Thank you for taking the time to complete the survey for The Solar Foundation's National Solar Jobs Census 2015. Your responses will help The Solar Foundation and its research partners, including the Solar Energy Industries Association (SEIA) provide an accurate assessment of the status of the solar industry workforce.

As a token of our appreciation, attached below is a copy of the U.S. Solar Market Insight 2014 Year in Review full report, published by SEIA and GTM Research. This issue sold for $3,995 when released in March 2015 and now it is yours free of charge. Please do not share this report or any links to the report with anyone outside your company.

SEIA and GTM Research release new U.S. Solar Market Insight reports every quarter with the best information available on national and state activity in the U.S. solar energy industry. An executive summary of the report is available for free, while Full Report versions are discounted extensively for SEIA members.

If you are not already a member of SEIA, please visit http://www.seia.org/membership, email membership@seia.org or call (202) 556-2907 to learn more about how joining SEIA can help your solar business grow.

Best Regards,

Justin Baca
Senior Director of Research
Solar Energy Industries Association

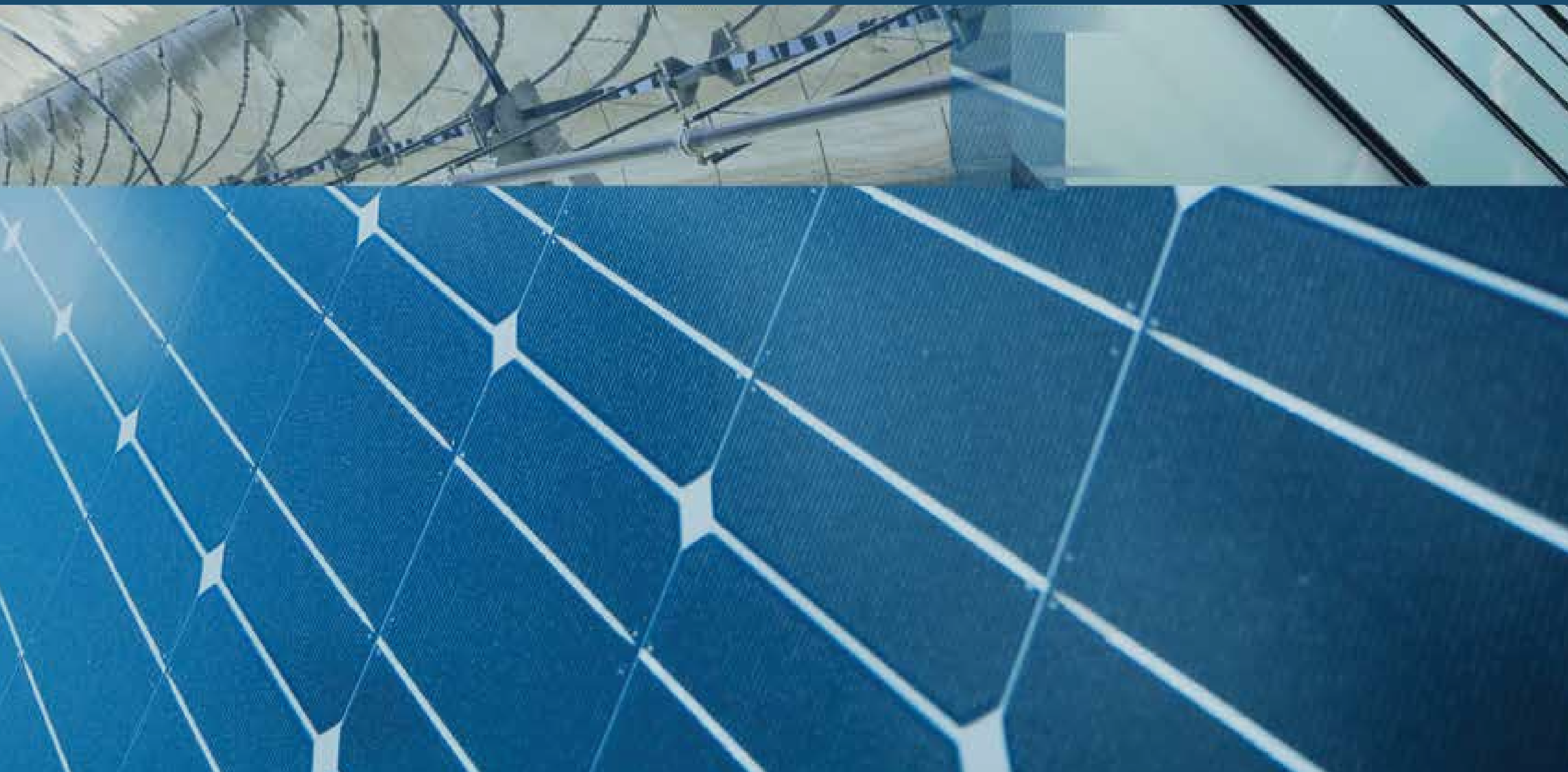
Andrea Luecke
President and Executive Director
The Solar Foundation

Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1
Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4

GTM RESEARCH
A Greentech Media Company

40 YEARS SEIA Solar Energy Industries Association®

U.S. SOLAR MARKET INSIGHT REPORT | 2014 YEAR IN REVIEW | FULL REPORT



Contents

About the Authors

GTM Research

Cory Honeyman, Solar Analyst
Shayle Kann, Senior Vice President
Leandra Cooper, Research Associate
Nicole Litvak, Solar Analyst
MJ Shiao, Director of Solar Research
Jade Jones, Solar Analyst

SEIA

Tom Kimbis, Vice President of Executive Affairs
Justin Baca, Director of Research
Shawn Rumery, Research Manager
Aaron Holm, Research Analyst

License

Ownership Rights

This report ("Report") and all *Solar Market Insight* ("SMI") reports are jointly owned by Greentech Media and the Solar Energy Industries Association, Inc. (jointly, "Owners") and are protected by United States copyright and trademark laws and international copyright/intellectual property laws under applicable treaties and/or conventions. Purchaser of Report or other person obtaining a copy legally ("User") agrees not to export Report into a country that does not have copyright/intellectual property laws that will protect rights of Owners therein.

Grant of License Rights

Owners hereby grant User a personal, non-exclusive, non-refundable, non-transferable license to use Report for research purposes only pursuant to the terms and conditions of this license. User agrees not to permit any unauthorized use, reproduction, distribution, publication or electronic transmission of any report or the information/forecasts therein without the express written permission of either Owner. User purchasing this report may make a report available to other persons from his organization at the specific physical site covered by the terms of sale, but are prohibited from distributing the report to people outside the organization, or to persons whose principle work location is a different geographic site within the organization.

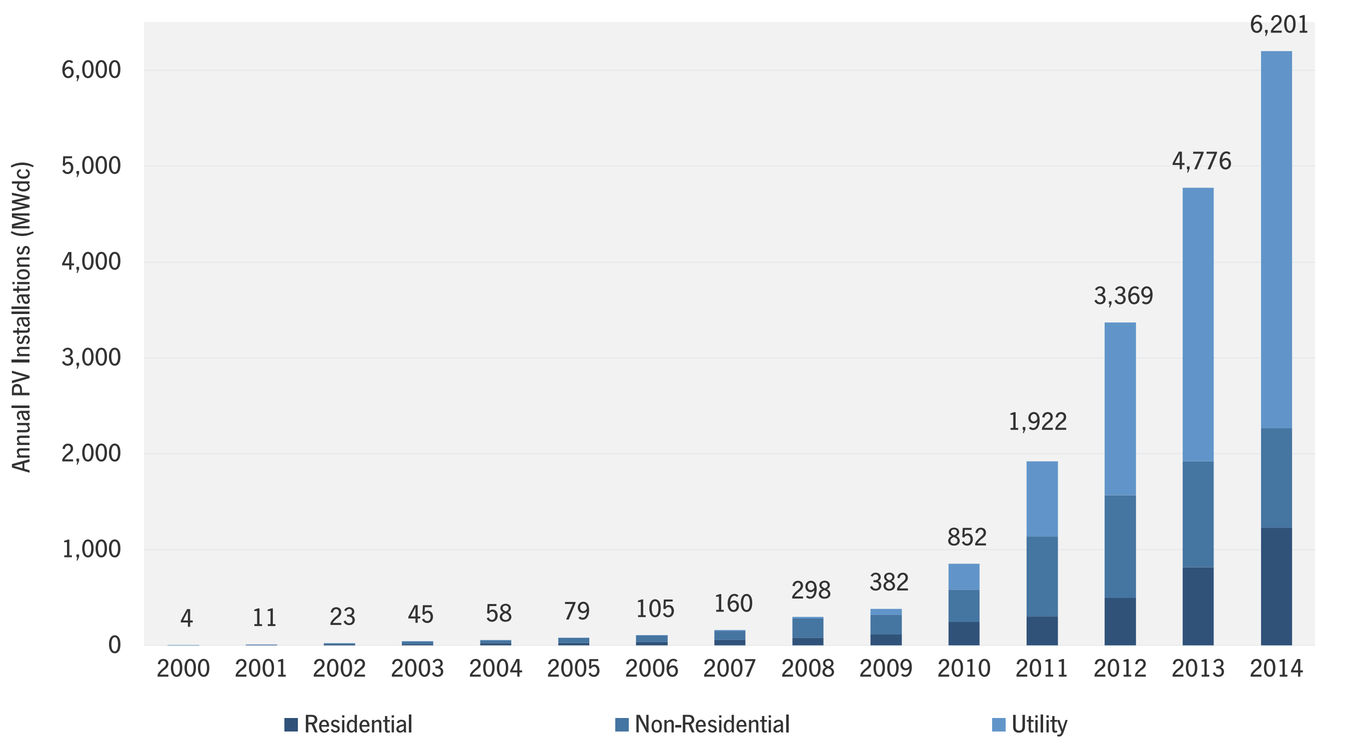
Disclaimer of Warranty and Liability

Owners have used best efforts in collecting and preparing each report. Owners, their employees, affiliates, agents, and licensors do not warrant the accuracy, completeness, correctness, non-infringement, merchantability, or fitness for a particular purpose of Report. Owners, their employees, affiliates, agents, or licensors shall not be liable to user or any third party for losses or injury caused in whole or part by our negligence or contingencies beyond Owners' control in compiling, preparing or disseminating Report or for any decision made or action taken by User or any third party in reliance on such information or for any consequential, special, indirect or similar damages, even if one or more Owners were advised of the possibility of the same. User agrees that the liability of Owners, their employees, affiliates, agents and licensors, if any, arising out of any kind of legal claim (whether in contract, tort or otherwise) in connection with its goods/services under this license and sales shall not exceed the amount User paid to Owners for use of Report.

1. Introduction

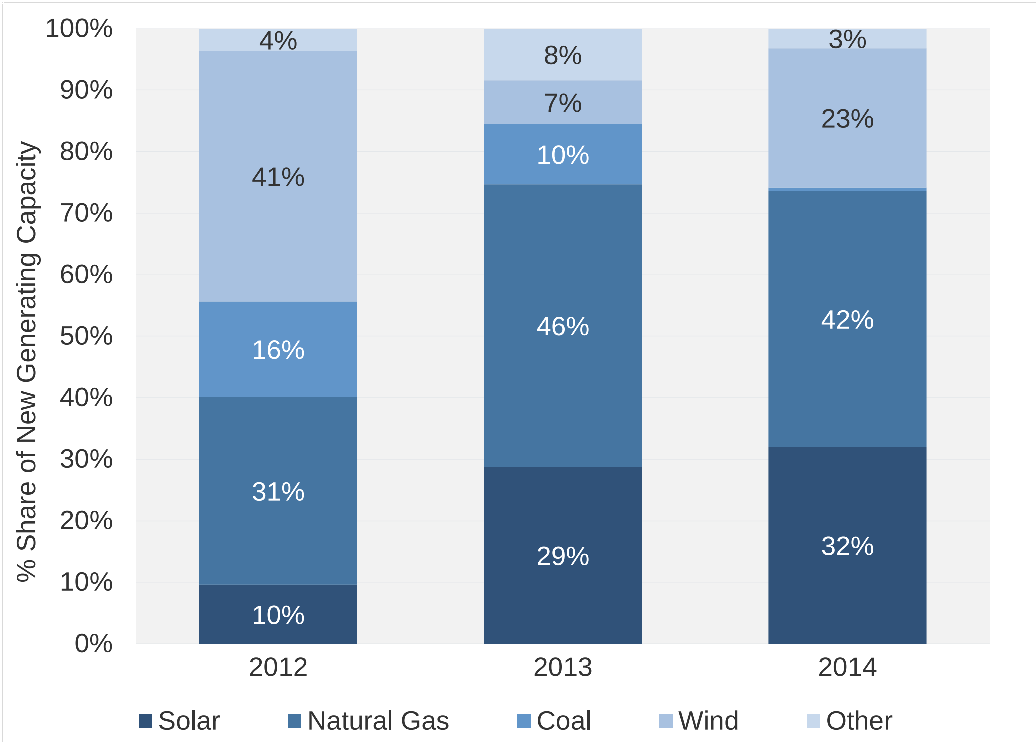
Solar energy posted another banner year in the U.S. in 2014. Photovoltaic (PV) installations reached 6,201 MW_{dc}, up 30% over 2013 and more than 12 times the amount installed five years earlier. By the end of the year, a cumulative total of 18.3 GW_{dc} of solar PV and another 2.2 GW_{ac} of concentrating solar power were operating in the U.S. Over 600,000 homes and businesses now have on-site solar (nearly 200,000 of these installations were completed in 2014), and six states are home to more than 500 MW_{dc} of operating solar capacity.

Figure 1.1 Annual U.S. Solar PV Installations, 2000-2014



As solar has grown in the U.S. over the past few years, so has its share of total new electricity generation capacity. In 2014, solar accounted for 32% of new generating capacity in the U.S., second only to natural gas and up from 29% in 2013.

Figure 1.2 New U.S. Electric Generating Capacity Additions, 2012-2014



Source: GTM Research, FERC

Note: SMI data used for solar and PV installation figures converted from DC to AC for apples-to-apples comparison. FERC data used for all other technologies.

