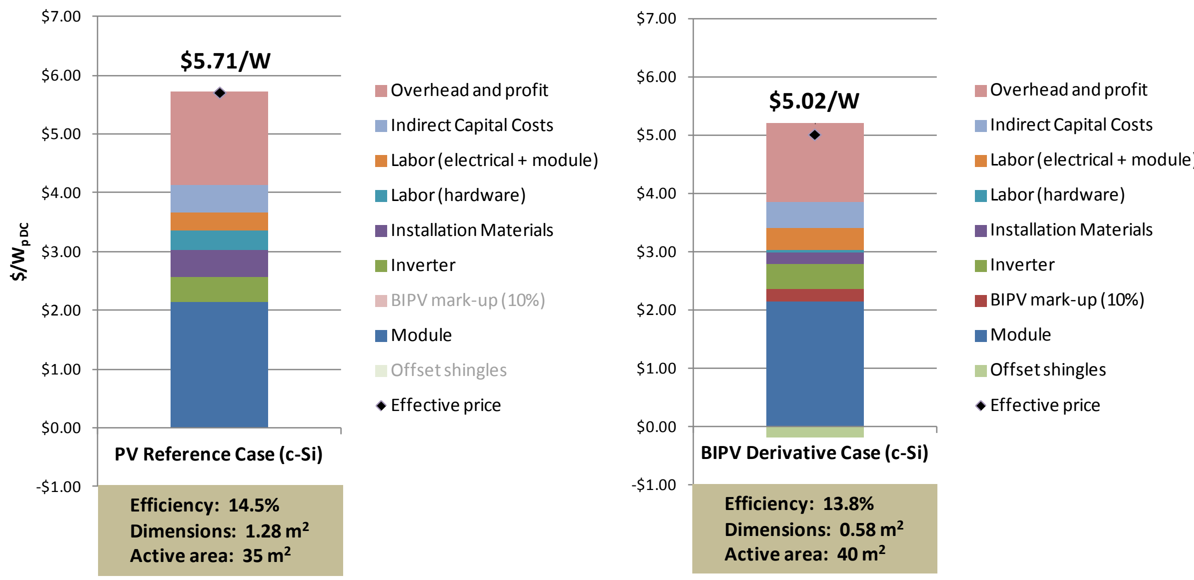

Figure 5. Comparison of residential rooftop prices for the PV Reference Case and the BIPV Derivative Case.

Note: The listed BIPV price includes shingle cost offsets, shown as a negative bar in the figure on the right.[21]

The context of the illustrated BIPV price advantages is critical to the understanding of general opportunities and challenges for BIPV products. In today's market, few BIPV products are fully integrated with building materials as described in the BIPV cases of this report; therefore, the hypothetical BIPV cases are essentially *near-term possibilities* that are compared with the 2010 benchmark PV system price. Because PV system prices continue to decrease, soon-to-be commercialized BIPV products are chasing a moving target. In addition, this report's analysis assumes that the BIPV cases benefit from the cost advantages of manufacturing products on a similar scale as rack-mounted PV products. As discussed previously, the costs associated with converting a PV device into a BIPV product remain highly uncertain. We chose a 10% module mark-up for the BIPV cases, but this mark-up could be much higher, adding to overall channel costs such as installer O&P. For these reasons, BIPV cases in this report are not representative of today's BIPV system prices.

4.3.2 Summary Results for All Cases

Figure 6 illustrates the system price differences between the PV Reference Case and the BIPV cases. The effective prices of the BIPV Derivative Case and BIPV Thin-film Case 1 are about the same, with prices that are more than 10% lower than the PV Reference Case. The effective price of BIPV Thin-film Case 2 is about 1% less expensive than the PV Reference Case. BIPV

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[20] In the BIPV thin-film cases, indirect capital costs are higher than in the PV Reference Case owing to smaller system capacities.

[21] Indirect capital costs include sales tax in this chart.

Thin-film Case 2 is the only flexible product shown in Figure 6, and potential benefits of flexible form factors are not accounted for in the figure.

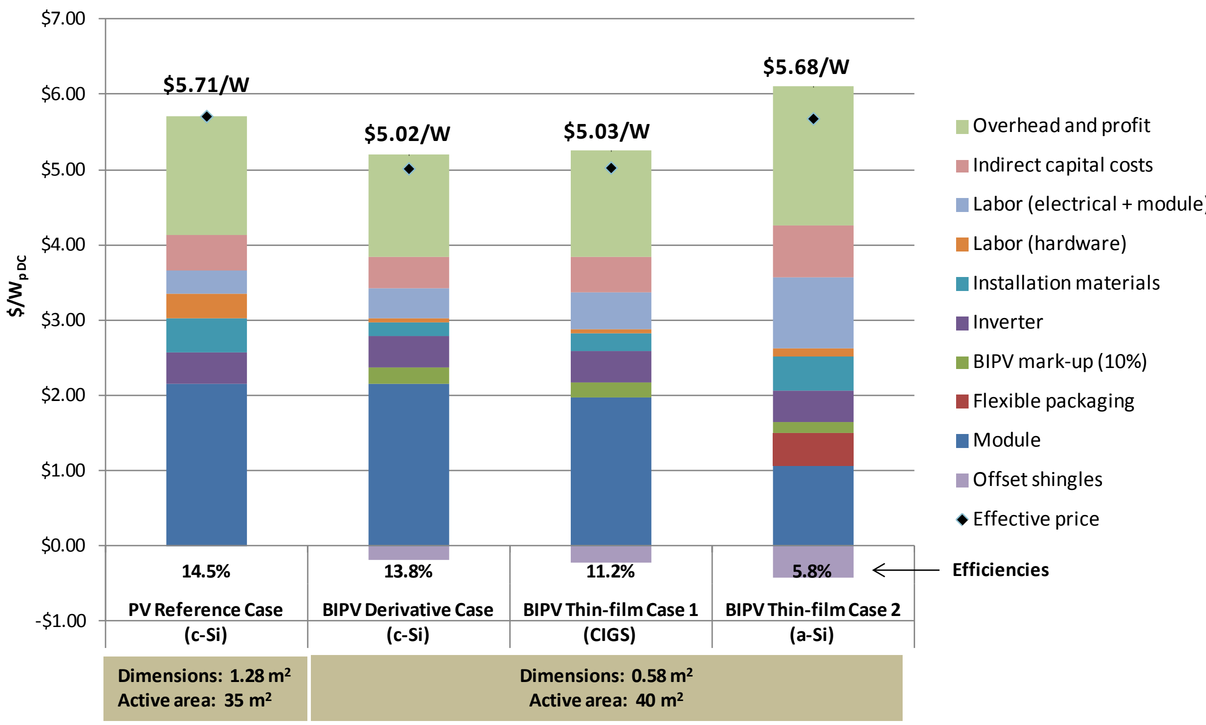

Figure 6. Comparison of residential rooftop prices for the PV Reference Case and three BIPV cases.

Note: Listed BIPV prices include building-material cost offsets (shown as negative bars in the figure).

