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List of Acronyms

ABS	asset-backed securitization
AHJ	authorities having jurisdiction
BDC/RIC	business development companies/registered investment companies
BOS	balance of system
bps	basis points
CPI	Consumer Price Index
CRO	cost-reduction opportunities
DC	direct current
DG	distributed generation
DOE	U.S. Department of Energy
FHA	Federal Housing Authority
FHFA	Federal Housing Financing Authority
HELOC	home equity line of credit
HUD	U.S. Dept. of Housing and Urban Development
IOU	investor-owned utility
IPO	initial public offering
IPP	independent power producer
ITC	investment tax credit
ITRPV	International Technology Roadmap for Photovoltaics
ITRS	International Technology Roadmap for Semiconductors
JOBS Act	Jumpstart Our Business Startups Act
LCOE	levelized cost of energy
LTV	loan to developer equity value
M&A	merger and/or acquisition
MLP	master limited partnership
MUSH	municipal (state/local government), universities, K-12 schools, and hospitals
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PACE	property assessed clean energy
PII	permitting, inspection, and interconnection

PUC	public utility commission
PV	photovoltaics
R&D	research and development
REIT	real estate investment trusts
RPS	renewable portfolio standard
SEC	Securities and Exchange Commission
SIA	Semiconductor Industry Association
SREC	solar renewable energy certificate
VC/PE	venture capital and private equity
VDC	volt direct current
WACC	weighted average cost of capital

Executive Summary

Non-hardware (soft) costs have become a major driver of U.S. photovoltaic (PV) system prices, and aggressive soft-cost-reduction pathways must be developed to achieve the U.S. Department of Energy (DOE) SunShot Initiative's PV price targets.

This report roadmaps the cost reductions and innovations necessary to achieve the SunShot soft-cost targets by 2020, focusing on advances in four soft-cost areas: (1) customer acquisition; (2) permitting, inspection, and interconnection (PII); (3) installation labor; and (4) financing. A fifth soft-cost category—"other soft costs," which includes profit and overhead—was not explicitly benchmarked by past survey efforts and is not roadmapped here. Exploring ways to reduce this "other soft costs" category will be a subject of future research.

In 2010, U.S. PV soft costs totaled \$3.32/W[1] for 5-kW residential systems and \$2.64/W for small commercial systems (250 kW and smaller), representing approximately 50% of the total installed residential PV system price (\$6.60/W) and 44% of the total installed small commercial system price (\$5.96/W). The SunShot Initiative aims to reduce the installed-system price contribution of total soft costs to approximately \$0.65/W for residential systems and \$0.44/W for commercial systems by 2020, with total installed system prices of \$1.50/W and \$1.25/W, respectively.

To create the roadmaps, we adapted the methodologies used in the Semiconductor Industry Association's International Technology Roadmap for Semiconductors and the SEMI PV Group's International Technology Roadmap for Photovoltaics. We gathered granular and sector-specific data through literature reviews, National Renewable Energy Laboratory and Rocky Mountain Institute data, and over 70 in-depth PV industry interviews with financiers, analysts, utility representatives, residential and commercial PV installers, software engineers, industry organizations, and others. The roadmaps draw on industry expertise to plot conceivable courses to achieving the residential and small commercial 2020 SunShot targets, and they suggest the level of effort that might be required to achieve SunShot-level cost reductions in specific soft-cost areas.

We used survey data and market analysis to derive baseline values (2012 for financing, 2010 for all other cost categories[2]) for residential and small commercial PV system prices and their soft-cost components. We then assigned corresponding target (2020) values based on DOE's *SunShot Vision Study* to evaluate the level of cost reduction needed to achieve SunShot targets (DOE 2012). We defined the path from the 2010/2012 baseline values to the 2020 target values in terms of solution sets, each of which contains one or more specific cost-reduction opportunities (CROs), such as innovative technologies, business models, financial structures, regulatory changes, and industry best practices. We asked interview and survey participants to estimate soft-cost reductions—in terms of maximum cost-reduction potential and market penetration—through 2020 based on the PV industry's *current trajectory* of advancements and expectations. We then re-reviewed research sources, followed up with original interviewees, and directly inquired with additional interviewees to determine the most likely further cost reductions from the *current trajectory* to the roadmap targets.

We estimated the uncertainty of achieving each CRO by calculating the cost-reduction difference between the current-trajectory CRO values and the roadmap CRO values. We translated these uncertainties

[1] Per watt direct current. Expressed as "\$/W" throughout report.

[2] 2010 selected as baseline year for all costs measured in \$/W to correspond with beginning of SunShot Initiative.

into a color code, or "readiness factor," that indicates the level of research, development, and pre-commercialization needed to achieve the roadmap targets—similar to the International Technology Roadmap for Semiconductors (ITRS) and International Technology Roadmap for Photovoltaics (ITRPV) coding system. In our system, red denotes the lowest level of readiness/certainty; specifically, it indicates that for a given CRO, the market penetration required to achieve a roadmap target in any year is more than 25% higher than the current trajectory. Orange indicates a deviation in market penetration of 10%–25%, while yellow indicates a deviation in market penetration of up to 10%. Green denotes the highest level of readiness/certainty and that the roadmap target is realizable under the current trajectory. Results indicate that at both the residential and small commercial scales, ***the current-trajectory case does not achieve SunShot targets by 2020.*** Table ES-1 shows the readiness factor legend with color codes.

Table ES-1. Readiness Factor Legend

Achieving roadmap target is ***realizable*** under current trajectory (no deviation in roadmap market penetration from current trajectory penetration)	Green
Achieving roadmap target has ***low uncertainty*** (deviation in roadmap market penetration of up to 10% higher than current trajectory penetration)	Yellow
Achieving roadmap target has ***medium uncertainty*** (deviation in roadmap market penetration of 10 to 25% higher than current trajectory penetration)	Orange
Achieving roadmap target has ***high uncertainty*** (deviation in roadmap market penetration of more than 25% higher than current trajectory penetration)	Red

For some cost areas, the resulting roadmap identifies reasonable, yet substantive, advances that reduce soft costs to target levels by 2020. For other cost areas, there is less certainty about the emergence—and elements—of specific solution sets and CROs required to reach the targets. In these cases, the roadmap incorporates future deployment of innovations with greater cost-reduction potential, referred to as "undefined" solution sets and CROs.

The residential PV roadmap shows a challenging path to SunShot soft-cost targets (Table ES-2). Additional reductions of $0.46/W and 1.6% weighted average cost of capital (WACC) beyond the current-trajectory reductions are required. Overall, customer acquisition costs have the highest likelihood of decreasing to 2020 target levels,[3] although the implementation of several individual site-assessment-software and consumer-targeted CROs is highly uncertain. Financing has the next-most-certain cost-reduction pathway; the primary challenge is developing scalable homeowner financing products, for which the homeowner maintains equity control. In contrast, the pathways for PII and installation labor are highly uncertain. Because achieving the required PII cost target is nearly impossible with a piecemeal approach, an undefined solution set is introduced that may represent the

[3] Preliminary NREL 2012 benchmarking data made available shortly before release of this report show residential customer acquisition costs averaging below 2013 current trajectory values. Friedman et al 2013 "Second Annual Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey". Forthcoming.

combination of unknown regulatory mechanisms that enable wider-scale uniformity across authorities having jurisdiction (AHJs), a market-wide average fee of $100 [instead of $250 (i.e., in the lower permitting fees solution set)], and streamlined inspection. Similarly, an undefined solution set is required to achieve the installation labor target, which could entail a combination of additional equipment standardization and classification and/or reduced through-roof penetration.

Table ES-2. Residential PV Soft-Cost Reduction Roadmap

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition ($/W)	$0.67	—	—	$0.53	$0.49	$0.45	$0.41	$0.36	$0.28	$0.19	$0.12
PII ($/W)	$0.20	—	—	$0.18	$0.16	$0.15	$0.13	$0.11	$0.10	$0.06	$0.04
Installation Labor ($/W)	$0.59	—	—	$0.51	$0.46	$0.42	$0.36	$0.30	$0.24	$0.19	$0.12
Other Soft Costs ($/W)	$1.86	—	—	$1.30	$1.14	$0.97	$0.82	$0.68	$0.56	$0.48	$0.37
Financing (WACC %-real)	—	—	9.9%	9.4%	8.8%	8.2%	7.7%	7.7%	4.8%	3.4%	3.0%
Total Soft Costs ($/W)	$3.32	—	—	$2.52	$2.25	$1.99	$1.72	$1.45	$1.18	$0.92	$0.65
Total System Costs ($/W)	$6.60	—	—	$4.99	$4.49	$3.99	$3.49	$3.00	$2.50	$2.00	$1.50

The commercial PV roadmap offers a more certain path to SunShot soft-cost targets (Table ES-3). Additional reductions of $0.11/W and 1.1% WACC beyond the current-trajectory reductions are required. Overall, customer acquisition has a relatively certain path, although reaching the 2020 target hinges on the highly uncertain market penetration of improved site assessment and design CROs, in addition to advanced customer acquisition tools that couple well with market-expanding ("new markets") innovative finance. In the area of installation labor, commercial PV is more amenable than residential PV to streamlined installation practices, thus achieving the SunShot target by 2020 is more certain; the near-universal adoption of integrated racking provides one plausible cost-reduction pathway. Commercial financing exhibits a similar level of challenge to reach the roadmap WACC target as residential financing. However, the commercial financing path requires the highly uncertain implementation of an undefined host-finance CRO (e.g., special rooftop property rights/easements or energy service agreements) as well as highly uncertain expansions of green bond programs and commercial property assessed clean energy (PACE) financing. Though we do not develop a commercial PII roadmap, our findings suggest that streamlining the interconnection process could reduce the major PII cost component substantially.

Table ES-3. Commercial PV Soft-Cost Reduction Roadmap

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition ($/W)	$0.19	—	—	$0.15	$0.13	$0.10	$0.08	$0.08	$0.08	$0.05	$0.03
Installation Labor ($/W)	$0.42	—	—	$0.33	$0.30	$0.25	$0.20	$0.16	$0.12	$0.09	$0.07
Other Soft Costs + PII ($/W)	$2.03	—	—	$1.53	$1.36	$1.22	$1.08	$0.90	$0.72	$0.53	$0.34
Financing (WACC %-real)	—	—	8.6%	9.5%	9.2%	8.2%	7.9%	5.1%	4.4%	3.9%	3.4%
Total Soft Costs ($/W)	$2.64	—	—	$1.98	$1.76	$1.54	$1.32	$1.10	$0.88	$0.66	$0.44
Total System Costs ($/W)	$5.96	—	—	$4.03	$3.64	$3.24	$2.84	$2.44	$2.05	$1.65	$1.25

Regardless of the specific path taken to achieve the SunShot targets, the concerted efforts of numerous PV market actors and stakeholders will be required. We illustrate how the required participation of each type varies substantially by soft-cost category while noting that roles and responsibilities will be complementary and evolve over time. This report is the first of a series that will track soft-cost reductions and quantify the impacts of innovations. Future work will elaborate and refine soft-cost benchmarks, cost-reduction strategies, and the distinctions among the nation's geographically diverse PV markets with the goal of tracking—and helping enable—progress toward SunShot targets.

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1 Introduction

The objective of this analysis is to roadmap the cost reductions and innovations necessary to achieve the U.S. Department of Energy (DOE) SunShot Initiative's total soft-cost targets by 2020. The roadmap focuses on advances in four soft-cost areas: (1) customer acquisition; (2) permitting, inspection, and interconnection (PII); (3) installation labor; and (4) financing. Financing cost reductions are in terms of the weighted average cost of capital (WACC) for financing PV system installations, with real-percent targets of 3.0%[4] (residential) and 3.4%[5] (commercial). A fifth soft-cost category—"other soft costs," which includes profit and overhead—was not explicitly benchmarked by past survey efforts and is not roadmapped here. Exploring ways to reduce this "other soft costs" category will be a subject of future research.

With global photovoltaic (PV) module prices declining rapidly, non-hardware PV costs have accounted for a significant and increasing portion of average installed U.S. PV system prices (Barbose et al. 2012). Therefore, it is critical to understand non-hardware costs—also referred to as "non-hardware balance of system (BOS)," "business process," or "soft" costs—such as permitting, inspection, interconnection, profit, overhead, installation labor, customer acquisition, and financing. Non-hardware costs are both a major challenge and a major opportunity for reducing PV system prices and stimulating SunShot-level PV deployment in the United States.

Results from a 2010 installer survey and cost-modeling analysis indicate that in 2010 soft costs, including profit and overhead, totaled \$3.32/W[6] for 5-kW residential systems and \$2.64/W for small commercial systems (≤250 kW) (Ardani et al. 2012; Feldman et al. 2012; Goodrich et al. 2012). This represented approximately 50% of 2010 U.S. total installed residential PV system price (\$6.60/W) and 44% of total installed small commercial system price (\$5.96/W) (Ardani et al. 2012; Barbose et al. 2012). DOE's SunShot Initiative aims to reduce the installed-system price contribution of total soft costs to approximately \$0.65/W for residential systems and \$0.44/W for commercial systems by 2020, with total installed system prices of \$1.50/W and \$1.25/W, respectively (DOE 2012). Figure 1 depicts benchmark PV system prices, total soft costs, and SunShot targets for residential and commercial PV.

Of the \$3.32/W in residential soft costs, specifically surveyed costs total \$1.46/W[7] in the categories of customer acquisition (including system design and marketing); permitting, inspection, and interconnection (including typical delays and an assumed permitting fee of \$450); and installation labor

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[4] Derived from NREL's SolarDS modeling basis for the *SunShot Vision Study* (DOE 2012)at 80%–100% debt and homeowner's equity at 0%–20%. For the purposes of this report, this debt was calculated based on 2010-to-2012 average 30-yr \$30,000 home equity loans (2.9%-real) at 80% and homeowner's equity at 20% at 3.1%-real based on the 30-yr (to January 2013) Standard &Poor's 500 real compound annual growth rate.

[5] Derived from NREL's SolarDS modeling basis for the *SunShot Vision Study* (DOE 2012)at 60% debt and company equity at 40%. For the purposes of this report, the debt rate came from 2010-to-2012 average Moody's Baa bond ratings (2.9%-real) and U.S. corporate WACC from New York University (NYU) Stern (http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm; data as of January 2013) of 6.8%-nominal (corrected to 4.2%-real).

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

[7] This value is \$1.50/W in Ardani et al. (2012). We use \$1.46/W in this report because we do not include the cost of arranging third-party financing (\$0.02/W) or incentive application costs (\$0.02/W). In this report, we include these in "other soft costs" because we do not roadmap fixed financing costs (this is the subject of ongoing NREL research) and the SunShot 2020 targets do not include incentives.

(Ardani et al. 2012).[8] Assuming the surveyed soft costs' proportional shares of total soft costs remains constant through 2020, achieving the SunShot residential aggregate target of $0.65/W requires an 80% reduction in total surveyed costs from $1.46/W to $0.28/W.

Of the $2.64/W in small commercial soft costs, specifically surveyed soft costs total $0.98/W,[9] or 17% of the total system price (Ardani et al 2012).[10] Assuming the surveyed soft costs' proportional shares of total soft costs remains constant through 2020, achieving the SunShot aggregate commercial target of $0.44/W requires an 85% decrease in surveyed costs from $0.98/W to $0.13/W.

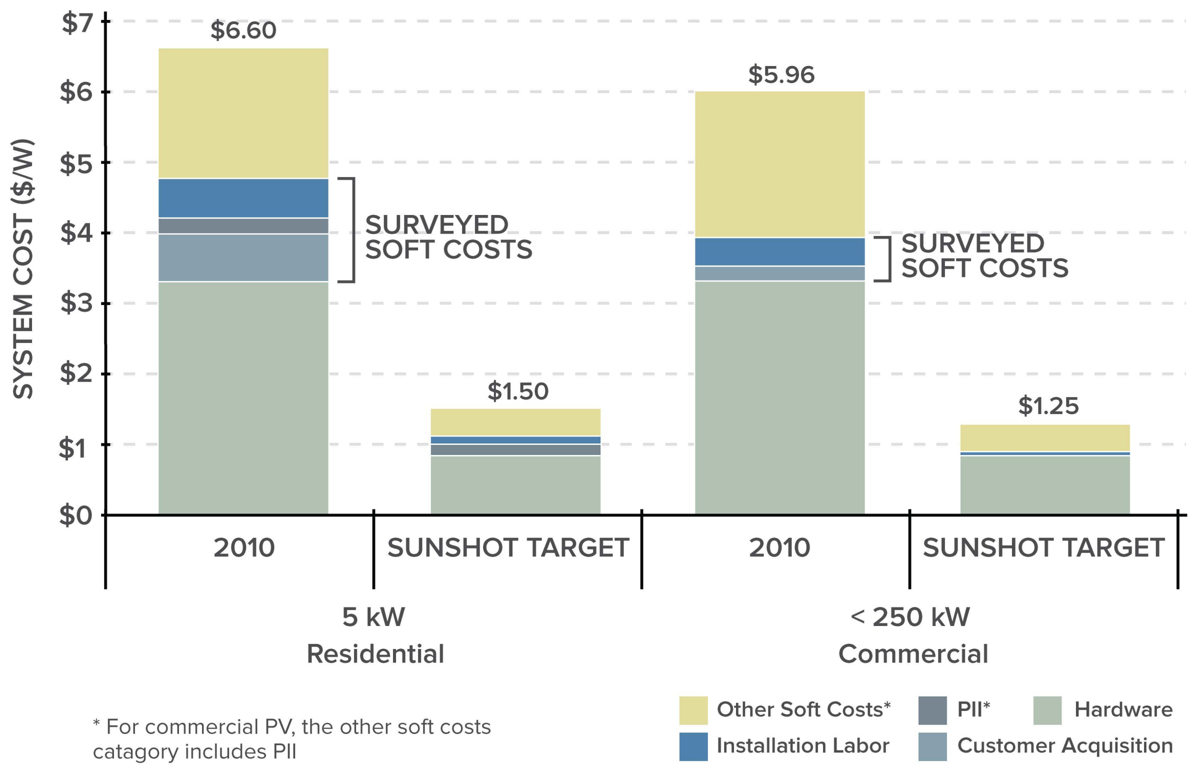

Figure 1. Total PV system prices and SunShot targets

The remainder of this report is structured as follows. Section 2 describes the roadmap data collection and analysis methodology we used. Sections 3 through 6 present roadmap data collection and analysis findings for residential and small commercial PV systems by cost category: customer acquisition (Section 3); permitting, inspection, and interconnection (Section 4); installation labor (Section 5); and

[8] Customer acquisition costs account for $0.67/W; permitting, inspection, and interconnection $0.20/W; and installation labor $0.59/W.

[9] This value is $0.99/W in Ardani et al. (2012). We use $0.98/W in this report because we do not include the cost of arranging third-party financing ($0.02/W; this only reduces the value by $0.01/W because of rounding). In this report, we include these in "other soft costs" because we do not roadmap fixed financing costs (this is the subject of ongoing NREL research).

[10] Customer acquisition costs account for $0.19/W; permitting, inspection, and interconnection (including an assumed permitting fee of $25,000) $0.37/W; and installation labor $0.42/W. Commercial soft costs are median values unless otherwise stated. Given the relatively small sample of commercial installers (n = 17), the median was deemed more meaningful than a simple or capacity-weighted average (as was used for residential PV, n = 80).

financing (Section 6). Section 7 addresses the key actors and stakeholders whose participation is required to achieve the roadmap targets. Section 8 discusses conclusions, study limitations, and directions for future research. Appendix A contains our underlying data used for calculations. Appendix B provides our interview and survey questions. Appendix C expands the definitions of the cost-reduction opportunities.

2 Roadmap Methodology

To roadmap soft-cost reductions through 2020, we adapted the methodology used in the Semiconductor Industry Association's (SIA) annual International Technology Roadmap for Semiconductors (ITRS) (http://www.itrs.net/). Through numerous working groups producing annual updates or full revisions, the ITRS summarizes the technical capabilities that must be developed for the industry to advance; it provides a 15-year outlook on major trends and outlines clear targets for researchers in the outer years. After demonstrating a significant industry impact for nearly 20 years, the SIA roadmapping methodology was adapted by the SEMI PV Group Europe (a group of European solar energy manufacturers) in 2010 to develop the International Technology Roadmap for Photovoltaics (ITRPV) (http://www.itrpv.net/). The ITRPV provides a long-term trajectory for advancements in the manufacture of crystalline silicon PV and defines the improvements necessary to advance along the PV learning curve.

The ITRS and ITRPV include tables focused on specific technical areas, listing solution pathways in the far left column with targets and associated metrics to track progress over time in corresponding rows. The ITRS and ITRPV use a color-coded scale to depict the certainty of a solution being realized and distinguish the level of research needed to achieve targets. In the ITRS, white indicates the highest level of certainty (solutions exist and are being optimized), while red indicates that significant research breakthroughs are needed or that solutions are unknown. Intermediate levels of certainty and research requirements are designated with yellow and yellow stripes. Figure 2 provides an example from the 2011 ITRS, illustrating this color coding and methodology for lithography.

Year of Production	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
DRAM ½ pitch (nm) (contacted)	36	32	25	25	23	20.0	17.9	15.9	14.2	12.6
DRAM										
DRAM ½ pitch (nm)	36	2	28	25	23	20	18	16	14	13
CD control (3 sigma) (nm) [B]	3.7	3.3	2.9	2.9	2.3	2.1	1.9	1.7	1.5	1.3
Contact in resist (nm) - Note Optical now, EUV later	55	55	55	55	29	26	23	21	18	16
Contact after etch (nm)	36	32	28	25	23	20	18	16	14	13
Overlay [A] (3 sigma) (nm)	7.1	6.4	5.7	5.1	4.5	4.0	3.4	3.2	2.8	2.5
k1 (13.5nm) EUVL	0.66	0.59	0.52	0.47	0.55	0.49	0.44	0.51	0.45	0.40

Manufacturable solutions exist, and are being optimized

Manufacturable solutions are known

Interim solutions are known

Manufacturable solutions are NOT known

Source: http://www.itrs.net/Links/2011ITRS/2011Tables/Litho_2011Tables.xlsx (accessed 3/28/13)

Figure 2. 2011 ITRS lithography technology requirements

Our soft-cost roadmap follows the general ITRS/ITRPV methods with some key differences. Unlike the ITRS and ITRPV, our roadmap addresses multi-stakeholder, multi-business aspects of PV and is not limited to technical issues. In addition, this roadmap tracks progress in terms of cost reduction—measured in $/W and WACC—rather than technical nodes. Our sources of information and industry expertise are different as well. Where the ITRS approach employs industry working groups, we gathered granular and sector-specific data through literature reviews, National Renewable Energy Laboratory (NREL) and Rocky Mountain Institute data, and in-depth interviews. Over 70 interview participants included financiers, analysts, utility representatives, residential and commercial PV installers, software engineers, industry organizations, and others. Appendix B contains the interview questions.

