NON-HARDWARE COST REDUCTION ROADMAP TO 2020 FOR RESIDENTIAL AND COMMERCIAL PV: PRELIMINARY FINDINGS

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ABSTRACT

This paper presents preliminary results from the first effort to quantitatively roadmap reductions in non-hardware, soft costs for photovoltaic (PV) systems at the residential and small <250-kilowatt (kW) commercial (commercial) scales with annual resolution to 2020. This roadmap intentionally adapts the methodology employed by the semiconductor and crystalline silicon PV industries to derive a non-hardware corollary to technology-based roadmaps (International Technology Roadmap for PV and International Technology Roadmap for Semiconductors). Installer-level survey data in the areas of (1) customer acquisition; (2) permitting, inspection, and interconnection (PII); and (3) installation labor are used to benchmark 2010 soft costs relative to the U.S. Department of Energy's (DOE's) SunShot Initiative total soft cost \$/watt (W) targets by 2020 of \$0.65/W for residential systems and \$0.44/W for commercial systems. Financing cost benchmarks and reductions are measured in terms of weighted average cost of capital (WACC). The research-based trajectory to 2020 (Reference Case) and the trajectory to SunShot targets (Roadmap Case) are compared. The Reference Case results in \$0.42/W higher cost and 0.9% higher WACC for residential PV and \$0.15/W and 0.6% higher WACC for commercial PV by 2020, than the Roadmap Case. This paper identifies solutions and potential pathways capable of reducing soft costs in the Reference Case to SunShot target levels.

1. INTRODUCTION

With rapid decline in the global average wholesale price for photovoltaic (PV) modules, non-module hardware and non-hardware costs have accounted for a significant and increasing portion of average installed U.S. PV system prices (Barbose et al. 2011). Of the various costs of a PV system, it is critical to understand non-hardware costs, referred to as "non-hardware balance of system (BOS)," "business process," or "soft" costs, such as permitting and commissioning, profit, overhead, installation labor, customer acquisition, and financing. Non-hardware costs are directly related to the U.S. market maturity and regulatory landscape for PV.

Results from a recent National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) installer survey and NREL cost modeling analysis indicate that total soft costs, including profit and additional overhead, total \$3.30/W[1] for residential systems and \$2.65/W for commercial systems installed in 2010. This represents approximately 50% of 2010 U.S. installed residential PV system price and 44% of installed commercial system price (Ardani et al. 2012). The U.S. Department of Energy (DOE) SunShot Initiative aims to reduce the installed-system price contribution of total soft costs to approximately \$0.65/W for residential systems and

[1] \$/W measured in $\$/W_{DC}$ unless otherwise noted.

$0.44/W for commercial systems, by 2020 (DOE 2012). The objective of this analysis is to roadmap the near- and long-term trajectories of decline in the soft cost areas of (1) customer acquisition (CA); (2) permitting, inspection, and interconnection (PII); (3) installation labor; and (4) financing[2] to determine the cost reductions and innovations necessary to achieve the SunShot Initiative total soft cost $/W targets by 2020. Weighted average cost of capital (WACC) Roadmap targets for financing costs[3] of 3.0% and 3.4% are adopted for residential and commercial PV, respectively. The fifth cost category, "other soft costs," includes profit and overhead not explicitly benchmarked by past survey efforts and is not the focus of this analysis.

2. METHODOLOGY OVERVIEW

To create a roadmap of soft cost reductions through 2020, we adapted the general methodology used in the Semiconductor Industry Association's (SIA) International Technology Roadmap for Semiconductors (ITRS) and the photovoltaics industry's International Technology Roadmap for Photovoltaics (ITRPV). Similar to ITRS and ITRPV, this Soft Cost Reduction Roadmap ("Roadmap") identifies the solutions that must be developed for the industry to advance, provides a view on the challenge for specific advances, and provides annual, quantitative resolution.

Through reviews of existing literature, conference presentations, NREL and Rocky Mountain Institute (RMI) data, and in-depth interviews with installers and industry experts, we identified solutions with the potential to lower residential and commercial PV soft costs to specific $/W and % cost of capital targets, established by the DOE SunShot Vision Study for the year 2020. For 2010 baselines, this Roadmap benchmarks total installed system prices using data from Barbose et al. (2011), sourced primarily from state and utility PV incentive programs. We used installer- level survey data (n=87) to benchmark soft costs in the areas of (1) customer acquisition; (2) permitting, inspection, and interconnection; and (3) installation labor (Ardani et al 2012) and established baseline financing costs, as measured by the WACC, through a combination of depth interviews and public and private reports[4].

This Roadmap includes several cost reduction solutions (including business models, financial structures, regulatory changes, and industry best practices) capable of reducing costs in each of the four major soft cost areas. The two focus markets are residential (single-family) and <250 kilowatt (kW) commercial (commercial, municipal/university/school/hospitals (MUSH), and multi-family residential). A grouping of related solutions is defined as a solution set and there are two major attributes to each solution:

1. *Cost Reduction Potential:* the amount by which a given solution is estimated to reduce soft cost benchmark, measured in ($/W) for all soft cost areas except for finance, which is measured in (%) WACC.