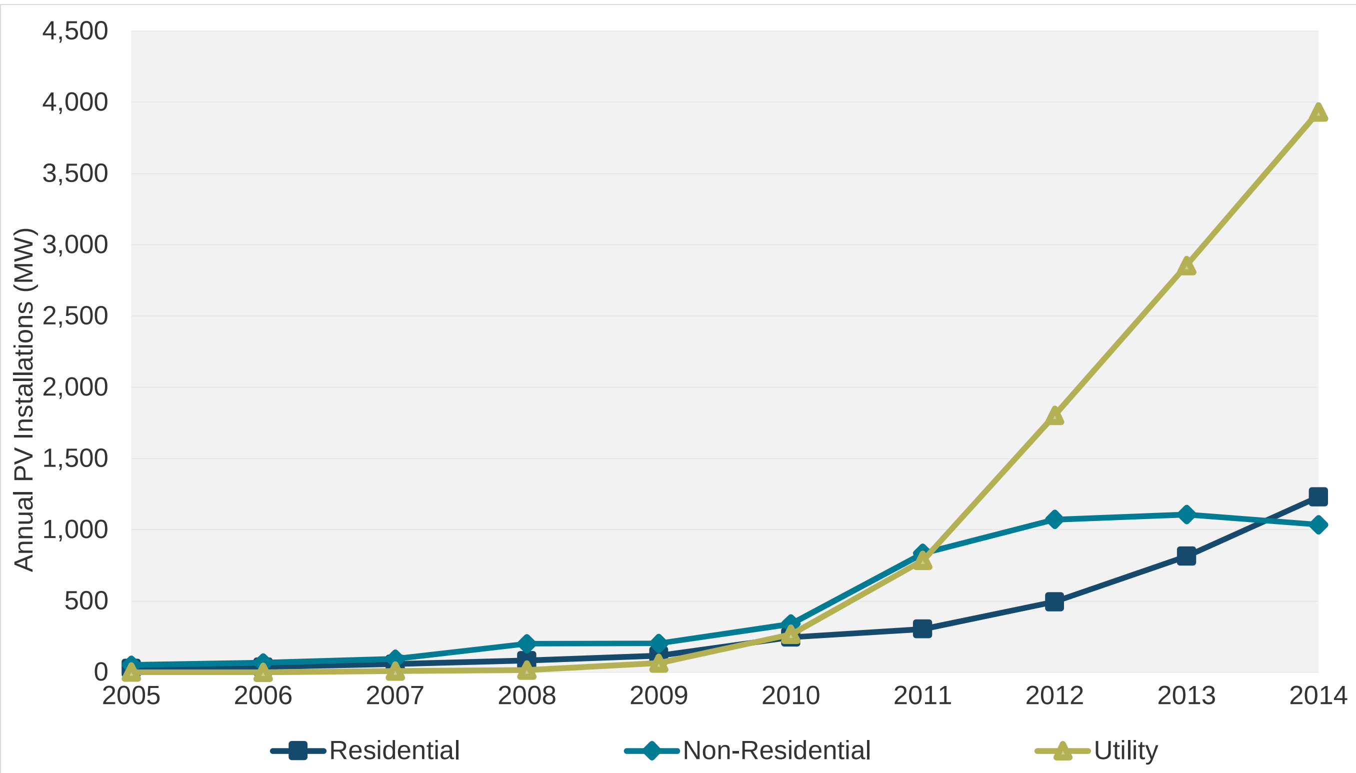
Three fundamental drivers have contributed to solar's continued growth streak in the U.S.

1. Falling prices: The cost of solar continues to fall across segments and states. While PV module prices remained relatively flat in 2014, balance-of-systems (BOS) prices fell precipitously, leading to an average 10% annual decline in system prices, depending on the market segment. In many states, solar is just on the cusp of economic feasibility, so each incremental decline in prices opens up new potential customers and makes solar more competitive with the alternative, whether that's retail electricity or a combined-cycle natural gas plant.
2. Downstream innovation and expansion: As the cost of solar has fallen, solar companies have created new, better ways to make solar available and attractive to customers. In the residential market, the advent of financial solutions including PPAs, leases and increasingly solar-optimized loans has opened up a wide swath of demand that previously did not exist. In the commercial market, developers sell multi-site portfolios to retailers, standardize their contracts so as to streamline financing, and now offer energy storage as an add-on to maximize solar's benefits. And in the utility-scale market,

developers have sought procurement mechanisms outside utility regulatory or legislative requirements, resulting in over 4 GW_{dc} of new PPAs signed through nontraditional means over the past 12 months.

3. Stable policy and regulation: Despite an increasing number of proceedings on solar and electricity rate structures, the regulatory and policy environment for solar in the U.S. has generally been stable for the past few years. At the federal level, the industry has benefitted from a continued 30% federal Investment Tax Credit (more on that to follow), and most state policies have been clear and visible. As a result, players in the market have been able to plan strategically and chart a clear course for expansion.

Figure 1.3 U.S. PV Installations by Segment, 2005-2014



Without question, 2015 will be another growth year for U.S. solar. But a number of factors will dictate the course and trajectory of growth. Some key themes to watch in 2015:

- The residential solar boom continues, but rate structure revisions threaten growth. Home solar has been the biggest growth story of the past three years, posting annual growth rates over 50% in 2012, 2013 and 2014. But as we detail in this report, there are more than 20 ongoing proceedings that could impact residential solar's value proposition through either changes to net energy metering or electricity rate structures. 2015 will be the year in which some of the most prominent proceedings (most notably California's AB 327) start to see resolution, while new debates will undoubtedly emerge.
- Commercial solar is seeking a comeback. While residential solar has soared in the U.S., commercial solar has stagnated. In 2014, just over 1,000 MW_{dc} of commercial solar were installed, down 6% from

2013 and even down 3% from 2012. Many factors have contributed to this trend, ranging from tight economics to difficulty financing small commercial installations. But 2015 will be a telling year for the commercial market. Many participants expect a pickup in demand in key states including California, New Jersey and New York, which, if it comes to pass, could reignite the sector and bring it back on pace with the residential market.

- The enormous utility-scale solar pipeline comes to fruition. There are just over 14 GW_{dc} of utility-scale solar projects in the U.S. with power-purchase agreements in place and expected completion dates of 2015 or 2016. The next two years will see a flurry of project completion announcements and unprecedented installation figures from the utility solar sector. There is no question that this segment will remain by far the largest in terms of annual capacity additions through 2016, but its fate after the 2017 ITC expiration remains in doubt.

The U.S. solar market remains highly concentrated in a relatively small number of key states. While the top 10 states accounted for 90% of the overall market, many states saw growth. In fact, 24 of the 32 states we track grew on a year-over-year basis in 2014.

Figure 1.4 State Solar PV Installation Rankings, 2012-2014

	Rank			Installations (MW_{dc})		
State	2012	2013	2014	2012	2013	2014
California	1	1	1	1,046	2,621	3,549
North Carolina	6	3	2	124	335	397
Nevada	4	12	3	198	47	339
Massachusetts	5	4	4	134	240	308
Arizona	2	2	5	719	421	247
New Jersey	3	5	6	419	236	240
New York	10	9	7	63	72	147
Texas	12	8	8	51	75	129
Hawaii	7	6	9	109	144	107
New Mexico	18	13	10	24	45	88
Missouri	23	17	11	7	28	73
Maryland	8	16	12	79	29	73
Colorado	9	10	13	76	56	67
Indiana	31	11	14	-	54	59
Tennessee	14	19	15	27	25	56
Georgia	22	7	16	11	91	45
Connecticut	21	15	17	11	37	45
Vermont	20	21	18	12	16	38
Florida	17	18	19	24	26	22
Ohio	16	20	20	25	21	15
Washington	25	23	21	4	9	14

	Rank			Installations (MW_{dc})		
State	**2012**	**2013**	**2014**	**2012**	**2013**	**2014**
Utah	29	29	22	1	2.4	10
Pennsylvania	11	14	23	54	38	10
Oregon	15	24	24	27	7	8
Delaware	19	22	25	18	9	7
Illinois	13	32	26	30	1.5	6
Minnesota	24	25	27	4	6	6
Virginia	31	26	28	-	6	6
New Hampshire	26	31	29	2	2.0	3
Washington, D.C.	27	30	30	1	2.1	3
Wisconsin	28	28	31	1	3	2
South Carolina	30	27	32	0	4	1

1.1. In Focus: ITC Expiration

The 30% solar Investment Tax Credit (ITC), which has underpinned the economics of virtually every U.S. solar installation to date, is scheduled to expire on December 31, 2016. Under current rules, at that point the commercial ITC (Section 48) will drop to 10%, while the residential ITC (Section 25D) will drop to zero. It is also important to note that third-party-owned residential solar utilizes the commercial Section 48 credit.

Barring an early extension, much of the U.S. solar industry will spend the next two years focused on this issue. SEIA and solar companies will dedicate their resources toward extension, while business planning groups will seek to determine the impact of non-extension.

The GTM Research forecast, which assumes no extension, suggests a 57% annual reduction in installation capacity, from 11.8 GW in 2016 to 5.1 GW in 2017. This would be the first down year in more than two decades for U.S. solar.

Within this 2017 forecast, two independent forces are at play, one in the distributed (residential plus non-residential) sector and one in the utility solar market.

1.1.1. Distributed Solar

At the national level, GTM Research forecasts that the distributed solar market will fall 20% in 2017. This represents a smaller decline than will be seen in the utility market, implying that distributed solar will be more resilient in the face of ITC reduction. Indeed, GTM Research does anticipate that some homeowners and businesses will still find it economically attractive to install solar in 2017 with a 0% or 10% ITC, depending on the structure. However, the biggest impact of ITC reduction in the distributed solar market will be the reversal of geographic diversification.

Based on GTM Research analysis, by 2016 there could be 16 states in the U.S. which have surpassed retail "grid parity" in the residential solar sector – even taking into account current rate structures and ignoring state-level incentives. But if the ITC is removed in 2017, even with continued system price reductions, that number falls to eight. In other words, this year and next year (2015 and 2016) will see the emergence of a new group of state solar markets that have been essentially dormant in the past, but ITC expiration will largely eliminate that progress and the market will contract, focusing only on states with particularly attractive solar economics.

The second impact that this geographic contraction will have is to place further importance on state-level policies and regulations. Even in bedrock state markets such as California, solar economics will tighten significantly in a post-30% ITC era. As a result, changes to net energy metering, electricity rate structures, and incentive programs will have an outsized influence on the viability of these markets. As such, it will be increasingly important to monitor these proceedings in key states in order to predict the impact of ITC expiration.

1.1.2. Utility Solar

Without an ITC extension, the utility solar market will see a far more drastic impact in 2017. GTM Research forecasts 1,082 MW of utility solar PV to be installed that year, down 84% from 2016. The impacts of the impending ITC expiration are already being felt in the utility solar market; developers are rushing to complete projects in 2016, sometimes even when their power-purchase agreement begins in 2017 or later, and virtually no PPAs are being signed with the expectation of operations commencing in 2017.

The reason for this precipitous decline is straightforward: utility solar projects operate under slim margins, and the ITC expiration will push many projects that would have been feasible into the red. Initially, the utility solar market was largely built on projects that were procured in order for utilities to comply with state renewable portfolio standards (RPS), particularly in the Southwest. As these utilities began to fulfill their requirements and procurement slowed, utility-scale solar began to achieve cost-competitiveness in some states without these requirements in place. This has resulted in a new wave of procurement, with over 4 GW of contracts signed since 2013 outside of RPS requirements. This opportunity has reinvigorated the utility solar market, but it relies on highly competitive PPA pricing (often in the range of $0.05/kWh-$0.06/kWh), which will scarcely be available in a post-ITC world.

2. Photovoltaics

2.1. Residential PV

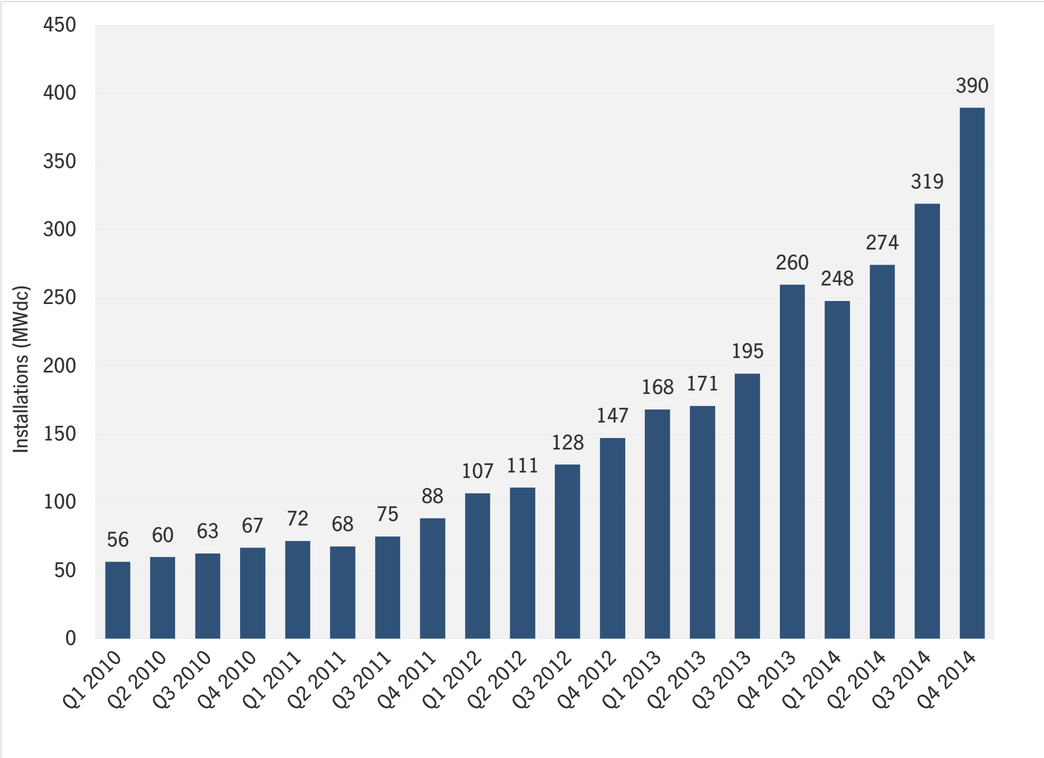
2.1.1. National Installations

Key figures:

- 390 MW_{dc} installed in Q4 2014, up 22% over Q3 2014 and 50% over Q4 2013
- 1,231 MW_{dc} installed in 2014, representing 51% annual growth over 2013