To create our roadmaps, we used survey data and market analysis to derive baseline values (2012 WACC for financing; 2010[11] $/W for all other cost categories) for residential[12] and small commercial[13] PV system prices and their soft-cost components. The residential baseline values are $6.60/W for the system, $3.32/W for total soft costs, and 9.9% for WACC[14] (Barbose et al. 2011; Ardani et al. 2012; Feldman et al. 2012; Goodrich et al. 2012). Within the soft costs, baseline values are as follows: $0.67/W customer acquisition, $0.20/W PII, $0.59/W installation labor, and $1.86/W “other soft costs” (Ardani et al. 2012). The small commercial baseline values are $5.96/W for the system and $2.64/W for total soft costs (Barbose et al. 2011; Ardani et al. 2012; Feldman et al. 2012; Goodrich et al. 2012) and 8.6% for WACC. Within the soft costs, baseline values are as follows: $0.19/W customer acquisition,

[11] 2010 was selected as the baseline year for all costs measured in $/W to correspond with the beginning of the SunShot Initiative.
[12] For the purposes of this study, residential systems are installed on single-family residences.
[13] For the purposes of this study, commercial systems include systems of 250 kW or smaller installed on commercial, municipal, university, school, hospital, and multi-family residential buildings, unless otherwise noted.
[14] For this study, a combination of in-depth interviews and public and private reports was used to benchmark the WACC in late 2012 and early 2013. Thus, WACC benchmarks reflect recent and more ITC-monetizing, tax-equity-dependent data, with 2011 data used in some cases.

$0.42/W installation labor, and $2.03/W "other soft costs." For commercial PV, we included PII in the "other soft costs" category because no comprehensive data exists for benchmarking interconnection study costs and permitting fees in the commercial sector. Anecdotally, interconnection study costs are reported to vary substantially—from $2,500 to more than $30,000—depending on PV penetration rates in a given utility service territory and system size. Due to the lack of existing data, this study quantitatively roadmaps cost reductions for residential PV only and assesses commercial-scale PII based on qualitative data and interview findings. Collecting comprehensive PII cost data for commercial PV systems remains an area for future research.

We next assigned target (2020) values for residential and commercial PV system prices and their soft-cost components based on the *SunShot Vision Study* (DOE 2012). The residential baseline values are $1.50/W for the system, $0.65/W for total soft costs, and 3.0% for WACC. Because of data limitations, we set the specific soft-cost target values by assuming the cost in each category decreases commensurately based on its proportion of 2010 soft costs: $0.12/W customer acquisition, $0.04/W PII, $0.12/W installation labor, and $0.37/W "other soft costs." The commercial baseline values are $1.25/W for the system, $0.44/W for total soft costs, and 3.4% for WACC, with the following specific soft-cost targets: $0.03/W customer acquisition, $0.07/W installation labor, and $0.34/W "other soft costs" (including PII). Refining 2020 soft-cost values to account for different rates of cost reduction across categories has been identified as an important area for future research.

Table 1. Baseline and Roadmap Targets for Residential and Commercial PV System Costs and WACC

MARKET	RESIDENTIAL		COMMERCIAL	
YEAR	BASELINE (2010/2012)*	TARGET (2020)	BASELINE (2010/2012)*	TARGET (2020)
SYSTEM PRICE ($/WDC)	$6.60	$1.50	$5.96	$1.25
TOTAL SOFT COSTS ($/WDC)	$3.32	$0.65	$2.64	$0.44
CUSTOMER ACQUISITION COSTS	$0.67	$0.12	$0.19	$0.03
PII COSTS**	$0.20	$0.04	—	—
INSTALLATION LABOR COSTS	$0.59	$0.12	$0.42	$0.07
OTHER SOFT COSTS**	$1.86	$0.37	$2.03	$0.34
MARKET AVERAGE WACC (%-REAL)	9.9%	3.0%	9.2%	3.4%

*The baseline is 2012 for WACC and 2010 for all other cost categories.
**For commercial PV, the other soft-cost category includes PII.

We defined the paths between the 2010 baselines and the 2020 targets in terms of solution sets, each of which contains one or more specific cost-reduction opportunities (CROs), such as innovative technologies, business models, financial structures, regulatory changes, and industry best practices. For example, the residential customer acquisition roadmap has a solution set called “consumer targeting strategies,” which includes four CROs: marketing programs and partnerships, lead qualification and generation programs, referral programs, and consumer awareness campaigns. The finance section CROs were limited to financial structures, but other CRO elements (e.g., improvement in business models and expanded financial data) were assumed to support specific structures. Each CRO has two major attributes:

1. <u>Maximum cost-reduction potential</u>: The estimated amount by which each CRO could reduce its corresponding soft-cost baseline value, measured in $/W for all soft-cost areas except for finance, which is measured in WACC percent.[15]

[15] We assumed that maximum cost-reduction potential is the same in both the current-trajectory and roadmap cases. Market penetration varies.

2. Market penetration: The estimated annual market penetration rate of each CRO by 2020, as a percentage of each sector's total annual installed PV capacity. All finance-related CROs are assumed to be mutually exclusive, while some CROs in other soft-cost areas could be deployed concurrently.

To derive a roadmap from the 2010 baseline to 2020 target values, we primarily used information provided by interview participants, supplemented with literature and data from the following sources: Ardani et al. (2012); Barbose et al. (2011); Bony et al. (2010); Brooks (2011); Bromsley (2012); Bullard (2012); Bullock et al. (2012); Coughlin and Cory (2009); DOE (2012); Feldman et al. (2012); Goodrich et al. (2012); GTM-SEIA (2012); GTM-SEIA (2013); Hubbell et al. (2012); Linder and Di Capua (2012); Mendelsohn et al. (2012); Pitt (2008); Rose et al. (2011); Schwabe et al. (2012); Seel et al. (2012); Smith and Shaio (2012); Sunrun (2011); Tong (2012); Vote Solar (2012); and Woodlawn Associates (2012).

For PII, labor, and customer acquisition, we first asked interview participants to estimate soft-cost reductions—in terms of maximum cost-reduction potential and market penetration—through 2020 based on the PV industry's current trajectory of advancements and expectations. Similarly for financing, we asked participants how they envisaged WACC changing over time for specific CROs, what additional CROs should be considered, and what CRO penetrations they expected from 2013 to 2020.[16] These responses produced our current-trajectory case.

We then re-reviewed research sources, followed up with original interviewees, and directly inquired with additional interviewees to determine the most likely further cost reductions from the current trajectory to the roadmap targets. In some cases, the authors arbitrated between CROs, particularly when mutually exclusive market penetration conditions existed (e.g., in the financing section, the sum of CRO penetrations must always equal 100% in any year). This included lowering the penetration of certain CROs in the roadmap compared with the current trajectory. This lowering of CRO market penetration was necessary to allow for higher penetration of other CROs that enable roadmap target achievement by 2020. However, arbitration between CROs is not a zero-sum exchange. The roadmap assumes a larger overall future market, due to lower cost. Thus, for a given CRO, reducing the market penetration in the roadmap compared with the current trajectory might actually result in an absolute increase in project development employing the "reduced" CRO.

For some cost areas, the resulting roadmap identifies reasonable, yet substantive, advances that reduce soft costs to target levels by 2020. For other cost areas, there is less certainty about the emergence—and elements—of specific solution sets and CROs required to reach the targets. In these cases, the roadmap incorporates future deployment of innovations with greater cost-reduction potential, referred to as "undefined" solution sets and CROs.[17]

We estimated the uncertainty of achieving each CRO by calculating the cost-reduction difference between the current-trajectory CRO values and the roadmap CRO values. We translated these certainties into a color code, or "readiness factor," that indicates the level of research, development, and pre-

[16] Interviewees often made qualitative statements about the penetration of CROs, such as "a lot," "most," "not that much," and "a minority." Although the interviewees were asked to reframe such responses quantitatively, they did not always do so. In addition, clear annual resolution between 2013 and 2020 was not always provided. In such cases, we assigned quantitative, annual-resolution values based on interview outcomes, relative to one another.

[17] Over time, we will track progress toward the roadmap targets and will work with stakeholders to identify specific solution sets and CROs in place of the "undefined" solution sets and CROs.

production needed to achieve the roadmap targets—similar to the ITRS/ITRPV coding system. In our system, red denotes the lowest level of readiness/certainty; specifically, it indicates that for a given CRO, the market penetration required to achieve the roadmap target in any year is more than 25% higher than the current trajectory. Orange indicates a deviation in market penetration of 10–25%, while yellow indicates a deviation in market penetration of up to 10%. Green denotes the highest level of readiness/certainty and the roadmap target is realizable under the current trajectory. Table 2 shows the readiness factor legend with color codes. White is not shown in the color code but denotes a PII, labor, or customer acquisition CRO that may have no or low penetration and offers very minimal (less than $0.01/W) or no cost-reduction benefits. For financing, white represents no meaningful (less than 1%) penetration.

Table 2. Readiness Factor Legend

Achieving roadmap target is ***realizable*** under current trajectory (no deviation in roadmap market penetration from current trajectory penetration)	(green)
Achieving roadmap target has ***low uncertainty*** (deviation in roadmap market penetration of up to 10% higher than current trajectory penetration)	(yellow)
Achieving roadmap target has ***medium uncertainty*** (deviation in roadmap market penetration of 10 to 25% higher than current trajectory penetration)	(orange)
Achieving roadmap target has ***high uncertainty*** (deviation in roadmap market penetration of more than 25% higher than current trajectory penetration)	(red)

In this report, readiness factor is provided for each CRO and summarized for each soft-cost category. For PII, labor, and customer acquisition, the cost category summary readiness factor is determined from a cost reduction weighted average of the products of the $/W cost reduction enabled by each CRO, multiplied by its readiness factor (1 = green, 2 = yellow, 3 = orange, 4 = red). The financing summary readiness factor is determined via a market penetration weighted average of the products of the readiness factor number (again, 1 through 4) of each CRO multiplied by its penetration.

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. Innovative financing offerings, including third-party ownership, have been cited in connection with significant decreases in customer acquisition costs but higher transaction costs. For example, companies offering no-money-down leases can more easily attract customers, but those same projects incur upfront and continuous costs of financing. Quantitatively roadmapping this dynamic is outside the scope of this analysis. Rather, innovative financing, as it relates to WACC, is discussed in the financing section (see Section 6).

The traditional sales model for PV installers often begins with an initial phone conversation with the potential customer to prescreen for project viability. Typical items discussed include current monthly electricity expenditures, property ownership status, and customer credit quality. After this initial screening, an in-person visit is completed to assess the installation site. After the installer gathers the necessary site specifications and consults with the property owner, a PV system engineer back in the office designs the system as part of a bid package. Once the bid is complete, the sales person presents it to the potential customer, usually requiring a second visit to the site. For many PV installation firms, this work is completed at risk, without a contract in place. Through technological advancements, this model is evolving to a less labor-intensive process. High-volume installers in particular have begun to employ computer-generated modeling to prequalify properties, even before the customer is contacted.

Homeowners and businesses considering the purchase of a PV system have many factors to consider, including identifying a reputable installation company, gaining familiarity with manufacturers' and installers' warranties, selecting the most suitable financing option, and understanding the overall customer economics of the system. Increased consumer awareness and retailer-installer partnerships can streamline the purchasing decision process and increase an installer's customer base. While most installers we interviewed consider customer acquisition activities to be a necessary cost of doing business, they also indicated that reducing expenses related to lead generation, bid and pro-forma preparation, contract negotiation, and system design can significantly reduce system prices offered to potential customers and enable broader PV deployment.

3.1 Residential Customer Acquisition Roadmap

Average 2010 customer acquisition costs for residential PV systems totaled $0.67/W[18]: $0.11/W for system design, $0.33/W for marketing and advertising, and $0.23/W for all other customer acquisition costs[19] (Ardani et al. 2012). Achieving the SunShot price target of $1.50/W requires an 80% decrease in total customer acquisition costs from $0.67/W to $0.12/W.

Our findings suggest three solution sets that can decrease residential customer acquisition costs: (1) software tools,[20] which reduce total time spent on site; (2) design templates, which reduce system design costs; and (3) consumer-targeting strategies, which increase the number of leads generated. Table 3 shows the residential PV customer acquisition roadmap, including the solution sets and corresponding CROs, the market-wide cost reductions ($/W) enabled by each CRO through 2020, the sum of cost reductions for all CROs combined, and the resulting average cost target from the 2010 baseline. For instance, under the software tools solution set, one CRO is remote site assessment tied to bid-preparation software. Sungevity is an example of a company that uses satellite imagery, aerial photographs, and commercially available software to gather information necessary for bid preparation, which is then transmitted to design engineers. Potential customers receive free, customized project quotes within 24 hours of inputting their street address to the Sungevity Web platform.

Compared with the current-trajectory case (in which customer acquisition costs decline to $0.25/W by 2020), achieving the customer acquisition roadmap target requires additional cost reduction of $0.13/W by 2020 (see Figure 3 and Figure 4).Two CROs require no additional market penetration in the roadmap

[18] Interviewees indicated that employee or contractor sales commissions typically range from 3%–7% of system cost and up to 10% for high margin sales. These costs were not specifically surveyed for prior benchmarking analyses and are thus included in the "all other soft costs" category.

[19] All installer survey results and cost benchmarks are based on PV systems installed in 2010. "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.

[20] The software tools CROs reduce costs in two customer acquisition categories, sales calls (included in "all other customer acquisition costs") and system design. Therefore, the total cost reductions are greater than 100% of the system design costs.

beyond the current trajectory: (1) standardized system designs and (2) marketing programs and partnerships. In other words, the readiness/certainty of deploying these two CROs at the levels required to reach the roadmap target is high through 2020. Thus, additional cost reductions of $0.13/W from the remaining CROs are needed (Figure 3).

In the 2020 roadmap, additional cost reductions of $0.03/W and ~$0.10/W are achieved through increased market penetration of software tools (remote system design/bid prep and next-generation site assessment) and consumer targeting strategies, respectively. Specifically, for the solution set of consumer targeting strategies, the CRO of lead qualification/generation programs captures 30% more of the market by 2020 than anticipated in the current-trajectory case (see Appendix A), reducing costs by an additional ~$0.03/W. Increased diffusion of referral programs (18% more of the market) and consumer awareness campaigns (10% more of the market) yield an additional cost reduction of $0.03/W each. For these CROs, readiness/certainty is higher through 2017 but then declines; all have the lowest level of readiness/certainty by 2020.

Table 3. Residential Customer Acquisition Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE ($0.67/W)							
		2013	2014	2015	2016	2017	2018	2019	2020
SOFTWARE TOOLS	Remote site assessment tied to bid prep software	$0.01	$0.02	$0.03	$0.03	$0.04	$0.05	$0.07	$0.08
	Next Gen: site assessment plus on-location bid prep on initial site visit	$0.01	$0.01	$0.02	$0.02	$0.02	$0.03	$0.04	$0.04
DESIGN TEMPLATES	Standardized system designs	$0.02	$0.02	$0.03	$0.03	$0.04	$0.04	$0.05	$0.05
CONSUMER-TARGETING STRATEGIES	Marketing programs & partnerships (e.g., Solar City, Home Depot)	$0.02	$0.02	$0.03	$0.03	$0.04	$0.04	$0.05	$0.05
	Lead qualification & generation programs	$0.01	$0.02	$0.02	$0.02	$0.02	$0.04	$0.06	$0.07
	Referral programs	$0.03	$0.04	$0.05	$0.05	$0.06	$0.08	$0.09	$0.12
	Consumer-awareness campaigns (including online outreach)	$0.02	$0.04	$0.06	$0.07	$0.09	$0.11	$0.13	$0.14
SUM OF COST REDUCTIONS ($/W)*		$0.14	$0.18	$0.22	$0.26	$0.31	$0.39	$0.48	$0.55
RESULTING AVERAGE COST ($/W)		$0.53	$0.49	$0.45	$0.41	$0.36	$0.28	$0.19	$0.12
CURRENT TRAJECTORY ($/W)		$0.53	$0.49	$0.45	$0.41	$0.37	$0.33	$0.29	$0.25

*For any given year, equal to [2010 baseline of $0.67/W] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

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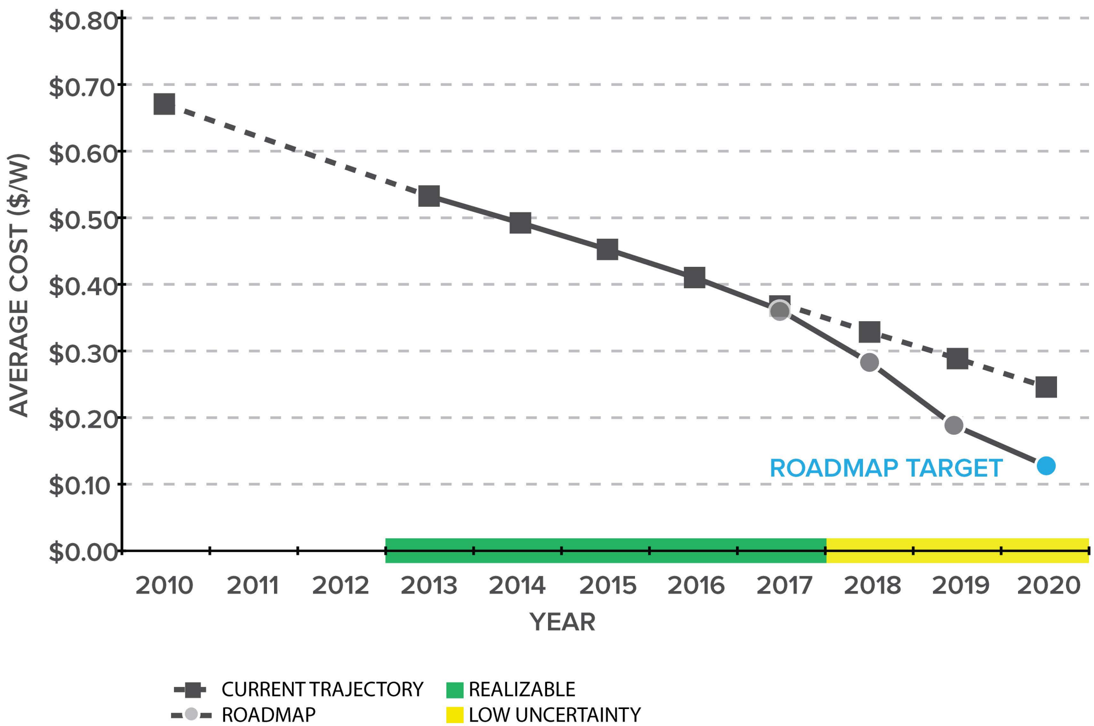

Figure 3. Residential PV customer acquisition costs: Current trajectory and roadmap

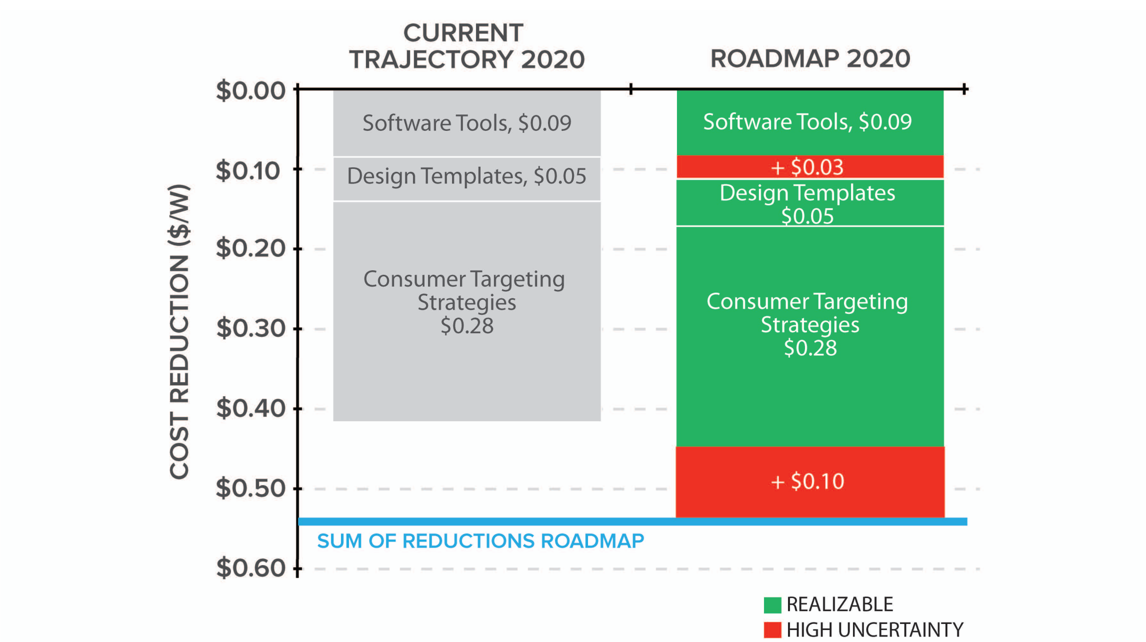

Figure 4. 2020 residential PV customer acquisition cost reductions: Current trajectory and roadmap

3.2 Commercial Customer Acquisition Roadmap

Median 2010 customer acquisition costs total \$0.19/W for small commercial PV systems: \$0.10/W for system design, \$0.01/W for marketing and advertising, and \$0.08/W for all other customer acquisition costs (Ardani 2012). Achieving the SunShot price target requires a decrease in total customer acquisition costs from \$0.19/W to \$0.03/W.