Among the three BIPV cases, installed system prices vary as a result of module costs and efficiencies. Module costs are representative of module spot prices in December 2010 with a 10% distributor margin (Photon International 2011). The magnitudes of the other mark-ups, as well as offset values, are also affected by module costs and system efficiencies. Appendix C provides more information about the estimated system prices for the BIPV cases in this report, using a Monte Carlo analysis to address the uncertainties about a number of assumptions.

5 System Performance and Levelized Cost of Energy

The sections above summarize residential rooftop PV and BIPV system costs in terms of price per unit of installed capacity ($/W). To understand the economic viability of solar systems, costs must also be understood in terms of the levelized cost of energy (LCOE), which is based on a system's installed price, its total lifetime cost, and its lifetime electricity production. The following sections address LCOE.

5.1 System Performance

It is unlikely that BIPV systems will perform as well as rack-mounted PV products, and, although models have been developed using empirical data from select products, performance changes for BIPV are not easy to generalize (Neises 2011). In some cases, BIPV has shown higher average operating temperatures, thermally accelerated degradation (e.g., corrosion of metallization), and increased soiling on low-sloped roofs (Schams and TamizhMani 2011). Novel products require stringent testing under a range of environmental conditions, yet lacking lifetime performance data can complicate the process of developing appropriate product warranties. For an analysis of LCOE, we only consider the relative losses that result from higher average cell temperatures for BIPV compared with off-roof mounted PV.[22]

The operating temperatures of rooftop solar systems are affected by several parameters, including installation configurations, ambient temperatures, irradiance, and wind speeds. As such, assessing BIPV system lifetime performance is complex and highly dependent on technologies, installation designs, and local environmental conditions (Neises 2011). Air gaps under modules improve system performance because convective currents help cool modules, and studies have suggested mounting PV arrays 3–6 inches from roof decks in order to optimize power output, cooling, and wind loading (Dunlop 2007). However, by the nature of BIPV designs, most integrated systems are mounted directly onto building surfaces with no air gaps. Compared to off-roof mounted systems, products installed directly onto building roof surfaces have shown performance losses as high as 7% in high-temperature environments such as Arizona, where module temperatures can reach 95°C (Schams and TamizhMani 2011).[23] In cooler climates, performance losses from heating are less of an issue: one study of two PV-integrated tile systems in Colorado found that a product mounted on counter battens (about 1 inch of air space) produced 3.4% more power than an identical tile system mounted directly on the roof deck (Muller et al. 2009).

5.2 Levelized Cost of Energy Analysis

To account for the relative performance losses of BIPV systems, which we consider to be mounted directly onto building surfaces with minimal underside airspaces, we examine LCOE using the installed price assumptions listed in Figure 6. To estimate LCOE ranges, we analyze two U.S. locations with different solar resource conditions (Tucson and Boston) and consider that all systems are south-facing with a 25-degree tilt and a derate factor of 85%. Financing costs and tax benefits are included in the calculation, and we use a typical structure of 80% financing of system prices with a 30-year mortgage and weighted average capital costs (WACC) of 5.9%. We assume a nominal discount rate of 10.8%. Other assumptions are summarized in Table 5.

Table 5. Selected Performance Assumptions for the PV and BIPV Cases

Scenario	Technology	Rated Efficiency	Temperature Coefficient (Pmpp(%/ °C)[24])	Annual Degradation
PV Reference	c-Si	14.5%	-0.49	0.5%
BIPV Derivative	c-Si	13.8%	-0.49	0.5%
BIPV Thin-film 1	CIGS	11.2%	-0.45	1.5%
BIPV Thin-film 2	a-Si	5.8%	-0.21	1.0%

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[22] We assume that the BIPV cases do not have higher degradation rates than comparable rack-mounted PV systems. Inputs for module degradation rates (Table 5) are specific to each technology.

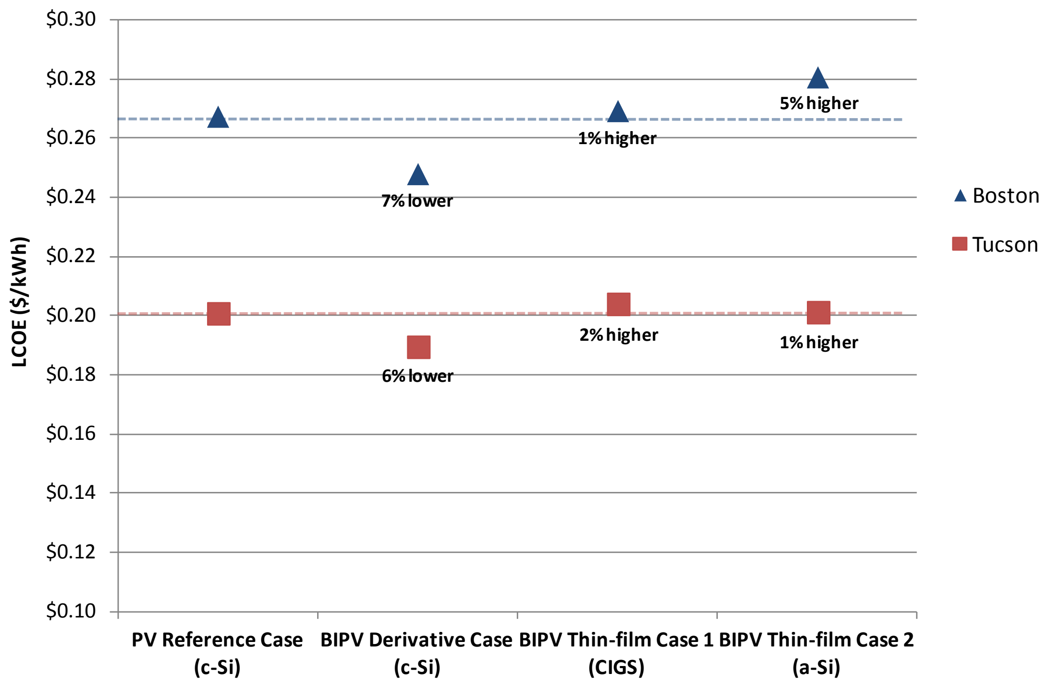
[23] This study also found evidence that a system with no air space could have a 28% shorter system lifetime than a system with a 4-inch air space in high-temperature environments.

[24] Pmpp – power maximum power point. These values are from NREL's SAM (www.nrel.gov/analysis/sam/).

Estimates of the unsubsidized LCOE values for the cases in this report are illustrated in Figure 7. These values were derived using NREL's System Advisor Model (SAM),[25] which includes options to estimate performance losses for BIPV based on module mounting structure inputs and weather data.[26] For most locations and PV technologies, SAM estimates a performance loss of 2.0%–4.5% (relative) between open-rack systems and close-mount systems; this assumes that differences in module edges and framing designs do not affect heat transfers (Neises 2011).