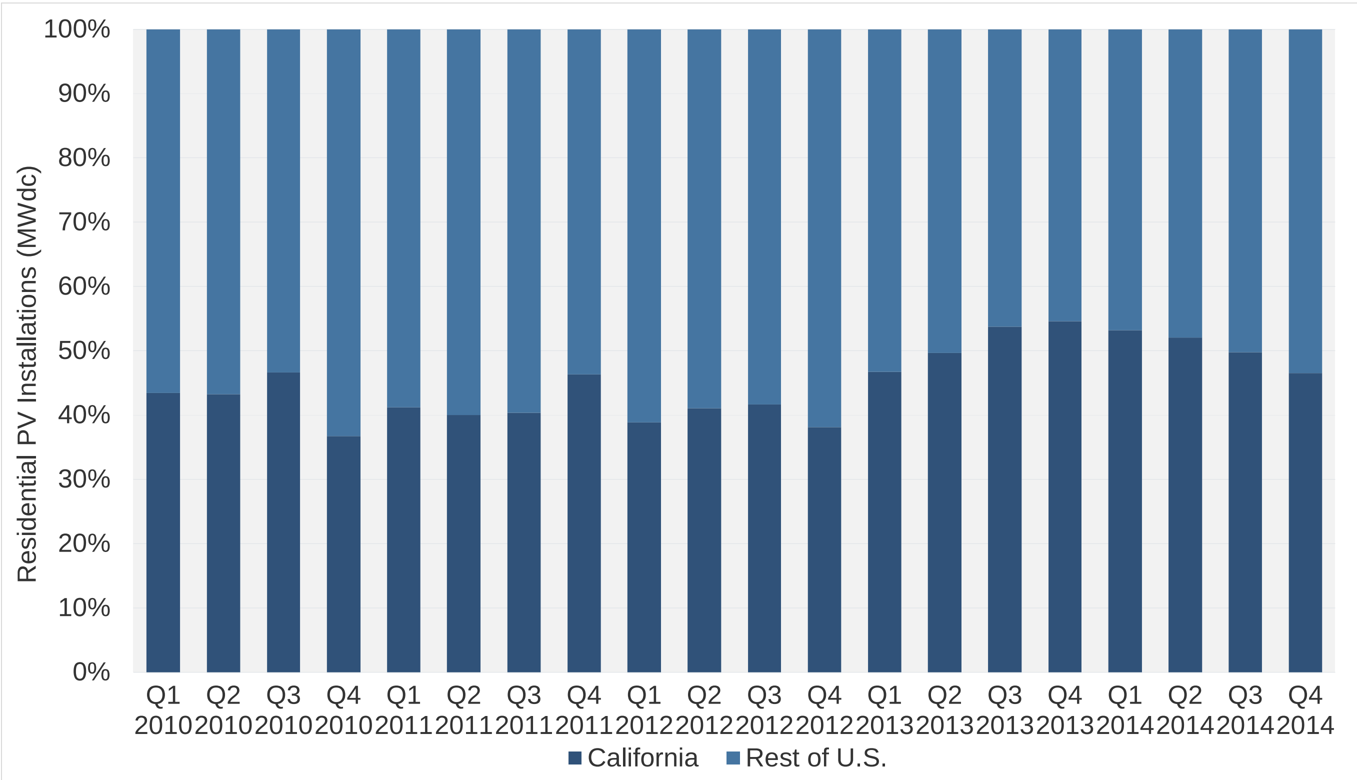
2014 marked the third consecutive year of greater than 50% annual growth in the residential solar market, with over 186,000 individual installations completed during the year.

Figure 2.1 Residential PV Installations, Q1 2010-Q4 2014



While California remains by far the dominant source of residential solar demand, Q4 2014 was the first quarter since early 2013 during which more than half of all residential solar in the U.S. came from other states. This has been a slow but consistent trend throughout 2014, with states such as Massachusetts, New York, Maryland and others growing even faster than California.

Figure 2.2 Residential PV Installations in California vs. Rest of U.S., Q1 2010-Q4 2014



	2010				2011				2012				2013				2014			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
CA	43%	43%	47%	37%	41%	40%	40%	46%	39%	41%	42%	38%	47%	50%	54%	55%	53%	52%	50%	47%
Rest of U.S.	57%	57%	53%	63%	59%	60%	60%	54%	61%	59%	58%	62%	53%	50%	46%	45%	47%	48%	50%	53%

2.1.2. Quarterly Installations by State

Figure 2.3 Quarterly Residential PV Installations by State (MW_{dc}), 2012-2014

State	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4
Arizona	13.8	13.8	16.3	18.2	16.6	15.2	16.9	24.0	23.0	19.1	22.2	29.9
California	41.5	45.5	53.2	56.1	78.6	84.9	104.6	141.8	131.9	142.8	158.8	181.3
Colorado	3.2	3.3	5.1	6.1	8.3	6.7	5.5	7.7	10.5	9.2	9.2	12.9
Connecticut	1.2	0.6	1.9	2.6	1.7	2.0	2.2	1.4	1.4	2.7	6.4	6.1
Delaware	0.3	0.4	0.3	0.2	0.2	0.2	0.5	0.3	0.6	0.6	0.4	0.6
Florida	1.5	1.6	1.2	1.2	2.7	1.7	1.4	1.6	3.1	1.9	2.2	2.5
Georgia	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.0	0.0	1.0	0.1	0.1
Hawaii	9.5	12.2	13.2	22.4	22.8	18.8	16.1	25.6	17.7	13.6	9.8	19.6
Illinois	0.1	0.3	0.1	0.2	0.1	0.2	0.1	0.2	0.1	0.1	0.2	0.3
Indiana	-	-	-	-	0.0	0.2	0.1	0.1	0.1	0.1	0.2	0.3
Louisiana	-	-	-	-	-	-	-	-	6.9	8.0	9.8	5.1
Maryland	1.9	3.1	1.8	1.2	0.4	3.4	2.9	2.6	4.7	7.7	10.1	17.1
Massachusetts	2.6	3.0	4.1	5.5	6.4	7.0	8.0	8.6	7.8	14.1	19.6	23.0
Minnesota	0.2	0.2	0.3	0.3		0.0	0.2	0.2	0.1	0.0	0.5	0.8
Missouri	0.2	0.2	0.9	1.4	2.5	2.9	4.4	4.6	4.8	7.2	6.5	1.9
Nevada	0.3	0.1	0.1	0.0	0.2	0.1	0.4	0.4	0.8	0.3	0.3	0.8
New Hampshire	-	-	-	-	0.2	0.3	0.4	0.3	0.3	0.4	0.8	0.9
New Jersey	12.5	10.7	10.0	9.8	11.1	11.3	6.2	9.2	11.6	12.8	17.4	18.8
New Mexico	1.1	1.1	1.0	1.0	0.9	0.7	1.1	1.6	1.2	1.2	1.3	1.5
New York	2.6	2.5	4.0	5.9	3.0	5.1	6.1	13.2	9.1	15.9	22.7	41.6
North Carolina	0.9	0.3	0.1	0.1	0.4	0.6	0.6	0.7	0.7	0.9	1.2	1.6
Ohio	0.2	0.3	0.2	0.3	0.2	0.5	0.5	1.3	0.1	0.2	0.5	0.4
Oregon	3.0	1.2	1.0	1.0	1.7	0.9	1.2	1.8	1.0	1.5	1.3	2.7
Pennsylvania	2.2	1.9	2.0	0.9	3.3	0.5	4.5	1.8	0.5	0.5	0.5	0.4
South Carolina	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.2
Tennessee	0.5	0.9	0.4	1.2	1.3	0.4	0.4	0.2	0.1	0.3	0.7	0.5
Texas	1.4	1.6	2.8	2.5	1.5	1.7	2.8	3.2	2.7	2.8	4.7	4.4
Utah	0.1	0.1	0.1	0.2	0.0	0.0	0.2	0.4	0.6	1.3	0.5	2.0
Vermont	0.5	0.1	0.6	0.5	0.9	1.0	0.9	1.8	1.8	1.0	1.5	2.1
Virginia	-	-	-	-	0.4	0.4	0.5	0.3	0.3	0.4	0.7	0.7
Washington	0.6	0.6	1.0	1.1	1.3	2.4	2.0	2.1	1.8	2.7	3.6	3.9
Washington, D.C.	0.2	0.2	0.4	0.5	0.0	0.1	0.7	0.5	0.6	0.4	0.5	0.4
Wisconsin		0.0	0.0	0.3	0.2	0.1	0.3	0.4	0.1	0.2	0.4	0.6
Other	4.6	4.8	5.5	6.2	1.2	1.7	2.8	2.1	1.9	3.5	4.2	4.5
Total	107	111	128	147	168	171	195	260	248	274	319	390

2.1.3. Residential Market Trends

Trends in Third-Party Ownership

Figure 2.4 Percentage of New Residential Installations Owned by a Third Party in CA, AZ, CO, and NJ, Q1 2011-Q4 2014

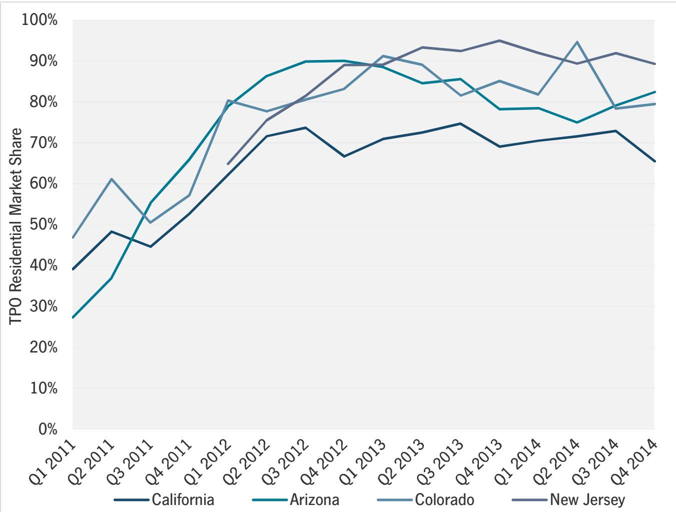
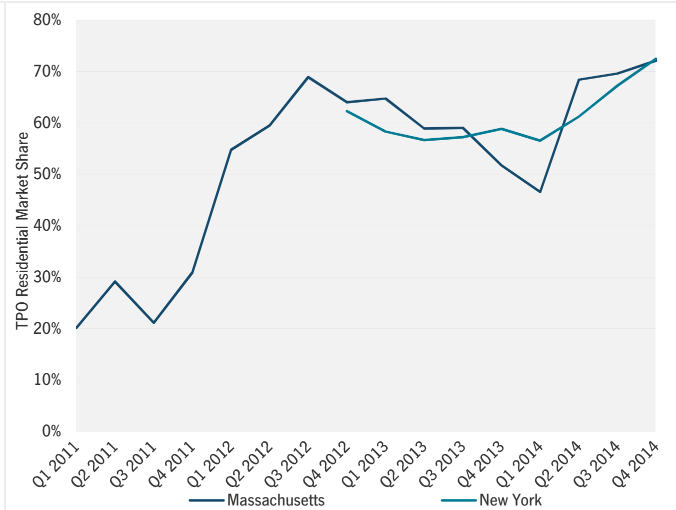


Figure 2.5 Percentage of New Residential Installations Owned by a Third Party in MA and NY, Q1 2011-Q4 2014



	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
CA	62%	72%	74%	67%	71%	73%	75%	69%	71%	72%	73%	65%
AZ	79%	86%	90%	90%	89%	85%	86%	78%	78%	75%	79%	82%
CO	80%	78%	81%	83%	91%	89%	82%	85%	82%	95%	78%	79%
MA	55%	59%	69%	64%	65%	59%	59%	52%	47%	68%	70%	72%
NJ	65%	75%	81%	89%	89%	93%	92%	95%	92%	89%	92%	89%
NY	-	-	-	62%	58%	57%	57%	59%	57%	61%	67%	72%

In most mature state markets, third-party-owned (TPO) residential PV systems continue to be an attractive option for many homeowners. However, Arizona, California, and Colorado have all experienced a leveling-off and even a slight decline in TPO market share (with the exception of a temporary spike in Colorado in Q2) over the past year, as 1) an increasing number of installers have partnered with national and regional banks to provide loans and 2) the cost of solar has fallen enough that more customers can afford to pay in cash. New Jersey also continues to see a consistently high share of third-party-owned systems. Aside from the strong presence of national players in New Jersey that primarily offer TPO solar, the volatility of SREC prices may have contributed to this trend, since consumers often prefer to avoid SREC price risk.

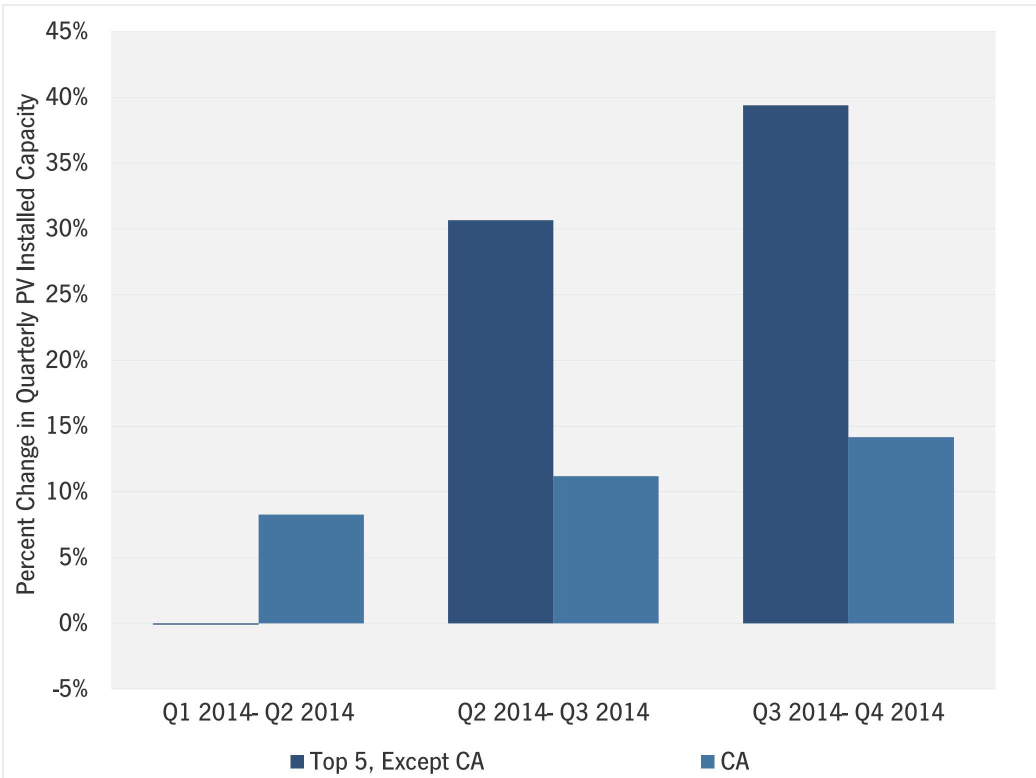
Massachusetts and New York historically have had lower shares of third-party-owned systems than other leading state markets. Some installers attribute this to a more educated and wealthier consumer base that prefers to spend money upfront in order to secure better returns in the long run. However, both of these states have experienced an uptick in third-party ownership over the past year as leading national solar providers who primarily sell leases and PPAs have grown much more quickly than have the local installers who would prefer to sell systems for cash.

The addressable residential market is still massive compared to the number of customers who have gone solar, leaving an enormous opportunity for growth, and no single strategy to deliver systems to residential rooftops has yet proven dominant. In the near term, we expect that TPO PV systems will continue to drive the residential market. Looking forward, however, cash and loan deals could play a larger role, especially as most national TPO providers have by now introduced loan products. On the regulatory and legislative front, select states and utilities have designed incentive programs and issued rules that aim to ramp direct-owned residential PV systems. For example, Xcel's Solar*Rewards rebate program in Colorado offers higher incentive rates for direct-owned systems than for TPO systems, Massachusetts launched a $30 million loan program in 2015 for residential solar, and in 2014, Arizona's Department of Revenue ruled that TPO systems are no longer exempt from property taxes. For these reasons, GTM Research expects the relative share of residential TPO systems to decline in 2015.