2. *Market Penetration:* estimated annual market penetration rate of solution from 2012 – 2020, as a percentage of total annual installed PV capacity (excluding utility scale). All finance-related solutions are assumed to be mutually exclusive, while some solutions in other soft cost areas may be deployed concurrently.

Using the cost reduction solutions identified and the attributes above, we estimated an annualized future reference case ("Reference Case") between 2013 and 2020 for each of the residential and commercial market segments. The Reference Case depicts a cost reduction trajectory for each soft cost area, and incorporates considerable advancements given known market conditions and future expectations. It is based on NREL/RMI research and interview data. For all soft cost areas in both markets, the Reference case did not meet the SunShot targets.

We then used the aforementioned data sources to derive a more aggressive Roadmap Case that achieves SunShot targets in the four soft cost areas in both markets. For some cost areas the Roadmap Case identifies reasonable, yet substantive, advances which reduce soft costs to near SunShot target levels by 2020; for other cost areas, there is less certainty about the emergence, and elements, of specific solutions required to reach the SunShot targets. In such instances, the Roadmap Case incorporates the future deployment of new innovations with greater cost reduction potential, referred to as *undefined* solutions.

Overtime, we will be tracking progress towards meeting the Roadmap near-term cost reduction trajectory and will be working with industry and others stakeholders to identify specific strategies to achieve the long-term roadmap (and SunShot) targets for 2020.

Solutions in the Roadmap Case correspond with a four-color scale "readiness factor" to indicate the level of advancement needed to achieve SunShot cost targets. This concept is

[2] As measured by % weighted average cost of capital (WACC), rather than ($/W).
[3] derived from SunShot Vision Study financial modeling assumptions.
[4] Benchmarking effort for finance costs was completed a year later, and focused on historical data from 2011 and 2012.

adapted from a similar color-coded approach used in the ITRS and ITRPV. The color legend is shown in Figure 1.

Solutions Status Legend
Commercialized Solution - Market Penetration Realizable
Commercialized or Known Solution - Market Penetration Realizable but Challenged
Known, Uncommercialized Solution - Highly Challenged Launch or Market Penetration
Specific Solution Unknown and Uncommercialized

Fig. 1: Readiness Factor Legend.

Figure 2, below, depicts a summary of the Residential Roadmap Case, including the ($/W) cost or WACC impact of aggregate solution sets and the associated readiness factor. Figure 3 depicts the Commercial Roadmap Case .

Focus Area	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Other Soft Costs - $/W	$1.84	—	—	$1.52	$1.35	$1.19	$1.03	$0.87	$0.70	$0.53	$0.37
Finance - WACC	—	—	10.3%	10.0%	9.1%	8.3%	7.6%	4.3%	4.1%	3.7%	3.0%
PII	$0.20	—	—	$0.18	$0.16	$0.15	$0.13	$0.12	$0.09	$0.07	$0.04
Installation Labor	$0.59	—	—	$0.51	$0.47	$0.43	$0.36	$0.31	$0.25	$0.19	$0.12
Customer Acquisition	$0.67	—	—	$0.53	$0.49	$0.45	$0.40	$0.35	$0.27	$0.18	$0.12
Total Soft Costs	$3.30	—	—	$2.74	$2.47	$2.22	$1.93	$1.65	$1.31	$0.98	$0.65
Total System Costs	$6.60	—	—	$4.99	$4.49	$3.99	$3.49	$3.00	$2.50	$2.00	$1.50

Fig. 2: Residential PV Soft Cost Reduction Roadmap.

Focus Area	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Other Soft Costs and PII - $/W	$2.04	—	—	$1.66	$1.47	$1.28	$1.10	$0.91	$0.72	$0.53	$0.34
Finance - WACC	—	—	8.64%	9.5%	9.6%	9.1%	9.1%	4.7%	4.2%	3.6%	3.4%
Installation Labor	$0.42	—	—	$0.31	$0.27	$0.23	$0.20	$0.17	$0.13	$0.10	$0.07
Customer Acquisition	$0.19	—	—	$0.15	$0.14	$0.12	$0.10	$0.08	$0.07	$0.05	$0.03
Total Soft Costs	$2.65	—	—	$2.12	$1.88	$1.63	$1.39	$1.16	$0.92	$0.68	$0.44
Total System Costs	$5.96	—	—	$4.03	$3.64	$3.24	$2.84	$2.44	$2.05	$1.65	$1.25

Fig. 3: Commercial PV Soft Cost Reduction Roadmap.

3. CUSTOMER ACQUISITION

The cost to acquire a customer is influenced by several factors, including market maturity, installer business model, and system financing options available to the end user. Reducing expenses related to lead generation, bid and pro-forma preparation, contract negotiation, and system design can significantly reduce overhead costs and enable broader PV deployment.

Customer Acquisition Cost Reduction Solutions – Data collection and interview findings indicate that the following solutions decrease customer acquisition expenditures by shortening sales cycle duration and increasing bid success rates (see Table 1).