The spread of LCOE estimates for the four scenarios shown in Figure 7 varies from the range of installed system prices owing to differences in module efficiencies, degradation rates, and performance in moderate (Boston) and high-temperature (Tucson) environments.[27] The BIPV LCOE values range from 7% lower to 5% higher than the PV Reference Case. The greatest BIPV installed price advantages (about 12% for the BIPV Derivative Case and BIPV Thin-film Case 1) are reduced by performance disadvantages. The most temperature-tolerant BIPV case, BIPV Thin-film Case 2 (a-Si), maintains its cost disadvantages, although it is more competitive in a high-temperature environment like Tucson. The LCOE analysis highlights how higher degradation rates and performance disadvantages can affect the economic viability of some technologies and system designs. Commensurate with our assumptions, this analysis shows that LCOE values of c-Si BIPV and CIGS BIPV could be competitive with c-Si rack-mounted PV in most environments. For the purposes of additional discussion, a sensitivity analysis of LCOE and system prices for the BIPV Derivative Case (c-Si) is provided in Appendix D.

[25] LCOE numbers are given in terms of "real" (as opposed to nominal) dollars, and they do not include any federal, state, or local incentives.
[26] The option of "close roof mount" in SAM represents a product with minimal air flow under modules. Performance-loss estimates are within the range of performance losses observed for direct-mount BIPV products.
[27] Assessments of product quality and project risks that impact lending rates (i.e., bankability) also affect LCOEs. Novel BIPV products may have less certain performance than some PV technologies, and, as a result, financing costs could be higher. In this report, we use the same financing assumptions for all PV and BIPV cases.



	PV Reference Case (c-Si)	BIPV Derivative Case (c-Si)	BIPV Thin-film Case 1 (CIGS)	BIPV Thin-film Case 2 (a-Si)
Efficiency	14.5%	13.8%	11.2%	5.8%
Installed Price	$5.71/W	$5.02/W	$5.03/W	5.68/W

Figure 7. Unsubsidized U.S. residential rooftop LCOE values for the BIPV shingle cases compared with the PV Reference Case.

Note: Listed percentages illustrate LCOE differences relative to the PV Reference Case.[28] *The LCOE calculations are based on consistent system price and financing structure assumptions for both locations—Boston and Tucson—but account for differences in estimated system prices, efficiencies, temperature coefficients, and degradation rates. All systems are south-facing and tilted at 25 degrees.*

6 Qualitative Considerations for BIPV

The limited deployment of BIPV worldwide is likely a result of higher system prices (see Section 2), but other factors may also affect market opportunities. Especially when cost differences between PV and BIPV are modest, less-quantifiable issues may impact growth rates for the BIPV sector. Factors germane to BIPV include the following:

- ***The value of aesthetics***

  One of BIPV's core advantages is that it might better address the aesthetic interests of many stakeholders. Market data have shown some level of consumer willingness to pay premiums for BIPV (Barbose et al. 2011), yet it is too early to determine how consumers value aesthetics and whether this tolerance of premium prices will recede or expand as solar markets evolve. Most importantly, it is unclear to what degree aesthetics will be a driving force for widespread deployment of PV technologies.

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[28] LCOE estimates do not include any federal, state, local, or utility incentives. They assume host ownership and that no taxes are paid on electricity. Mortgage payments are tax deductible.

Although it is not possible to assess objectively whether a PV system is attractively designed, previous experiences suggest that aesthetics matter to PV consumers. In Oradell, New Jersey, for example, PV panels recently installed on municipal electric poles have drawn public criticism for looking "ugly" (Navarro 2011). BIPV responds to these types of concerns with designs that blend or are otherwise visually consistent with traditional building materials (Zanetti 2010). To assess a number of design criteria, one recent survey of more than 170 building professionals resulted in guidelines about the quality of PV integration into building structures (Probst and Roecker 2007); BIPV case studies have also provided insights about specific design opportunities (Eiffert and Kiss 2000). Incorporating architectural considerations into solar product designs might help marginally higher-priced BIPV systems vie for market share, although BIPV's perceived aesthetic advantages might be challenged by PV mounting structures that are increasingly designed to appeal to similar architectural interests. Overall, the behavioral economic drivers of PV adoption are not well understood, but there may be substantial opportunities for aesthetically designed BIPV systems if costs are competitive with other technologies.

- ***Codes and standards***

  The landscape of codes and standards issues is more complex for BIPV than for competing PV products. PV devices and roofing products have different durability, safety, and performance requirements, and certification processes for PV and BIPV are often disconnected (Sharma and Herron 2011). Standards bodies are working to harmonize codes and expand BIPV-specific guidelines. However, navigating codes and standards issues may continue to be more complex for BIPV.

- ***Policy and regulatory issues***

  There have been increasing policy opportunities to support BIPV through tailored incentive programs, measures to promote sustainable buildings, and efforts to address building codes and other relevant regulations. Targeted, price-driven incentive programs such as premium-rate feed-in tariffs for BIPV can increase market opportunities, as assessments of experiences in Italy and France have suggested (EuPD Research 2009). Solar access laws can also create environments that are amenable to BIPV products. Switzerland has building regulations, for instance, that serve to protect the cultural nature of architectural designs, and these regulations inhibit PV installations unless they are integrated into building envelopes (Zanetti 2010). In this regard, historic preservation commissions and code officials can influence the designs of residential PV systems. Solar access laws and local regulatory policies vary (DSIRE 2011), and some regulatory structures present barriers for all types of residential solar applications (Starrs et al. 1999). BIPV might help overcome some of these regulatory barriers, and growth opportunities are likely to remain strongly linked to policy schemes.

- ***Market segmentation***

  The dynamics of BIPV adoption might differ from those of rack-mounted PV because products are often designed for more discrete market opportunities such as new residential roofs or specific building products (e.g., clay tiles). PV modules are not necessarily fungible across sectors (residential, commercial, and utility), but they are much more transferrable than BIPV products, where designs vary greatly even within sectors. Although BIPV opportunities are more segmented, they must compete with the costs of a much more robust rack-mounted PV industry. Limiting installations to smaller markets can affect the ability to achieve cost targets through manufacturing scale-up.

7 Conclusions

Although the deployment of BIPV is relatively low, opportunities remain promising. Decreasing module costs, increasing consumer interest in solar energy, and policy schemes that support distributed generation systems have the potential to increase rates of BIPV market growth. The commercialization of solar products that have the full functionality of building materials has been very limited, but systems are increasingly being developed to account for design aesthetics and installation-cost reductions. This continuum of integration is leading to more solar products that may fully replace traditional building materials.

Significant challenges have affected product development and market adoption of BIPV over the past 30 years, and several barriers remain. Despite high interest from solar energy stakeholders, substantial research and development efforts, and policy support in some markets, BIPV and semi-integrated PV products accounted for less than 1% (250–300 MW) of global installed capacity of distributed systems in 2009. A primary reason for BIPV's limited deployment is that the average market price of installed systems is currently higher than for rack-mounted PV. However, our findings support the notion that BIPV could have competitive and, in some cases, lower installed system prices than rack-mounted PV, by reducing installation costs and offsetting traditional building materials. Lower-efficiency PV products have higher offset values than higher-efficiency products, although these gains may be reduced by higher overall system prices. In the best case, effective system prices for c-Si BIPV and CIGS BIPV could be more than 10% lower than for rack-mounted c-Si PV. However, across all the cases analyzed in this report, the opportunities for BIPV to reduce solar system prices may become more limited as the prices of rack-mounted PV continue to decrease. If installed system prices are lower for BIPV, then select products may also have marginally lower LCOE values than PV depending on anticipated performance losses from the higher average operating temperatures that result from systems mounted directly onto rooftop surfaces. Accounting for higher installed system prices and performance issues, the LCOEs for a-Si thin-film BIPV likely will exceed those for rack-mounted c-Si PV in the residential rooftop sector. The value of aesthetic designs and flexible module form factors is not well understood, but these system characteristics may help mitigate the disadvantages of higher prices for select products.