Our findings suggest four solution sets that can decrease commercial customer acquisition expenditures: (1) software tools, which reduce total time spent on site; (2) design templates, which reduce system design costs; (3) consumer-targeting strategies, which increase the number of leads generated; and (4) new markets, which increase bid success rate as financing becomes available to new customers. Table 4 shows the commercial customer acquisition roadmap. Compared with the current-trajectory case (in which customer acquisition costs decline to \$0.09/W by 2020), achieving the roadmap target requires an additional cost reduction of ~\$0.06/W by 2020 (see Figure 5 and Figure 6). In the roadmap, cost reductions from lead qualification and generation programs are in line with the current trajectory, though increased market penetration of software tools (specifically, next-generation site assessment) and standardized design templates provides one potential pathway to enabling additional cost reductions market wide.

The major roadmap improvements are achieved through the new markets solution set. Financing innovations that expand PV deployment to lower building owner credit classes[21] and/or to real estate properties in which solar misaligns with investor's interests (e.g., split incentives on energy savings with utility-bill-paying tenants and misaligned investment time horizon) have the potential to unlock the future commercial PV market. Three financing innovations/CROs that might expand the commercial PV market in this way are green bonds, commercial PACE, and the "undefined" CRO (further explained in Section 6.2 and Appendix C).

Innovative financing might enable solar PV projects where capital was otherwise unavailable. However, financing solutions may be insufficient to drop average customer acquisition costs below \$0.19/W by themselves. For example, interviewees cited numerous customer acquisition problems with existing commercial PACE programs. One issue is customer drop-outs as potential customers go through the process of getting their mortgage lender to allow subordination to the PACE loan, which often results in a refusal by the mortgage lender if that lender is not one and the same as the PACE lender.

Thus, the slight increase in customer acquisition costs from 2017 to 2020 in the current trajectory arises from the conservative assumption that new financial models do not improve against the 2010 \$0.19/W customer acquisition cost baseline. The roadmap target of \$0.03/W is only achieved when these innovative financial models are combined with new, customer acquisition advancements (together the "undefined" CRO within the "new markets" solution set).

[21] Most small commercial PV financing is made available to high credit quality corporations and MUSH entities (less than 10% of available commercial rooftop space). In addition, many real estate companies intend to sell building assets within 5 to 7 years, which does not align with much longer duration (10 to 25 years) solar PV leases and PPA contracts. Other commercial building assets are held real estate entities, such as REITs, that are challenged to monetize tax benefits (see "Third-party with REIT" in Appendix C for further discussion). In addition, many real estate investment entities do not pursue solar because they consider it an atypical asset or income stream for other business-related reasons.

Table 4. Commercial Customer Acquisition Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE ($0.19/W)							
		2013	2014	2015	2016	2017	2018	2019	2020
SOFTWARE TOOLS	Remote site assessment tied to bid prep software	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01
	Next Gen: site assessment plus on-location bid prep on initial site visit	$0.00	$0.00	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
DESIGN TEMPLATES	Standardized system designs	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
CONSUMER-TARGETING STRATEGIES	Marketing programs & partnerships (e.g., Solar City, Home Depot)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01
	Lead qualification & generation programs	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01
	Consumer-awareness campaigns (including online outreach)	$0.02	$0.03	$0.04	$0.05	$0.04	$0.04	$0.04	$0.04
NEW MARKETS	Undefined (includes innovative financing to open new markets coupled with new customer acquisition advancments)	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.03	$0.06
SUM OF REDUCTIONS ($/W)*		$0.04	$0.06	$0.09	$0.11	$0.11	$0.11	$0.14	$0.16
RESULTING AVERAGE COST ($/W)		$0.15	$0.13	$0.10	$0.08	$0.08	$0.08	$0.05	$0.03
CURRENT TRAJECTORY ($/W)		$0.15	$0.13	$0.11	$0.09	$0.09	$0.09	$0.09	$0.09

*For any given year, equal to [2010 baseline of $0.19/W] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

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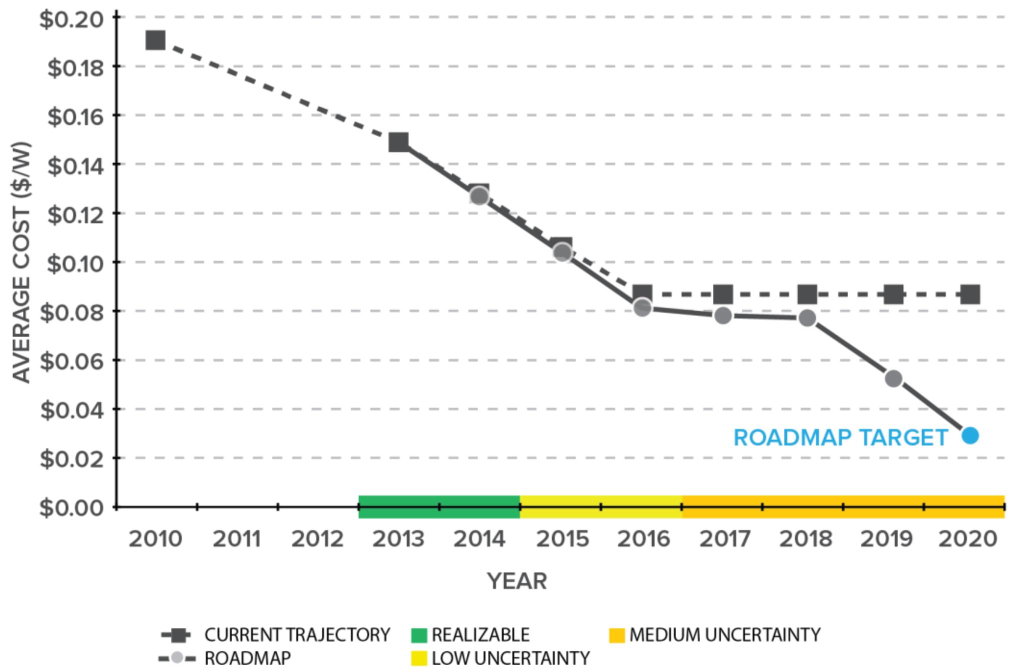

Figure 5. Commercial PV customer acquisition costs: Current trajectory and roadmap

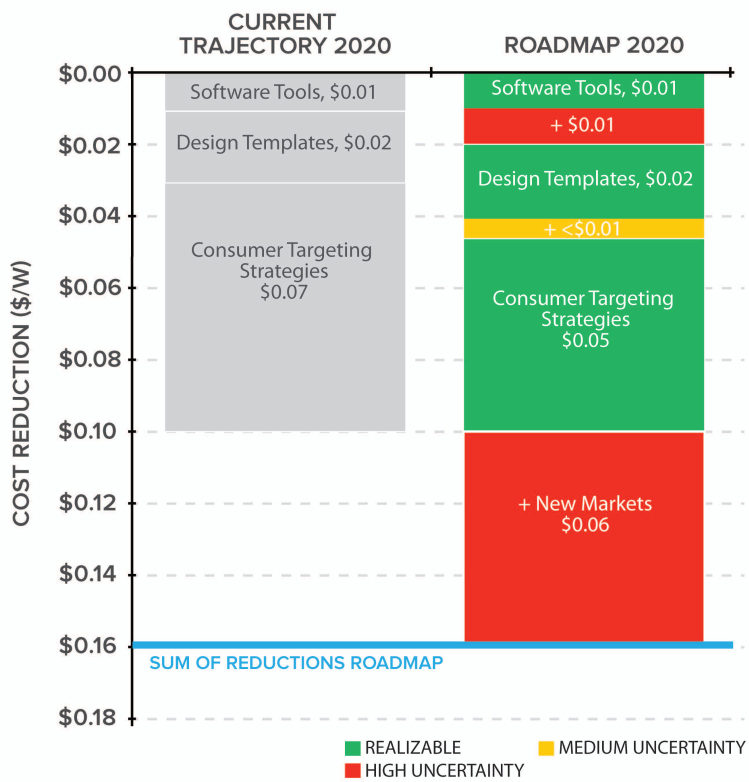

Figure 6. 2020 commercial PV customer acquisition cost reductions: Current trajectory and roadmap

4 Permitting, Inspection, and Interconnection

Germany has an approximately $2.00/W PV price advantage over the United States. While this cost differential can be attributed, in part, to variation in federal policies, greater U.S. permitting, inspection, and interconnection costs contribute as well. German permitting requirements are minimal compared to many parts of the United States. The feed-in tariff registration form, which enables grid-connected solar residences to receive federal incentives, is the only German paperwork required for PV systems. Typically, this form takes as little as five minutes to fill out and is conveniently submitted online. In contrast, most U.S. AHJs require a combination of engineering drawings, building permit, electrical permit, design reviews, and multiple inspections before approving a PV installation. A recent study by Clean Power Finance (Tong 2012) found that 36% of installers limit or avoid sales efforts in certain jurisdictions due to cumbersome permitting processes. This impedes overall market growth, while decreasing competition, thereby increasing system prices in these areas. Moreover, the lack of standardization in permitting and regulatory requirements across the country's more than 18,000 AHJs and more than 5,000 utility service territories adds considerable time and cost to project completion, as installers expend resources determining the specific requirements of each AHJ and utility. As a result, it takes on average only five labor hours for German installers to complete the permitting, inspection, and interconnection process for residential PV, compared to 19 labor hours for U.S. installers (Seel et al. 2012).

At the commercial scale, interconnection procedures can be especially costly and can deter project completion entirely. However, for commercial PV, we included PII in the "other soft costs" category because no comprehensive data exists for benchmarking interconnection study costs and permitting fees in the commercial sector. Anecdotally, interconnection study costs are reported to vary substantially—from $2,500 to more than $30,000—depending on PV penetration rates in a given utility service territory and system size. Due to the lack of existing data, this study quantitatively roadmaps cost reductions for residential PV only and assesses commercial-scale PII based on qualitative data and interview findings. Collecting comprehensive PII cost data for commercial PV systems remains an area for future research.

4.1 Residential Permitting, Inspection, and Interconnection Roadmap

Average 2010 PII labor costs total $0.11/W for residential PV systems, including typical delays, travel time, and paperwork completion related to permit preparation ($0.05/W), permit package submittal ($0.02/W), permitting inspection ($0.03/W), and interconnection ($0.01/W). An assumed average permitting fee of $430 adds $0.09/W (Sunrun 2011) for a total of $0.20/W, although permitting fees vary widely across jurisdictions (Vote Solar 2012). Achieving the SunShot price target requires a reduction in total PII labor costs and fees from $0.20/W to $0.04/W.[22] Note: PII cost benchmarks are for completed installations and do not include the cost of projects which fail due to regulatory and policy hurdles. Quantifying the impact of these market barriers would likely add to total PII costs, but is outside the scope of this analysis.

Our findings suggest five solution sets that can decrease residential PII expenditures: (1) standardization of requirements (2) transparency of requirements, both of which reduce the time installers spend determining jurisdiction specific permitting processes; (3) online permit application submittal, which reduces travel and wait time at the permitting office; (4) lowering market-wide average permitting fees from $430 to $250, which decrease fixed permitting costs; and (5) interconnection best practices, which reduce labor by lowering application expense and wait time. Beyond these, a sixth, undefined solution set is included to meet the PII cost target of $0.04/W. Vermont's PV registration model, for installations of 10 kW and smaller, exemplifies a standardized, streamlined PII process. An installer or homeowner in Vermont can apply for all necessary permits with a single registration form that specifies system components, configuration, and compliance with interconnection requirements. If no opposition or interconnection concerns are raised within 10 days of registration, a Certificate of Public Good is granted and the project is considered approved.

Table 5 shows the SunShot residential PII roadmap. Compared with the current-trajectory case (in which PII costs decline to $0.14/W by 2020), achieving the roadmap target requires additional cost reductions of $0.10/W by 2020 (see Figure 7 and Figure 8). A plausible cost-reduction pathway for achieving the roadmap PII target is not immediately apparent, for even when assuming near-universal adoption of at least two of the four labor-saving CROs across AHJs, total PII costs miss the 2020 target by at least $0.03/W. The roadmap therefore includes an undefined solution set that likely combines unknown regulatory mechanisms that enable wider-scale uniformity across AHJs, an average fee of $100 [instead of $250 (i.e., in the lower permitting fees solution set)], [23] and streamlined inspection. In most jurisdictions, finalizing a PV installation requires at least two inspections, one by either the city or county and another by the utility. Increased coordination between the utility and the city/county inspectors and combining multiple inspections into a single, streamlined process would enable time and cost savings. However, because reducing PII costs to target levels depends on regulatory and policy reform, reaching the roadmap PII target is highly uncertain. Additional PV cost reductions will likely need to be achieved in other soft-cost areas to meet aggregate SunShot targets.

[23] Assumes sufficient efficiency improvements in municipal permit processing to ensure an average fee of $100 covers AHJ costs

Table 5. Residential Permitting, Inspection, and Interconnection Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE ($0.20/W)							
		2013	2014	2015	2016	2017	2018	2019	2020
STANDARDIZATION	Uniform permitting & inspection requirements across jurisdictions (excludes interconnection)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
TRANSPARENCY	Online database of requirements by jurisdiction	< $0.01	< $0.01	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02
ONLINE PERMITTING	Online permit application submittal	< $0.01	< $0.01	< $0.01	$0.01	$0.01	$0.01	$0.01	$0.01
LOWER FEES	Market-wide average fee reduction from $430 to $250	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.03
INTERCONNECTION BEST PRACTICES	Interconnection best practices (e.g., rapid application process, defined process for systems > 15% peak load)	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01
UNDEFINED	Undefined (likely includes market-wide average fee of $100 and streamlined inspection)	$0.00	$0.02	$0.02	$0.03	$0.05	$0.05	$0.06	$0.07
SUM OF REDUCTIONS ($/W)*		$0.02	$0.04	$0.05	$0.07	$0.09	$0.10	$0.14	$0.16
RESULTING AVERAGE COST ($/W)		$0.18	$0.16	$0.15	$0.13	$0.11	$0.10	$0.06	$0.04
CURRENT TRAJECTORY ($/W)		$0.18	$0.17	$0.16	$0.16	$0.16	$0.15	$0.15	$0.14

*For any given year, equal to [2010 baseline of $0.20/W] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

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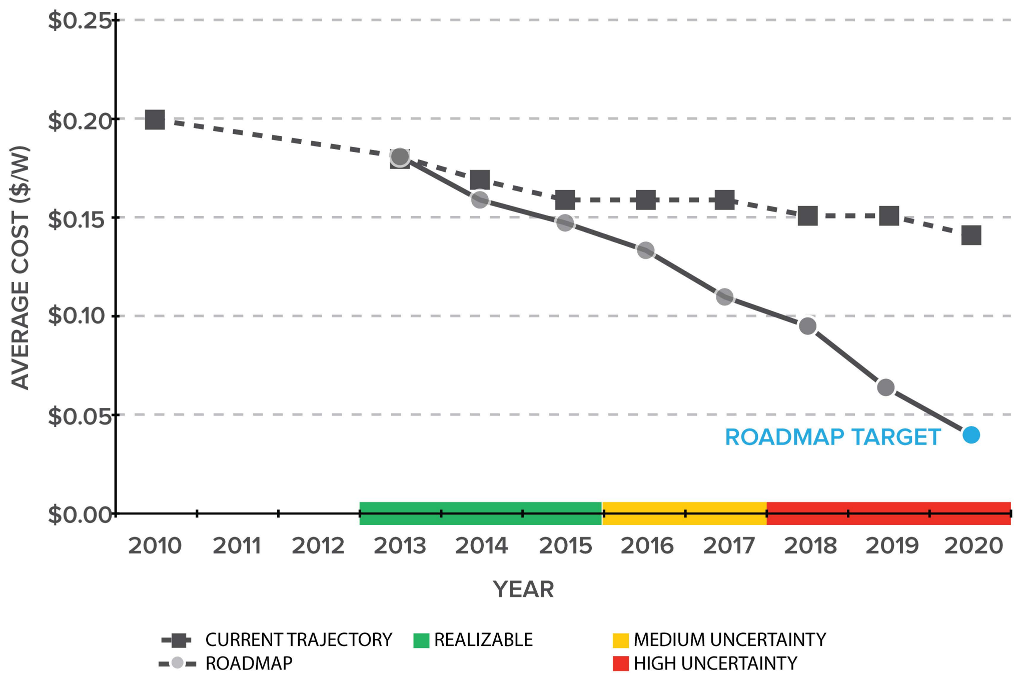

Figure 7. Residential PV permitting, inspection, and interconnection costs: Current trajectory and roadmap

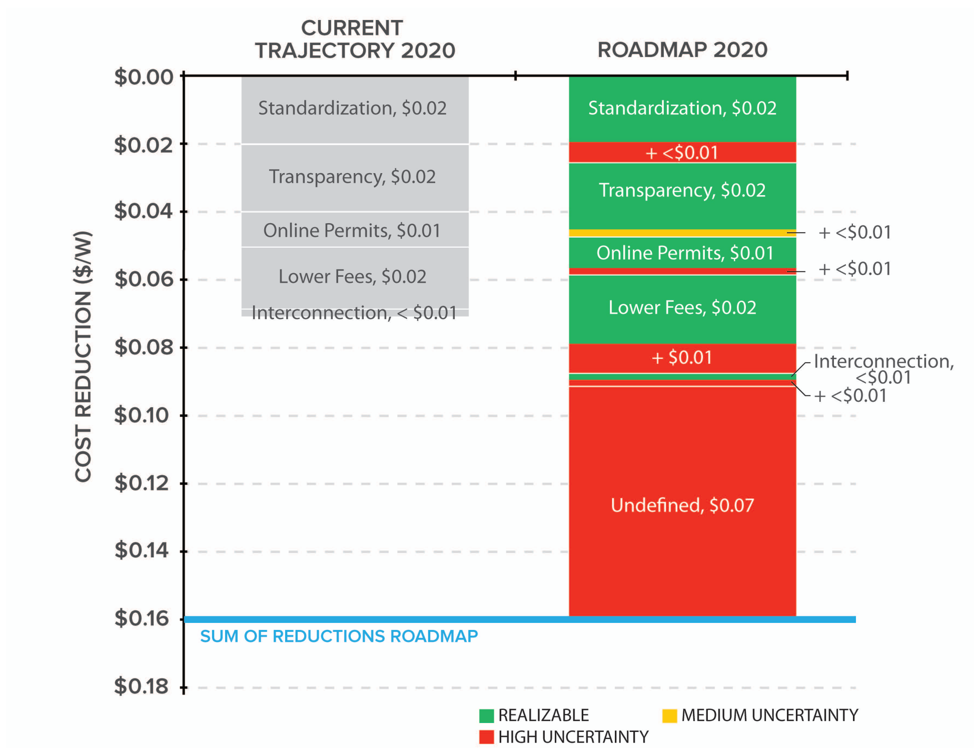

Figure 8. 2020 residential PV permitting, inspection, and interconnection cost reductions: Current trajectory and roadmap

4.2 Commercial Permitting, Inspection, and Interconnection

Because no comprehensive cost data exists for commercial PV interconnection studies and permitting fees, we quantitatively roadmap cost reductions for residential PV only and assess commercial-scale PII based on qualitative data and interview findings.

Interconnection costs typically consist of an interconnection agreement application fee, labor for agreement application completion, engineering labor for supplemental documentation (such as line drawings, output calculations, and an energy audit), wait time for application processing, equipment costs (such as an external disconnection switch or transformer), and labor costs for final inspection. For proposed PV systems that pass initial review screens and are connected to an existing load base feeder, interconnection costs are relatively predictable. In contrast, for PV systems that do not pass initial review screens, utilities generally require at least two additional interconnection studies, and costs vary widely. For most interconnection screening procedures, projects in an area of high distributed generation (DG) penetration (above 15% of peak load) trigger the need for these supplemental studies at an average cost of $25,000. 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, which can lead 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 $25,000. 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 could significantly reduce commercial PII costs. These programs can reduce interconnection study fees paid by the developer from $25,000 down to $5,000 and reduce turnaround time for initial determination 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. In the United States, streamlining residential rooftop installations is complicated by the heterogeneity of installation platforms, roof materials, electric systems, and utility requirements. Customer preferences also vary drastically. Optimizing the system typically requires customizing both system design and installation and incorporating shading, roof obstructions, and load limitations. As a result, it is difficult for installers to standardize processes and challenging for technology manufacturers to further integrate hardware without compromising needed system flexibility.

For the commercial sector, we limit this analysis to roof-mounted commercial applications, which are usually, but not always, flat roofs. Relative to residential, usable roof space is typically less constrained by shading, enabling more design options. Flat roof structure enables lower labor costs by facilitating movement of workers and often by enabling systems to be ballasted, avoiding the additional step of roof penetration. Given the large size of these systems, commercial systems benefit from economies of scale in installation labor as crews gain efficiency, and electrician labor makes up a smaller portion of overall labor hours.

Inherently, integrators and installers pursue efficiencies wherever possible. While some interviewees indicated few additional technology or process efficiencies were possible, many suggested that further installation labor cost reductions can be achieved by focusing on increasing labor efficiency or reducing the steps required to install a PV system via hardware innovation.

5.1 Residential Installation Labor Roadmap

Average 2010 labor costs for residential PV systems total \$0.59/W—\$0.33/W for roofer labor and \$0.26/W for electrician labor. The cost associated with roofer labor is greater because the higher respective labor requirements (49 hours per installation for roofers versus 26 hours for electricians) more than offset the lower roofer wages (\$40.49/hr for roofers versus \$60.12/hr for electricians). Achieving the SunShot price target requires a reduction in total installation labor costs from \$0.59/W to \$0.12/W.