TABLE 1: CUSTOMER ACQUISITION SOLUTIONS AND ESTIMATED COST REDUCTION POTENTIAL ($/W)

Solution Set	**Solution**	***$/W Reduction**	
		Res.	**Com.**
Software Tools	remote site assessment/bid prep software	0.12	0.02
	combine site assessment and bid prep on-location on initial site visit	0.05	0.05
Design Standardization	standardize design according to common building/ site parameters	0.06	0.07
Consumer Targeting Strategies	installer-retailer partnership (i.e., Solar City and Home Depot)	0.06	0.10
	lead generation programs (i.e., pay-per-lead services)	.11	.02
	referral programs (residential PV)	0.12	–
Market Evolution	consumer awareness campaigns/online disclosure of product information	0.22	0.10

	innovative business models (i.e., leasing, power purchase agreements, community solar)	0.05	0.15
Undefined Solution *(commercial PV)*	likely includes opening of new markets via finance	–	.16

*The cost ($/W) reductions shown in Tables 1 through 3 represent the cost reduction if the solution penetrated 100% of the residential or <250 kW commercial markets. Actual reductions for any year 2013-to-2020 in the Reference Case and Roadmap Case are the product of the table $/W reduction and each Case's percent penetration for that solution.

3.1 <u>Residential Results (5kW)</u>

Cost Benchmark and SunShot Goal – NREL/LBNL installer survey results indicate that average customer acquisition costs total $0.67/W[5]. This includes $0.11/W for system design, $0.33/W for marketing and advertising, and $0.23/W for all other customer acquisition costs[6] (Ardani 2012). Assuming customer acquisition's share of 2010 total PV system price remains constant through 2020, achieving the SunShot price target of $1.50/W requires an 80% decrease in total customer acquisition costs from $0.67/W to $0.13/W.

Reference vs. Roadmap Case – In the Reference Case, customer acquisition costs steadily decrease through 2020, attributed to higher prevalence of all the strategies mentioned above, especially referral programs. Installers cited referral programs as their most cost-effective form of targeted marketing. Firms noted that customers referred by others cost up to 75% less to acquire. In addition to an anticipated increase in referral programs, from a current rate in 2012 of 10% to 50% in 2020, interviewees indicated that it is feasible for software tools and standardized system design to become market norms. However, increased customer awareness provides the overall greatest impact on reducing CA costs.
Taken together, these strategies reduce customer acquisition to $0.23/W market wide in the Reference Case (Figure 4).

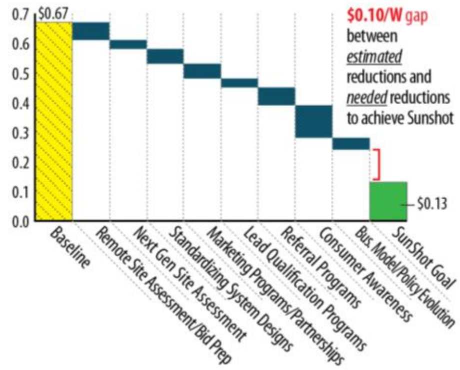

Fig. 4: Customer Acquisition Costs and SunShot Targets for Residential PV Installers.

To meet the SunShot target, customer acquisition costs would need to be reduced by an additional $0.10/W. Achieving the SunShot target is envisioned in the *Roadmap Case* through a combination of wider utilization of lead generation programs (Roadmap Case 50% market penetration in 2020, vs. 30% Reference Case), referral programs, and consumer awareness campaigns (Roadmap Case 65% market penetration in 2020, compared to Reference Case 50% market penetration).

3.2 <u>Commercial Results (<250 kW)</u>

Cost Benchmark and SunShot Goal – NREL/LBNL installer survey results indicate that median customer acquisition costs[7] total $0.19/W. This includes $0.10/W for system design, $0.01/W for marketing and advertising, and $0.08/W for all other customer acquisition costs. Assuming customer acquisition's share of 2010 total PV system price remains constant through 2020, achieving the SunShot price target requires decrease in total in customer acquisition costs from $0.19/W to $0.03/W.

Reference vs. Roadmap Case – In the Reference Case, employing the identified solutions at their anticipated market penetrations nearly achieves the SunShot target by 2020.

[5] All NREL/LBNL installer survey results and cost benchmarks are based on PV systems installed in 2010.
[6] "All other customer acquisition costs" include sales calls, site visits, travel time to and from the site, contract negotiation with the system host/owner, and bid/pro-forma preparation—but exclude marketing/advertising and system design.

[7] Given the relatively small sample of commercial installers (n=17), the median was deemed more meaningful a metric than a simple or capacity-weighted average (as was used for residential PV; (n=80))

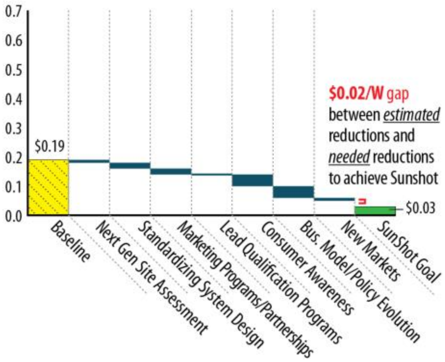

Fig. 5: Customer Acquisition Costs and SunShot Targets for Commercial PV Installers.