BIPV faces more complex product development issues and market adoption dynamics than rack-mounted PV, and these issues may significantly impede progress to capitalize on price-reduction opportunities. The key issues that may limit market growth include new system performance considerations, more discrete market opportunities, and greater testing requirements to ensure relevant codes, standards, and warranty issues are addressed appropriately. BIPV-specific incentives are not widespread, but they have increased deployment of BIPV systems in some regions.

In the near-term, the more complex technology and design issues and relatively small-scale production capacity of BIPV likely may result in continued price disadvantages compared with rack-mounted PV systems. In this regard, the success of many residential rooftop BIPV products may hinge on the aesthetic value of product designs and a consumer willingness to pay premiums for non-traditional systems. Our analysis supports the notion that BIPV has the potential to reduce the installed system prices of comparable rack-mounted PV in residential rooftop markets. Market experiences suggest, however, that realizing these opportunities can be challenging.

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Appendix A: Background on Efficiency Assumptions

This report uses 2010 commercial modules as reference points for assumptions about the BIPV cases. Because we assume that the BIPV shingles are smaller than incumbent PV modules and likely include additional materials and extra spacing, we assume slightly lower efficiencies. These assumptions are listed in Table 6. Examples of typical 2010 commercial module efficiencies are listed in Table 7.

Table 6. Summary of Efficiency Assumptions for the PV and BIPV Cases

Case	Module Dimensions (m^2)	Cell efficiency	Module Derate	Module efficiency
PV Reference Case (c-Si)	1.28	16.7%	87.0%	14.5%
BIPV Derivative Case (c-Si)	0.58	16.7%	83.0%	13.8%
Thin-film BIPV Case 1 (CIGS)	0.58	14.0%	80.0%	11.2%
Thin-film BIPV Case 1 (a-Si)	0.58	7.3%	80.0%	5.8%

Table 7. Examples of 2010 Commercial Modules for c-Si, CIGS, and a-Si PV Technologies[29]

PV Technology	Product	Module Dimensions (m^2)	Cell-to-Module Derate	Module Efficiency
c-Si	**Residential-sector modules**			
	Suntech: STP185S - 24/Adb+	1.28	87.3%	14.5%
	SunPower: E19/320	1.63	-	19.6%
CIGS	**Residential-sector modules**			
	MiaSolé: MS140GG	1.07	-	13.1%
	MiaSolé: MS120GG	1.07	-	11.2%
	Q-Cells: QSMART 75	0.76	-	9.9%
	Q-Cells: QSMART 95	0.76	-	12.5%
	Solar Frontier: SF140-L	1.23	-	11.4%
	Solar Frontier: SF155-L	1.23	-	12.6%
a-Si	**Residential- and commercial-sector modules (flexible)**			
	Uni-Solar: PVL-68	1.12	83.4%	6.1%
	Uni-Solar: PVL-136	2.16	86.6%	6.3%
	Xunlight: XR-12 1117 A	1.64	-	5.9%
	Xunlight: XR-36 1117 A	4.72	-	6.2%

[29] This information is from datasheets published by solar module manufacturers in 2011: Suntech (www.suntech-power.com), SunPower (http://us.sunpowercorp.com), MiaSolé (www.miasole.com), Q-Cells (www.q-cells.com), Solar Frontier (www.solar-frontier.com), Uni-Solar (www.uni-solar.com), and Xunlight (www.xunlight.com).

Appendix B: Cost Input Tables

Estimated system prices in this report are generated from various inputs, including component costs (e.g., modules, racking hardware, inverters), labor rates, channel costs (i.e., margins), and indirect costs (e.g., commissioning fees, taxes). Inputs vary according to supply and demand, regional issues, project scale, and a number of other factors. In this sense, costs reflect a snapshot of market dynamics for a given period. The costs input assumptions listed below (Table 8 through Table 13) represent U.S. averages for residential rooftop systems in 2010.

Table 8. Assumptions of Mark-ups

Module distributor mark-up	10%
Materials mark-up	30%
Inverter mark-up	15%
Installer overhead	54%
Installer profit mark-up	30%

Table 9. Assumptions of Indirect Costs

Permitting & Commissioning	$900/system
Sales Tax	5%

Table 10. Material Costs and Installation Labor Requirements for the PV Reference Case

Material Category	Component costs ($/W)	Installation labor allocation requirements Units	Units/ system	Electrical (hours/unit)	General (hours/unit)
Module	2.15*	Modules	27	0.2	
Inverter	$0.42	Inverters	1	4	2
Wiring	$0.03	Linear feet (ft)	237†	0.05	
Other electrical‡	$0.19	Electrical subsystem	1	4.5	
Mounting hardware	$0.37	Module racks	27		1.4
Total materials cost	$3.16				
Total installation labor requirements				25.8	39.8

* Ex-factory gate price ($1.95/W, 2010 Photon) + retail margin (10%) = $2.15/W

† Total wiring (237 ft) = home run wiring (77 ft) + row to combiner wiring (160 ft)

‡ "Other electrical" includes: meter, system monitor, and disconnects.

Table 11. Material Costs and Installation Labor Requirements for the BIPV Derivative Case

Material Category	Component costs ($/W)	Installation labor allocation requirements: Units	Units/ system	Electrical (hours/unit)	General (hours/unit)
Module	2.37*	Modules	68		0.07
Inverter	$0.42	Inverters	1	4	2
Wiring	$0.07	Linear feet (ft)	541†	0.05	
Other electrical‡	$0.17	Electrical subsystem	1	4.5	
Mounting hardware	$0.00	Module racks	0		0
Total materials cost	$3.03				
Total installation labor requirements				35.6	6.8

* Ex-factory gate price ($1.95/W, 2010 Photon) + retail margin (10%) + BIPV mark-up (10%) = $2.37/W
† Total wiring (541 ft) = home run wiring (141 ft) + row to combiner wiring (400 ft)
‡ "Other electrical" includes: meter, system monitor, and disconnects.

Table 12. Material Costs and Installation Labor Requirements for the BIPV Thin-film Case 1

Material Category	Component costs ($/W)	Installation labor allocation requirements: Units	Units/ system	Electrical (hours/unit)	General (hours/unit)
Module	2.17*	Modules	68		0.07
Inverter	$0.42	Inverters	1	4	2
Wiring	$0.09	Linear feet (ft)	541†	0.05	
Other electrical‡	$0.21	Electrical subsystem	1	4.5	
Mounting hardware	$0.00	Module racks	0		0
Total materials cost	$2.89				
Total installation labor requirements				35.6	6.8

* Ex-factory gate price ($1.79/W, 2010 Photon) + retail margin (10%) + BIPV mark-up (10%) = $2.17/W
† Total wiring (541 ft) = home run wiring (141 ft) + row to combiner wiring (400 ft)
‡ "Other electrical" includes: meter, system monitor, and disconnects.