Our findings suggest five solution sets that can decrease residential labor expenditures: (1) integrated racking, (2) module-integrated electronics, (3) prefabrication, (4) plug and play, and (5) solar-ready homes. Beyond these, a sixth, undefined solution set is included to meet the installation labor cost target of \$0.12/W. Table 6 shows the residential PV installation labor roadmap. Compared with the current-trajectory case (in which labor costs decline to \$0.38/W by 2020), achieving the roadmap target requires additional cost reduction of \$0.26/W by 2020 (see Figure 9 and Figure 10). This could be achieved through increased market penetration of Generation 1 plug-and-play systems (combined integrated racking and AC modules) and earlier commercialization of a transformative, off-the-shelf system such as Generation 2 plug-and-play. Generation 2 plug-and-play has 0% market penetration by 2020 in the current-trajectory case, compared to 20% in the roadmap. An increase in either plug-and-play solution would reduce the required penetration of more piecemeal CROs, such as AC modules and integrated racking. However, for both Generation 1 and 2 plug-and-play, reaching roadmap market penetration levels is uncertain. Thus, an undefined solution is included, which could entail a combination of additional equipment standardization and classification and/or reduced through-roof penetration. Further, additional labor cost reductions may be achieved via increased business process efficiency, such as a steadier pipeline (less idle time/overtime), reduced hours spent on reworking errors, and/or more efficient crew routing. Because the precise combination of mechanisms of this solution is undefined, this is considered highly uncertain.

Table 6. Residential Installation Labor Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE ($0.59/W)							
		2013	2014	2015	2016	2017	2018	2019	2020
INTEGRATED RACKING	Integrated racking (eliminates additional mounting structure)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01
MODULE INTEGRATED ELECTRONICS	AC Modules (microinverter integrated at factory)	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.01
	Microinverters (small inverters on racking convert to AC)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00
PREFABRICATION	Preassembly of panels and racking in warehouse/ factory	$0.01	$0.01	$0.02	$0.02	$0.03	$0.03	$0.04	$0.04
PLUG AND PLAY	Gen 1 (AC module with integrated racking)	< $0.01	$0.01	$0.02	$0.06	$0.08	$0.10	$0.11	$0.13
	Gen 2 (fully inclusive off-the-shelf system)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.05	$0.10
SOLAR-READY HOMES	Solar-ready homes (new building design integrates rooftop PV)	< $0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
UNDEFINED	Undefined (likely includes more equipment standardization, reduced through-roof penetration, experience gains)	$0.04	$0.06	$0.08	$0.10	$0.12	$0.14	$0.16	$0.18
SUM OF REDUCTIONS ($/W)*		$0.08	$0.13	$0.17	$0.23	$0.29	$0.35	$0.40	$0.47
RESULTING AVERAGE COST ($/W)		$0.51	$0.46	$0.42	$0.36	$0.30	$0.24	$0.19	$0.12
CURRENT TRAJECTORY ($/W)		$0.55	$0.53	$0.51	$0.49	$0.46	$0.44	$0.42	$0.38

*For any given year, equal to [2010 baseline of $0.59/W] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

REALIZABLE / MEDIUM UNCERTAINTY / ROADMAP TARGET / HIGH UNCERTAINTY

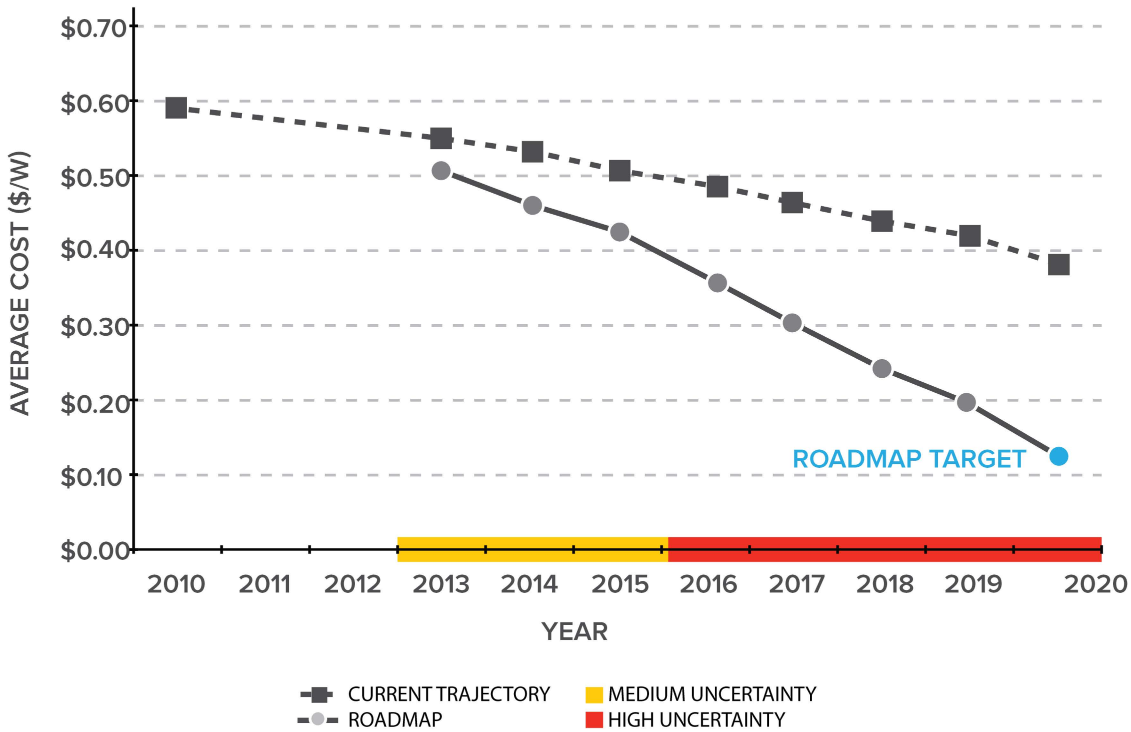

Figure 9. Residential PV installation labor costs: Current trajectory and roadmap

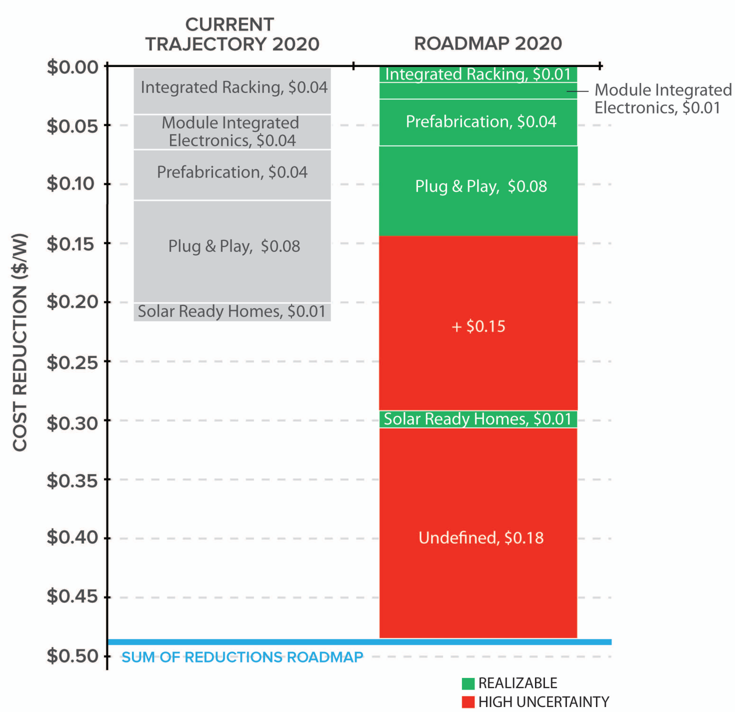

Figure 10. 2020 residential PV installation labor cost reductions: Current trajectory and roadmap

5.2 Commercial Installation Labor Roadmap

Median 2010 labor costs for commercial PV systems of 250 kW or smaller total \$0.42/W—\$0.32/W for roofer labor and \$0.10/W for electrician labor (8 hours of installation labor per kilowatt). Achieving the SunShot price target requires a decrease in total installation labor costs from \$0.42/W to \$0.07/W.

Our findings suggest four solution sets that can decrease commercial installation labor costs: (1) integrated racking, which reduces balance of system hardware; (2) module-integrated electronics, which reduces cable runs; (3) prefabrication, which streamlines installation; and (4) 1,000-volt direct current (DC), which enables more modules wired together per string. Table 7 shows the SunShot commercial installation labor costs roadmap. The commercial rooftop market is generally better poised to take advantage of streamlining solutions than the residential rooftop market due to more homogenous roof space and fewer design constraints. Even at a current-trajectory pace, the market is well positioned to move toward large-scale adoption of installation-labor-saving CROs. Thus, under the current trajectory, installation labor costs decline to \$0.12/W by 2020, and achieving the roadmap target requires additional cost reductions of \$0.05/W by 2020 (see Figure 11 and Figure 12). Near-universal adoption of integrated racking (90% market penetration in the roadmap) provides one possible path to this needed, additional cost reduction. While higher-than-anticipated market penetration of the other CROs would also enable installation labor costs to decline to target levels, the near-universal adoption of integrated racking is more plausible, albeit uncertain.

Table 7. Commercial Installation Labor Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE ($0.42/W)							
		2013	2014	2015	2016	2017	2018	2019	2020
INTEGRATED RACKING	Integrated racking (eliminates additional mounting structure)	$0.02	$0.04	$0.07	$0.11	$0.14	$0.17	$0.19	$0.20
MODULE INTEGRATED ELECTRONICS	Microinverters (small inverters on racking convert to AC)	$0.02	$0.03	$0.03	$0.04	$0.04	$0.05	$0.05	$0.06
	DC optimizers (track & optimize module performance individually)	$0.01	$0.02	$0.02	$0.03	$0.03	$0.04	$0.04	$0.04
PREFABRICATION	Preassembly of panels and racking in warehouse/ factory	$0.03	$0.04	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05
1,000- VOLT DC	1,000-volt DC (enables more modules wired together per string)	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01	< $0.01
SUM OF REDUCTIONS ($/W)*		$0.09	$0.12	$0.17	$0.22	$0.26	$0.30	$0.33	$0.35
RESULTING AVERAGE COST ($/W)		$0.33	$0.30	$0.25	$0.20	$0.16	$0.12	$0.09	$0.07
CURRENT TRAJECTORY ($/W)		$0.33	$0.30	$0.27	$0.24	$0.22	$0.19	$0.17	$0.12

*For any given year, equal to [2010 baseline of $0.42/W] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

ROADMAP TARGET | REALIZABLE | MEDIUM UNCERTAINTY | LOW UNCERTAINTY | HIGH UNCERTAINTY

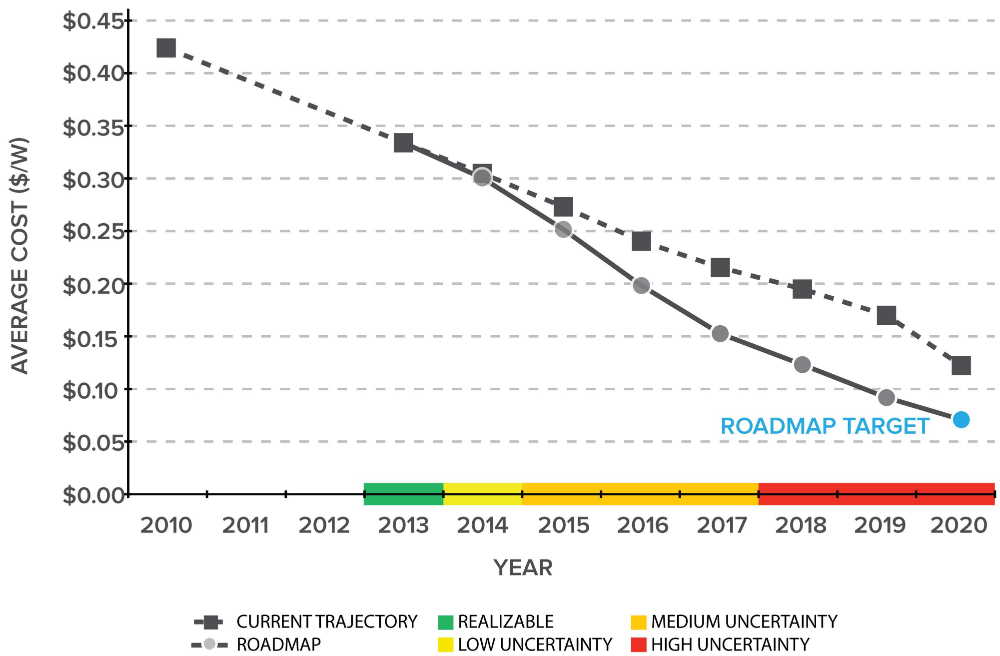

Figure 11. Commercial PV installation labor costs: Current trajectory and roadmap

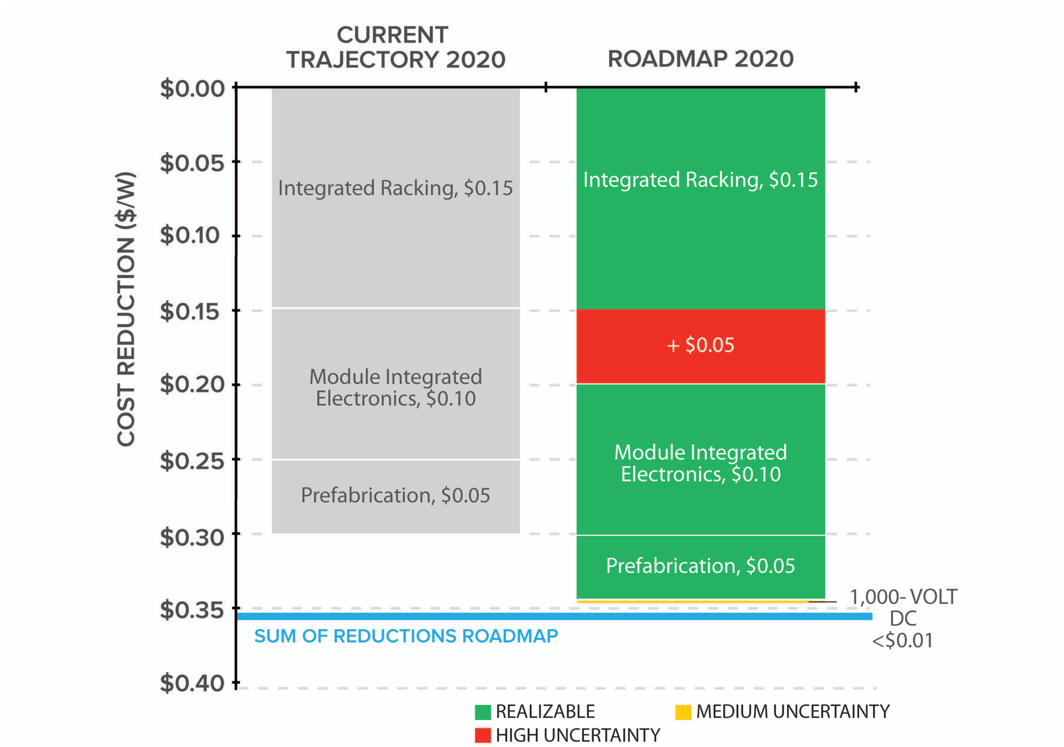

Figure 12. 2020 commercial PV installation labor cost reductions: Current trajectory and roadmap

6 Financing

Financing strategies play a significant role in reaching SunShot targets. For the financing roadmaps, we interviewed more than 40 industry experts. On average, interviewed experts foresaw substantial lowering of financing cost of capital between 2013 and 2020. Specifically, the current trajectory could lead to an average *decrease* of 5.3% [~530 basis points (bps)] for residential and 4.7% (~470 bps) for commercial by 2020.

The projected improvement does not happen "on its own." The decreases are expected to result from the effects of all known and predicted consortia, governmental, corporate, entrepreneurial, and nonprofit actions targeted at improving finance for distributed solar. In early 2013 these actions were considerable and varied. Achieving goals set forth in the roadmap case would require all known actions plus additional and different actions.

The residential and, to a lesser degree, commercial markets have experienced a boom in tax-equity-backed, third-party finance. Industry data suggest third-party finance supported nearly half of installed residential systems in 2011, and about three-quarters in 2012. While important for customer uptake and rapid market growth, this type of financing has a high cost of capital, which could impede the competitiveness of PV.

According to many interviewees, the limited supply of tax-equity participants is a key contributor to high third-party financing costs. Still, tax equity remains a prevalent source of financing because of the ability to monetize the federal investment tax credit (ITC) and accelerated depreciation.

As a result of third-party financing growth, customer facing costs of distributed PV are now measured in cents per kilowatt-hour and dollars per month, rather than dollars per watt. Cost of capital can have a substantial influence on customer-facing costs. Reducing either the cost of capital or the "other soft costs" (inclusive of finance transaction costs) to roadmap targets, while holding the other constant, results in nearly identical reductions in the cost of solar PV, as measured in cents per kilowatt-hour.[24]

Achieving cost reductions on a dollar-per-watt basis for "other soft costs," including the cost of transactions, such as legal fees, and ongoing asset management costs, such as fund administration, is believed to be critical to the continued growth of the distributed PV market. This report, however, benchmarks only cost of capital.

Methodology

All estimates of WACC reduction were assumed to be nominal, and most source data on investment return rates were given in nominal terms. All nominal rates were corrected downward by an inflationary rate of 2.6% to arrive at an approximate real rate. [25]

[24] Lowering cost of capital for residential PV from 9.9%-real. (2012 average) to 3.0%-real (2020 Roadmap Case target) without any reduction in the $1.86/W other/profit cost category (so $2.99/W total cost in 2020) produces roughly the same 2020 LCOE as 9.9%-real and $1.50/W (roadmap target) total cost. In making this statement, it is assumed for calculation simplicity purposes that there is full tax-benefit capture in both cases.

[25] The 3-year (2010 to 2012) compounded annual growth rate of the Consumer Price Index (CPI) from the U.S. Bureau of Labor Statistics was 2.61%. This inflationary rate was chosen because it is representative of recent macroeconomic conditions.

All WACC values[26] in this report are defined as synonymous with "minimum expected returns."In circumstances of high market inefficiency, returns may be significantly higher than the minimum expected returns. However, we deemed WACC a reasonable metric for assessing the minimum expected returns of an investment class, assuming PV assets are sufficiently low risk to merit capital at or close to that WACC.

CROs in the roadmap are named to highlight their unique attributes, but these solutions are all complete financing vehicles employing one to three distinct products, such as developer equity, homeowner equity, commercial host equity, tax equity, utility equity, other equity sources, and debt products. .

Markets were segmented into 12 residential and 15 commercial CROs that sufficiently cover average market characteristics and reflect interviewee expectations that finance CROs would be highly variable. This variation is due to the diverse interests of residential customers and commercial real estate types. Additional variety is due to state and utility territory regulatory dynamics, investment appetites of different and competing investment sources, and degree of utility engagement in solar PV. Appendix C provides extended descriptions of the CROs.

Not all CROs reduce the cost of capital. Some, like asset-backed securitization (ABS) for subprime residential customers, increase the cost of capital but expand the market. Thus, this roadmap was constructed with an eye toward the changes likely to occur as businesses work to expand the solar market, not just reduce cost of capital.

We did not directly consider asset backed securities (ABS) and yieldCos or similar structures which provide capital to projects years after completion. However, we did consider those structures if they provided capital at project initiation or shortly after project completion. In addition, we indirectly considered the role of viable secondary financing in enticing initial sources of capital.

[26] All estimates of WACC reduction impact for a given solution, cited by interviewees, were assumed to be nominal, and most source data on investment return rates were found in nominal terms. Many interviewees indicated the nominal nature of their responses by stating that their estimates of cost of capital were predicated on continued, historically low, "risk free" rates, such as short-term Treasury notes, LIBOR, and EURIBOR. It is recognized that a nominal rate is a real rate plus inflation, not a real rate plus risk-free rate. However, U.S. inflation has held a strong correlation factor with nominal Treasury rates when viewed over several decades, albeit multi-year periods of deviation from the correlation have occurred. Due to this generally close inflation to risk-free rate correlation over longer periods of time, constant inflation adjustments were made between nominal and real throughout the roadmap 2013-to-2020 period.

In this report, "utility finance" is reserved for utilities financing within a regulated territory, whether it be via equity, debt, or a utility's direct role in bringing financing to their customers. Conversely, utilities acting as independent power producers (IPPs) are considered developers rather than utilities, and when IPPs use tax equity, the financing is considered "standard third party." Unregulated utility affiliates can also take tax-equity positions, which are treated like any other tax-equity investor within the third-party finance solution set.

Ultimately, levelized cost of energy (LCOE) is a more indicative metric of the economic viability of solar PV than cost of capital. However, due to great variation in interviewee future expectations for the industry to capture tax benefits, particularly with innovative financing products [e.g., crowdsourced funding, yieldCos, real estate investment trusts (REITs)], LCOE is not presented in this report. Tax-capture capabilities currently have major impacts on LCOE and will continue to be meaningful when the ITC is lower (10% instead of the current 30%) for years 2017 to 2020, as accelerated depreciation has no expiry. In the absence of LCOE determinations, the solution sets hold significant implications for the monetization of tax benefits.[27]

As to changes in federal legislation and regulation, only tax-advantaged entity reclassifications, such as master limited partnerships and REITs, were considered. Other federal programs capable of lowering renewable projects' costs of capital (e.g., New Market Tax Credits and Clean Renewable Energy Bonds) were not considered. At the state and local level, we excluded additional incentive programs, such as direct rebates, debt for solar renewable energy certificates (SRECs), grants, and other upfront governmental funding, from the analysis.

A finance expert review panel was assembled to review the aggregation of data from interviews and additional research. More information on the panel is found in Appendix C.

6.1 Residential Financing Roadmap

Third-party financing has transformed the residential solar PV market. The long-standing discussion around years of payback on a solar system has become moot for most home installations today. Instead, the savings are immediate. Solar leases and PPAs cost less than the homeowners' prior utility rates from day one, and homeowners frequently incur no out-of-pocket expenses to initiate the lease or power purchase agreement (PPA). Customers appear to value these and other advantages provided by third-party financing. However, due to cost of capital, homeowners may find equivalent or lower LCOE by purchasing a system.