However, this result is misleading, as the Reference Case does not account for potential projects that remain undeveloped due to lack of available financing—a pervasive market barrier to commercial PV deployment. Today, financing is generally limited to very high quality credit, behind-the-meter offtakers, such as government-backed, MUSH entities and investment grade companies. Financing innovations that expand PV deployment to challenging real estate entity types and lower credit classes has potential to unlock the market for commercial PV. These innovations include debt financing through issuances of state or local government-backed bonds (e.g. general obligation bonds/ rate payer obligation bonds), real estate investment trusts (REITs) engaging in solar development (enabled via IRS letter ruling approving PV for REIT asset and income tests), commercial property assessed clean energy (PACE) programs, and an undefined finance solution (discussed in Section 6, Finance).

While these finance solutions should enable further market expansion, they may be available in limited geographies, be administered by government entities not adept at customer outreach, be unable to address large client bases with lower or medium-level credit, or otherwise be limited. For these reasons, an undefined CA solution is included in the Roadmap Case. While there is still some uncertainty about the specific elements of this solution, standardization of full project credit review would likely be a component[8].

<u>4. PERMITTING, INSPECTION, INTERCONNECTION</u>

The PII process for residential and commercial PV installations is determined at the municipal level and regulatory requirements across the country's more than 18,000 authorities having jurisdiction (AHJs) and over 5,000 utility service territories vary widely. Most AHJs require a combination of engineering drawings, building permit, electrical permit, design reviews, and multiple inspections before approving a PV installation. The lack of standardization in permitting and regulatory requirements adds considerable time and cost to PV deployment, as installers expend resources determining the specific requirements of each AHJ. At the commercial scale, interconnection procedures can be especially costly, deterring project completion entirely.

PII Cost Reduction Solutions – As total PII cost depends on fees and labor requirements to complete various PII processes, cost reduction solutions focus on decreasing fees paid by installers and total labor hours. NREL/LBNL cost benchmarks for commercial PII labor are minimal on a $/W basis ($.02/W), as commercial-scale PII costs are primarily driven by interconnection studies and fees. Due to this unique commercial PII dynamic, the Roadmap quantifies fee and labor cost reduction solutions for residential PV only, and assesses commercial-scale PII based on qualitative data and interview findings related to the interconnection process:

<u>TABLE 2: RESIDENTIAL PII SOLUTIONS AND ESTIMATED COST REDUCTION POTENTIAL ($/W)</u>

Solution Set	Solution	*$/W Reduction (Res.)
Standardized Requirements	uniform permitting and inspection requirements across jurisdictions *(excludes interconnection)*	0.05
Database of Requirements	online database with PII requirements, by jurisdiction	0.03
Online Permit Application Submittal	submitting an application online, directly to the AHJ, or through a centralized database/system	0.01
Lower, Standardized Fees	fee reduction from $430 to $250	0.04
Streamlined Interconnection Process	interconnection best practices (i.e., minimum response and review times for applications, defined approval process for systems generating above 15% peak load)	0.005
Undefined	likely combines market	.16

[8] Examples include efforts of the truSolar and NREL Solar Access to Public Capital consortia initiatives or maturation of proprietary offerings such as is currently offered by SCS Renewables and SolMarkets.

Solution	wide average fee of $100, standardization, database, online submittal, and interconnection best practices	

*The cost ($/W) reductions shown in Tables 1 through 3 represent the cost reduction if the solution penetrated 100% of the residential or <250 kW commercial markets. Actual reductions for any year 2013-to-2020 in the Reference or Roadmap Cases are the product of the table $/W reduction and each Case's percent penetration for that solution.

4.1 Residential Results (5kW)

PII Cost Benchmark and SunShot Goal – NREL/LBNL installer survey results indicate that average labor costs for completing PII procedures total $0.11/W. Labor costs include typical delays, travel time, and paperwork completion in the following areas: permit preparation, permit package submittal, permitting inspection, and interconnection process. Most installers reported total PII labor hours per installation within the range of 15 to 25 hours, or $0.08/W to $0.15/W. An assumed average permitting fee of $430 adds $.09/W (Sun Run 2012), for a total of $0.20/W, though permitting fees vary widely across jurisdictions (Vote Solar). Assuming PII's share of 2010 total PV system price remains constant through 2020, achieving the SunShot price target of $1.50/W requires a decrease in total PII labor costs and fees from $0.20/W to $0.04/W.

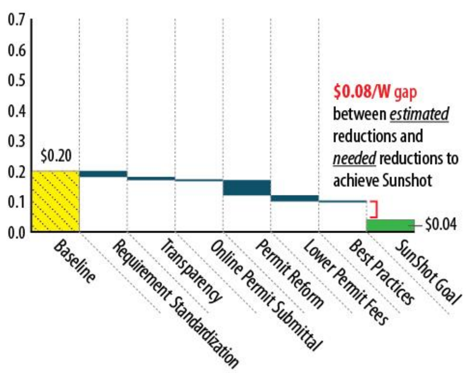

Fig. 6: Permitting, Inspection, and Interconnection Costs and SunShot Targets for Residential PV Installers .

Reference vs. Roadmap Case – In the Reference Case, total PII costs decline ~50% by 2020, attributed to piecemeal adoption of a $250 fee and best practices across AHJs. While this contributes to market-wide PII cost reductions from $0.20/W in 2010 to $0.12/W by 2020, an additional $0.08/W cost savings is needed to achieve the SunShot target of $0.04/W (Figure 6). Interview findings suggest that it will be nearly impossible to achieve the level of PII cost reductions required for SunShot with a piecemeal approach. Even when assuming near universal, simultaneous adoption of at least two of the four labor-saving solutions across AHJs, total PII costs miss the SunShot target in 2020 by at least $.03/W. This finding indicates that the estimated cost reduction potential of any single PII solution, or pair of solutions, is insufficient to drive PII labor costs to SunShot target levels.