Table 13. Material Costs and Installation Labor Requirements for the BIPV Thin-film Case 2

Material Category	Component costs ($/W)	Installation labor allocation requirements Units	Units/ system	Electrical (hours/unit)	General (hours/unit)
Module	1.65*	Modules	68		0.07
Inverter	$0.42	Inverters	1	4	2
Wiring	$0.17	Linear feet (ft)	541†	0.05	
Other electrical‡	$0.41	Electrical subsystem	1	4.5	
Mounting hardware	$0.00	Module racks	0		0
Total materials cost	$1.00				
Total installation labor requirements				35.6	6.8

* Ex-factory gate price ($1.36/W, 2010 Photon) + retail margin (10%) + BIPV mark-up (10%) = $1.65/W

† Total wiring (541 ft) = home run wiring (141 ft) + row to combiner wiring (400 ft)

‡ "Other electrical" includes: meter, system monitor, and disconnects.

Appendix C: Installed System Price Uncertainty Analysis

The analysis of PV and BIPV systems in this report relies on a number of assumptions, including national average labor rates. We recognize that installed residential system prices vary across the United States, and that there are significant uncertainties in our assumptions, such as the module costs for the BIPV cases. Labor costs, component costs, site-specific costs (e.g., permitting and taxes) and supply chain costs (operating O&P margins) differ across regions. Incentives and the scale and experience of companies can impact these factors; thus, it is difficult to compare the costs of specific projects or to generalize the costs of systems without including margins of error. This Monte Carlo analysis provides insights into the factors that most contribute to uncertainties of the BIPV price analysis results in this report. Information about the uncertainties of the PV Reference Case (2010 PV system benchmark price) is available in the NREL report by Goodrich et al. (2011).

The following uncertainty analysis, summarized in Figure 8 through Figure 10 and Table 14 through Table 16, is based on factors that are most likely to vary across projects. Values listed are considered reasonable for 2010 based on published data and installer-reported information. The most frequently reported information is listed as “mode.” Triangular distributions were assumed for all variables. Because the BIPV cases are hypothetical and less defined by the market, we include a relatively broad assessment of module efficiencies, module prices, and module sizes that can impact installed system prices. Offsets for traditional building materials are excluded. The factors affecting system prices that we noted earlier, such as module efficiencies and system sizes, are particularly relevant to this uncertainty analysis (see Section 4.2 *Major Cost Differential Categories*) along with the listed range of input assumptions (Table 14 through Table 16).

Table 14. Assumptions for the Monte Carlo Simulation of the BIPV Derivative Case

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.0%	13.8%	19.0%
[2] Module price	per $W_{P\ DC}$	$2.00	$2.37	$2.60
[3] Module size	m^2	0.50	0.58	1.28
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)

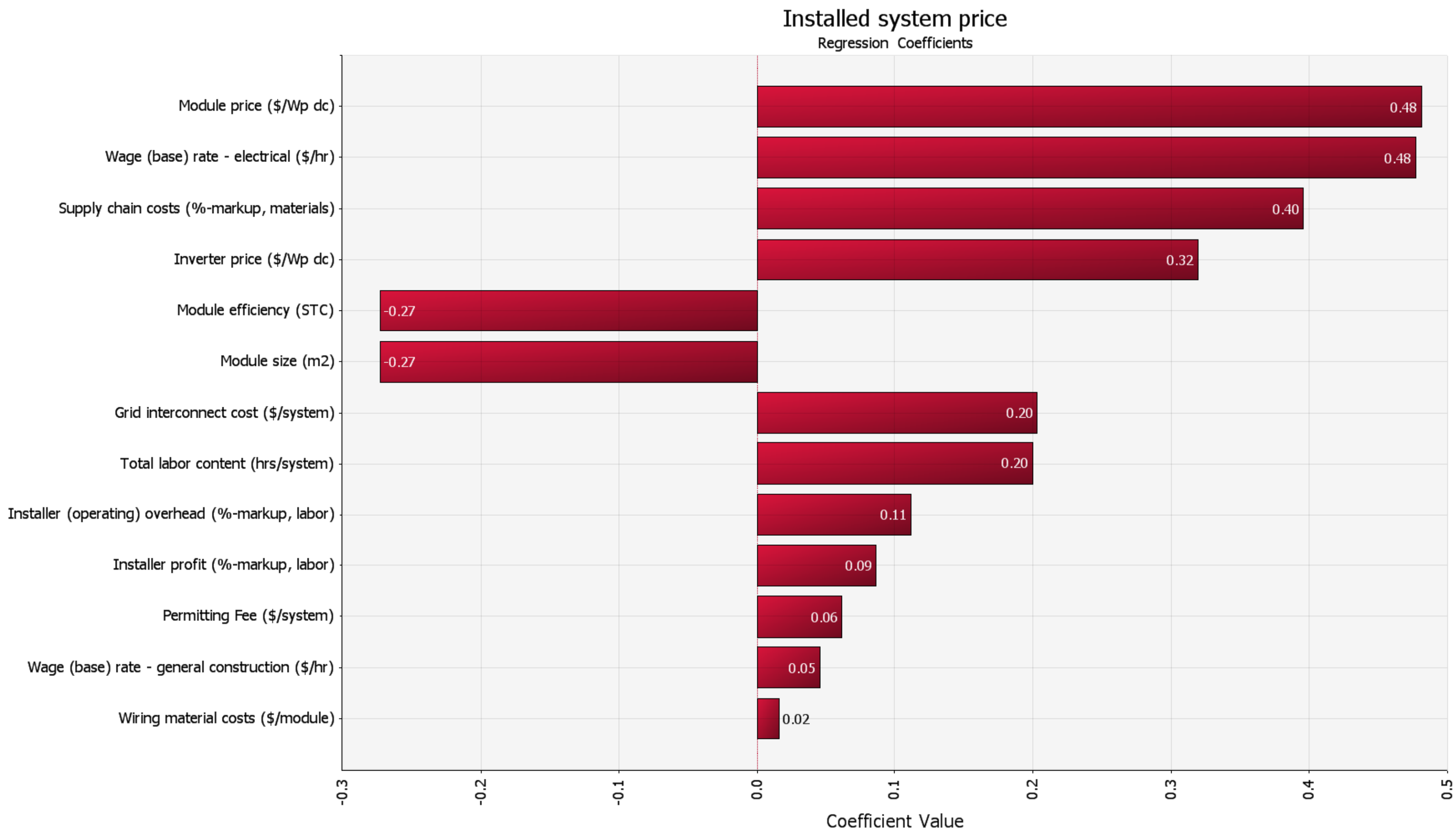

Figure 8. Residential system price Monte Carlo analysis results, probability distribution function, for the BIPV Derivative Case

Table 15. Assumptions for the Monte Carlo Simulation of the BIPV Thin-film Case 1

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	10.0%	11.2%	12.5%
[2] Module price	per $W_{P\ DC}$	$1.90	$2.17	$2.40
[3] Module size	m^2	0.50	0.58	1.28
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)