Geographic Distribution of Demand

Q4 2014 was the first quarter in over a year in which California represented less than half of all residential solar installations. Secondary markets were accelerating throughout the year, and the top five non-California states saw a growth rate of nearly 40% in the fourth quarter.

Figure 2.6 Quarterly Change in Installed Capacity Throughout 2014, Top 5 States



New York was the biggest growth story among residential solar markets in 2014. It was the first state other than California to eclipse 30 MW_{dc} of residential PV installed in a single quarter, bringing 41.5 MW_{dc} on-line—a 215% increase over Q4 2013. Massachusetts also made major strides in its residential market in the last year, experiencing over 100% growth. Arizona and Hawaii filled out the other states in the top five, knocking New Jersey off the list despite its steady growth throughout 2014.

Figure 2.7 Change in Q4 Installed PV Capacity, Top 5 States, by Rank, Q4'14

Top 5 Q4 2014	Change Between Q4 2013 and Q4 2014
CA	28%
NY	215%
AZ	25%
MA	168%
HI	-23%

The success of residential markets in these states has continued to depend on installers and customers finding attractive rate designs, decreasing reliance on state incentives, high levels of customer awareness, and strong referral bases to achieve scale.

Even beyond the top five states, the residential market continues to grow at an impressive clip. Q4 2014 more than tripled the national residential installed capacity of the same quarter two years earlier and grew a full 50% since Q4 2013.

The residential market remains heavily consolidated; over 90% of quarterly and annual residential installations are in the top 10 state markets. While the targeted approach has arguably helped the residential market to achieve over 50% growth year-over-year since 2010, eight of the top 10 states face pending or recently implemented reforms to net energy metering or residential rate design. As such, the residential market has become disproportionately exposed to regulatory risk.

Retail Rate Parity: Are We There Yet?

"Retail rate parity" is a term that has become increasingly popular of late—largely because of the growing number of states where residential solar projects are being installed with only net energy metering (NEM), the federal 30% Investment Tax Credit, and in the case of third-party-owned systems, accelerated depreciation.

Markets where utility or state incentives have come and gone, such as in California or Arizona, can provide valuable insight as to the ability of solar projects to pencil out once incentives are out of the picture.

Figure 2.8 California Residential Installations, Q4 2012-Q4 2014

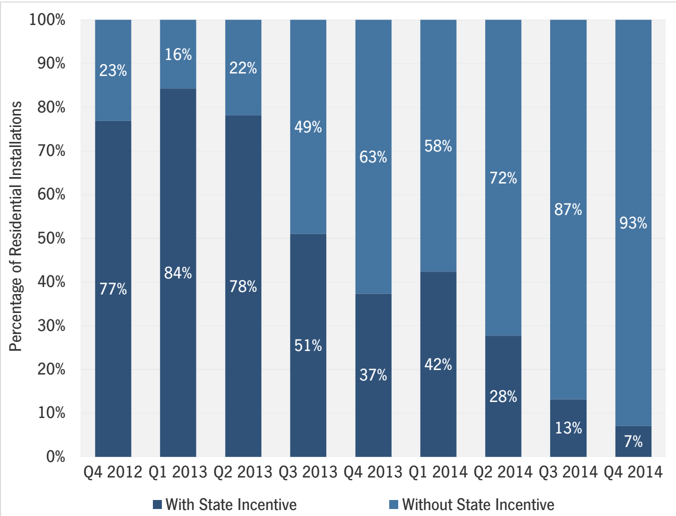
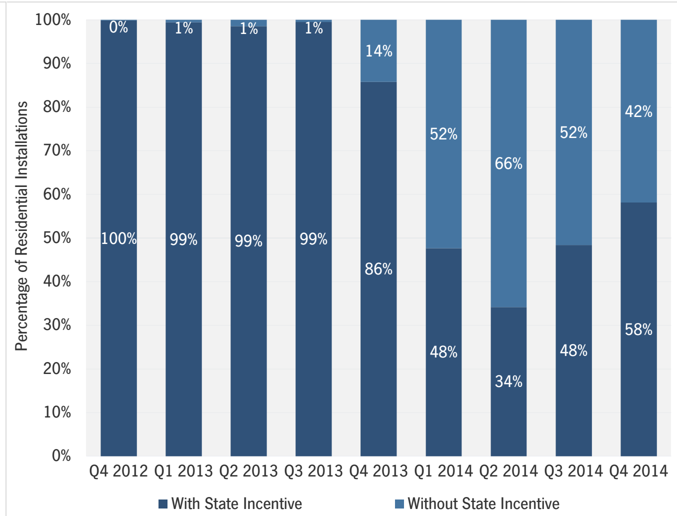


Figure 2.9 Arizona Residential Installations, Q4 2012-Q4 2014



In California, the residential incentives offered by the California Solar Initiative are now fully depleted in all three investor-owned utility service territories. Installation trends in PG&E's residential market serve as a particularly valuable litmus test of the health of California's residential market as a whole, since it was the first utility to deplete its CSI rebate funding. As evidence of PG&E's market attractiveness without state incentives during 2014, PG&E added more residential installations than any individual state market across the U.S., and 93% of these installations did not have financial support from state incentives.

Meanwhile, Arizona has become the next major state market to see meaningful residential installation growth without state incentives following the depletion of upfront residential rebates in APS territory in September 2013 and incentive reductions across other utilities within the state. In Q4 2014, nearly half of Arizona's residential installations came on-line without a state incentive.

Collectively, the number of residential installations that came on-line in CA and AZ without state incentives in Q4 2014 surpassed the entire size of the national residential market in Q4 2012.

Unlike California and Arizona, where retail rate parity began to be achieved as rebates neared depletion, some state markets with incentive programs, including New York, Maryland, and smaller state markets such as Nevada, have a minor but growing share of installations coming on-line without the support of state incentives. This trend has been driven largely by installers that forgo rebates in order to execute aggressive growth plans, and it further demonstrates that some projects can pencil out without incentives, even when incentives are available.

2.1.4. Updates to Proposed Net Metering and Rate Structure Reforms

Where are net metering and rate design reforms being implemented or proposed in 2015?

Net energy metering (NEM) at the full retail rate has long served as the primary approach employed to compensate homeowners for excess energy exports. However, as residential solar adoption rates grow, many utilities have begun to consider, propose and implement reforms to this approach.

Through February 2015, 21 states have considered, approved, or implemented various reforms to NEM and/or electricity rate design across markets where residential solar has reached a wide range of customer penetration levels. The most recent notable update comes from South Carolina, where the utilities reached an agreement with solar industry stakeholders to ensure the availability of net metering at the full retail rate for the next decade, and also to guarantee that no fixed or other fees specifically for DG customers would be proposed until 2021 or later.

Across the country, approved and proposed reforms can be broken down into the following categories:

- Value-of-solar tariff (VOST) in lieu of NEM at the full retail rate
- Increase to aggregate NEM capacity limits
- Lower value of NEM from the retail to a lower wholesale avoided-cost rate
- Introduce a monthly minimum bill for all customers
- Introduce a peak demand charge for distributed generation customers
- Introduce fixed monthly fees for distributed generation customers
- Increase fixed monthly fees for all residential customers

Figure 2.10 Proposed Net Metering and Solar-Relevant Rate Design Reforms as of February 2015

State	Type of NEM/Rate Reform	Key Details	Decision
AZ (APS)	**New DG Fixed Charge**	Monthly NEM fee: $0.70/kW/month	**In Effect:** $0.70/kW/month
AZ (SRP)	**New DG Fixed, DG Peak Demand Charges, and Lower DG Consumption Rate**	Fixed Charge: Approximately $12.50/month; Peak demand charge ranging from approximately $30 to $90/month; Lower consumption rate from 10 cents/kWh to 4 cents/kWh	**Approved** **Note 1:** Customer-wide fixed charge will be increased by $1.50 in 2015 and another $1.50 in 2016 **Note 2:** Demand charge calculation will be based on a 30-minute period, rather than 15-minute period, during peak hours in each month. This revised rule should result in lower demand charges than the originally expected range of costs.
	Customer-Wide Fixed Charge Hike	Increase fixed charge from $17 to $20	
	Other	Grandfathering in existing customers, plus those with interconnection applications submitted by December 8, 2014, under current NEM program and rate structure for 20 years from installation date	
AR	**Lower Value of NEM**	Roll back NEM retail to wholesale rate	**Pending**
CA	**Other**	Grandfathering in existing customers under current NEM program for 20 years from installation date	**Approved:** Grandfathering periods become relevant upon expiration of current NEM program
CT	**Customer-Wide Fixed Charge Hike**	The Public Utilities Regulatory Authority approved a fixed charge hike that jumped $16 to $19.25/month	**Approved**
ID	**New DG Fixed Charge**	Increase fixed charge from $5 to $21	**Rejected:** PUC decided that reforms should be reintroduced in a general rate case
GA	**New DG Fixed Charge**	Introduce fixed charge of $22/month	**Rejected**
HI	**Customer-Wide Fixed Charge Hike; New DG Fixed Charge; Lower Value of NEM**	Introduce fixed charge for all homeowners, additional fixed charge for DG, and replace NEM at the full retail rate with a feed-in tariff	**Pending**
IN	**Customer-Wide Fixed Charge Hike**	Increase fixed charge from $11 to $17/month for all homeowners	**Pending**
KY	**Customer-Wide Fixed Charge Hike**	Increase fixed charge from $10.75 to $18/month for Kentucky Utilities and Louisville Gas and Electric; increased fixed charge from $8 to $16 for Kentucky Power	**Pending**
KS	**Lower Value of NEM**	Lower eligible system sizes for NEM, roll back NEM from retail to wholesale rate	**Approved**
LA	**Lower Value of NEM; VOST**	Roll back NEM from full retail rate and introduce a VOST (note that current residential rate structures in Louisiana have relatively low volumetric charges)	**Rejected:** Roll back value of NEM **Pending:** VOST study
MA	**Minimum Bill; Lower Value of (Virtual) NEM**	Remove NEM cap, introduce minimum bill, lower value for virtual NEM systems, and replace SRECs with fixed PBI	**Rejected:** NEM caps were increased as part of stopgap legislation
MD	**Customer-Wide Fixed Charge Hike**	Increase fixed charge for residential and commercial customers	**Pending**
ME	**VOST**	Introduction of VOST; PUC must develop methodology by February 15, 2015	**Pending**
MN	**VOST**	Introduction of a VOST that cannot be lower than NEM for first three years it is in effect	Methodology is **approved:** Xcel has refrained from submitting a VOST value to date

State	Type of NEM/Rate Reform	Key Details	Decision
MO	**Customer-Wide Fixed Charge Hike**	Increase fixed charge for residential and commercial customers, proposed in August and October 2014	**Pending**
MT	**Other**	Establish virtual and aggregate NEM and increase the eligible system size for NEM from 50 kW to 1 MW	**Pending**
NC	**Lower Value of NEM**	Roll back NEM from retail to wholesale rate	**Pending**
NY	**Other**	Aggregate NEM capacity limit was raised from 3% to 6%	**Approved**
OK	**New DG Fixed Charge**	New monthly NEM fee	**Approved**
SC	**Other**	SCE&G and Duke Energy signed an agreement that guarantees NEM at the full retail rate until 2021; in February 2015, SCE&G proposed an optional feed-in tariff program as an alternative option to NEM	**Approved:** NEM settlement **Pending:** SCE&G's Optional FIT
SD	**New DG Peak Demand Charge**	All residential customers with PV installed from October 2014 onward would pay a demand charge $9.75/kW	**Withdrawn**
TX	**VOST and Other**	Austin Energy: VOST reduction in 2014 CPS: Introduce a competitive bid program in which PPA rates are negotiated between installers and utilities; NEM at the full retail rate will be available through at least 2015	**Approved:** Availability of NEM program beyond 2015 remains to be determined
UT	**New DG Fixed Charge**	NEM fee of $4.25/month	**Rejected**
VT	**Other**	Increase aggregated NEM capacity limit from 4% to 15% of peak load	**Approved**
VA	**Other**	Allow virtual NEM	**Rejected**
WA	**Customer-Wide Fixed Charge**	Pacific Power and Light: Increase fixed charge from $7.75 to $14/month	**Pending**
WI	**Customer-Wide Fixed Charge; DG Fixed Charge**	WE Energies: Increase customer-wide fixed charge from $9 to $16/month; introduce DG fixed charge of $3.80/kW/month Madison Gas & Electric**:** Increase customer-wide fixed charge from $10.50 to $19/month	**WE Energies: Approved** by PUC, but pending lawsuit launched by solar industry advocacy groups **Madison Gas & Electric: Approved**

California's investor-owned utilities collectively rank as the largest residential state market and are poised to implement the most comprehensive reforms to NEM and rate design. To date, the California Public Utilities Commission (CPUC) has only determined *when* a second, uncapped NEM program will take effect and that preexisting customers will be grandfathered in under the current NEM structure for 20 years from their systems' installation dates.

The following data table provides an overview of the major reforms to NEM and rate design that the key bill, AB 327, authorizes the CPUC to implement.

Figure 2.11 AB 327 Update: New Proposals Shed Light on Future Net Metering and Rate Design Scenarios

Legislation Item	AB 327 Language	Relevant Updates or Proposals
Fixed Charges	Up to $10/month	CPUC Staff, SCE, and PG&E: Phase-in approach of $5/month to $10/month by 2018 (annual increases post-2015 to align with inflation)
Rate Design	Tiered electricity rates could be flattened from four to as few as two	CPUC staff, SCE, and PG&E: Gradual reduction to two tiers between 2014 and 2018 with rate differential narrowing to 20% between Tier 1 and Tier 2 in 2018
Expiration of Current NEM Program	The earlier date of July 1, 2017 or when each utility hits a predefined capacity cap	Aggregate cap limits: 5% of non-coincident peak demand
Grandfathering In Customers Under the Current NEM	After the current NEM program expires, preexisting NEM customers will be grandfathered in under the current scheme for a "length of time determined by the commission." This length of time will depend on a "reasonable expected payback period" of the PV system based on the year it came on-line.	CPUC's decision: 20 years
New Uncapped NEM Program Upon Current NEM's Expiration	Setting in place a process through which the CPUC will introduce a new, uncapped NEM program to take effect when the current one expires	CPUC must develop a new NEM structure by the end of 2015

Outside California, Hawaii continues to test the valuation and management of distributed generation with the highest solar penetration levels in the country. In August 2014, HECO issued a comprehensive DG Interconnection Plan, which included the proposed revisions to NEM and rate design shown in the following figure, which would take effect in the beginning of 2017.