The Roadmap Case includes an undefined solution that integrates an average fee below $250 with all the PII innovations identified: wide-scale adoption of standardized requirements, disclosed through a centralized permitting database, online permitting submittal, interconnection best practices, and sufficient efficiency improvements in municipal permit processing to ensure an average fee of $100 covers AHJ costs. Because fees in some AHJs are below $250, or non-existent, it may be feasible to reduce fees to a market wide average of $100/project, though the realization of the Roadmap Case is highly uncertain given known and expected regulatory conditions. Overall, without wide scale adoption of integrated PII reform, cost reductions will likely need to be achieved in another soft cost area to meet aggregate SunShot targets.

4.2 Commercial Results (< 250 kW)

PII Cost Benchmark and SunShot Goal – NREL/LBNL survey data indicate the median labor hours required to complete the PII process total 41, translating to $0.02/W (Ardani et al 2012). Permitting or interconnection fees at the commercial scale generally significantly exceed direct PII labor costs and an assumed average interconnection fee of $25,000 equates to an additional $0.35/W. Given that commercial PII labor costs are negligible on a per watt basis, the roadmap methodology is not deemed to accurately depict the opportunities for cost reduction and is not applied here to commercial-scale PII. Instead, qualitative data and interview findings related to interconnection study costs and fees are summarized, below:

Interconnection for Commercial PV – Proposed PV systems that pass initial review screens and are interconnected to an existing load base feeder have minimal interconnection costs. In contrast, PV that does not pass initial review screens generally requires at least two additional interconnection studies. For most interconnection screening procedures, projects proposed in an area of high distributed generation (DG) penetration (above 15% of peak load) trigger the need for these supplemental studies, with average costs between $20,000 and $30,000. Typical turnaround times vary; interviewees cited a range of eight weeks to four months, but also noted that when supplemental studies are required the review process rarely has a defined timeline for approval or denial, leading to project delay and cancellation.

While detailed studies are most commonly required for systems larger than 250 kW, the initial screening criteria and 15% threshold apply to systems of all sizes, and even residential systems proposed in areas of high DG penetration have been quoted supplemental interconnection study fees of $20,000 to $30,000. Overall, interview findings indicate that implementing interconnection best practices has the greatest potential to reduce commercial-scale PII costs (including setting minimum response and review times for interconnection applications and supplemental studies, defining an interconnection approval process for systems generating above 15% peak load, and streamlining administrative requirements).

Emerging bulk transmission and distribution load flow software, which enables the utility to model grid impacts of proposed PV based on total DG penetration rather than feeder by feeder, also demonstrate potential to significantly reduce commercial PII costs. These programs have been cited to reduce interconnection study fees, paid by the developer, from an estimated $20,000 to $30,000 to $5,000 and reduce turnaround time for initial determination from eight weeks to four months, to 15 days or less. In the long term, linking load flow program data with an online permitting and inspection interface could further enable PII cost reductions to SunShot target levels.

5. INSTALLATION LABOR

Installing a PV system requires both electrician and non-electrician labor and includes assembling the module racking and mounting it to the roof (or ballasting for commercial systems), mounting PV panels, running conduit, and connecting the inverter, meter, and disconnect. Streamlining residential rooftop installations is complicated by the heterogeneity of install platforms, roof materials, electric systems, and utility requirements. Customer preferences also vary drastically. In contrast, flat rooftops, common in the commercial sector, are typically less design constrained.

Installation labor cost reduction solutions focus on labor hour, time savings and hardware innovation that decreases the steps required to install a PV system. Identified solutions with the largest estimated cost-reduction potential are discussed in Table 3.

TABLE 3: INSTALLATION LABOR SOLUTIONS AND COST REDUCTION POTENTIAL ($/W)

Solution Set	Solution	*$/W Reduction	
		Res	**Com**
Integrated Racking	products that integrate the panel and mounting structure, often incorporates wire management/grounding	0.14	0.22
Module-integrated Electronics	microinverters	0.03	0.13
	AC Modules (*residential*)	0.10	
	DC power optimizers (*commercial*)		0.08
Plug and Play	Gen 1: AC module with integrated racking	0.28	
	Gen 2: Long term vision of fully off-the-shelf system	0.51	
Preassembly	pre-assembling panels and racking in a warehouse	0.20	0.30
Solar-ready Homes	new building design which integrates roof-mounted PV	0.10	
1,000 Volt DC Systems	higher voltage systems		0.05
Undefined Solution	likely includes Gen 2 plug and play	.22	–

*The cost ($/W) reductions shown in Tables 1 through 3 represent the cost reduction if the solution penetrated 100% of the residential or <250 kW commercial markets. Actual reductions for any year 2013-to-2020 in the Reference or Roadmap Cases are the product of the table $/W reduction and each Case's percent penetration for that solution.