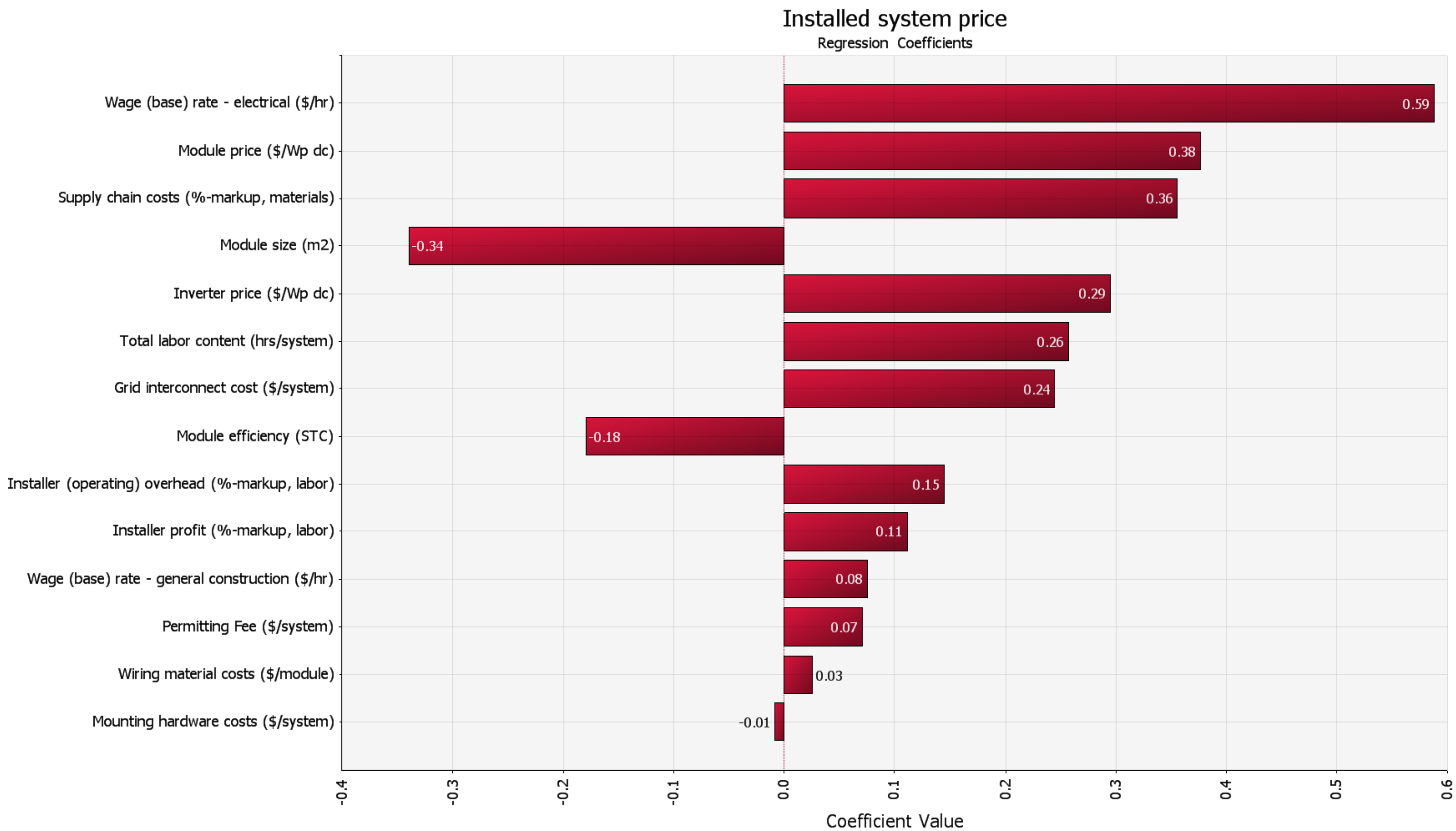

Figure 9. Residential system price Monte Carlo analysis results, probability distribution function, for the BIPV Thin-film Case 1

Table 16. Assumptions for the Monte Carlo Simulation of the BIPV Thin-film Case 2

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	5.0%	5.8%	6.5%
[2] Module price	per $W_{P\ DC}$	$1.40	$1.65	$1.90
[3] Module size	m^2	0.50	0.58	1.28
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)