The average 2012 residential WACC benchmark was 9.9% in real terms. The benchmark was derived from values that were approximately three-quarters third-party financing (GTM-SEIA 2012),[28] one-sixth cash purchases, and about 7% of other homeowner financing vehicles, including property-assessed clean

[27] For example, third-party finance = high tax benefit capture ; homeowner finance = moderate-to-high ITC benefit capture, no accelerated depreciation capture; utility finance = investor-owned utilities have high tax benefit capture but with the ITC normalized over rate-basing periods (except on-bill financing which has similar tax benefit captures as homeowner finance); commercial host finance = high tax benefit capture; community solar = tax benefit capture dynamics mixed between those of utility and third-party finance depending on the financing source

[28] Based on the market report, GTM-SEIA (2012) indicated about two-thirds third-party financing in the first half of 2012 with a steadily upward trend in market penetration for Colorado, Arizona, California, and Massachusetts toward three-fourths for a full-year average.

energy (PACE) loans, mortgages on new-build homes with PV, and specialty loan products, such as the Federal Housing Authority (FHA) PowerSaver. Community solar[29] and utility on-bill financing accounted for about 1% of the 2012 new-build market. Third-party financing was split roughly evenly into two CROs: (1) "standard third-party," involving only developer equity and tax equity and (2) "third-party with debt/ABS," involving debt (as bank loans or securitized debt) as well as developer equity and tax equity. In 2012, developers were commonly backed by high cost of capital sources, such as venture capital and private-equity (VC/PE), with a notable transition away from these sources in the initial public offering (IPO) of SolarCity in December of 2012. Total cost of capital for standard third-party financing deals held a WACC of about 14%-real. Achieving the SunShot target requires reducing average residential WACC from 9.9%-real to 3.0%-real by 2020 (DOE 2012).[30]

Back-leveraging (debt provided at a holding company level above a portfolio fund) was regularly cited by interviewees as occurring for at least a couple of third-party financing companies with high market share, with a loan to developer equity value ("LTV") of approximately 0.5. Debt, at about 6%-real, was estimated to lower project WACC by about 300 bps below standard third-party financing without debt. Such debt was available only for "prime" financing, where credit quality of the project hosts were high (FICO score > 680). Though rare in terms of the number of third-party financing companies, interviewees considered the share of "third-party with debt/ABS - prime" financing in 2012 relatively common in terms of installed capacity. Thus, we estimate that half of the third-party financing in 2012 benefited from such debt (although the debt in 2012 was considered to be mostly or entirely bank debt, not ABS.)

Our findings suggest four solution sets that can decrease residential WACC: (1) third-party finance, (2) utility finance, (3) homeowner finance, and (4) community solar. Table 8 shows the residential solution sets and corresponding CROs.

6.1.1 Third-Party Finance

In the context of solar finance, third parties are entities other than a utility or homeowner that provide financing for a project, typically with investment cash flows captured via an operating lease or PPA and with tax benefits primarily accruing to tax-equity investors. All CROs for third-party finance in this report involve external tax-equity partnerships except for "corporate on-balance sheet,"[31] which describes companies, most likely larger corporations, placing the entire financing (so no tax equity partnership) on their balance sheet. A number of innovative—or at least new-to-distributed solar—financing products can potentially fit into third-party finance, including direct investment by institutional equity and yieldCos. CROs covering a number of variations of third-party financing are explained in Appendix C.

[29] Community solar projects generally are not built on residential or commercial building rooftops. However, community solar is included in this report due to its unique features including virtual net metering provisions and cash flow dependencies on a range of subscribing residential and commercial customers. Classification of community solar into residential or commercial markets is based on proportions of subscribers from these two markets.

[30] The 2020 target was partially derived from NREL's SolarDS modeling assumptions for the DOE *SunShot Vision Study*. SolarDS modeling used financing assumptions of mortgage and home equity debt at 80% and homeowner's equity at 20%. For the purposes of this report, debt was calculated at 2.3%-real based on a 50/50 ratio of the 2010-2012 averages of 30-yr mortgages (1.7%-real) and 30-year amortization $30,000 home equity loans (2.9%-real). Homeowner's cost of equity was 3.1%-real.

[31] Calculation of WACC for CROs with external tax equity assumes a long-term hold by the tax-equity participant for WACC calculation simplicity purposes.

6.1.2 Utility Finance

"On-bill financing/repayment" is the only utility-finance CRO for the residential market considered in this report[32]. While on-bill financing is technically homeowner finance (debt provided to homeowner), and on-bill "repayment" can involve repayment of an equity purchase by a third- party, these solutions were included in the utility finance solution set because of the active and supportive role of the utility.

6.1.3 Homeowner Finance

The homeowner finance solution set includes debt products and standard cash purchases. These CROs are expected to become more important if the federal ITC decreases from 30% to 10% as scheduled in 2017. They do compete against leases and PPAs today. This competition is partially based upon considerations beyond LCOE, such as some homeowner preference for ownership over leasing. CROs in the homeowner-finance set also help homeowners attain solar in regulated utility states that do not allow third-party ownership.

The roadmap case identifies a potential 1.6% (~160 bps) cost of capital reduction over the current trajectory. This reduction is primarily achieved through an increase in debt provision to homeowners. Refined offerings of specialized solar or bundled distributed energy solution loans, and in particular, inclusion of solar in standard real estate lending, could have considerable market impact in the post-30%-ITC period. In the roadmap, the two CROs within the homeowner finance solution set that could benefit most from this market transition are "mortgage—new build" and "solar loans." The "solar loans" CRO, particularly in the 2017–2020 period, is inclusive of an advancement in home equity loans that include PV within the property appraisal value. Achieving the targets for these two CROs by 2020 is highly uncertain.

To allow for the roadmap increase in homeowner finance, all third-party finance CROs, except for "corporate on-balance sheet," featured lower-or-equal penetration than in the current trajectory case.

A few interviewees anticipate that "cash purchases" will rebound. If roadmap targets are realized, the cost of a residential system in 2020 will be $1.50/W (adjusted for inflation against 2010). If a system costs ~ $7,500 in 2010 dollars,[33] or ~$10,000 in 2020-dollars,[34] these interviewees believe fewer people will need financing. However, no participants on the expert review panel indicated market penetrations above 5% for outright cash purchases in 2020.

6.1.4 Community Solar

Finally, the community solar solution set applies to PV projects with virtual net metering. Community members subscribe to a commercial-sized PV system located locally but not on their residence premises yet receive net-metering benefits. Community solar projects are generally financed through other solution sets, namely third-party or direct utility finance, but we separately categorized community solar

[32] Interviewees found only residential debt financing through on-bill financing to be likely, although minority opinions strongly believed in substantial utility residential PV full ownership by 2020. Whether considered likely or unlikely, many interviewees and recent solar conference speakers stated that utilities are the most natural owners of PV systems. However, many interviewees believed utilities will be resistant to equity positions until public utility commissions and state legislatures allow for new utility business models.

[33] Assumes a 5-kW average system size.

[34] Assumes consistent inflation rates witnessed from 2010 to 2012 (2.61% per annum).

because it entails unique investment risks and opportunities, utility value propositions and challenges, and policy treatment.[35]

Table 8 shows the SunShot residential finance roadmap. Compared with the current trajectory case, which reduces average WACC to 4.6%-real by 2020, achieving the roadmap target requires an additional reduction in WACC of 1.6% (~160 bps) by 2020 to achieve a WACC of 3.0%-real (see Figure 13 and Figure 14).

[35] Community solar can benefit from subscriber-sourced financing models (small cooperative investments or broader,"crowd-sourced financing," the latter of which is discussed in the commercial finance section). Direct subscriber financing has been limited due to concerns around the federal Securities and Exchange Commission's (SEC's) and states' securities regulations. SEC promulgation of rules (still ongoing as of July 2013) stemming from the 2012 Jumpstart Our Business Startups Act (JOBS Act) may alleviate these concerns. Crowdsourced funding is sometimes called "community solar," but for the purpose of this report the term "community solar" is reserved for the financing of projects, however achieved, with virtual net metering (or comparable) opportunities.

Table 8. Residential Financing Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE (9.9%-REAL)							
		2013	2014	2015	2016	2017	2018	2019	2020
THIRD-PARTY FINANCE	Standard Third Party	-0.8%	-0.4%	-0.2%	-0.1%	< 0.1%	< 0.1%	< 0.1%	0.0%
	Third Party with Debt/ABS - Prime	< 0.2%	-0.1%	0.1%	0.6%	1.2%	0.7%	0.3%	0.1%
	Third Party with Debt/ABS - Subprime	0.0%	-0.1%	-0.1%	-0.2%	0.1%	0.1%	< 0.1%	< 0.1%
	Corporate On-Balance Sheet	0.0%	0.1%	0.1%	0.1%	0.9%	1.4%	2.1%	2.5%
	Third Party with YieldCo	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.5%	0.8%
	Third Party with Institutional Equity	< 0.1%	< 0.1%	< 0.1%	< 0.1%	0.2%	0.2%	0.1%	0.0%
UTILITY FINANCE	On-Bill Financing/ Repayment	0.2%	0.2%	0.2%	0.2%	0.4%	0.4%	0.3%	0.3%
HOMEOWNER FINANCE	Cash Purchase	0.7%	0.5%	0.4%	0.3%	0.3%	0.3%	0.3%	0.2%
	Solar Loans	0.3%	0.6%	0.7%	0.8%	0.8%	1.3%	1.4%	1.6%
	Mortgage—New Build	0.2%	0.4%	0.4%	0.4%	0.8%	1.0%	1.2%	1.4%
	Residential PACE	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
COMMUNITY SOLAR	Community Solar	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%
SUM OF REDUCTIONS (%-REAL)*		0.6%	1.2%	1.7%	2.3%	5.1%	5.8%	6.5%	6.9%
RESULTING AVERAGE COST (%-REAL)		9.4%	8.8%	8.2%	7.7%	4.8%	4.2%	3.4%	3.0%
CURRENT TRAJECTORY (%-REAL)		9.4%	8.8%	8.2%	7.8%	5.1%	4.9%	4.6%	4.6%

*For any given year, equal to [2010 baseline of 9.9%] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

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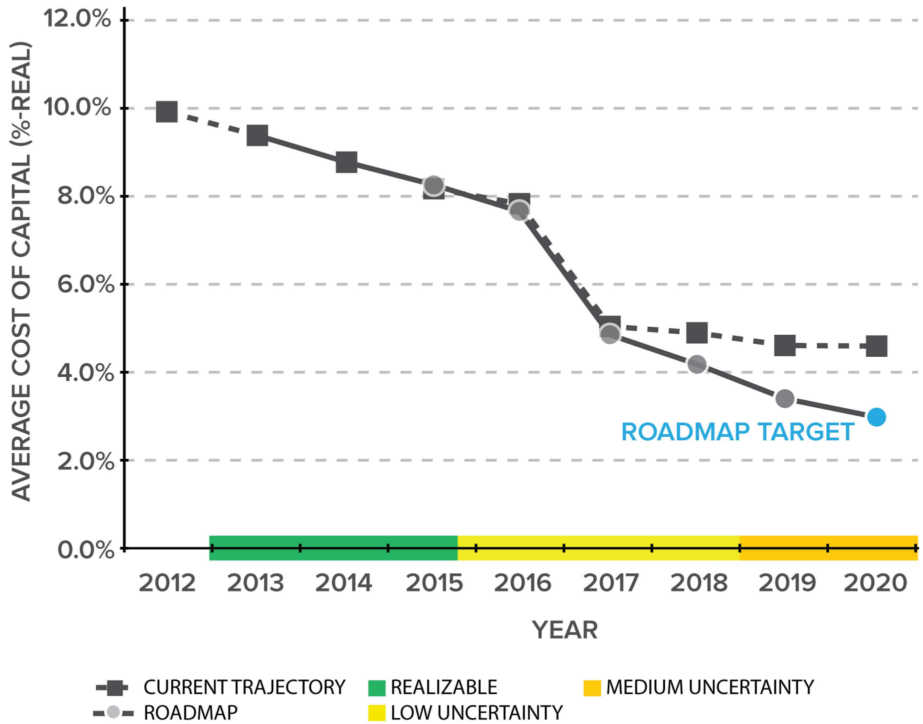

Figure 13. Residential PV WACC: Current trajectory and roadmap

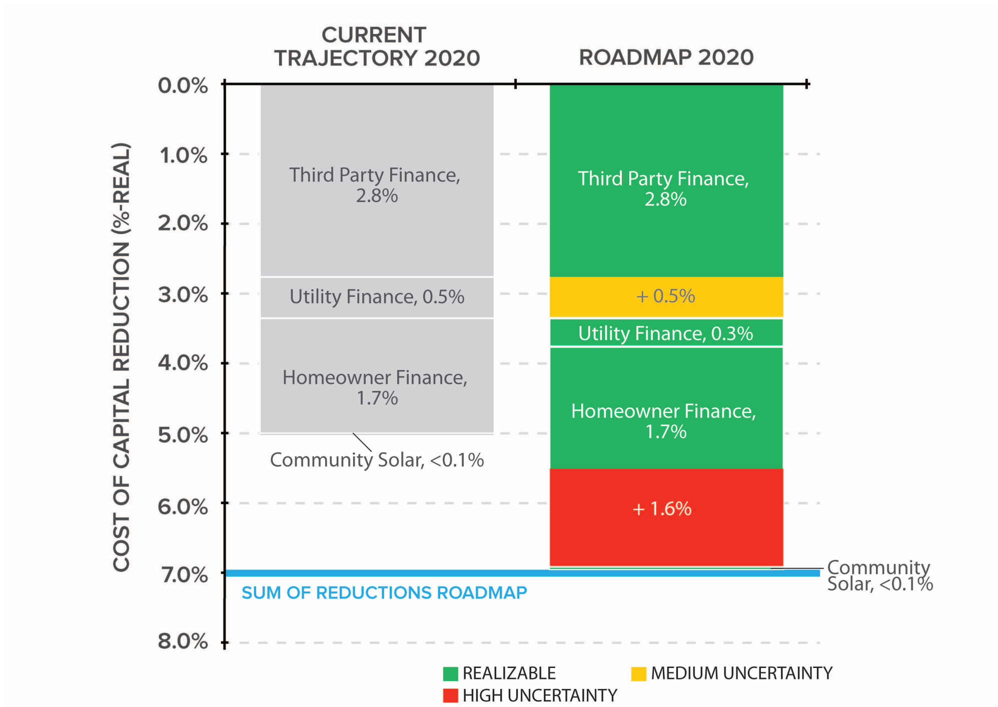

Figure 14. 2020 residential PV WACC reduction: Current trajectory and roadmap

6.2 Commercial Financing Roadmap

About 0.6 GW[36] of small (250 kW or smaller) commercial PV cumulative capacity existed in the United States as of the end of 2012, less than 10% of cumulative U.S. solar capacity. Where references existed that addressed this small market segment, 250 kW or smaller was not the consistent market descriptor. Because clear penetration rates of prevailing finance solutions for this small market segment were not attainable, we relied on general commercial market insights and derived resolution on this smaller segment when possible.

Only some interviewees distinguished between large and small commercial projects. However, the interviewees made clear that one-off financings with tax equity, bank loans, or bonding are rare for 250 kW or smaller commercial projects. Transaction costs are often prohibitively high for these small deals when evaluated as singular investment opportunities. As with residential projects, third-party financing for small commercial projects is through portfolio funds that apply standard leasing criteria to a set of projects. However, for small commercial projects, portfolio fund approaches are more challenging than residential when trying to tie in a diversity of project hosts. This challenge is partly due to the lack of a standard credit review system for entities owning commercial buildings.

Our research yielded an average 2012 WACC of 9.2%-real, with small commercial PV financed approximately 42% from third-party finance, 9% from utility finance, 47% from host (typically building owner) equity, and 2% from community solar.

Third-party finance was dominated (roughly five-sixths) by "standard third-party" financing—the pairing of developer equity with tax equity at a WACC of about 15%-real. The remaining third-party finance in 2012 involved private debt associated with a portfolio fund[37] at a WACC of about 13%-real and the coupling of municipal bonds with third-party portfolio funds on MUSH[38] buildings (9%-real).

For host finance, cash purchases constituted nearly 90%, and the remainder included low levels of real estate investment trust (REIT) financing,[39], commercial PACE, and municipal bonding for MUSH projects. Solutions undefined to the authors are assumed to have achieved about 1% penetration, and are included in a broad "undefined solution" CRO. Achieving the SunShot target requires reducing commercial WACC from 9.2%-real to 3.4%-real by 2020.

[36] NREL's Open PV Project (openpv.nrel.gov/search) lists 428 MW of PV projects nationwide as fo December 31, 2012, between 20 kW and 250 kW. In this capacity range, projects would likely be commercial or, more likely, single-family residential. It should be noted that NREL's Open PV Project depends on voluntary reporting of projects, and thus not all projects are recorded.

[37] Such as SolarCity and Bank of America-Merrill Lynch's "SolarStrong" program on multi-family buildings.

[38] MUSH stands for municipal (state/local government), universities, K-12 schools and hospitals.

[39] Most interviewees cited that favorable IRS letter rulings, which had not occurred, would be necessary to enable REIT solar financing. However, several conference panelists cited that start-up solar-REIT companies are "active" in deal financings. This "active" description might have referred to non-REIT companies that hoped to become REITs upon receipt of positive IRS letter rulings. Following the interview period, Greentech Media posted that Hannon Armstrong Sustainable Infrastructure Capital had received a private letter ruling (not made public by the IRS as of June 16, 2013) in February 2013 in relation to REIT finance in renewable energy (Trabish 2013).   Hannon Armstong made an initial public offering as a REIT on April, 17, 2013, but at that time it remained unclear if their intended financing activities in solar qualified as "good" income or assets for REIT- status, or if these activities were permitted under the minority "bad" income and asset ownership allowances for REIT- status.

Our findings suggest four solution sets that have the potential to decrease commercial WACC: (1) third-party finance, (2) utility finance, (3) host finance, and (4) community solar.

6.2.1 Third-Party Finance

Third-party finance for commercial PV involves financing by an entity other than a utility or building owner (host). Tax benefits for CROs in the third-party finance solution set primarily accrue to outside tax-equity investors except for "corporate on-balance sheet." Modeling of solutions with external tax equity assumes a long-term hold by the tax-equity participant for simplicity. Another CRO in commercial financing similar to residential financing is "third-party with debt/ABS," though interviewees only saw a market opportunity for high credit quality MUSH and business offtakers. In other words, no "subprime" equivalent was suggested for commercial third-party financing.

Interviewees also cited "third-party with crowdsourced funding" and "MUSH: muni bonds + third-party." Both involve specialized debt instruments that interviewees thought were better suited for the commercial market. See Appendix C for expanded CRO descriptions.

Yield-oriented investment vehicles were separated into two solutions for the commercial market: "third-party with yieldCo" and "third-party with REIT." Many interviewees believed REITs would emerge as a significant financing source for commercial solar. Because of this clarity, the REIT solution was broken out. See Appendix C for further explanation.

6.2.2 Utility Financing

Utilities expressed more interest in financing commercial projects than residential projects. Both municipal and investor-owned utilities (IOUs) have fully financed (i.e., for IOUs this means "rate-based") commercial PV systems in their service territories, and utilities may be able to bring in external tax equity while holding developer equity positions themselves. The latter partnership scenario ("utility equity and tax equity") has been practiced in IPP investing for utility-scale projects. The authors are not aware of these partnership investments in regulated territories for small commercial PV, and enabling them might require public utility commission (PUC[40]) regulatory changes.

In the roadmap case, full utility ownership achieves 14% market penetration in 2020, up modestly from 13% in the current-trajectory case. Commercial PACE achieves 9% market penetration in 2020, up from 5% in the current-trajectory case.

6.2.3 Host Finance

Host finance describes ownership by the host and includes direct cash purchases of PV systems by host-site companies and loans to host companies. Host finance is likely the greatest opportunity for financing innovation for small commercial PV. Short investment time horizons, perceptions of solar as a non-core business activity, and split incentives for energy cost savings between building owners and tenants may hinder innovations in host-finance solutions.

[40] All primary regulatory commissions governing utility activity within states are called "PUCs" in this report. It is recognized that some state regulatory commissions are actually called a PUC, such as the California and Colorado Public Utility Commissions, several others are called Public Service Commissions, such as the Maryland and Florida Public Service Commissions, and others have names unique to the state. Two examples are the Connecticut Siting Council and the Nebraska Power Review Board. Texas has multiple entities holding responsibilities usually housed in a single state PUC.

Commercial PACE is a structured solution that can solve several misalignments and credit concerns. However, interviewees had divergent views on commercial PACE penetration. Only a few indicated market penetration would be considerable. In the current trajectory, PACE penetration is 5%. In the roadmap case, penetration is nearly double that at 9%. Even at 9% penetration, availability of host finance may not meet demand.

To achieve the additional 1.1% (~110 bps) reduction from the current trajectory to meet the roadmap target, we assumed an undefined host finance CRO with a low WACC of 1.9%-real is required. Penetration of the undefined host finance CRO would need to meet approximately a quarter of the market's financing needs. This undefined CRO, likely to actually be a mixture of CROs, must include financing innovations that overcome challenged credit conditions of building owners and a number of real estate investor misalignments. This undefined CRO may involve special rooftop property rights/easements, nuanced energy service agreements, or lending products that include energy savings in the appraised value of the real estate.

A number of other CROs contribute to the host finance solution set in the roadmap case. "Green bonds" (state- and local-government-enabled specialty bonds and loan guarantees with an estimated WACC of 1.7%-real) achieve 3% market penetration in 2020, up from 0% in the current-trajectory case.

6.2.4 Community Solar

Finally, the community solar solution set applies to PV projects with virtual net metering. Community solar power is generally offered through a contracted subscription program to multiple power offtakers. Though in some locations, such as in Pennsylvania, commercial PV can be aggregated with geographic and site ownership limitations, providing virtual net metering for a single commercial customer.

Table 9 shows the commercial finance roadmap. Compared with the current-trajectory case (which reduces average WACC to 4.4%-real by 2020), achieving the roadmap target requires an additional reduction in WACC of 1.1% (~110 bps) by 2020 to reach 3.4%-real.[41]

To allow for the increased roadmap CRO penetrations addressed above, most notably the new undefined solution(s) for host finance, several CROs had their penetrations decreased in the roadmap from the current trajectory. All of the third-party CROs had their penetrations decreased except for "corporate on-balance sheet." Other CROs (MUSH with debt/bonds, cash purchase, and community solar) were decreased because their WACCs were deemed too high in light of competition against the emerging undefined solution at 1.9%-real.

[41] The difference between the current trajectory (4.4%-real) and roadmap case (3.4%) is 1.1%—not 1.0%—due to significant figures not shown.