Figure 2.12 Hawaii Update: HECO's Proposed NEM/Rate Reforms as Part of DG Interconnection Plan

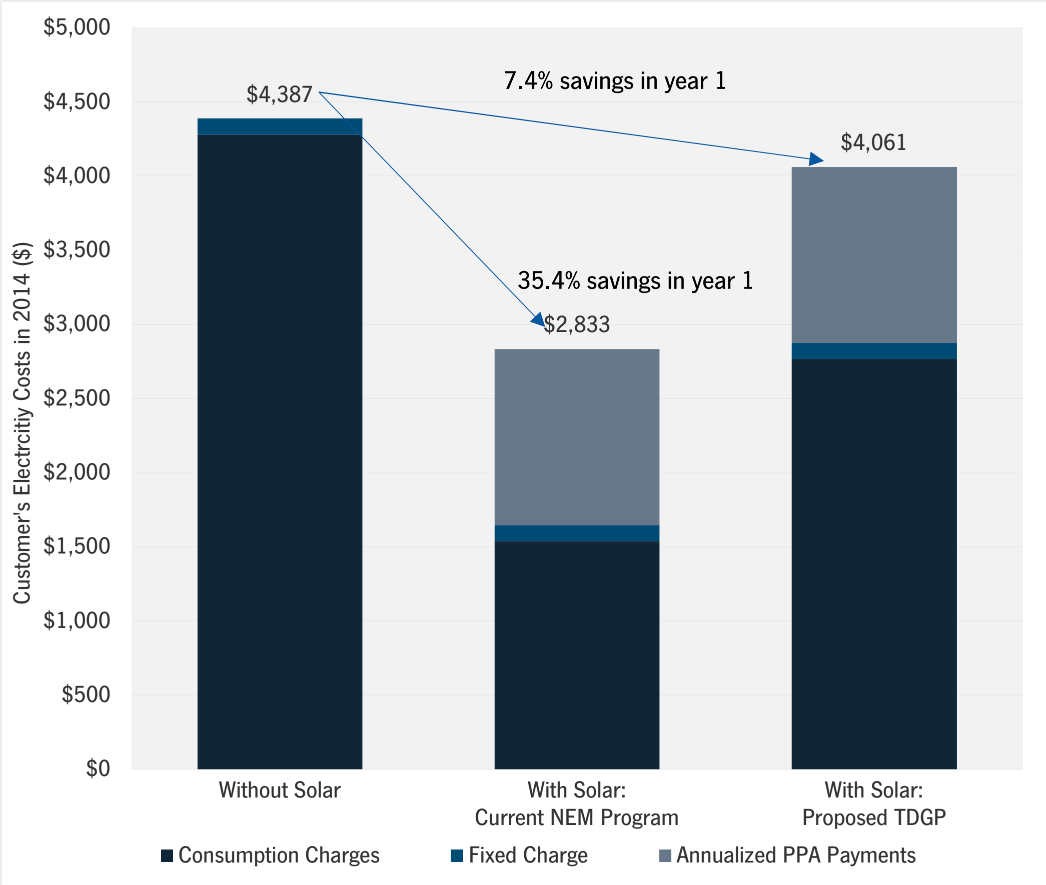
Reform Item	HECO	HELCO	MECO
Monthly Fixed Charges (All Homeowners)	$55	$61	$50
Additional Monthly Fixed Charges (DG Only)	$16	$16	$12
Replace NEM at Full Retail Rate With FIT ($/kWh)	$0.16	$0.18	$0.20
Year Above Reforms Take Effect	2017 (pending approval)		

In January 2015, HECO also proposed near-term revisions to net metering that would roll back the value of NEM from the full retail rate to levels that are approximately 50% lower than HECO's 2014 rate, 36% lower than MECO's 2014 rate, and 48% lower than HELCO's 2014 rate. Equally important, the utilities proposed that by the earlier date of aggregate NEM capacity limits being reached or by March 20, 2015, all new PV interconnection applications would be subject to these lower Transition Distributed Generation (TDG) tariffs. The proposals are pending approval by the Hawaii PUC, but if approved, they are expected to significantly curtail the savings potential for new residential PV systems that fall under the new proposed tariffs.

GTM Research modeled the impact that the TDG tariff would have had on a theoretical HECO residential customer in Honolulu in 2014. The analysis is conducted for a customer with above-average electricity usage in Hawaii (1,045 kWh/month), who would therefore be a prime candidate for installing a 5 kW rooftop solar system. As the figure below reveals, under the preexisting NEM rules, a third-party-owned system on Oahu would have enabled a residential customer to save 35% on his or her 2014 electricity bill with a 15 cents/kWh PPA in year one. Meanwhile, under the proposed TDG tariff, that same PV system would have only offered 7.4% savings in 2014 for the same customer.

Given that, if the PUC were to approve HECO's proposed revisions to NEM, customers under the TDG tariff would miss out on more than 25% in electricity savings which their neighbors received under preexisting NEM rules. While HECO is requesting that a transition to TDG take effect by March 20 of this year, it remains to be seen if the PUC will request a formalized proceeding to evaluate the proposal further.

Figure 2.13 Year 1 PV Savings Under Current NEM Rules vs. Proposed TDG Tariff: Theoretical HECO Customer[1] in 2014



Source: GTM Research and Genability

Figure 2.14 HECO Customer's Electricity Costs and Solar PV System Cost Assumptions, 2014

Key Details	Without Solar PV	With Solar: Current NEM Program	With Solar: Proposed TDG Tariff
15 ¢/kWh PPA in Year 1 with 2% escalator	N/A	$1,188	
Fixed Charge	$108	$108	$108
Consumption Charge: Base Fuel Energy Cost	$1,704	$628	$628
Consumption Charge: Energy Cost Adjustment	$687	$250	$250
Consumption Charge: All Other Charges	$1,888	$660	$1,188
Total Electricity Costs	**$4,387**	**$2,833**	**$4,061**

[1] Average electricity consumption: 1,045 kWh_{ac}/month; insolation: 5.7 kWh_{ac}/m^2/day; system size: 5 kW_{dc}; Year 1 PV system production: 7,917 kWh_{ac}/year; system price $4.50/$W_{dc}$

2.1.5. State Market Analysis

Figure 2.15 Key Residential State Markets in Review, Q4 2012-Q4 2014

Installations (MW_{dc})	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
California	56.1	78.6	84.9	104.6	141.8	131.9	142.8	158.7	181.3
New York	5.9	3.0	5.1	6.1	13.2	9.1	15.9	22.7	41.6
Hawaii	22.4	22.8	18.8	16.1	25.6	17.7	13.6	9.8	19.6
Arizona	18.2	16.6	15.2	16.9	24.0	23.0	19.1	22.2	29.9
Massachusetts	5.5	6.4	7.0	8.0	8.6	7.8	14.1	19.6	23.0

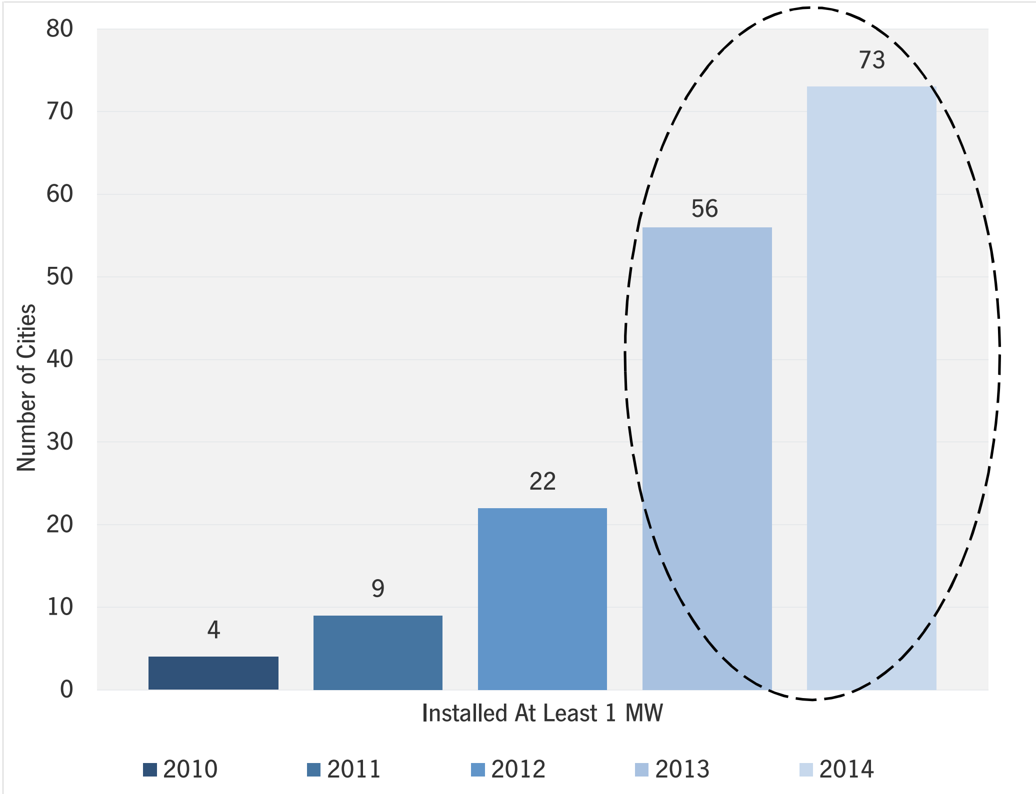
California

- 181.3 MW_{dc} installed in Q4 2014: Up 28% over Q4 2013
- 615 MW_{dc} installed in 2014: Up 50% over 2013

In 2014, California once again reigned supreme as the largest residential state market in the U.S., adding a record 615 MW. As mentioned, rebate funding offered by the California Solar Initiative (CSI) has been fully depleted for residential installations. Given that, three key factors fueled California's continued momentum in 2014.

- Scale via geographic diversification: This past year saw numerous in-state and national installers ramp up sales footprints from one to two utility service territories, especially those with a longstanding, exclusive presence in either SDG&E or SCE's markets. Several installers, especially leading in-state companies, noted an ability to corner new communities with minimal competition besides niche small contractors. As Figure 2.16 shows, installers have experienced unprecedented geographic diversification over the last 24 months. More than 70 towns and cities in Southern California added at least 1 MW of residential solar in 2014, a milestone that only 22 cities achieved two years prior.

Figure 2.16 Cities in Southern California That Installed 1 MW or More on an Annual Basis, 2010-2014

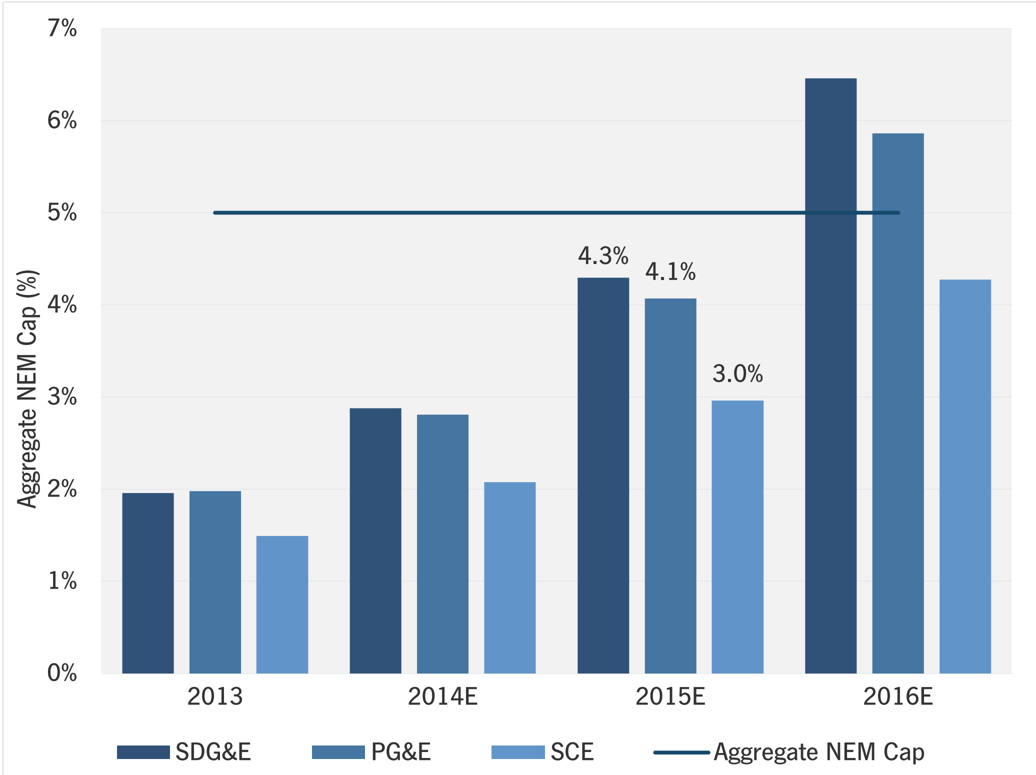


Source: Includes residential PV installation figures for SDG&E, SCE, and LADWP territories

- Above-average electricity bill hikes spurred higher sales: In the summer of 2014, the CPUC approved retail rate hikes for customers in the territories of investor-owned utilities who use less energy, which in turn expanded the pool of customers willing to install solar in California, albeit at slimmer savings to their monthly bills of 10% to 20%.
- Standardizing financing and installation solutions: The diversification of homeowner financing solutions, including PACE and solar loans, has scaled up closing rates for customers eager to own rooftop solar rather than signing a lease or PPA. On top of that, installers are speeding up sales-to-installation timelines by tapping into communities with over-the-counter permitting processes.

The final quarter of 2014 saw California's market add a record-breaking 181 MW. Looking ahead, in 2015, California will be the first state to add more than 200 MW of residential installations in a single quarter. Based on the continued availability of third-party financing solutions, along with the increasing penetration of PACE and other loan products, California's market remains well positioned to sustain its rank as the top residential state market. But amidst this continued growth, for the first time since its passage, AB 327 is having a material impact on demand for residential solar within the state. In particular, certain installers across SDG&E's service territory are pushing to expedite sales through the first half of 2015 due to concerns that the aggregate NEM capacity limit could be reached by Q4 2015. Once the cap is reached, the next version of NEM is scheduled to take effect, although no decisions regarding NEM rule revisions have been finalized yet, since the CPUC has until December 2015 to do so.