5.1 Residential Results (5 kW)

NREL/LBNL benchmark installation labor costs total, on average, $0.59/W to $0.33/W for installer (roofer) labor and $0.26/W for electrician labor. The installer cost is higher because the higher installer labor requirements (49 hours (h) per installation for installers vs. 26 hours per installation for electricians) more than offset the lower installer wages ($40.49/h for installers vs. $60.12/h for electricians). Assuming installation labor's share of 2010 total PV system price remains constant through 2020, achieving the SunShot price target requires a decrease in total installation labor costs from $0.59/W to $0.12/W.

Reference vs. Roadmap Case – Interview findings suggested that integrated racking and decreased part count would play a significant role in reducing labor costs, while cost reductions from module-level DC-AC conversion (microinverters and AC modules) is less certain. Several interviewees stated that module-level electronics provided a net benefit by reducing string calculations and eliminating the central inverter, though performance and O&M implications, as well as the added equipment cost, complicated the purchasing decision. Most importantly, these products do not yet have a sufficient track record to be considered bankable on third-party owned systems. Module-level electronics may play a crucial role in paving the way for first-generation "plug and play" (AC modules with integrated racking) products, which interviewees cited as a clear labor cost reduction opportunity. Other solutions explored include prefabrication and solar-ready homes. In the Reference Case, the identified solutions foster labor cost reductions from $.59/W to$.34/W, $.22/W short of SunShot goals (Figure 7).

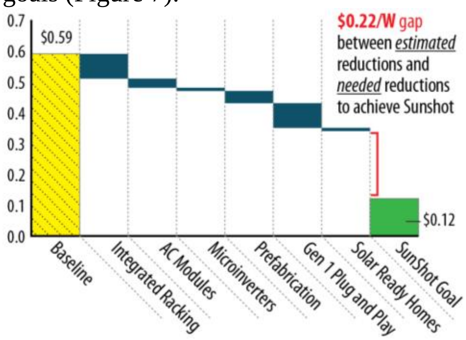

Fig. 7: Installation Labor Costs and SunShot Targets for Residential PV Installers.

Meeting SunShot goals requires reducing installation labor costs to $.12/W, for a typical residential system. This could be achieved through earlier commercialization of a transformative, integrated system, like Gen 2 Plug and Play. In the Reference Case, Gen 2 Plug and Play has the cost reduction potential to achieve the SunShot target, though reaching the aggressive levels of market penetration by 2020 in the Roadmap Case is unlikely (20% market penetration by 2020 in the Roadmap Case vs. 0% Reference Case).

Given this uncertainty, an undefined solution is included as an alternative pathway to reach the SunShot target. While the exact specifics of this cost reduction pathway are unclear from where we sit today, this solution could include a combination of additional equipment standardization and classification, reduced through-roof penetration, and process efficiency gains due to experience.

5.2 Commercial Results (< 250 kW)

Cost Benchmark and SunShot Goal – NREL/LBNL installer survey results indicate that installation labor costs varied substantially depending on the size of the system. On average, a typical system <250 kW requires eight hours/kW to install, equating to $0.42/W. Assuming installation labor's share of 2010 total PV system price remains constant through 2020, achieving the SunShot price target requires a decrease in total installation labor costs from $0.42 to $0.07.

The commercial rooftop space is generally better poised to take advantage of streamlining solutions, due to more homogenous roof space and fewer design constraints. As a result, the market is well-positioned to move towards large-scale adoption of labor-saving solutions, such as DC optimizers and integrated racking, and to a much lesser degree, 1,000-volt systems and prefabrication. Several integrated racking products are currently proliferating in the market, some cost competitive with the alternative. Interviewees noted a growing interest in DC optimizers, attributed to both reduced strings and combiner boxes (and therefore, associated labor), and to maximize levelized cost of energy (LCOE). Overall, research findings suggest that given the "business as usual" market pace of innovation, we can expect just over a 50% decrease in installation labor costs by 2020, to $0.19/W (requiring $0.11/W in additional cost reduction to meet SunShot targets).

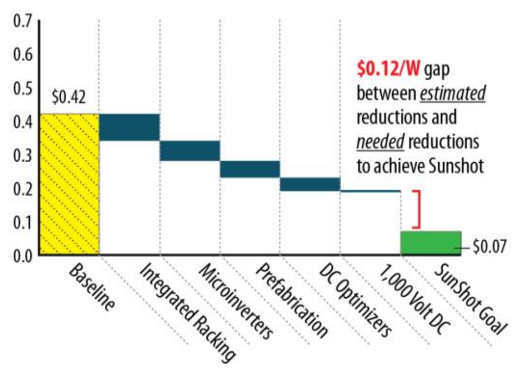

Fig. 8: Installation Labor Costs and SunShot Targets for Residential PV Installers.

Near-universal adoption of integrated racking, (90% market penetration in the Roadmap Case), provides a potential path for achieving the SunShot target. While higher than anticipated market penetration of the other solutions identified would also enable installation labor costs to decline to SunShot target levels, the near-universal adoption of integrated racking is more of a certainty.

6. FINANCE

The residential and, to a lesser degree, commercial markets have experienced a boom in tax equity-backed, third-party finance. Industry figures indicate third-party finance supporting nearly half of installed residential systems in 2011, rising to roughly two-thirds for the 2012 average (SEIA-GTM). While important for customer uptake and rapid market growth, third party with tax equity financing has a high cost of capital (averaging ~13%-real in 2012), which hinders LCOE competition with prevailing utility rates.