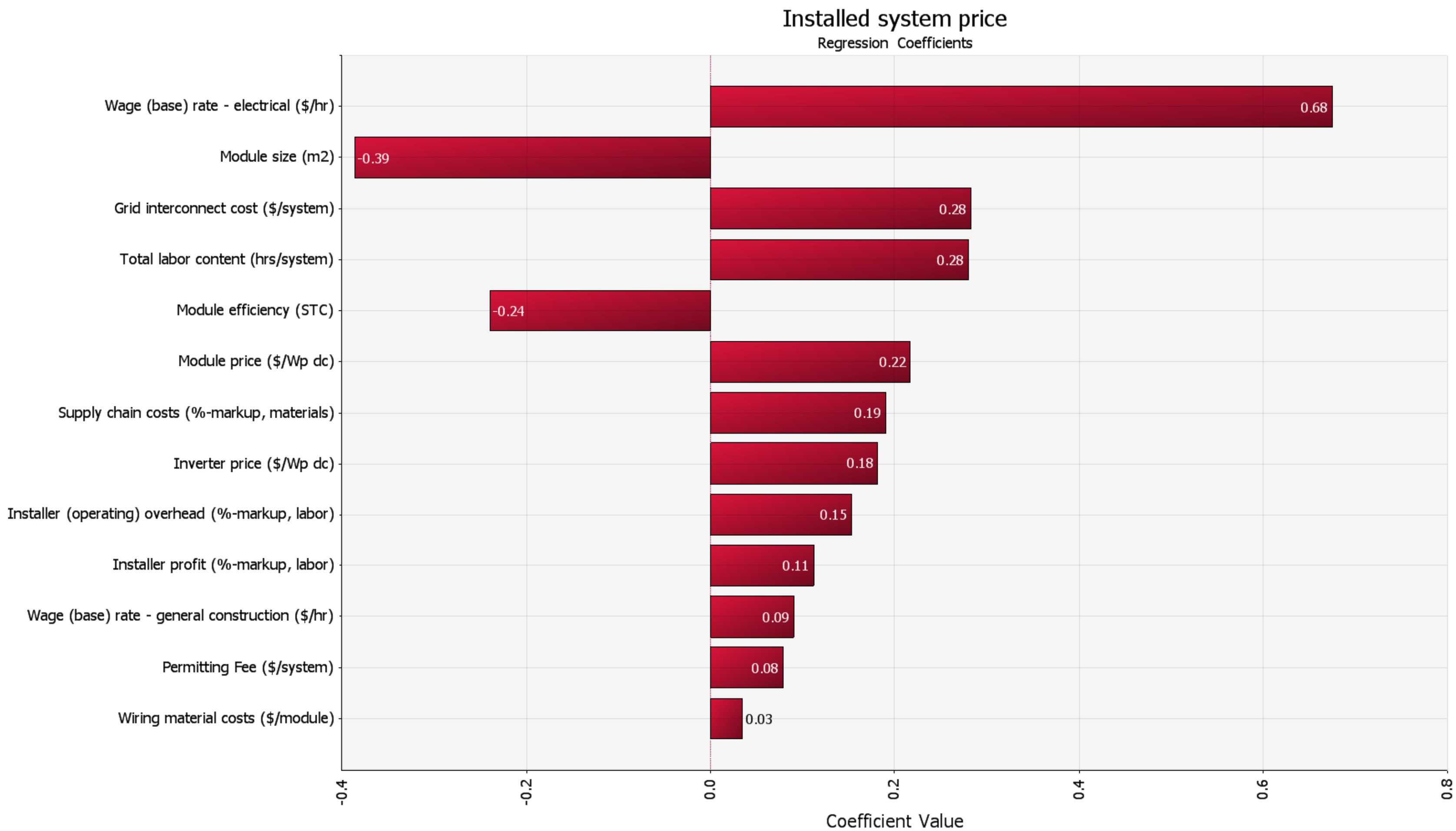

Figure 10. Residential system price Monte Carlo analysis results, probability distribution function, for the BIPV Thin-film Case 2

Appendix D: Levelized Cost of Energy and System Cost Parametric

LCOE estimates are sensitive to many variables including solar resources, site-specific weather conditions, capital costs, and operations and maintenance costs. The LCOE values in this report were calculated using SAM (version 2011.5.23), which is available for download on the NREL website.[30] Performance losses for BIPV cases were estimated using the options for select mounting structures in SAM's "Simple Efficiency Module."[31] Because this report focuses on an assessment of installed system prices, which contain uncertainties, a parametric analysis of LCOE values and installed system prices for the BIPV Derivative Case is provided below (Figure 11). The simulation is for a system located in Tucson, and it is financed by a mortgage loan with a 5.9% WACC without incentives and a nominal discount rate of 10.8%.

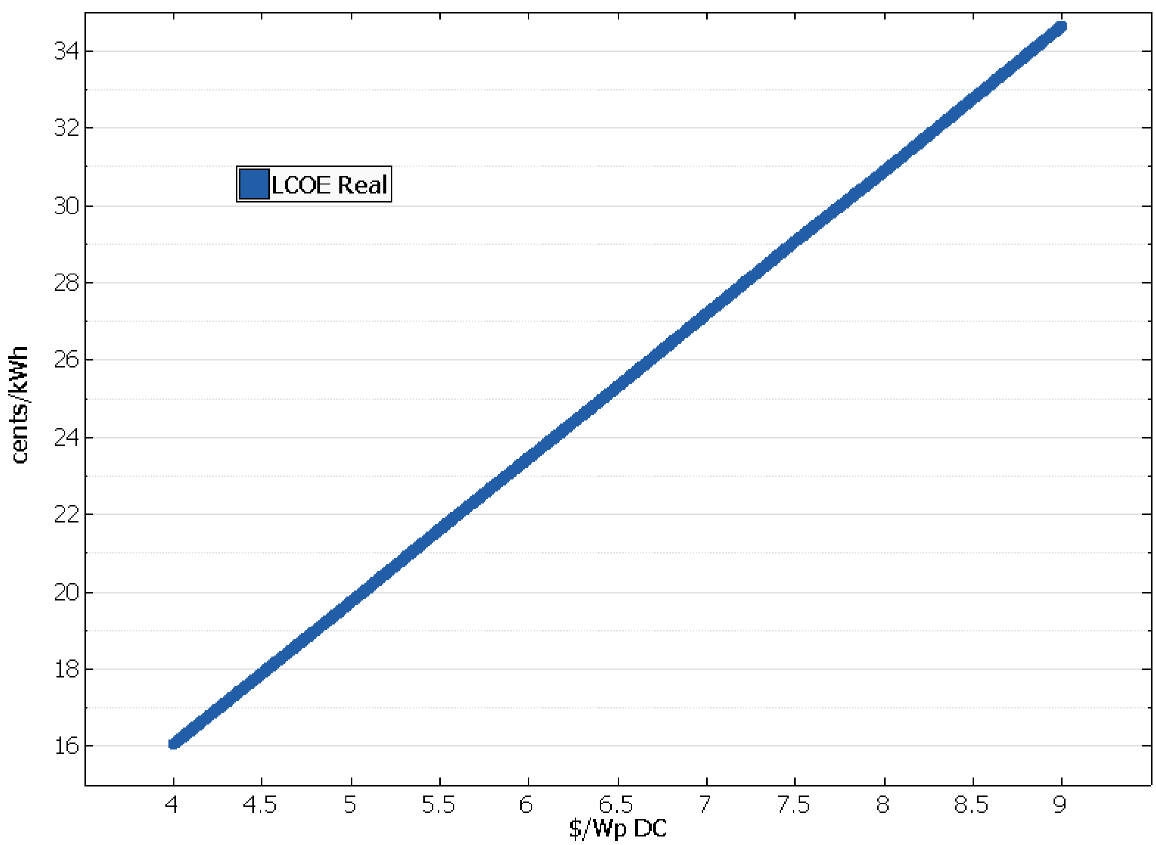

Figure 11. Sensitivity analysis of LCOE and installed system prices for the BIPV Derivative Case

30 www.nrel.gov/analysis/sam.

31 SAM's "CEC Performance Model" also has the functionality to analyze BIPV systems with additional specificity about mounting configurations.

Appendix E: Technical Potential of BIPV on U.S. Building Surfaces

A number of studies assess how building surfaces could be used to generate electricity from PV devices. Most studies focus on small areas or cities, and, owing to a range of assumptions, national estimates cannot be extrapolated easily. Our analysis of the technical potential for PV on buildings is mostly based on one national study by NREL in combination with a report by IEA.

A 2008 NREL study quantified supply curves for PV-generated electricity under three scenarios. Using building data from 2007, the study estimated that rooftops could host about 660 GW of PV capacity (350 GW residential, 310 GW commercial) from 13.5%-efficient PV modules (Denholm and Margolis 2008). Total roof space estimates were developed using building data from McGraw-Hill and the U.S. Energy Information Administration's 2005 Residential Energy Consumption Survey (RECS) and 2003 Commercial Building Energy Consumption Survey (CBECS).

Estimating PV-suitable spaces on building surfaces is a key factor in determining the technical potential of PV. The NREL study cited a 2008 report from Navigant Consulting, Inc. (NCI) about PV-penetration scenarios. Because suitable areas vary by region, average national estimates are uncertain and subject to a range of assumptions. Climate conditions and roof designs, obstructions from HVAC equipment, shading from adjacent structures and vegetation, and weight limitations can all affect suitability (Paidipati et al. 2008). NCI's study divided the United States into two climate zones, considering the southernmost states—including California, Nevada, Georgia, South Carolina, and Hawaii—to be warm climates. The study assumed that PV-suitable space on residential rooftops is 22% of total roof areas on homes in cold climates and 27% of roof areas in warm/arid climates. For commercial buildings, NCI estimated PV-suitable space as 65% of total roof area in cold climates and 60% in warm/arid climates.[32] We assume that the differences between these numbers are due to reduced tree shading and larger HVAC units in warm/arid climates for residential and commercial buildings, respectively.