Figure 2.17 Aggregate NEM Capacity by Investor-Owned Utility



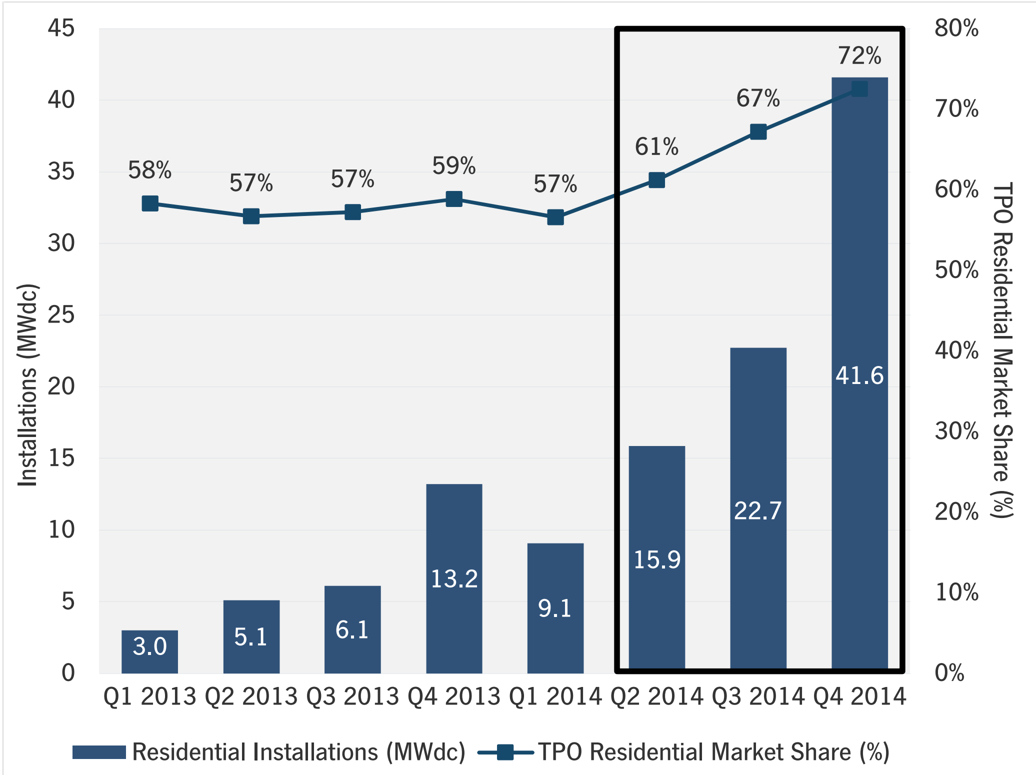
As the figure above illustrates, SDG&E will be the first utility to reach its aggregate NEM capacity limit, and GTM Research base-case installation forecasts suggest that SDG&E will reach its cap in the first quarter of 2016, rather than in December 2015. In addition to that regulatory deadline, a decision on potential rate design reforms is expected in the second quarter of 2015. The key reforms on the table include phasing in new fixed charges, flattening the number of rate tiers from four to two by 2018, and reducing the differentials between the tiers as they are flattened.

While any rate design reforms that are approved would be phased in over time, the first wave of reforms could take effect as early as this summer. In the near term, the timeline for phasing in any revisions will play a key role in impacting residential solar's attractiveness in California – especially for customers with higher energy usage. Equally important, continued growth in 2016 will be inextricably linked to the final decisions surrounding the future of NEM and a smooth transition into that program, given that all three utilities will reach their caps by 2016.

New York

- 41.6 MW_{dc} installed in Q4 2014: Up 215% over Q4 2013
- 89.3 MW_{dc} installed in 2014: Up 226% over 2013

Figure 2.18 New York Residential PV Market: Quarterly Installations vs. TPO Market Share



New York's residential market achieved record-breaking growth in 2014 due to a confluence of three key factors: state incentive reform, retail rate parity, and increased investment from national installers and financiers. In turn, New York emerged as the third-largest residential market in 2014, and unequivocally the biggest growth market relative to 2013.

The surge in installations can largely be attributed to the introduction of a new incentive program that replaced NYSERDA's and PSEG Long Island's former rebate programs. The new MW Block program, part of the NY-Sun Initiative, took effect in August 2014 and is now administered by NYSERDA for all systems up to 200 kW_{dc} statewide. This portion of the step-down rebate program is designed to support 868 MW_{dc} of residential solar systems up to 25 kW_{dc}, sub-divided into three regions:

- 122 MW_{dc} available on Long Island, starting at \$0.50/W_{dc} (4 blocks)
- 302 MW_{dc} available in Con Edison territory, starting at \$1.00/W_{dc} (9 blocks)
- 444 MW_{dc} available in upstate New York, starting at \$1.00/W_{dc} (9 blocks)

With a predictable, scheduled step-down in rebates, akin to the California Solar Initiative, national installers and financiers ramped up sales efforts during the second half of this year. Figure 2.18 shows that New York's juggernaut-like growth paralleled a stark uptick in the role of third-party financing solutions. In Q4 2014, third-party-owned systems accounted for more than 70% of new residential installations brought on-line in New York for the first time ever. While the incentive application process remains extensive, installers with a recent entrance into New York have remarked that the timeline for customer acquisition across New York has proven to be much quicker than in nearby Northeastern markets, such as Connecticut.

Looking ahead, all signs point to New York supplanting Arizona as the second-largest residential market on an annual basis. A critical step in that ascension occurred in December 2014, when the New York Public Service Commission doubled the net metering capacity limits from 3% to 6% of utilities' 2005 peak loads. Equally important, New York's growth has become increasingly unchained from the availability of state incentive funding. While the majority of residential installations in the state still take advantage of rebates offered by NYSERDA, more than 25% of Q4 2014 residential installations came on-line without a rebate. The fact that a portion of installers are currently passing on rebates ranging from $0.30/W (Long Island) to $0.80/W (rest of the state) illustrates the market's growing economic attractiveness based on the federal Investment Tax Credit, accelerated depreciation, and net metering alone.

From 2015 onward, we expect that New York will rank as the second-largest residential market as the MW Block program further ramps up, alongside a growing pool of projects that come on-line without rebate funding. Across the state, Con Edison, National Grid, and PSEG Long Island will continue to rank as the utility territory hotbeds of demand as installers expand their geographic footprints.

Hawaii

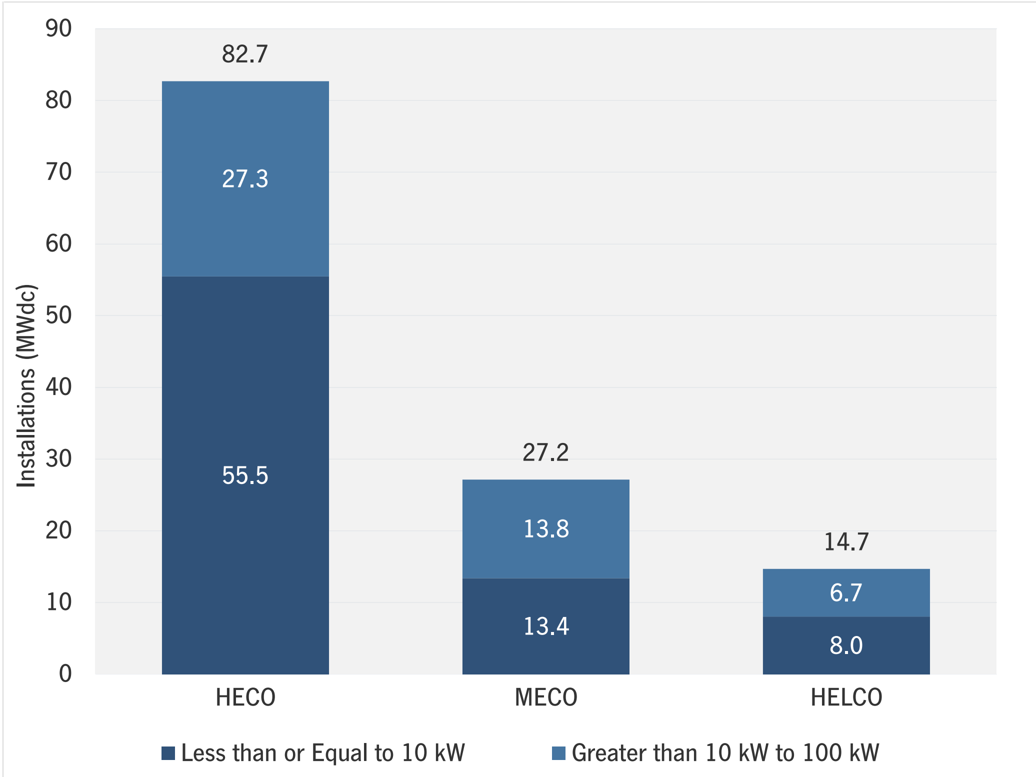
- 19.6 MW_{dc} installed in Q4 2014; Down 23% over Q4 2013
- 64.4 MW_{dc} installed in 2014; Down 27% over 2013

As has been the case for the past two years, Hawaii experienced a significant quarter-over-quarter bump in residential installations during the fourth quarter, as installers rushed to monetize the federal ITC and lucrative 35% in-state tax credit. This rush to install before year's end, however, was severely hampered due to the ongoing challenges related to PV grid saturation. With an increasing number of circuits reaching penetration levels over 120% minimum daytime load (DTL) and an ever-growing backlog of interconnection requests, Hawaii's residential market still managed to grow quarter-over-quarter, but dropped 23% year-over-year.

Despite ongoing efforts to address the backlog of PV systems seeking interconnection approval, new requests continue to outpace pre-existing applications accepted onto the grid. Installers note that wait times for PV customers last four to six weeks on distribution circuits with less than 75% PV penetration, three to six months on circuits between 75% and 100% PV penetration, and are frozen indefinitely across a majority of circuits above 100% PV penetration.

As further evidence of these anecdotes, the state's utilities reported that 124.6 MW of distributed solar remain stuck in their interconnection queues as of January 2015. Of that total, 76.9 MW come from systems of 10 kW or less, a value that serves as a useful proxy for gauging the backlog in demand from the past 12 to 18 months. To put this figure in perspective, the backlog of systems 10 kW or less awaiting interconnection approval is 12.5 MW larger than the total residential installations brought on-line in Hawaii throughout all of 2014.

Figure 2.19 Net Metered PV Systems in the Interconnection Queue by System Size and Utility, January 2015



Source: Hawaii PUC

Looking ahead to 2015, Hawaii's market is poised to drop on a year-over-year basis for the second straight time. While installation volumes continue to slow down, recent regulatory activity and proposals shed light on key upside and downside factors to Hawaii's growth potential in the latter half of 2015 and beyond.

As mentioned, the utilities have proposed revisions to net metering that would roll back the value of NEM from the full retail rate to levels that are approximately 50% lower than HECO's 2014 rate, 36% lower than MECO's 2014 rate, and 48% lower than HELCO's 2014 rate. The PUC's final decision on these proposed revisions, which could take effect for new interconnection applications as early as March 20, 2015, would have a major impact on the value proposition of rooftop solar in the latter half of 2015. Meanwhile, HECO has also proposed to increase the allowable PV penetration threshold on each circuit from 120% of minimum DTL to 250% of minimum DTL. Raising this threshold would allow HECO to expedite review of a significant portion of the thousands of systems awaiting approval to proceed with installation.

Hawaii's ability to exceed expectations in 2015 and return to year-over-year growth depends on the extent to which HECO is able to achieve its goal of approving the backlog of interconnection requests by December 2015. Further out, Hawaii's market will be subject to the PUC's final decisions on proposed reforms that would take effect in 2017, including new fixed charges for DG customers, higher fixed charges for all customers, and new rate structures for PV customers selling power back to the grid (NEM customers) and those with storage who do not sell power back to the grid (non-export).

Arizona

- 29.9 MW_{dc} installed in Q4 2014, up 25% over Q4 2013
- 94.2 MW_{dc} installed in 2014, up 30% over 2013

Arizona's residential market grew year-over-year by more than 25% for the fourth consecutive quarter. This growth has come in spite of a new monthly net metering fee of $0.70/kW/month, which took effect for residential customers in Arizona Public Service (APS) territory who submitted PV interconnection applications on or after January 1, 2014.

During the first half of 2014, Arizona's market worked off the pipeline of residential PV customers who locked in deals in the second half of 2013 in order to be grandfathered in under APS's old NEM program, thus avoiding the fixed NEM fee. In the second half of 2014, the residential market in APS territory was almost entirely depleted of the backlog of customers falling under the old NEM rules. But statewide growth continued as installers diversified sales footprints, particularly into Salt River Project (SRP) territory, as a hedge against NEM uncertainty in APS' domain. Subsequently, during the back half of 2014, nearly half of the residential PV market came from installations outside of APS territory.

In 2015, Arizona's residential market is poised to see continued growth as the market benefits from a more geographically balanced demand landscape within Arizona. However, those benefits may be short-lived due to recently approved rate reforms in SRP territory. At the end of 2014, SRP proposed a host of rate structure reforms including a new fixed charge, a decrease to consumption charges (the key component of a rate offset by rooftop solar), and a new demand charge for PV customers.

On February 26, 2015, SRP's Board of Directors approved those reforms, albeit with a slight modification to the peak demand charge calculation (see Section 2.1.4 for more information). The board also decided that any customers with operational systems or interconnection applications submitted by December 8, 2014 would be grandfathered in under the old NEM rules for 20 years from installation date. This deviates from SRP's proposal to only grandfather in systems that were directly owned by the customer and installed as of December 8, 2014 for just 10 years.

Arizona's residential market is expected to grow 27% year-over-year, adding 120 MW in 2015. That growth trajectory is still on track, as the first half of 2015 will benefit from the backlog of SRP customers still eligible for preexisting NEM rules and rate design. But the ultimate outcome of the SRP rate design battle is expected to hamper growth in the latter half of 2015, as installers have benefited from a more balanced presence in SRP and APS territories. Separate from activity in SRP, the other notable market consideration this year will be utility-owned rooftop solar. In December 2014, the Arizona Corporation Commission approved a pared-down proposal by APS to own and subcontract the installation of 10 MW of residential solar, along with the utility Tucson Electric Power's original proposal to own 3.5 MW of residential solar in 2015.

Massachusetts

- 23 MW_{dc} installed in Q4 2014, up 168% over Q4 2013
- 64.4 MW_{dc} installed in 2014, up 116% over 2013

Similar to New York in 2014, Massachusetts experienced unprecedented growth in 2014 in response to ramped-up investment from third-party financiers of rooftop solar. In Q4 2014, Massachusetts added more than 20 MW of residential installations for the first time ever on a quarterly basis. Paralleling that impressive installation growth, third-party-owned residential PV systems accounted for more than 70% of installations in Q4.