Table 9. Commercial Financing Roadmap

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	ENABLED REDUCTION FROM 2010 BASELINE (9.2%-REAL)							
		2013	2014	2015	2016	2017	2018	2019	2020
THIRD-PARTY FINANCE	Standard Third Party	-1.9%	-1.4%	-0.6%	-0.4%	-0.1%	-0.1%	-0.1%	0.0%
	Third Party with Debt/ABS	-0.3%	-0.4%	-0.5%	-0.5%	0.7%	0.3%	0.3%	0.1%
	Third Party with REIT	< 0.1%	0.1%	0.1%	0.1%	0.3%	0.3%	0.4%	0.7%
	Third Party with Crowdsourced Funding	< 0.1%	< 0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%
	Corporate On-Balance Sheet	< 0.1%	0.1%	0.3%	0.4%	0.7%	0.9%	0.9%	0.9%
	MUSH: Muni Bonds + Third Party	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	< 0.1%	0.0%
	Third Party with YieldCo	< 0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.0%
UTILITY FINANCE	Full Utility Ownership	0.4%	0.4%	0.4%	0.4%	0.3%	0.3%	0.5%	0.6%
	Utility Equity and Tax Equity	< 0.1%	< 0.1%	< 0.1%	< 0.1%	0.0%	0.0%	0.0%	0.0%
HOST FINANCE	Cash Purchase	1.1%	0.8%	0.7%	0.7%	0.7%	0.7%	0.4%	0.4%
	MUSH: with Debt/Bonds	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%
	Green Bonds	0.0%	0.0%	0.0%	0.0%	< 0.1%	0.1%	0.1%	0.2%
	Commercial PACE	0.1%	0.1%	0.2%	0.2%	0.5%	0.5%	0.5%	0.6%
	Undefined CRO(s)	0.1%	0.1%	0.1%	0.1%	0.4%	0.9%	1.5%	1.9%
COMMUNITY SOLAR	Community Solar	< 0.1%	< 0.1%	< 0.1%	< 0.1%	0.2%	0.2%	0.2%	0.2%
SUM OF REDUCTIONS (%-REAL)*		-0.3%	0.0%	1.0%	1.3%	4.1%	4.8%	5.2%	5.8%
RESULTING AVERAGE COST (%-REAL)		9.5%	9.2%	8.2%	7.9%	5.1%	4.4%	4.0%	3.4%
CURRENT TRAJECTORY (%-REAL)		9.6%	9.5%	8.7%	8.7%	5.4%	4.9%	4.5%	4.4%

*For any given year, equal to [2010 baseline of 9.2%] – [sum of cost reductions]

*Individual values may not add up to totals owing to rounding

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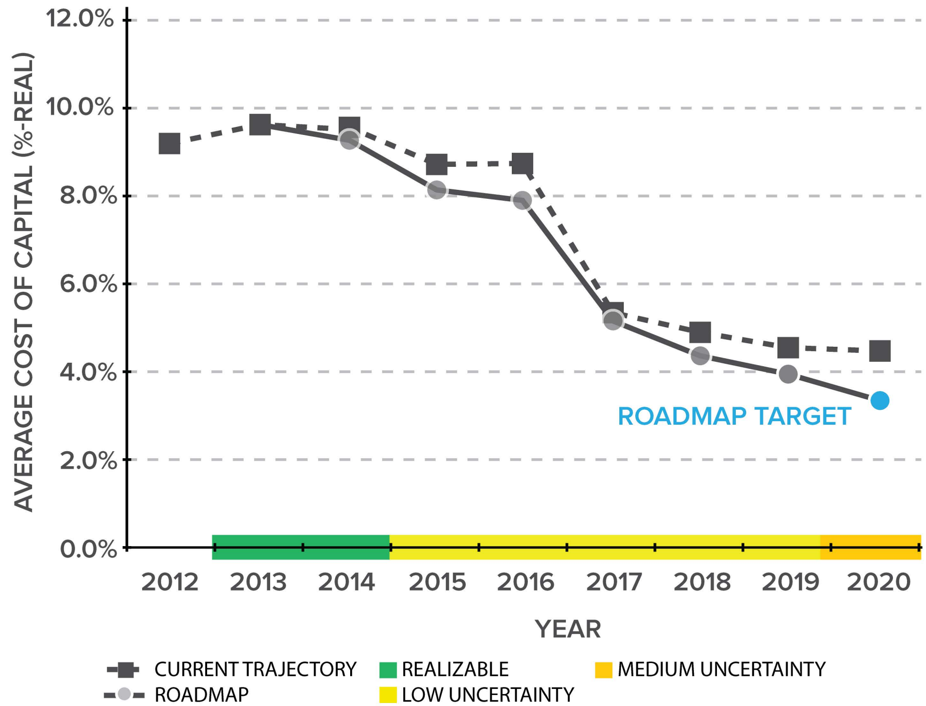

Figure 15. 2020 commercial PV WACC reduction: Current trajectory and roadmap

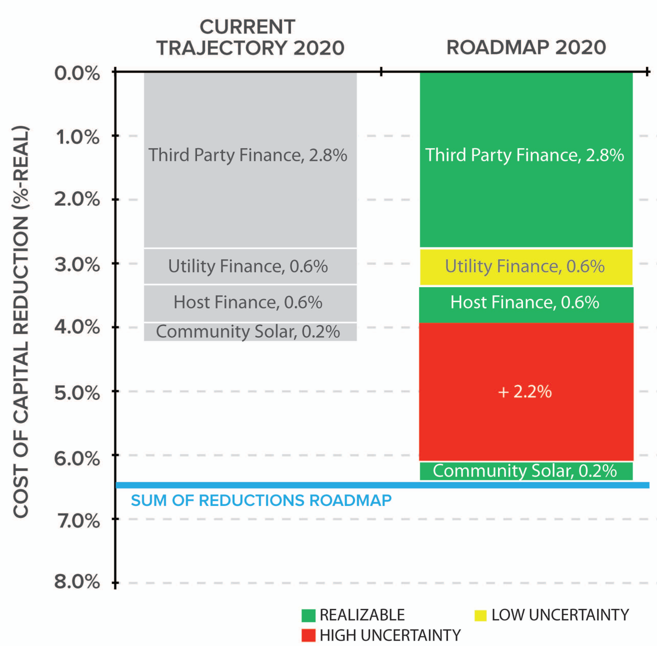

Figure 16. 2020 commercial PV WACC reduction: Current trajectory and roadmap

7 Key Actors and Stakeholders

This section discusses the actions required by the multiple market actors and stakeholders involved in realizing the roadmap targets. "Radar charts" illustrate findings on the required level of engagement related to customer acquisition, PII, installation labor, and financing. In these charts, a more outward-from-center intersection with the stakeholder axis represents greater needed/anticipated action. First, we assigned stakeholder impact levels on a 0 to 4 scale (0 = lowest impact, 4 = highest impact) for each CRO based on interview findings. These impact levels were then multiplied by the cost reductions enabled by 2020 ($/W or WACC) in the roadmap and summed for all CROs for that stakeholder type. Each chart is normalized to the largest stakeholder's impact for each of the four soft-cost areas.

For example, in Figure 18 (customer acquisition), developers/installers and service providers are identified as the most active stakeholders in achieving the roadmap cost reductions, while the required level of engagement from the federal government and the financial community is lower. The charts represent total action between 2013 and 2020—*not the difference in action between the current-trajectory case and the roadmap*. The current trajectory requires considerable stakeholder action, and much of that activity is embedded in the overall action required for the roadmap case. For simplicity, residential and commercial market actor/stakeholder burdens are combined with equal weighting.

As the following discussion shows, actors and stakeholders participating to achieve cost reductions vary substantially by category. Achieving roadmap reductions will require further leveraging of key stakeholders. While categories are intended to be mutually exclusive, in reality the functions of various actors/stakeholders are continuously evolving and may overlap with other categories. Furthermore, no actor/stakeholder works in a silo, and achieving an objective will often require the engagement of other groups.

7.1 Customer Acquisition

7.1.1 Developers/Installers

The greatest engagement in customer acquisition is required from developers/installers (see Figure 17). Installers often create a suite of standard system designs to apply to sites with common parameters, which decreases costs, especially when designing systems for leads that are not yet sold. Most installers interviewed considered this a sound business practice that will become more prevalent. In addition, when developers reach out to and partner with big-box retailers and national corporations, such as Lowes and Home Depot, mainstream consumers become increasingly exposed to PV. Corporations and national organizations, such as Honda and NREL, are beginning to include PV options as benefits (SolarBenefits Colorado; Honda-SolarCity partnership) to their employees and customers.

7.1.2 Service Providers

The next-highest required engagement is from service providers.[42] Information technology and software development companies are developing tools to reduce customer acquisition costs. The DOE SunShot Incubator Program is supporting multiple projects to develop tools that reduce these costs, including an online quoting system (EnergySage.com), advanced siting tools (simuwatt), and sales process software (Genability).

[42] Services are often provided by installers, but in this section they are assumed to be provided by separate, non-installer entities.

7.1.3 Other Stakeholders

Among the actors/stakeholders with lower required engagement, utilities and PUCs as well as state and local governments determine the business models (such as virtual net metering, community solar, and third-party ownership) that are allowed in a region, which affects customer acquisition. Real estate and construction companies play a role in opening access to new customers. State and local governments (e.g., the City of Portland) and non-profit organizations (e.g., SmartPower) can administer group PV purchasing, or "solarize," programs, which provide a trusted venue for consumer education in addition to customer acquisition. The federal government plays a role providing research and development (R&D) to support innovative, game-changing technologies that help reduce soft costs, as seen with information technology/software product development through the DOE SunShot Incubator Program.

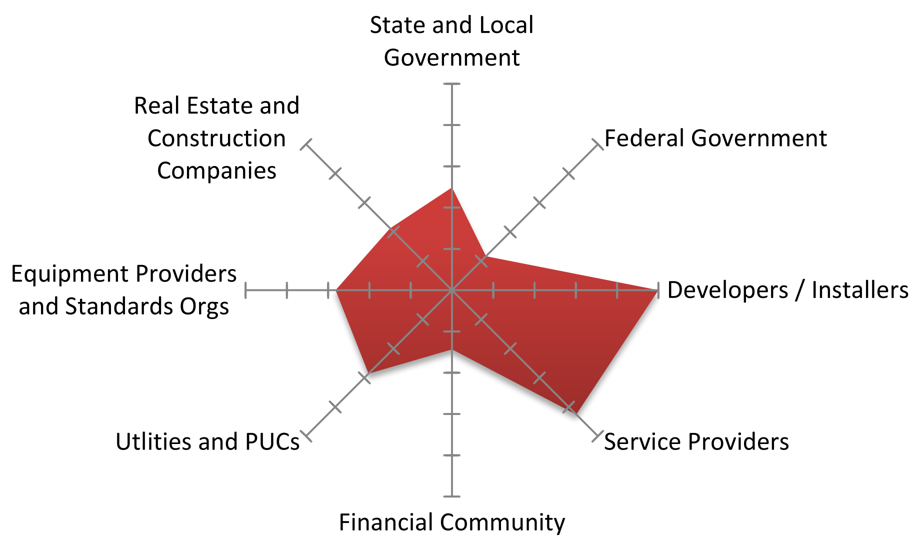

Figure 17. Customer acquisition actors and stakeholders

7.2 Permitting, Inspection, and Interconnection

State and local governments have the biggest role in improving PII processes and reducing associated costs (see Figure 18). They are faced with the challenge of streamlining bureaucratic hurdles and reducing fees to cost recovery levels, while ensuring safety and reliability. Similarly, because utilities and PUCs oversee interconnection requirements and processes, their participation is needed to overcome interconnection challenges and reduce costs. While the federal government cannot establish regulations directly, it can play a key role by supporting regulatory jurisdictions via funding, research, and suggested guidelines.

Developers and installers have an active role to play in improving process inefficiencies because they are the main stakeholder group to interface with regulatory bodies. For example, installer participation is key to the penetration of innovations, such as a permitting database.

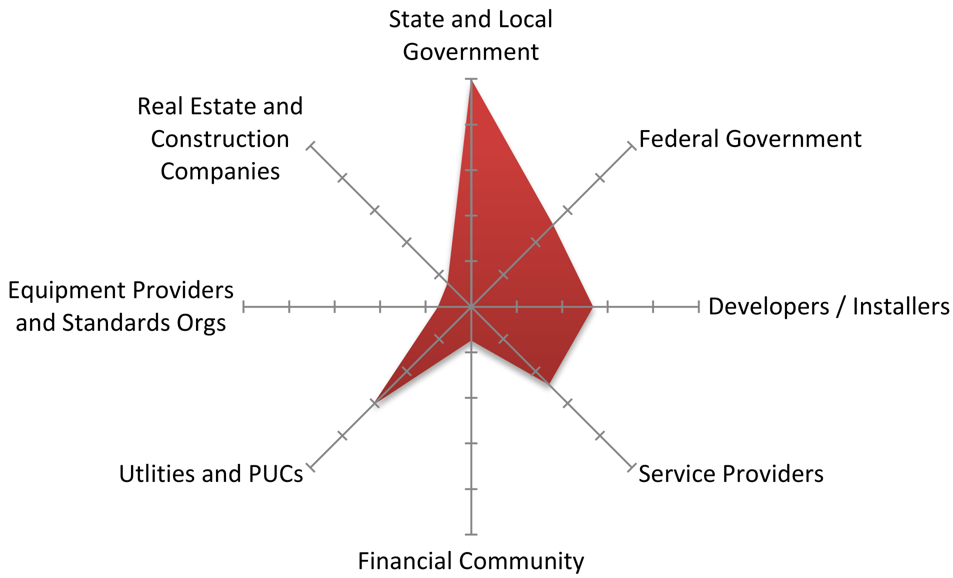

Figure 18. Permitting, inspection, and interconnection actors and stakeholders

7.3 Installation Labor

Equipment providers play a critical role in reducing installation labor costs by offering innovative labor-saving products (see Figure 19). Providers of different components must collaborate, particularly to develop streamlined/integrated systems that can provide a competitive advantage. Equipment providers are also responsible for ensuring product marketability.

Developers and installers must continually study, refine, and optimize interfaces between project elements and minimize business process inefficiencies. For example, developing a steady pipeline and routing crews effectively can reduce idle crew time. Large volume installers, in particular, are already implementing needed business process improvements.

The financial community is important as well. Private equity plays a key role in providing early-stage capital to new technologies that can reduce labor costs. Project financiers, particularly tax-equity investors, play a gatekeeper role in enabling the adoption of new technologies in new projects. This is currently evident in that module-level electronics have not been deployed on third-party-owned systems because they do not yet have an extensive track record.

State and local governments can enable labor-saving technologies by supporting solar-ready legislation, while utilities and PUCs must be informed of new products that affect compliance or present innovative configurations. The federal government can provide R&D to support innovative, game-changing technologies and improve installer efficiency through support for workforce development and training. Real estate and construction companies can play a key role in voluntarily implementing solar-ready building practices.

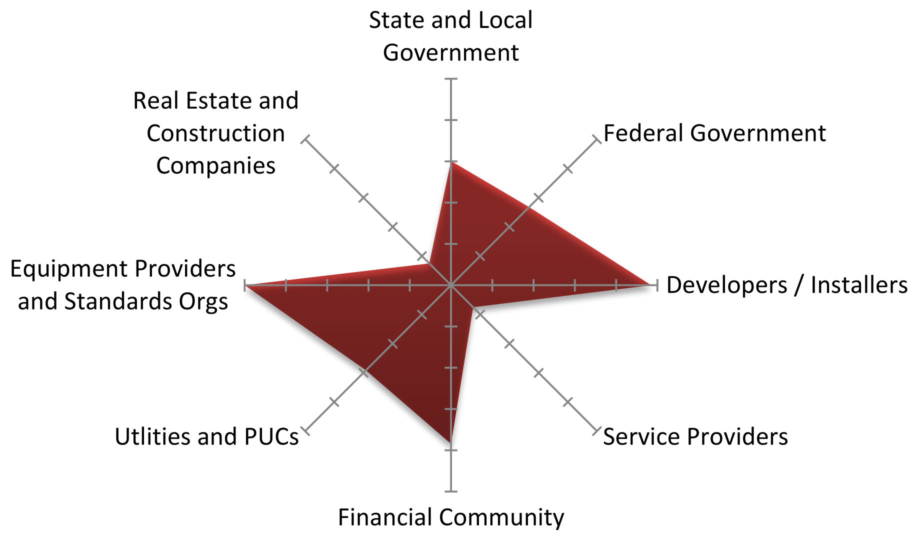

Figure 19. Installation labor actors and stakeholders

7.4 Financing

Naturally, the financial community has a large role to play in reducing financing costs (see Figure 20). Banks must provide securitized debt offerings, institutional investors must participate in direct financing or securities purchases, and the real estate lending financial ecosystem—particularly underwriters (e.g., Fannie Mae and Freddie Mac)—must allow and help facilitate PV value to be included in appraised value and be part of common real estate lending products. This underwriting is perceived to be key to the greater penetration of mortgages and home equity loans for solar PV. In addition, large public corporations must move into direct, full residential project third-party financing, likely through mergers and acquisitions of existing successful PV development companies. Financial community funding efforts also include advancement of crowdsourced funding and increased financing of community solar. Lastly, a reconceptualization of offtaker (e.g., PPA or lease counterparty) credit and/or new financial structures may be needed to enable the undefined commercial solution and realize roadmap targets. Whether the credit reconceptualization and/or new structures focus on meter payment history, real estate value and tenancy dynamics, and/or other longer-term credit elements is not certain.

The service provider intersection in Figure 20 is middle-level, as operations and maintenance (O&M) and system performance data providers are critical to providing reliable system performance, necessary in enticing a lower cost of capital financing. This role is similar to that of equipment manufacturers and standard organizations, which can work to make the quality of PV equipment and systems increasingly clear to the financial community.

Real estate and construction companies have a strong voice within the real estate finance community. Demand for appraisal value to include PV could go a long way to realizing standard mortgages and home equity loans inclusive of PV value. In addition, providing solar-ready homes can increase the opportunity set for mortgages to cover PV capital cost.

Developers, such as SolarCity, Verengo, and Sungevity, along with lease/PPA-provision companies, such as Clean Power Finance and SunRun, have led the transition to third-party financing. Further action is required in the following areas: standardization of contracts, greater availability of payment performance/default and technical performance data, and standardization of project credit reviews. These will support a transition to ABS. These third-party financiers also play a key role in opening up the lease and PPA market to subprime credit customers who, today, are usually unable to receive financing.

Utilities and PUCs enable the business models that are allowed in a region, notably third-party finance, but they also enable new utility business models that can improve utilities' desires to participate in distributed PV. Perhaps most importantly, they can influence the rate for solar power sold on the grid, such as innovative rates that move beyond simple net energy metering and capture the value of the solar power for the utility and the broader grid. These rates play a profound effect on the economic proposition and therefore also the desire for the customer to attain solar financing or pursue solar at all.

State and local governments also play a significant role, directly in the case of state "green" bonding programs or municipal bonding on MUSH buildings, as well as through collaborative actions between municipalities and their municipal utilities, such as community solar. State legislatures can also enact some policies that would otherwise be handled by PUC discretion.

The federal government's role can enable yieldCo opportunities through legislation [e.g., master limited partnership (MLP)] or regulatory (e.g., IRS letter rulings for REITs) actions. Another opportunity for the federal government exists around broader tax benefit monetization rule clarity, providing a stable accounting foundation underneath third-party financing. Considering the dynamism of solar business models and technology, continuous improvement on tax benefit monetization clarity will likely be critical to many solar business activities beyond today's third-party financiers. Also, the federal government can play a role in enabling residential solar loans through standard real estate lending vehicles in light of the conservatorship role the federal government holds over underwriters Fannie Mae and Freddie Mac.

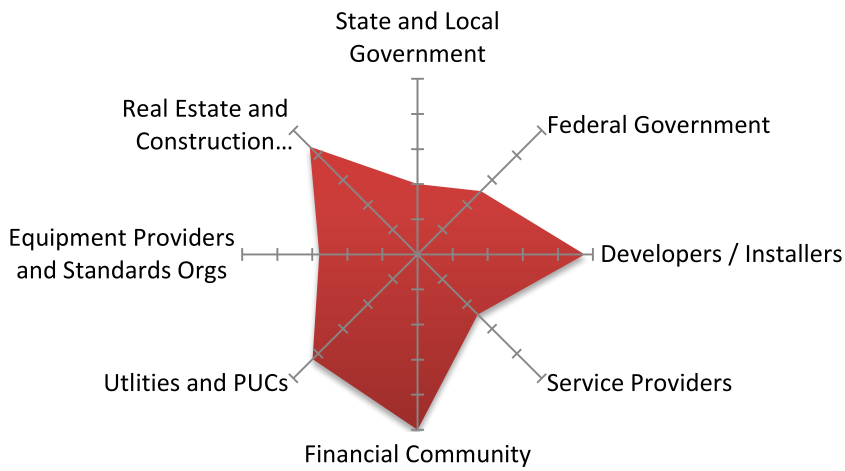

Figure 20. Finance actors and stakeholders

8 Conclusions, Limitations, and Future Research

Non-hardware (soft) costs have become a major driver of PV system prices. As a result, aggressive soft-cost-reduction pathways must be developed to achieve the SunShot PV price targets. The roadmaps detailed in this report offer such pathways. They are neither prescriptions nor projections. Rather, they draw on industry expertise to plot conceivable courses to the residential and commercial PV soft-cost reductions required to achieve the 2020 SunShot targets. They identify specific CROs, quantify the potential cost reduction associated with each, and estimate the certainty of achieving these cost reductions in relation to expert judgment of the reductions likely to result from today's current soft-cost-reduction trajectory. The resulting roadmaps suggest the level of effort that may be required to achieve SunShot-level cost reductions in specific soft-cost areas.