Financing Cost of Capital Reduction Solutions – The current tax equity market is non-standardized and participant-limited. A primary challenge to reducing the cost of capital required for tax equity-backed, third party financing, is transitioning to higher liquidity and retail investor markets. Financing cost reduction solutions focus on overcoming this challenge and decreasing the market-wide WACC to 3.0%-real and 3.4%-real for the residential and commercial PV markets, respectively.

Table 4 depicts the six high-level solution sets for residential and commercial PV finance, with corresponding 2012 WACC baselines and 2020 Roadmap Case values. Relative weightings of these six solution sets in the market-wide Roadmap Case between 2012 and 2020 can be found in Figure 9 for residential and Figure 10 for commercial PV.

<u>TABLE 4: FINANCING SOLUTIONS, WITH 2012 AND 2020 WACC COMPARISON</u>

Solution	**Description**	**WACC %[9] (Real)**	
		Res. 2012 2020	**Com. 2012 2020**
3rd Party with Tax Equity	pairing developer equity with tax equity via portfolio funds (includes transition from venture capital/private equity-backed funds to higher liquidity institutional investors, such as master limited partnerships (MLPs) and asset-backed securities)	11 5.0	14 7.2
3rd Party – Full Corp. Finance	mergers and acquisitions by large public corporations with/of solar developers	N/A[10] 2.9	N/A 2.9
Utility Finance	direct equity ownership for distributed PV systems, on-bill financing, and other utility-provided loan products	N/A 5.0	5.9 4.8
Community Solar	close-to-load projects that feed multiple contracted residences/ businesses, often benefitting from virtual net metering	11 9.4	11 11
Cash Purchase	Purchase with no external financing by resident or commercial business	3.1 3.1	4.2 4.2
Resident/ On-Balance Sheet Equity w/ Financing	*Res.* – mortgages, home equity loans, and R-PACE *Com.* –bonding or bank debt for MUSH and/or ESCO projects, C-PACE, REITs, and undefined solution	3.1 1.3	3.3 2.2

[9] U.S. inflation rate of 2.6% was used to convert nominal to real rates.

[10] N/A refers to no activity or minimal activity in solution.

6.1 <u>Residential Results</u>

Cost of Capital benchmark and Roadmap Target-
Total WACC for residential PV projects in 2012 was calculated as ~10%-real. A 3.0%-real rate Roadmap Case target for 2020 was derived from the DOE SunShot Vision Study's finance modeling basis of 80% mortgage/home equity loan debt and 20% equity[11]

Reference vs. Roadmap Case- For the Reference Case, industry interviewees cited the following anticipated market developments to lower financing costs through 2020; 1) an expanded role for large public corporations in the financing of PV systems upon expiration of the 30% ITC *(see Table 4, 3rd Party – Full Corporate Finance)* 2) significant incorporation of PV into mortgages and home equity loans by 2020 *(see Table 4 Resident Equity with Financing)*, and 3) an expanded role for utility financing. Tax equity-backed 3rd party finance is anticipated to greatly diminish, albeit with a substantial transitional role in the creation of a large secondary market for solar asset-backed securities. Cash purchases and community solar are expected to maintain a small market share in the 2020 Reference Case.

Presented in Figure 9,below, interviewees were confident about a transition to cheaper financing, as the 2020 Reference Case exhibits a mere 0.9% spread over the 2020 Roadmap Case target. Further growth of resident equity financing, via a larger share of projects financed with home equity loans and mortgages, provides a potential path to achieving the 2020 Roadmap Cast target. However, the increase in penetration of these solutions over the Reference

[11] Assumes updated reference cost of capital values of 3.0%-real debt and 3.1%-real equity.

case is highly uncertain.

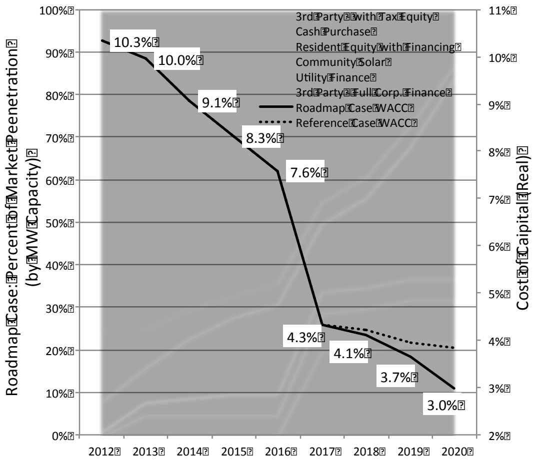

Fig. 9: Finance Roadmap Case Solution Penetration and Cost of Capital Target for Residential PV.

6.2 Commercial Results

Cost of Capital Benchmark and Roadmap Target – Total WACC for commercial PV projects in 2012 was calculated as 8.6%-real rate. A 3.4%-real rate Roadmap Case target for 2020 was derived from the DOE SunShot Vision Study's finance modeling basis of 60% debt and 40% equity[12].

Roadmap vs. Reference Case – Similar to residential finance, the Reference Case research for the commercial market yielded a 2020 WACC that was nearly as low as the Roadmap Case WACC—only 0.6% higher.