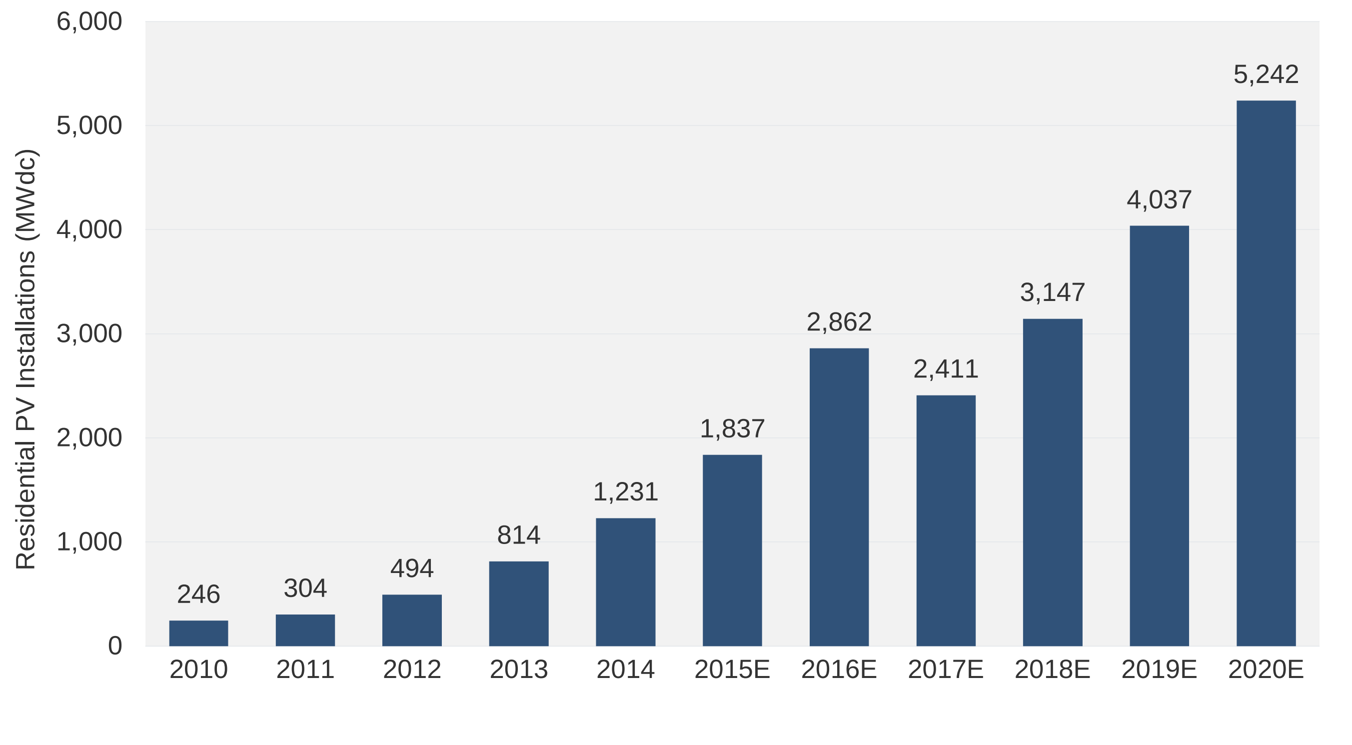
Massachusetts transitioned to the SREC II program in April, and legislation was passed in August that raised the net metering cap from 3% to 5%. The transition did nothing to hinder the residential market. Residential systems under SREC II receive a full SREC factor of 1.0, as opposed to some large systems which receive less than 1 SREC for each MWh produced. SRECs, however, have generally been one of the biggest challenges associated with selling residential solar in Massachusetts. The incentive is difficult to explain, and because a large portion of customers in Massachusetts choose to purchase a system, it needs to be explained often. Installers note, however, that the market has reached a level of maturity where consumers can see the history of the SREC program and have more confidence in taking on the risk.

Massachusetts is expected to rank as the fourth-largest residential market in 2015, adding 86 MW_{dc} and growing 34% on an annual basis. Legislative activity is focused on the ongoing developments surrounding the future of NEM, with a bill slated for review by the state sometime this summer. Any proposals that revise current NEM rules for residential customers would have substantial implications for Massachusetts' market in 2016. But at this point in time, Massachusetts remains one of the most attractive growth markets for residential solar, given stable SREC pricing and attractive rate design.

2.1.6. Residential Market Outlook

We continue to expect big things from the residential solar market over the next five years. We forecast 49% annual growth in 2015, followed by 56% growth in 2016 ahead of the ITC expiration and a 2.9 GW_{dc} year in 2016. In 2015, we expect that seven states will each install over 50 MW of residential solar, and California will approach the 1 GW_{dc} annual mark for residential solar (966 MW_{dc}) – a truly impressive feat given that the entire national residential market was less than 900 MW_{dc} in 2013.

Figure 2.20 U.S. Residential PV Installation Forecast, 2010-2020



2.2. Non-Residential PV

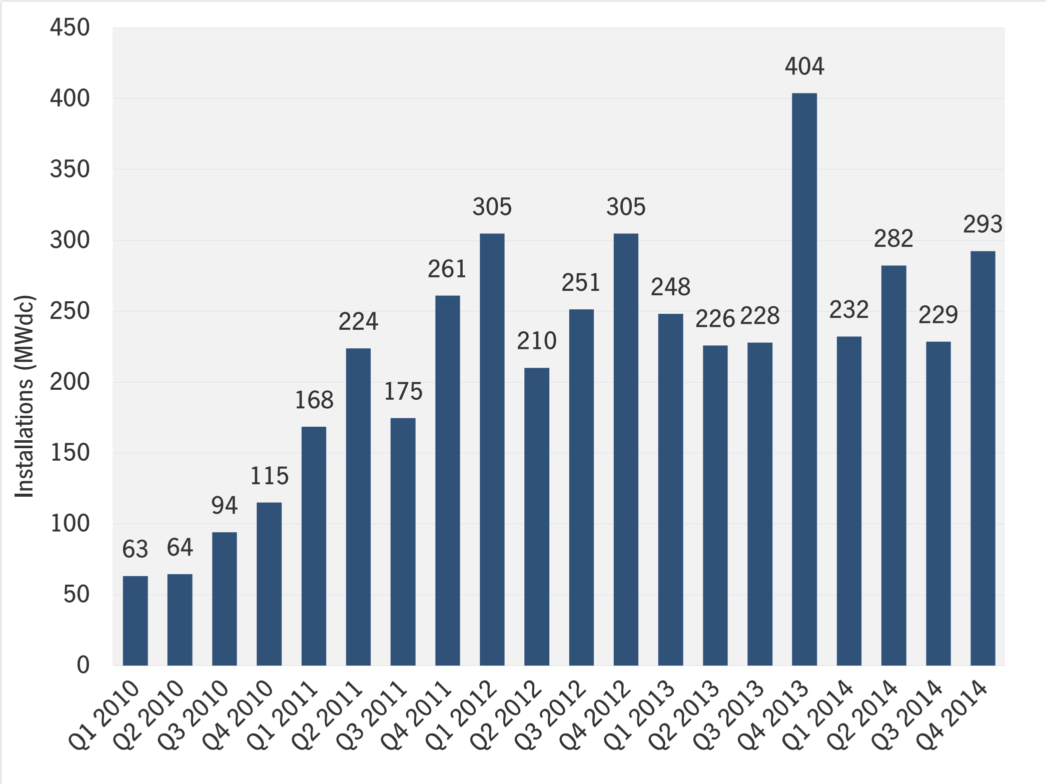
National Installations

Key figures:

- 293 MW_{dc} installed in Q4 2014, up 28% over Q3 2014 but down 28% from Q4 2013
- 1,036 MW_{dc} installed overall in 2014, down 6% from 2013

The non-residential market jumped 28% in Q4 2014 versus the previous quarter, but this number was insufficient to keep the market from having its first down year in recent history. As we have repeatedly noted in this report, the non-residential market has proven much harder to scale, and much more sensitive to incentive reduction, than the residential market. And while a few major state markets (Massachusetts, New York, California and Maryland) did grow in 2014, this expansion was overcome by significant downturns in New Jersey, Arizona and Hawaii.

Figure 2.21 Non-Residential PV Installations, Q1 2010-Q4 2014



We remain confident that the non-residential market will see a resumption of growth in 2015. A wide range of states are poised to have a stronger year, while some of the incumbent markets (most notably New Jersey) appear to have hit their nadir.

2.2.1. Quarterly Installations by State

Figure 2.22 Quarterly Non-Residential PV Installations by State (MW_{dc}), 2012-2014

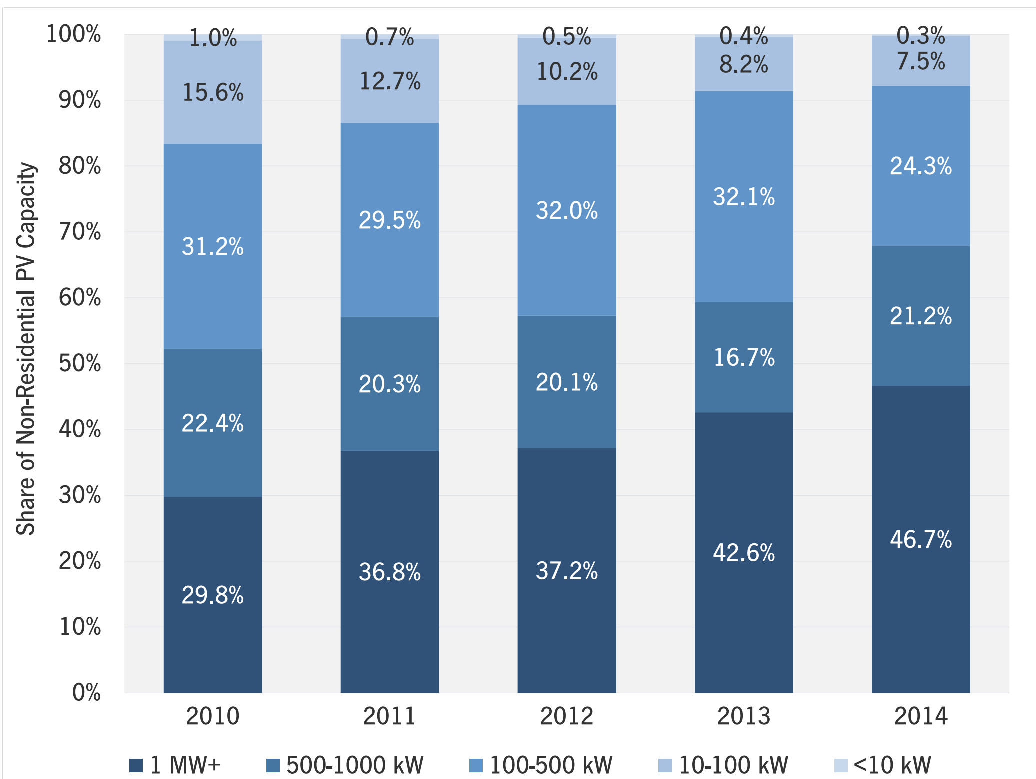
State	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4
Arizona	10.1	13.0	7.2	34.1	7.7	5.3	23.5	21.7	28.5	5.2	6.7	9.5
California	86.6	48.9	73.8	98.0	58.9	64.3	83.9	85.6	60.5	68.0	53.9	124.2
Colorado	5.9	3.8	9.4	4.6	4.9	6.7	7.0	9.1	6.4	2.4	9.0	7.6
Connecticut	1.0	0.6	1.2	1.7	4.1	5.8	7.4	5.4	3.4	10.0	5.3	2.8
Delaware	0.9	0.1	0.4	0.4	0.2	0.3	0.3	0.6	2.5	1.8	0.4	0.6
Florida	3.4	1.6	6.4	2.5	7.2	4.4	2.0	5.4	2.4	2.8	4.2	2.4
Georgia	1.4	3.4	0.6	3.5	3.0	0.7	0.3	0.3	0.8	1.3	0.0	0.0
Hawaii	9.7	5.3	5.2	17.6	15.2	10.9	8.7	14.2	9.4	7.3	5.4	10.0
Illinois	0.2	0.7	2.5	0.2	0.1	0.1	0.1	0.6	3.2	0.9	0.5	0.4
Indiana	-	-	-	-	0.0	1.6	0.9	0.2	-	1.5	0.5	0.4
Louisiana	-	-	-	-	-	-	-	-	0.1	0.1	0.4	0.2
Maryland	5.8	3.2	21.5	10.3	1.9	5.5	2.3	9.8	9.1	8.5	4.0	11.4
Massachusetts	12.0	19.2	36.4	40.4	21.8	17.5	37.6	93.9	19.0	94.1	67.2	43.9
Minnesota	0.6	0.5	0.9	0.9	2.2	0.1	0.1	1.0	0.7	0.3	2.1	1.4
Missouri	0.8	0.8	0.8	1.7	4.2	2.6	2.7	4.4	5.3	12.1	14.7	4.4
Nevada	1.6	1.2	1.6	2.7	0.5	3.7	0.3	3.4	2.4	3.5	4.9	7.9
New Hampshire	-	-	-	-	0.1	0.2	0.1	0.4	0.3	0.0	0.1	0.4
New Jersey	121.7	79.4	55.6	43.1	57.4	56.0	20.6	54.8	41.1	30.8	10.9	19.5
New Mexico	0.7	0.5	0.8	2.0	0.5	2.0	4.3	7.7	2.7	5.8	5.5	2.4
New York	4.6	5.6	6.8	17.4	3.1	5.7	6.7	27.0	11.8	9.7	10.8	16.5
North Carolina	1.2	0.6	-	-	23.2	2.8	0.0	31.0	1.1	0.5	0.5	0.6
Ohio	4.4	3.0	2.2	3.3	5.8	5.7	1.8	3.9	3.3	2.3	4.7	2.9
Oregon	1.3	2.4	2.2	4.7	0.2	0.4	0.4	0.6	0.1	0.3	0.8	0.5
Pennsylvania	16.2	4.2	5.5	4.0	4.9	9.4	5.9	8.1	1.7	2.5	2.5	1.6
South Carolina	0.0	0.0	0.0	0.0	0.0	0.1	-	-	0.1	-	0.0	0.1
Tennessee	6.4	7.1	0.4	1.2	15.4	1.6	0.7	0.4	0.7	0.2	0.9	0.4
Texas	0.7	0.5	4.3	1.4	0.8	2.5	1.2	2.0	4.1	2.0	2.8	6.6
Utah	0.1	0.0	0.1	0.1	0.1	0.9	0.0	0.8	4.3	0.7	0.8	0.2
Vermont	1.1	0.1	0.2	0.6	1.1	0.5	0.3	0.2	0.2	0.1	0.6	3.3
Virginia	-	-	-	-	0.1	0.1	0.1	3.7	1.8	0.1	0.4	0.1
Washington	0.1	0.1	0.2	0.2	0.3	0.1	0.2	0.3	0.9	0.3	0.5	0.2
Washington, D.C.	-	0.0	0.1	0.0	0.1	0.0	0.1	0.7	0.2	0.3	0.1	0.2
Wisconsin	0.6	0.3	0.0	0.0	0.7	0.0	0.2	0.2	0.1	0.3	0.4	0.4
Other	5.9	4.1	4.9	8.2	2.5	8.5	8.5	6.8	4.0	6.8	7.2	9.7
Total	305	210	251	305	248	226	228	404	232	282	229	293

2.2.2. Non-Residential Market Trends: System Size

Despite the tremendous growth of available capital for non-residential solar projects in the last five years, financing and developing small to mid-sized projects has often proven to be prohibitively difficult. Some of the most prominent detractions include lack of standardization (e.g., varying contract terms, power-purchasers that lack credit ratings or easily assessed creditworthiness, and onerous site-specific project requirements) and relatively high costs (the transaction costs of smaller commercial projects are often comparable to those for much larger deals, but lack the benefit of scale). These difficulties have generally led developers to focus their attention on larger commercial projects, particularly those 1 MW or larger.