The residential PV roadmap shows a challenging path to the SunShot soft-cost targets (see Table 10). Additional reductions of $0.46/W and 1.6% (~160 bps) WACC beyond the current-trajectory reductions are required. Overall, customer acquisition has the most certain pathway to its target, although the required implementation of several individual site-assessment software and consumer-targeted CROs is highly uncertain. Financing has the next-most-certain cost-reduction pathway; the primary challenge is enabling low cost of capital and otherwise desirable homeowner financing (i.e., homeowner maintains equity, so is not a "third party"). In contrast, the aggregate pathways for PII and installation labor are highly uncertain. Because achieving the required PII cost target is nearly impossible with a piecemeal approach, an undefined solution set is introduced that may represent the combination of unknown regulatory mechanisms that enable wider-scale uniformity across AHJs, a market-wide average fee of $100 [instead of $250 (i.e., in the lower permitting fees solution set)] and streamlined inspection. Similarly, an undefined solution set is required to achieve the installation labor targets, which may entail a combination of additional equipment standardization and classification, reduced through-roof penetration, and general business practice efficiency improvements.

Table 10. Residential PV Soft-Cost Reduction Roadmap

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition ($/W)	$0.67	—	—	$0.53	$0.49	$0.45	$0.41	$0.36	$0.28	$0.19	$0.12
PII ($/W)	$0.20	—	—	$0.18	$0.16	$0.15	$0.13	$0.11	$0.10	$0.06	$0.04
Installation Labor ($/W)	$0.59	—	—	$0.51	$0.46	$0.42	$0.36	$0.30	$0.24	$0.19	$0.12
Other Soft Costs ($/W)	$1.86	—	—	$1.30	$1.14	$0.97	$0.82	$0.68	$0.56	$0.48	$0.37
Financing (WACC %-real)	—	—	9.9%	9.4%	8.8%	8.2%	7.7%	7.7%	4.8%	3.4%	3.0%
Total Soft Costs ($/W)	$3.32	—	—	$2.52	$2.25	$1.99	$1.72	$1.45	$1.18	$0.92	$0.65
Total System Costs ($/W)	$6.60	—	—	$4.99	$4.49	$3.99	$3.49	$3.00	$2.50	$2.00	$1.50

The commercial PV roadmap offers a more certain path to the SunShot soft-cost targets (Table 11). Additional reductions of $0.11/W and 1.1% (~110 bps) WACC beyond the current-trajectory reductions are required. Overall, customer acquisition has a medium uncertainty. Reaching the 2020 target hinges on the highly uncertain market penetration of improved site-assessment and design CROs, in addition to effective customer acquisition tools that accompany innovative financing solutions for new commercial PV markets. In the area of installation labor, commercial PV is more amenable than residential PV to streamlined installation practices; thus, achieving the SunShot target by 2020 is more certain. The near-universal adoption of integrated racking provides one plausible cost-reduction pathway. Commercial financing exhibits an overall medium uncertainty in achieving the roadmap WACC target, similar to residential financing. However, the commercial financing path requires the highly uncertain implementation of an undefined host-finance CRO (e.g., perhaps special rooftop property rights/easements or nuanced energy service agreements) as well as highly uncertain expansions of green bond programs and commercial PACE financing. Though we do not develop a commercial PII roadmap, our findings suggest that streamlining the interconnection process could reduce the major PII cost component substantially.

Table 11. Commercial PV Soft-Cost Reduction Roadmap

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Customer Acquisition ($/W)	$0.19	—	—	$0.15	$0.13	$0.10	$0.08	$0.08	$0.08	$0.05	$0.03
Installation Labor ($/W)	$0.42	—	—	$0.33	$0.30	$0.25	$0.20	$0.16	$0.12	$0.09	$0.07
Other Soft Costs + PII ($/W)	$2.03	—	—	$1.53	$1.36	$1.22	$1.08	$0.90	$0.72	$0.53	$0.34
Financing (WACC %-real)	—	—	8.6%	9.5%	9.2%	8.2%	7.9%	5.1%	4.4%	3.9%	3.4%
Total Soft Costs ($/W)	$2.64	—	—	$2.01	$1.76	$1.54	$1.32	$1.10	$0.88	$0.66	$0.44
Total System Costs ($/W)	$5.96	—	—	$4.03	$3.64	$3.24	$2.84	$2.44	$2.05	$1.65	$1.25

Regardless of the specific path taken to achieve the SunShot targets, the concerted efforts of numerous PV market actors and stakeholders will be required. These include developers/installers, service providers, the financial community, utilities, PUCs, equipment providers, standards organizations, real estate and construction companies, state and local governments, and the federal government. We illustrate (in Section 7) how the required participation of each type varies substantially by soft-cost-reduction category while noting that roles and responsibilities will be complementary and somewhat fluid over time.

This roadmapping study has a number of analytical limitations. To capture market-wide trends, it focuses on average effects and does not explore differences at the individual installer or company level. Also, the CROs identified have cross cost-category effects, including potentially making certain cost categories more expensive. Therefore, we assume that for any CRO to gain substantial market penetration, it will reduce LCOE. In addition, the 2020 SunShot targets for each cost category are based on the 2010 proportional share of total soft cost. Further refining model assumptions to account for different rates of cost reduction across categories would improve the analysis. Finally, the roadmap's dollar-per-watt and WACC targets are not tied to installed-PV-capacity targets. Accounting for installed capacity would be particularly relevant for finance solution sets because it would help quantify the capital pools necessary to achieve the roadmap targets.

Our data sources also have limitations. The ITRS, now two decades in existence, applies a year-long, multi-working-group approach involving several hundred companies, and therefore, likely receives well into the millions of U.S. dollars of in-kind support. This paper represents a small-scale initial soft-cost roadmapping effort, depending on market analysis and more than 70 in-depth interviews. The ITRS approach likely provides more resolution on solutions, novel approaches for structuring the roadmap, a broader set of viewpoints, and results that more accurately represent the average of major stakeholders' views. Most interviewees we consulted were solar industry participants, and their views about the industry's possible advancements may be more optimistic than the views held by a broader, more diverse group of stakeholders.

This report is part of a series of NREL research efforts that will track soft-cost reductions over time and quantify the impacts of innovations. Future work will include further elaboration of interconnection costs and benchmarks, particularly to show the wide range in residential PV interconnection processing times and installer costs. Similarly, future analysis of customer acquisition costs will be improved by broadening the costs examined to include those currently in the additional overhead category.

Additional future work could focus on the geography of the PV market. The distributed PV market is regionally diverse, depending on factors such as each locality's solar radiation, government subsidies, and utility rules, rates, and programs. Actionable guidance aimed at the state and local levels—such as regionally focused roadmaps with detailed cost-reduction opportunities—would promote achievement of the national SunShot targets.

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Appendix A: Supplemental Data Tables

Table A-1. Residential Customer Acquisition Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX REDUCTION POTENTIAL FROM 2010 BASELINE ($0.67/W)
SOFTWARE TOOLS	Remote site assessment tied to bid prep software	2%	50%	70%	$0.12
	Next Gen: site assessment plus on-location bid prep on initial site visit	10%	65%	85%	$0.05
DESIGN TEMPLATES	Standardized system designs	10%	85%	85%	$0.06
CONSUMER-TARGETING STRATEGIES	Marketing programs & partnerships (e.g., Solar City, Home Depot)	10%	85%	85%	$0.06
	Lead qualification & generation programs	6%	30%	60%	$0.11
	Referral programs	10%	50%	68%	$0.17
	Consumer-awareness campaigns (including online outreach)	5%	50%	60%	$0.22

*Individual values may not add up to totals owing to rounding

Table A-2. Commercial Customer Acquisition Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX REDUCTION POTENTIAL FROM 2010 BASELINE ($0.19/W)
SOFTWARE TOOLS	Remote site assessment tied to bid prep software	0%	9%	6%	$0.02
	Next Gen: site assessment plus on-location bid prep on initial site visit	0%	28%	40%	$0.05
DESIGN TEMPLATES	Standardized system designs	9%	28%	34%	$0.07
CONSUMER-TARGETING STRATEGIES	Marketing programs & partnerships (e.g., Solar City, Home Depot)	9%	19%	12%	$0.10
	Lead qualification & generation programs	9%	19%	19%	$0.02
	Consumer-awareness campaigns (including online outreach)	9%	47%	40%	$0.10
NEW MARKETS	Undefined (includes innovative financing to open new markets coupled with new customer acquisition advancments)	0%	0%	38%	$0.16

*Individual values may not add up to totals owing to rounding

Table A-3. Residential, Inspection, and Interconnection Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION PPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX REDUCTION POTENTIAL FROM 2010 BASELINE ($0.20/W)
STANDARDIZATION	Uniform permitting & inspection requirements across jurisdictions (excludes interconnection)	10%	30%	45%	$0.05
TRANSPARENCY	Online database of requirements by jurisdiction	0%	65%	80%	$0.03
ONLINE PERMITTING	Online permit application submittal	20%	40%	55%	$0.01
LOWER FEES	Market-wide average fee reduction from $430 to $250	3%	40%	80%	$0.04
INTERCONNECTION BEST PRACTICES	Interconnection best practices (e.g., rapid application process, defined process for systems > 15% peak load)	3%	25%	60%	$0.01
UNDEFINED	Undefined (likely includes market-wide average fee of $100 and streamlined inspection)	0%	0%	45%	$0.16

*Individual values may not add up to totals owing to rounding

Table A-4. Residential Installation Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX REDUCTION POTENTIAL FROM 2010 BASELINE ($0.59/W)
INTEGRATED RACKING	Integrated racking (eliminates additional mounting structure)	1%	30%	5%	$0.14
MODULE INTEGRATED ELECTRONICS	AC Modules (microinverter integrated at factory)	1%	30%	10%	$0.10
	Microinverters (small inverters on racking convert to AC)	10%	35%	10%	$0.03
PREFABRICA-TION	Preassembly of panels and racking in warehouse/ factory	1%	20%	18%	$0.20
PLUG AND PLAY	Gen 1 (AC module with integrated racking)	0%	30%	45%	$0.28
	Gen 2 (fully inclusive off-the-shelf system)	0%	0%	20%	$0.51
SOLAR-READY HOMES	Solar-ready homes (new building design integrates rooftop PV)	1%	7.5%	7.5%	$0.10
UNDEFINED	Undefined (likely includes more equipment standardization, reduced through-roof penetration, experience gains)	0%	0%	70%	$0.25

*Individual values may not add up to totals owing to rounding

Table A-5. Commercial Installation Labor Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX REDUCTION POTENTIAL FROM 2010 BASELINE ($0.42/W)
INTEGRATED RACKING	Integrated racking (eliminates additional mounting structure)	5%	67%	90%	$0.22
MODULE INTEGRATED ELECTRONICS	Microinverters (small inverters on racking convert to AC)	10%	45%	45%	$0.13
	DC optimizers (track & optimize module performance individually)	5%	55%	55%	$0.08
PREFABRICATION	Preassembly of panels and racking in warehouse/ factory	5%	15%	15%	$0.30
1,000- VOLT DC	1,000-volt DC (enables more modules wired together per string)	1%	5%	5%	$0.05

*Individual values may not add up to totals owing to rounding

Table A-6. Residential Financing Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX WACC REDUCTION FROM 2012 BASELINE (9.9%), IN 2020 (%-REAL)
THIRD-PARTY FINANCE	Standard Third Party	38%	0%	-	-
	Third Party with Debt/ABS - Prime	38%	2%	4.8%	5.2
	Third Party with Debt/ABS - Subprime	0%	2%	9.3%	0.6%
	Corporate On-Balance Sheet	0%	35%	2.9%	7.0%
	Third Party with YieldCo	0%	11%	3.0%	6.9%
	Third Party with Institutional Equity	0%	0%	-	-
UTILITY FINANCE	On-Bill Financing/ Repayment	0%	6%	5.0%	4.9%
HOMEOWNER FINANCE	Cash Purchase	17%	3%	3.2%	6.7%
	Solar Loans	5%	19%	1.6%	8.3%
	Mortgage—New Build	1%	15%	0.6%	9.3%
	Residential PACE	1%	1%	4.4%	5.5%
COMMUNITY SOLAR	Community Solar	1%	6%	9.4%	0.5%

*Individual values may not add up to totals owing to rounding

Table A-7. Commercial Financing Market Penetration and Maximum Cost-Reduction Potential

SOLUTION SET	COST-REDUCTION OPPORTUNITY (CRO)	2010 MARKET PENETRATION	2020 MARKET PENETRATION—CURRENT TRAJECTORY	2020 MARKET PENETRATION—ROADMAP	MAX WACC REDUCTION FROM 2012 BASELINE (9.2%) IN 2020 (%-REAL)
THIRD-PARTY FINANCE	Standard Third Party	40%	0%	-	-
	Third Party with Debt/ABS	0%	3%	5.2%	4.0%
	Third Party with REIT	0%	11%	3.2%	6.0%
	Third Party with Crowdsourced Funding	0%	2%	4.5%	4.7%
	Corporate On-Balance Sheet	0%	16%	3.5%	5.7%
	MUSH: Muni Bonds + Third Party	2%	0%	-	-
	Third Party with YieldCo	0%	1%	3.2%	6.0%
UTILITY FINANCE	Full Utility Ownership	7%	14%	5.1%	4.1%
	Utility Equity and Tax Equity	0%	0%	-	-
HOST FINANCE	Cash Purchase	46%	9%	5.1%	4.1%
	MUSH: with Debt/Bonds	1%	2%	3.4%	5.8%
	Green Bonds	0%	3%	2.4%	6.8%
	Commercial PACE	3%	9%	2.3%	6.9%
	Undefined CRO(s)	0%	26%	1.9%	7.3%
COMMUNITY SOLAR	Community Solar	1%	4%	5.0%	4.2%

*Individual values may not add up to totals owing to rounding

Appendix B. Example Interview and Survey Questions

We collected data via a combination of interview questions and survey instruments. The process was iterative: we modified our instruments and re-surveyed participants as we learned what methods elicited the desired amount of detail. For example, for some iterations we pre-populated surveys with estimates and asked the participants to judge whether the estimates were high or low. Presented here are simplified/consolidated examples of the instruments we used in our data collection.

Table B-1. Example Interview Questions

Customer Acquisition
What are the most costly elements of the customer acquisition process?
(fill in the blank) Due to market maturity alone, customer acquisition costs are estimated to come down by X% by 2020.
What is the cost reduction potential of remote system design and site assessment in the near term and long term? (2015 vs. 2020) Where is the potential for further automation and streamlining in the customer acquisition process?
How much can customer acquisition costs be reduced by with the implementation of an installer data base with online quote system? (i.e. A Tire RAC interface for solar)
Is there cost reduction potential associated with providing educational materials for potential PV customers? Which market sectors would reap greatest cost reductions (residential, commercial, utility)? How much could customer acquisition costs be reduced by with increased awareness via education? (including the cost of marketing/advertising)
What other CA cost reduction activities we should investigate?
Permitting, Inspection, and Interconnection
What are the most costly and time consuming permitting, inspection, and interconnection tasks undertaken when completing a PV installation? What are the estimated costs per watt?
Regarding permit preparation, how much time/money could be saved from an online permitting database/clearinghouse of information?
How much extra cost do you incur due to variation in PII requirements across jurisdictions? AS AHJs and municipal permitting offices begin to harmonize and standardize requirements across jurisdictions, how much do you anticipate permitting costs to be reduced by in the near to long term?
What are the most significant cost adders throughout the inspection process? How can these costs be reduced in the near term and long term? By how much?
What are the system size thresholds for interconnection studies and what are the general cost points where these studies become cost prohibitive? What size system is typically required to offset the additional costs of interconnection studies?
What are the unique permitting, inspection, and interconnection challenges for commercial scale systems? How can the estimated costs of these by reduced and by how much in the near term and long term?

What other PII cost reduction activities we should investigate?
Installation Labor
In terms of percentage, by how much are installation labor requirements likely to be reduced with hardware innovations (i.e. AC modules, grid racking, integrated rail module systems) the near term and long term? (2015 vs. 2020)
In addition to improved training and pre-fabrication, what other market developments/interventions have potential to reduce installation labor costs in the near and long term? By how much?
What other installation cost reduction activities we should investigate?
Are there special installation techniques specific to larger systems that can help reduce installation time and cost? By how much in the near term and long term? (2015 vs. 2020)

Example Survey Instrument (Residential PII)

Table B-2. Example Survey Instrument (Residential PII)

NREL PV Cost Benchmarking and Road Mapping Overview and Industry Input

OBJECTIVE

While technological improvements are necessary to achieve U.S. DOE SunShot cost reduction targets, decreasing regulatory and process costs are equally important for the integration of solar into the national energy portfolio. This analysis quantifies the impact of regulatory and process hurdles on solar deployment and identifies potential pathways forward for achieving non-hardware BOS cost (“soft cost”) reductions.

PROJECT OVERVIEW

PHASE I: NREL recently collected data to benchmark soft costs for residential and commercial PV systems, installed in 2010, in support of the U.S. DOE SunShot Initiative. Phase I of this project collected installer level data in the following DOE priority cost categories, to provide further granularity to laboratory led PV system price modeling and analysis activities.

- Customer acquisition
- Permitting, inspection, interconnection
- Third-party Financing
- Installation

As a result of this surveying, we established the following benchmarks for a) Residential systems and b) Commercial Systems (<250kW)

Category	Residential Benchmark-2010	Interim	Residential SunShot target-2020
Other Costs	$ 1.86		
Permitting, Inspection, Interconnection (includes fee of $.09, $.11/W for labor)	$ 0.20		
Installation Labor	$ 0.59		12
Customer Acquisition	$ 0.67		$ 0.13
Total	**$ 3.32**		**$ 0.65**

Roadmap: How do we get from Benchmark to SunShot target?

PHASE II Meeting SunShot targets requires substantial cost reductions in each category (see above) Phase II develops a roadmap for plausible cost reduction pathways given a certain series of cost reduction interventions. The goal is to estimate the amount, measured in dollars per watt ($/W), that can be saved by specific actions (i.e. $/W saved by switching to an online permitting database). **<u>This is where we need industry input.</u>**

The following page provides an *initial proposed roadmap framework* with cost reduction measures (cost levers) that have been cited to have significant cost reduction potential. The focus of this data collection is to approximate and quantify the $/W amount that these cost levers can reduce costs by, by 2020 (given a PV system that adopts the solution). To do so, for each cost lever we approximate the current (2012) and anticipated-future market penetration levels by 2020. Market penetration is measured as a % of new PV capacity installed that year (annual installed capacity). Using these inputs, we then approximate the additional market penetration required, of each cost lever, in 2020 to meet SunShot targets. Given your experience and knowledge of the market, for the cost levers identified, what is the estimated maximum cost reduction potential ($/W), current market penetration (%), and anticipated-future market penetration (%)?

<u>Residential Permitting, Inspection, and Interconnection (5 kW)</u>

	$/w Cost Reduction from baseline by 2020	*% Current est. market penetration*	*% Anticipated market penetration by 2020*	Comments
Standardization of permitting requirements based on best practices(independent of interconnection requirements)				
Database of requirements (across jurisdictions) Data base assumed to ONLY disclose requirements, no online permitting submittal capabilities are included				
Online Permitting Submittal				
Fee reduction from $430 to $250 (assumed)				
Comprehensive permitting reform (Database+ standardization + online submittal)				
Best Practices, Interconnection (i.e. IREC Model Standards)				
Standard inspection check list with improved inspector training/education				

Appendix C: Solution Set and Cost-Reduction Opportunity Descriptions

Customer Acquisition

The following are expanded definitions of the residential and commercial customer acquisition **solution sets** and CROs discussed and roadmapped in Section 3.

Software Solutions: Upfront or "sunken" customer acquisition costs can be addressed through software solutions that aim to streamline sales and system design aspects of customer acquisition. Software solutions that automate portions of the sales and system design process can reduce overall customer acquisition costs as long as the cost to deploy the technology does not outweigh the benefit of lower per-unit customer acquisition costs over a period of time.

- **Remote Site Assessment Tied to Bid Prep Software**: This refers to conducting the initial site assessment and providing a proposal/bid without ever physically visiting the customer site where the PV is to be located. Reduces time spent labor intensive, in-person site visits to ascertain system design specifications needed for bid generation, such as installation size, location, and energy production potential. At present, the purchase of software for remote site assessment and system design may be cost prohibitive for lower volume installers, but this is subject to change as such innovations achieve greater market penetration and come down in cost.

- **Next Generation Site assessment plus on-location bid prep on initial site visit**: these tools enable streamlined sales and system design processes. For example, a tool may enable sales people to complete the site assessment and provide a proposal on-location site during the initial site assessment or allow the sales person to send data back to the system designer in the office in real time.

Design Templates: It is common for PV installers to employ standardized bid preparation templates and auto-fill forms to reduce duplicative work when preparing bids. This type of standardization is not included in the roadmap study because it is considered a standard practice that firms will engage in as a matter of striving for efficient business processes. The standardizing of system designs is included because it is recognized as a promising area for reducing system design costs.

- **Standardized System Designs**: Standard PV system designs that do not need to be custom-designed for each prospective customer can reduce system design engineering labor hours. PV system designs can be standardized around common housing or building stock and adapted to specific building and site parameters if needed. This reduces duplicative design work for similar sites. Standard designs also helps reduce associated hardware/equipment costs by allowing for a standard bill of materials for hardware greater economies of scale on hardware purchases. Standard system designs are more prevalent in the commercial sector than in the residential sector because the common flat commercial rooftop makes a better palate for standard designs than the diverse roofing configurations and surfaces seen in the residential market.

Consumer Targeting Strategies: Effective targeting strategies generate higher-quality leads that can increase sales-closing ratios or bid-success rates. This increases the overall volume sold and provides a larger customer base to spread costs across. Increasing the volume of PV sold will reduce an installer's customer acquisition cost per watt as long as the annual customer acquisition expenditures do not increase to levels that negate the added benefit of increased volume (in terms of customer acquisition cost per watt).

- **Marketing Programs and Partnerships**: Many PV installation firms seek partnerships with established market entities that have ready access to potential solar customers, such as utilities, energy marketers, and big-box retailers. The known brand adds a trusted layer of confidence for consumers. The distribution outlet may raise awareness across a broader market than might otherwise consider a PV system installation.
- **Lead Qualification and Generation Programs**: This refers to pay-per-lead services or group purchase programs through a city, employer, or neighborhood organization (i.e. Solarize Portland Program; Marin Group Buy Program), whereby installers receive leads through an outside organization. Close ratios associated with lead qualification and generation programs are the primary metric of their value to installers. For example, an expensive lead that closes is more valuable than free leads that do not close because employee time, which contributes to customer acquisition costs, is expended to try and close the lead. Companies participating in programs that offer groups of customers or qualified leads (e.g., group purchase programs and big-box retailer partnerships) may incur lower customer acquisition costs per unit sold if the cost of winning the group bid or participating in the program is offset by a commensurate increase in the volume of PV sold. Programs that group together potential PV customers by geographic region and offer a vetted discount option for purchasing PV systems have been termed "solarize" programs in many areas. These programs are typically run by an organization, usually a municipality or non-profit. The organization issues a request for bid and selects a vendor to install multiple PV systems at a discounted price.
- **Referral Programs:** This refers to formal and informal referral programs (whether a company actively solicits and pays for referrals or gets referral business by word of mouth without payment).
- **Consumer Awareness Campaigns**: Advertisements and outreach focused on increasing consumer awareness about the benefits of solar.