The IEA published a BIPV study in 2002 that analyzed both rooftop and façade areas for several IEA countries. The report defines PV suitability as areas that result in at least 80% of the maximum annual solar input for given slopes. In addition to shading, IEA accounted for factors such as architectural designs that would limit spaces in their assessment of six tilt angles among five types of building structures. Using this 80% solar yield criterion, IEA estimated that PV-suitable space on rooftops is about 64% (average) of total roof areas, which is similar to NCI's commercial building rooftop estimate. The IEA report estimated that suitable façade space is less than 50% of available façade areas. Applying these factors to U.S. building data, IEA estimated that PV-suitable space is about 10,000 km^2 on rooftops and about 3,800 km^2 on façades (IEA 2002). This rooftop estimate is about double the more recent NREL rooftop estimate, and it is reasonable to assume a wide margin of error in these types of national studies.

[32] A DOE BIPV report prepared by Arthur D. Little, Inc. (1995) estimated that 30% of roof areas on existing residential and commercial building rooftops would be suitable for PV.

Module efficiency assumptions are critical to estimating the maximum installed power capacity for given areas. In 2010, the average efficiency of the most widely installed PV technology, c-Si, was about 14.5%. Due to the assumptions of higher derate factors for BIPV (i.e., more framing and spacing), as outlined in Appendix A, we estimated a c-Si BIPV module efficiency of 13.8%. If we use NREL's PV-suitable rooftop space estimate (4,900 km^2) and assume 13.8%-efficient BIPV modules are installed (instead of the study's 13.5% efficiency assumption), the NREL capacity estimate of 660 GW would be scaled-up to about 675 GW. If PV-suitable façade space is added, the total technical potential for BIPV could be more than 900 GW—assuming that façades would increase the estimates of PV-suitable rooftop space by about 35%, as described by IEA.

However, BIPV façade systems are likely to have lower capacity factors (CFs) than BIPV rooftop systems because of suboptimal tilt angles. Using typical meteorological year data across more than 1,000 sites in the continental United States (Wilcox and Marion 2008), CFs for south-facing c-Si rooftop systems tilted at 25 degrees range from 10% to more than 21%. A south-facing BIPV system tilted at 90 degrees (like many building façade areas) will, on average, yield about 35% less energy than an identical system tilted at 25 degrees.[33] Figure 12 and Figure 13 illustrate where CFs are most affected across the United States. The locations in northern latitudes experience smaller CF differences between 25 degrees and 90 degrees, and some southern locations maintain higher CFs at 90 degrees than systems at 25 degrees in northern areas. These CF considerations are critically important when assessing the economic viability of BIPV technologies and system designs. BIPV façade systems tilted at 90 degrees can produce electricity, but these systems will not be as economically competitive as BIPV rooftop systems in most cases in the United States.

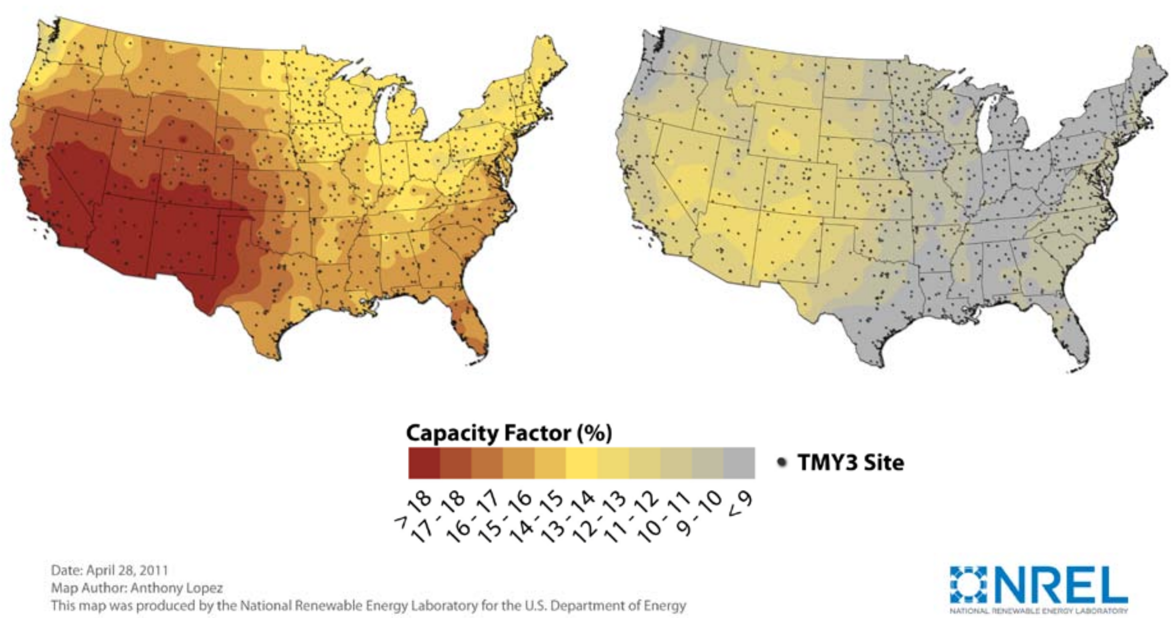

Figure 12. Regional variation of PV capacity factors for south-facing, fixed-mount systems tilted at 25 degrees (left) and 90 degrees (right)

[33] NREL's System Advisor Model.

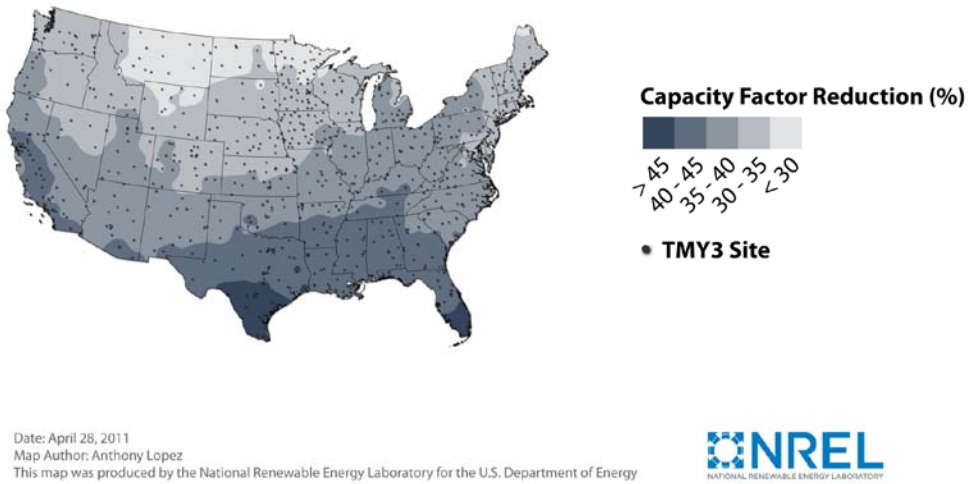

Figure 13. Relative reductions in PV capacity factors between south-facing, fixed-mount systems tilted at 25 degrees and 90 degrees