References and interviews support a diversified set of financing solutions by 2020 in the Reference Case. On-balance sheet equity with financing is expected to attain the largest share of all solutions, at 58% market penetration in 2020. Third-party financing holds moderately lower 2020 market share than in 2011 in the Reference case, but transition from a majority tax-equity-backed third financing model to a Third Party – Full Corporation Finance model is anticipated, given known and expected market conditions.

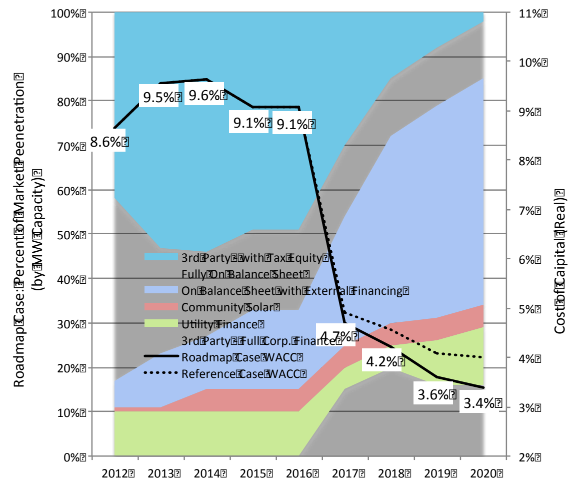

Fig. 10: Finance Roadmap Case Solution Penetration and Cost of Capital Target for Commercial PV.

However, a material difference between the residential and commercial markets is that in the commercial market, a pathway to reduce Reference Case WACC to the Roadmap Case target level is not readily identifiable. Within the "on-balance sheet equity with financing" solution, an undefined solution, with a WACC of 1.9%-real and a market penetration of 15% is needed to achieve the 2020 Roadmap Case WACC target. This solution could potentially involve specialty property rights over rooftops or lease and service agreements over broader building electrical systems.

7. LIMITATIONS

For the purpose of reporting market wide trends, this analysis focuses on average effects and is not intended to capture differences at the individual installer or company level. Furthermore, the solutions identified have both capital cost and LCOE implications, or may impact other categories of costs. Although adoption decisions will always incorporate these considerations, this is not a net cost analysis. Rather, we assume that for any solution to gain substantial market penetration, the LCOE benefit will be positive (i.e. lower cents/kWh). Finally, 2020 SunShot targets for the three $/W cost categories are based on 2011 proportional share of total soft cost. Further refining model assumptions to account for different rates of cost reduction across categories would improve the analysis.

[12] Assumes updated average debt rate of 2.9%-real (Moody's 2010 to 2012 Baa bonds average yield) and equity at 4.2%-real (U.S. public companies WACC (NYU-Stern)).

8. SUMMARY OF KEY FINDINGS.

8.1 Residential

For residential PV, additional reductions of $0.42/W and 0.9% cost of capital over the Reference are needed to achieve the Roadmap Case (and SunShot) targets by 2020. While customer acquisition cost reduction pathways are more certain than the other cost areas examined, CA costs would need to be reduced by an additional $0.10/W to meet the SunShot target. Aggressive permitting, inspection, and interconnection innovation provide a potential PII cost reduction pathway, and without meaningful adoption of integrated PII solutions, cost reductions will likely need to be achieved in another soft cost area to meet aggregate SunShot targets. Likewise, meeting SunShot targets in installation labor hinges on the commercialization of more transformative, streamlined systems than those currently on the market. For finance, current third party with external tax equity structures are expected to come down slightly in cost of capital over the next few years, but by 2017 are likely to be significantly displaced by large corporations providing full third party financing. Mortgages and, in particular, home equity loans are anticipated to play a substantially expanded role in PV finance by 2020.

8.2 Commercial

For commercial PV, additional reductions of $0.15/W and 0.6% cost of capital over the Reference are needed to achieve the Roadmap Case (and SunShot) targets by 2020. Customer acquisition costs are anticipated to decrease to near SunShot target levels by 2020, though financing innovation has potential to expand commercial PV deployment to more challenging real estate types and lower credit classes than seen today. Qualitative interview findings indicate that streamlining the interconnection process has potential to significantly reduce PII costs. With respect to installation labor, commercial PV labor cost reductions can be achieved through similar means as the residential market (through increased adoption of module integrated electronics and streamlined system design); however, the rate of adoption will need to be substantially higher than currently anticipated to enable SunShot target level cost reductions by 2020. For finance, large corporations are expected to play a significant role in full third-party financing after 2016. Debt financing products for different real estate types and credit classes are also anticipated to increase in market penetration by 2020. Yet, despite the robust set of solutions identified, an undefined solution involving on balance sheet equity is anticipated to be necessary to meet the 2020 Roadmap Case WACC target.

9. ACKNOWLEDGEMENTS

The authors would like to thank the following individuals and organization for their contributions to and review of this work: Barry Cinnamon (Cinnamon Solar Technology, Inc), Doug Fabini (SETP), David Feldman (NREL), Ben Foster (Optony), Katherine Liu (U.C. Berkeley), Michael Mendelsohn (NREL), James Tong (Clean Power Finance), and the more than 50 interview participants who provided confidential company and organization level data. This work was supported by the U.S. Department of Energy under Contract with the National Renewable Energy Laboratory.

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