New Markets: Opening up new market segments via innovative finance leads to lower customer acquisition costs for these new market segments. Decreased customer acquisition costs against the market average ($0.19/W in 2010), however, will only occur with the undefined CRO.

- **This undefined CRO** involves new and advanced customer acquisition practices that couple well with innovative financing solutions that open up challenged commercial market segments. These challenged segments include lower building owner credit classes[43] and/or real estate properties in which solar misaligns with their investor's interests (e.g., split incentives on energy savings with utility bill-paying tenants and misaligned investment time horizon).

[43] Most small commercial PV financing is made available to high credit quality corporations and MUSH entities (less than 10% of available commercial rooftop space). In addition, many real estate companies intend to sell building assets within five to seven years, which does not align with much longer duration (10 to 25 year) solar PV leases and PPA contracts. Other commercial building assets are held real estate entities, such as REITs, that are challenged to monetize tax benefits (see "Third Party with REIT" in Appendix C for further discussion). In addition many real estate investment entities don't pursue solar because they consider it an atypical asset or income stream for other business related reasons.

Permitting, Inspection, and Interconnection

The following are expanded definitions of the residential PII solution sets and CROs discussed and roadmapped in Section 4.

Standardization of Requirements

- **Standardization of Permitting Requirements**: Implementing uniform permitting and inspection requirements and fees across jurisdictions (independent of interconnection requirements).

Transparency of Requirements

- **Database of Requirements:** Currently Clean Power Finance is working to create an online database that discloses all the PII requirements by jurisdiction.

Online Permitting

- **Online Permit Application Submittal**: Submitting an application online, directly to the AHJ or through a centralized database/system.

Lower Permitting Fees

- **Lower, Standardized Fees not Based on System Size**: A typical fee identified by SunRun of $430 is used as a baseline for permitting fees for this analysis. A lower fee of $250 is considered for the purposes of roadmapping fee reductions through 2020.

Interconnection Best Practices

Interconnection Best Practices: The Interstate Renewable Energy Council and DOE have identified several measures to streamline the interconnection processes. This CRO includes the following:

- Setting minimum response and review times for interconnection applications
- Avoiding overly burdensome administrative requirements, such as obtaining signatures from local code officials unless such requirements are standard practice in a jurisdiction for similar electrical work
- Defining an interconnection approval process for systems generating above 15% peak load (for both residential and commercial PV).

Undefined Solution Set

- **This undefined CRO** likely combines unknown regulatory mechanisms that enable wider-scale uniformity across AHJs, an average fee of $100 [instead of $250 (i.e., in the lower permitting fees solution set)] and streamlined d inspection process (coordination between the utility and the city/county inspectors to combining multiple inspections into a single inspection).

Installation Labor

The following are expanded definitions of the residential and commercial installation labor solution sets and CROs discussed and roadmapped in Section 5.

Integrated Racking

- **Integrated racking** eliminates the additional mounting structure, as the module frame provides the structural support for the system. In addition to substantial reduction in mechanical labor by reducing the part count, integrated racking provides savings in manufacturing, project design, shipping, and installation. In some cases there can be an additional upfront cost. Examples include the Zep Groove system and the Andalay Groove mounting system.

Module Integrated Electronics

- **AC Modules:** (residential; not identified as a commercial solution): An AC module contains an integrated micro-inverter; DC from the module is wired directly to the micro-inverter at the factory. AC modules may add upfront cost to the system and/or have system LCOE implications.

- **Microinverters:** Microinverters are small inverters mounted on the racking, directly belowthe panel, converting DC to AC at the module-level. This is an alternative to central, or string inverters. Microinverters reduce labor associated with cable runs. Microinverters may add upfront cost to the system and/or have system LCOE implications.

Prefabrication

- **Prefabrication** involves pre-assembling panels and racking in a warehouse, which is then directly craned onto roof and locked into a mounting structure.

Plug and Play (Residential)

- **Generation 1 Plug and Play:** This CRO utilizes an AC module with integrated racking, enabling panels to directly connect without additional mounting hardware. An example of a system that employs integrated racking, wiring, grounding, and inverter is the Westinghouse Solar Instant Connect.

- **Generation 2 Plug and Play:** This refers to a commercial, off-the-shelf system that is fully inclusive with little need for individual customization. Any homeowner/consumer can buy and install (or have a contractor install) the system without the need for special training or specialized tools. This type of system reduces labor to a maximum of 10 unspecialized man hours and requires no electrician labor.

Solar-Ready Homes (Residential)

- **A solar-ready home** is a residential new-build that is designed to easily integrate roof-mounted PV. Considerations and building features can include, but are not limited to, designing roofs for solar loads, grouping roof equipment and vents on the north side of the roof, minimizing shading, pre-drilled mounting holes, pre-engineered roof trusses, and built-in wiring from roof to panels during construction.

Undefined Solution Set (Residential)

- **An undefined CRO** likely includes more equipment standardization, reduced through-roof penetrations, and installation labor-efficiency gains due to experience. For example, industry representatives have suggested that standardizing module dimension (akin to standardized lumber dimensions) would reduce installation labor by reducing on-the-job design costs and hardware selection, generally streamlining installs. Additional plausible standardization contingent upon standardized module dimensions include standardizing the junction box placement, cable harness, and mounting scheme. Reduced through-roof penetration could be achieved by an increase in standing seam metal roofs,- particularly on new build homes. Adjustment to current regulations could also allow systems to be secured to clay tile roofs via roof clamps—a practice currently employed in Germany. Last, learning-by-doing will certainly increase process efficiency and reduce costs. For example, less intermittent flows would better enable installers to optimize processes and efficiently use resources.

Power Electronics (Commercial)

- **DC Optimizer:** This CRO refers to equipment that connects to each PV module that replaces the traditional solar junction box. Typically optimizers track the maximum power point of each module individually, monitor performance, and communicate performance data. This architecture allows the connection of a large number of panels on a single cable run, reducing up-front solar array costs and providing more design flexibility. Examples include Parallel Solar from eiQ and SolarEdge and Tigo. DC optimizers have system LCOE implications.

- **1,000-Volt DC (VDC) Modules:** This CRO is included on account that PV systems that utilize 1,000-VDC modules, compared to traditional 600-VDC modules, realize a 40% BOS wiring savings (SMA Solar Technology), which reduces overall installation labor requirements and costs. While 1,000-VDC modules have been a standard best practice for commercial and utility-scale PV installations in Europe, barriers to adoption in the United States have included lack of UL-listed products, standard designs set at 600 VDC, and lack of inspector awareness that provisions exist in the current code to support 1,000-VDC modules for commercial installations. Recently, there has been a shift in the United States toward utilization of 1,000-VDC modules as many of these barriers are removed.

Financing

The following are expanded definitions of the residential and commercial financing CROs discussed and roadmapped in Section 6.

Residential

Third-Party Finance

- **Standard Third Party:** Developer equity is in partnership with tax equity, though both come from a single financing source. Venture capital and private equity (VC/PE are assumed to provide developer/sponsor equity for the majority of residential solar deals in 2013, transitioning to greater public capital (public market shareholder-provided equity) over time. Public equity provides the majority of developer equity by 2015 in both current trajectory and roadmap cases.

- **Third Party With Debt/ABS—Prime:** Involves developer equity, tax equity, and debt in a portfolio fund for high-FICO (>680) customers. The debt is provided either via lender debt, bonds, or ABS. Debt can be provided at a developer equity holding company level above the portfolio fund (back-leveraging) or within the portfolio fund (project-level). It is assumed that the average loan-to-value against developer equity begins around 1.5 in 2013 and transitions to a lower LTV ratio (1.3 in current trajectory and 1.2 in roadmap case) or equivalent (e.g., via overcollateralization) in later years. In addition, due to higher liquidity needs, it is assumed that the vast majority of debt is securitized in later years.

- **Third Party With Debt/ABS—Wubprime:** The same as prime definition but with a targeted customer market similar to the lending credit class of subprime mortgages. Debt rates are higher due to higher risk.

- **Corporate On-Balance Sheet:** Describes public companies developing and financing a large volume of projects without external tax equity. In the lower ITC years of 2017–2020, large public corporations (likely Fortune 500, possibly Fortune 100) should be able to fund high volumes of PV projects without maxing out their tax appetites. Currently, more pure-play solar developers and/or lease/PPA providers would likely be merger and/or acquisition (M&A) targets of these large corporations. It may be possible for a solar developer today to grow more organically to this size, particularly if it offers more diversified services and products. Public corporations conducting M&A would likely involve a mixture of engineering service, telecom, and energy (e.g., oil and gas) companies and IPP utilities. The existence of a robust secondary ABS market for solar may be critical to enable market participation by large corporations, ensuring that they need not hold the assets for long periods.

- **Third Party With YieldCo:** YieldCos are companies providing long-term steady yields based on regular cash flows, as debt payments or equity dividends or both, from solar projects. YieldCos are attractive to retail and institutional investors pursuing "income" investments. YieldCos could exist as more traditional company types, such as "C" corporations, or as tax-advantaged (i.e., none/limited taxation) entities, such as REITs,[44] MLPs, business development companies/registered investment companies (BDCs/RICs), or Canadian investment trusts. The yieldCo term can be used solely to describe "C" corporations, but the broader yield-oriented company meaning is used in this report. For residential PV, only MLPs garnered significant interviewee interest. Federal legislation, however, is required to enable solar projects to qualify as viable assets for MLP ownership. Following the interview period, on June 7, 2013, NRG announced intentions[45] for a $400 million IPO of a subsidiary "C" corporation yieldCo that would include solar (albeit not residential) project cash flows. Proceeds from the IPO would help raise capital for a utility-scale solar project.

- **Third Party with Institutional Equity:** This is the same as standard third party but with the developer able to source developer equity from long-term-focused, lower cost-of-capital investors, such as pension funds and endowments. This CRO is focused on direct investment by institutional equity sources without ABS, and as such, this is more of an early-year activity before ABS becomes robust for solar.

Utility Finance

- **Utility on-bill financing** are loans repaid via additional charges on the utility bill, resulting in overall lower bills where breakeven-or-better PV economics exist. The capital comes from the utility's balance sheet or bank loans routed through utilities with the utility as the debt servicer. Default recourse in on-bill finance is for the utility to cut off power and, in some cases, act on property liens. In some cases the financing remains with the meter after property sale. In

[44] See "third-party with REIT" under commercial market in appendix C for more detail.
[45] http://www.bloomberg.com/news/2013-06-07/nrg-plans-400-million-ipo-for-unit-to-own-operate-power-assets.html (accessed June 17, 2013).

this paper, on-bill "financing" and "repayment" are differentiated, as "repayment" allows for third-party financing routed through a utility's bill. On-bill repayment had no material residential solar financing activity in 2012.

Homeowner Finance

- **Cash Purchases:** While not regularly considered a "financing cost-reduction opportunity," cash purchases are in effect full equity financings by homeowners.

- **Solar Loans:** Specialized loan products for solar currently exist. This debt is provided as efficiency loan products, home equity loans, home equity lines of credit (HELOCs), mortgages, and home improvement loans. Despite what their name might imply, these types of debt generally do not include the value of the PV system in the real estate value. Instead, these loans are often unsecured (against the credit of the borrower) or against homeowner equity in their home (non-inclusive of the PV system's value). In other words, they are methods of putting cash in the hand of the homeowner that is somewhat uncorrelated with the solar PV system's value. Examples of current offerings include the FHA's PowerSaver Pilot Program, the U.S. Department of Housing and Urban Development (HUD) insured Title 1 Home Improvement Loan (Admirals Bank is a notable offering bank), the Colorado Energy Star Mortgage, and the Fannie Mae Energy Loan. Over time, solar loans are anticipated to transition to be party of standard real estate loan products, providing higher liquidity and lower cost of capital than first generation solar loans. These real estate loan products would likely include PV system value within the appraised real estate value. *Such appraisal practices did occur under common real estate appraisal conditions in 2012.* Home equity loans may become the most likely vehicle for finance solar on existing homes though mortgage refinancings may also play a role. The value of PV would be determined either on an income basis, as in Sandia National Laboratories' PV value valuation software or a comparable asset sale basis. To not require homeowner capital contribution, perhaps developers would put working capital at risk to bring the PV project to completion and then be paid back by the loan. Banks routing these loan products through developers, providing a "one-stop shop" and cents-per-kilowatt-hour-correlated offerings, would likely increase customer uptake.

- **Mortgage—New Build:** This CRO primarily entails a mortgage for the purchase of a newly built home that includes PV. This CRO assumes a transition from specialty mortgage products designed to support solar financing to standard mortgages that include solar in the appraised value of the home. This CRO may exceed the market penetration of solar-ready homes because it is assumed that there may be mechanisms for the home buyer to add solar as part of the mortgage financing.

- **Residential PACE:** Residential PACE programs provide loans for PV, paid back through property tax collections, which thus remain with the property and senior to most other liens including mortgages. Residential PACE has experienced recent challenges in relation to mortgage underwriting, putting many programs on "pause." In 2010, Fannie Mae and Freddie Mac refused to underwrite mortgages on homes involved with PACE lending. In 2012 the State of California, in support of PACE, won a federal court ruling against the Federal Housing Financing Authority (FHFA), Fannie Mae, and Freddie Mac. The court ruled the defendants must take in public and stakeholder comments before making such underwriting decisions. Greater clarity from FHFA should come in 2013. Despite the uncertainties, residential PACE persists in some areas. Nonetheless, interviewees felt that that residential PACE did not hold long-term scalability. However, after our interview period was complete, $100 million in loans were offered through the Riverside County, California, HERO program (accessible throughout California) and $500 million in loans offered through the Florida PACE Funding Agency. Both loan programs cover PV, other renewables, and energy efficiency.

Community Solar

- Community solar is generally financed through one of the third-party or utility-financing CROs. While community solar financing could be grouped within these other solution sets, it has unique investment risks, utility-value propositions and challenges, and policy treatment. Subscribers to community solar projects (usually built at a scale comparable to a medium-to-large commercial project) receive the net-metering benefits of solar as if a solar installation the size of their subscription was on their rooftop (hence, "virtual").

Commercial

Third-Party Financing

- **Standard Third Party:** VC/PE is assumed to provide developer equity. Developer equity is paired with tax equity.
- **Third Party With Debt/ABS:** Involves developer equity, tax equity, and debt supporting a portfolio fund. This CRO is best suited to high-credit-quality power offtakers. The debt is provided either via lender debt, bonds, or ABS. Debt can be provided at a developer equity holding company level above the portfolio fund (back-leveraging) or within the portfolio fund (project-level).
- **Third Party with REIT:** REITs are business entities electing REIT designation under Form 1120-REIT. REITs do not pay corporate tax and are able to access retail investors in public markets through public offering of shares. REITs must follow tax code minimums for asset holdings of and income streams from real property. While it is possible for REITs to participate at low levels in asset ownership and income streams if maintaining their real property asset and income minimums, substantial REIT involvement in solar is likely not possible without the PV holding real property status, a status not yet indicated via an IRS public publication of private letter ruling(s). REIT PV development could occur though specialty REITs that focus on owning PV or more traditional REITs that would develop PV on buildings they own or acquire. Both of these actions would fit under the "host finance" solution set. Interviewees were unsure of how either of these equity activities could marry well with tax benefit capture (i.e., with tax equity), and therefore believed REITs providing debt to commercial PV projects (back-leveraged or within project structure) would be the most likely route for early REIT activity. Hence, REITs are placed within this "third-party finance" solution set. There are also REIT work-around options (REITs leasing rooftop space to a third-party owner of a PV system), which was occurring in 2012, but that is considered "standard third-party" financing for this paper as the REIT is not involved in the financing.
- **Third Party with Crowdsourced Funding:** Crowdsourced funding is accessing retail investors through lower regulation pathways than traditional securities purchases. The 2012 Jumpstart our Business Startups (JOBS Act authorized expanded crowdsourced funding constructs, although the Securities and Exchange Commission has not yet promulgated JOBS Act regulations. Nevertheless, providing debt through crowdsourced funding was viable prior to

the JOBS Act, and interviewees believed that debt, rather than equity, will be the most natural fit for crowdsourced funding for PV going forward. Early crowdsourced debt has occurred directly to hosts (so under the "host finance" solution set), but to reach substantial scale, interviewees believed crowdsourced funding's primary role would be as a debt provider to commercial projects alongside developer equity and tax equity. Direct lending to hosts may serve a smaller but regular role in financing projects in those regulated utility territories that do not allow third-party financing.

- **Corporate On-Balance Sheet:** This CRO entails public developers financing deals without external tax equity, entirely on their balance sheet. Large corporations should be able to fully fund significant volumes of small commercial PV projects without maxing out their tax appetite in the 10% ITC later years (2017–2020). Currently, more pure-play solar developers (including lessors) would be likely M&A targets of these large corporations or public (e.g., SunPower and SunEdison) or later-to-become public developers could possibly organically grow to this size, although further diversification likely would be necessary.

- **MUSH—Municipal Bonds + Third Party:** For MUSH properties, it is possible to combine governmental-bonded debt with tax-equity-backed third-party funds. This enables lower-cost projects at lower WACC than either bonding or third-party financing alone. Taxable bonds can be loaned into developer portfolio funds. This has been called the "Morris Model," as this financing practice began in Morris County, New Jersey. A similar outcome can be achieved by pre-paying third-party PPAs with bond proceeds.

- **Third Party With YieldCo:** YieldCos are companies providing long-term steady yields based on regular cash flows, as debt payments or equity dividends or both, from solar projects. YieldCos are attractive to retail and institutional investors pursuing "income" investments. YieldCos could exist as more traditional company types, such as "C" corporations, or as MLPs, BDCs/RICs, Canadian investment trusts, or other novel approaches. Some use the yieldCo term to describe only "C" corporations, but the broader yield-oriented company meaning is used here. These entities usually benefit from limited taxation at the company level, and some, such as MLPs, also pass through passive tax benefits, which are desirable to a limited investor class. For residential PV, only MLPs garnered significant interviewee interest. Federal legislation, however, is required to enable solar projects to qualify as viable assets for MLP ownership. Following the interview period, on June 7, 2013, NRG announced intentions[46] for a $400 million IPO of a subsidiary "C" corporation yieldCo that would include solar project cash flows. Proceeds from the IPO would help raise capital for a utility-scale solar project. REITs may also be included as a kind of yieldCo but are broken out as a separate CRO for commercial PV financing because of high REIT-specific interests of interviewees.

Utility Financing

- **Full Utility Ownership**: Utilities can fully fund projects in their service territories and include them in the rate base. These full financings have generally occurred under the auspices of, or were made financially viable by, renewable portfolio standards (RPSs). New business

[46] http://www.bloomberg.com/news/2013-06-07/nrg-plans-400-million-ipo-for-unit-to-own-operate-power-assets.html (accessed June 17, 2013)

models for distributed-generation ownership by the utility may provide value when RPS programs are no longer available or as supportive.

- **Utility Equity and External Tax Equity:** This CRO may not be possible without PUC regulatory changes in many states. This has been done for larger projects (large commercial and utility-scale) by IPP utilities. If allowed in regulated territories, this CRO would allow much quicker monetization of the ITC (otherwise it must be spread over the rate-based period (i.e., monetized over about 25 years by the regulated utility instead of in first year by a tax-equity investor).

Host Finance

- **Cash Purchase**: The building owner buys the system outright (i.e., 100% equity asset purchase).
- **MUSH With Debt/Bonds:** Municipalities can offer debt to PV projects on their local MUSH buildings via municipal bond offerings. ESCO activities on MUSH properties supported by private bank loans are included in this category for simplicity.
- **Green Bonds:** In 2012 there already existed a growing market for "green bonds," but this market primarily consists of privately issued bonds for utility-scale project and renewable energy corporation-issued bonds as well as specialty federal government-enabled bonds, such as Clean Renewable Energy Bonds. Our CRO involves only state and local governmental backing and is specific to distributed solar energy, substantial differentiators from the vast majority of the current "green bond" market. State and local governments can offer bonds to fund small commercial PV systems within their jurisdictions. These offerings would offered to cover private and public businesses—not just (and possibly excluding) MUSH properties. This bonding construct has already been attempted for energy efficiency in private (non-MUSH) buildings in a few states. Green bonds for PV would likely be at rates lower than private lending rates because they would have recourse to public funds. For instance, these bonds could be issued as municipal general obligation bonds, which have recourse to the municipalities' other revenues and cash. Another option is an obligation charge bond (used in the past to fund environmentally beneficial power plant capital expenses like scrubbers), which would be funded through universal utility billing surcharges. State green bank loan guarantees for private loan issuances would also be covered under this CRO (albeit not necessarily "bonds").
- **Commercial PACE:** Commercial PACE programs provide loans for PV. The loans are paid back through property tax collections, thus they remain with the property and have enhanced credit owing to their senior position to most other liens including mortgages. This CRO is viable for commercial properties, where credit is often not strong and where owners possess shorter (about 5–7 years) investment horizons than third-party contract terms.
- **Undefined CRO(s):** As discussed in this report, other CROs presented were collectively insufficient to achieve the roadmap target. A single new, undefined CRO—or perhaps a collection of new CROs— likely will be necessary to meet the roadmap target.

Community Solar

- Community solar is generally financed through one of the third-party or utility-financing CROs. While community solar financing could be grouped within these other solution sets, it has unique investment risks, utility-value propositions and challenges, and policy treatment. Subscribers to community solar projects (usually built at a scale comparable to a medium-to-large commercial project) receive the net-metering benefits of solar as if a solar installation the size of their subscription was on their rooftop (hence, “virtual”).