This dynamic has only heightened over time. In 2010, 70% of all non-residential capacity installed was in systems smaller than 1 MW in size, whereas only 53.3% of the capacity installed through 2014 was in this category. The decline has been particularly stark for projects smaller than 100 kW in size, whose market share has been cut by more than half over the same period.

Figure 2.23 Non-Residential PV Capacity by System Size in AZ, CA, MA, NJ, and NY, 2010-2014

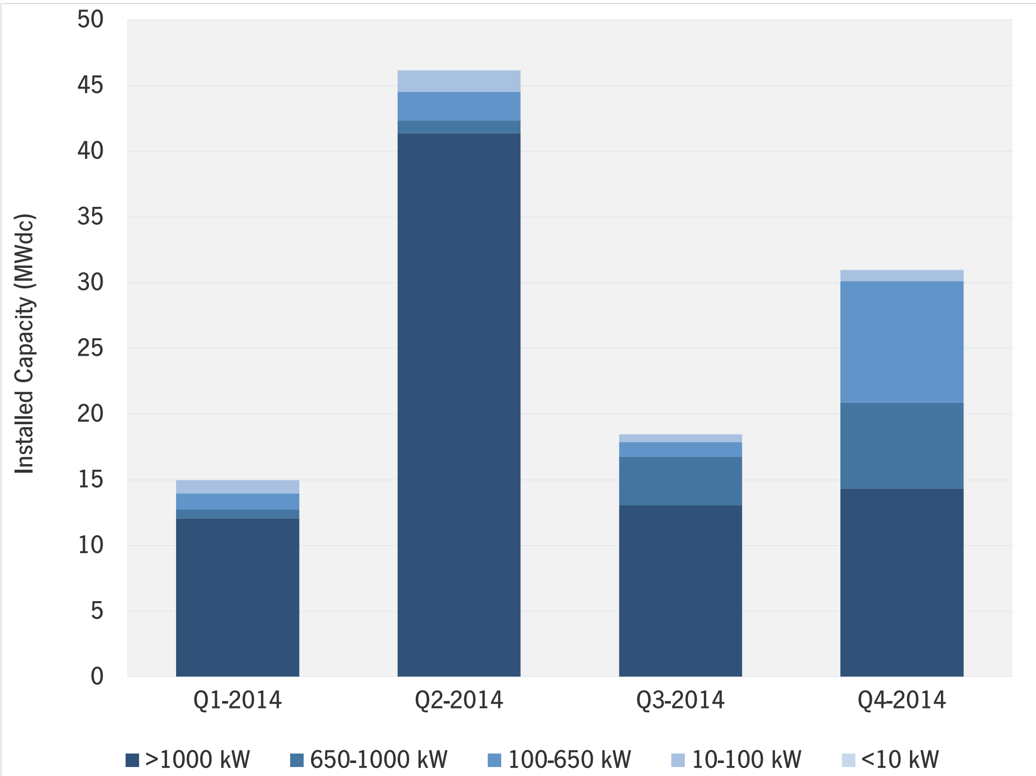


Another important factor contributing to the demand for large-scale systems 1 MW and above has been the evolving geographic demand landscape. Since 2012, Massachusetts has been a leader in the non-residential market, largely as a result of the state's initial SREC market design, which favored development of virtually net metered solar farms ranging between 1 MW and 6 MW.

The future of the non-residential market, particularly that of the small commercial segment, relies on innovative solutions to make projects more economically attractive. Fortunately, we foresee a number of developments that should aid in this transition. First, states are introducing new incentive programs with specific carve-outs for small commercial such as the SREC II program in Massachusetts.

Since the SREC II program was implemented in 2014, Q4 showed an uptick in mid-sized systems, especially those sized between 100 kW and 650 kW. The majority of new capacity in this category came from retail and commercial/office power-purchasers. As a result, for the first time in six quarters, systems over 1 MW accounted for less than half of the installed non-residential capacity.

Figure 2.24 Massachusetts Non-Residential Installed PV 2014 by System Size



System Size	Q1-2014	Q2-2014	Q3-2014	Q4-2014
<10 kW	0.16%	0.10%	0.32%	0.13%
10-100 kW	6.77%	3.50%	3.14%	2.66%
100-650 kW	8.18%	4.76%	5.86%	29.90%
650-1,000 kW	4.37%	2.14%	20.15%	21.16%
>1,000 kW	80.52%	89.51%	70.53%	46.16%

Similarly, New York's NY-Sun Program caps eligibility for non-residential systems at 200 kW, and California has implemented the ReMAT, which allows customers with renewable energy systems of less than 3 MW to sign into long-term energy-sale contracts with utilities. Continued and proliferating support for these types of programs in the near term will be critical to ramp up the market scalability for small and mid-sized systems.

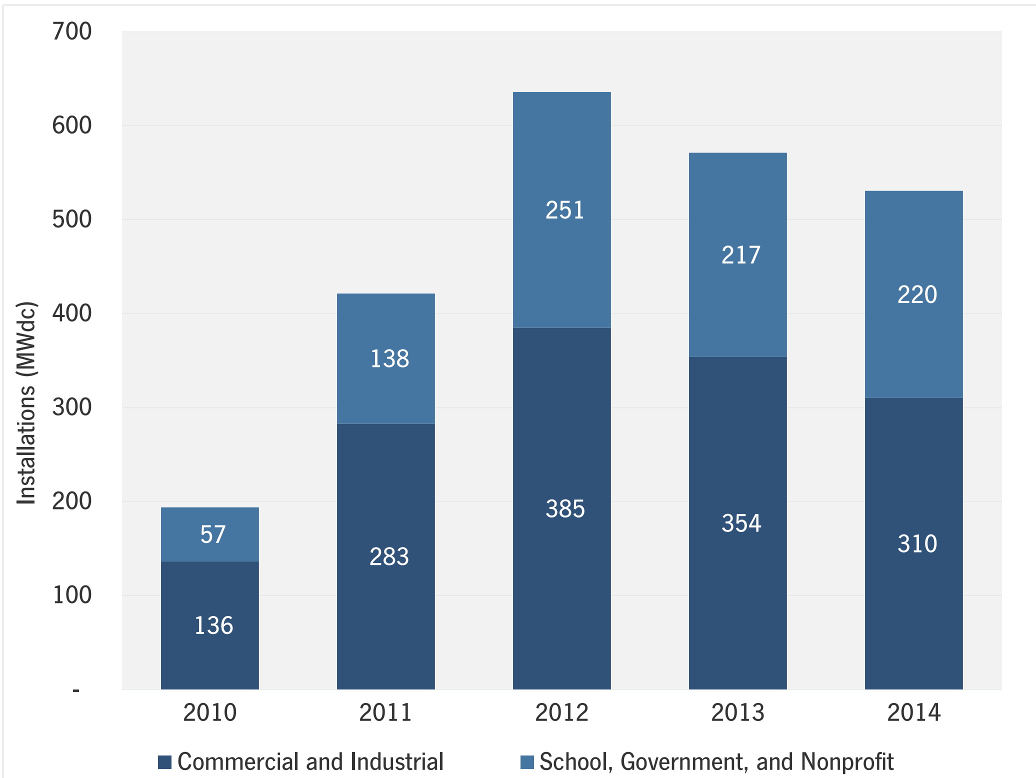
Second, we have seen a variety of companies seek out solutions that would lower the administrative burden associated with financing small commercial through solutions such as project scores, online diligence tools, and investment platforms.

Finally, some larger commercial developers have begun building small commercial assets on their own balance sheet as a proof of concept to attract third-party capital. We remain optimistic that the relative share of large commercial systems greater than 1 MW in size will slow and demand will increasingly shift toward smaller systems of less than 1 MW over the coming years.

2.2.3. Non-Residential Market Trends: Customer Segments

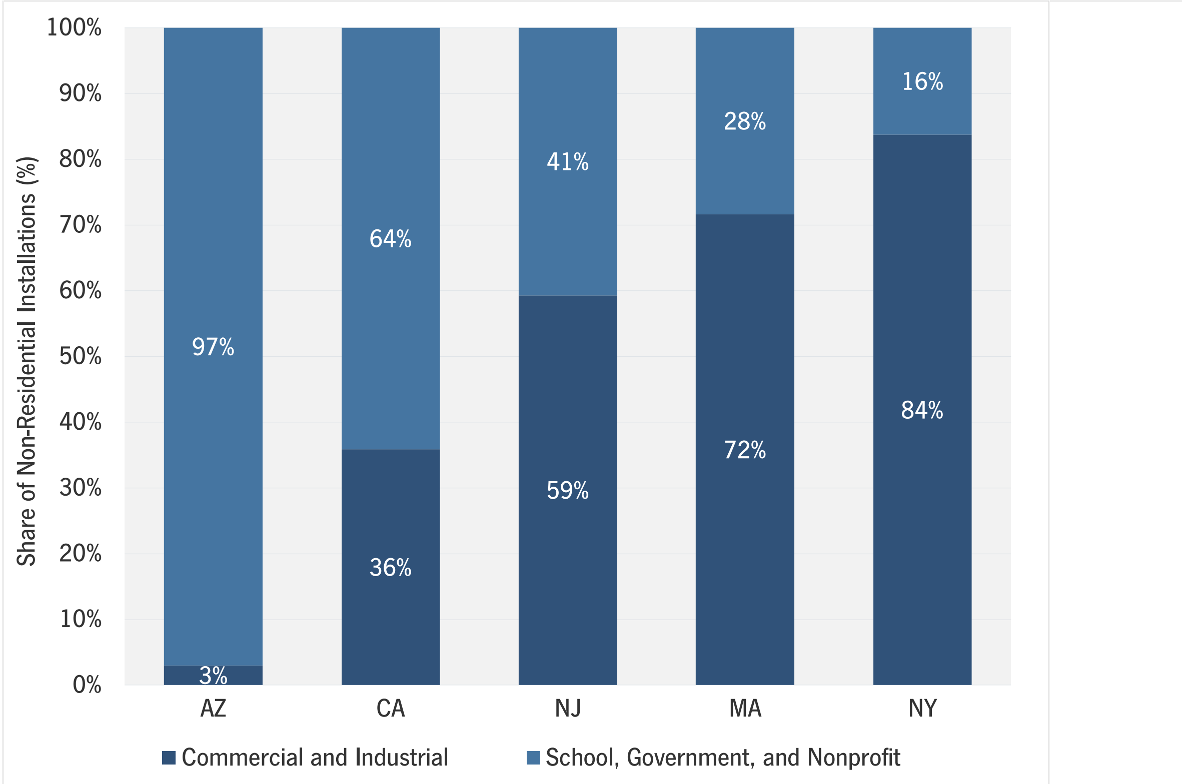
Much of the recent growth in the non-residential sector has come from public-sector installations at schools, government buildings, and, to a lesser extent, nonprofits. This segment has increased from an estimated 30% of all non-residential installations in 2010 to 42% in 2014.

Figure 2.25 Non-Residential PV Installations by Customer Segment, 2010-2014



This breakdown, however, is highly state-specific. Arizona and California have recently been largely public-sector markets, as incentives for school, government, and nonprofit systems were available long past the depletion of those for private-sector projects. The growing non-residential markets in Massachusetts and New York have been just the opposite, with 72% and 84% of installations coming from the private sector in 2014, respectively. New Jersey shows the most balance of major markets, with an even split between the public and private sectors.

Figure 2.26 Non-Residential PV Installations by Customer Segment in 2014, AZ, CA, MA, NJ and NY



2.2.4. State Market Analysis

Figure 2.27 Key Non-Residential State Markets in Review, Q4 2012-Q4 2014

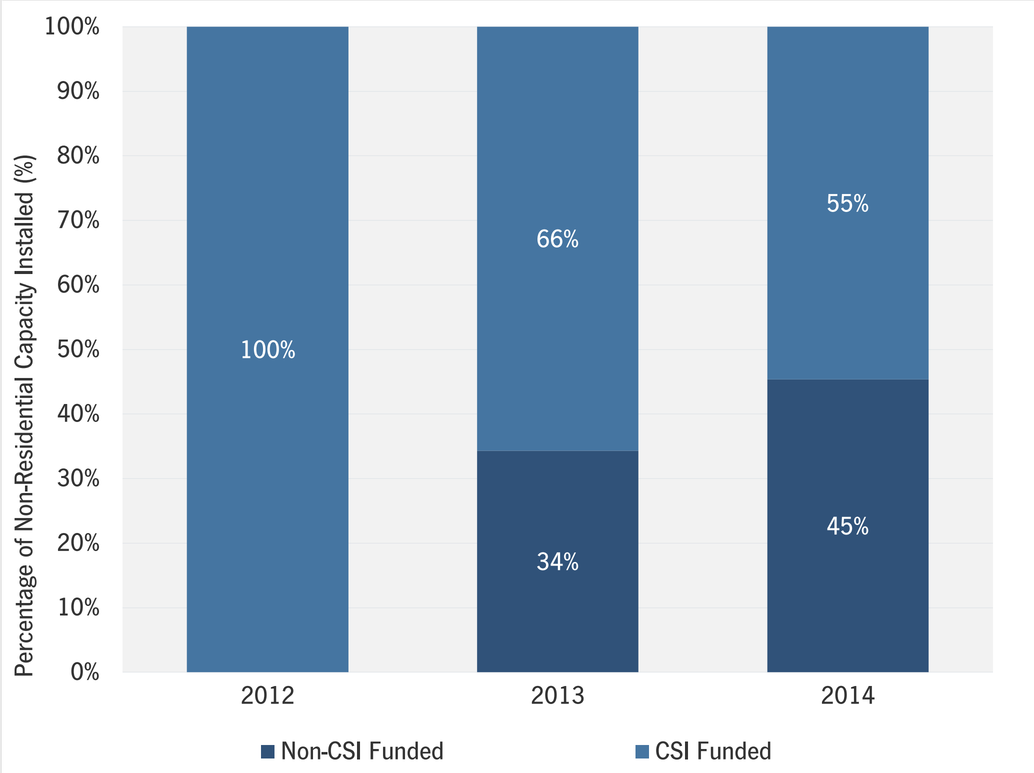
Installations (MWdc)	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
California	98.0	58.9	64.3	83.9	85.6	60.5	68.0	53.9	124.2
Massachusetts	40.4	21.8	17.5	37.6	93.9	19.0	94.1	67.2	43.9
New York	17.4	3.1	5.7	6.7	27.0	11.8	9.7	10.8	16.5
Colorado	4.6	4.9	6.7	7.0	9.1	6.4	2.4	9.0	7.6
Minnesota	0.9	2.2	0.1	0.1	1.0	0.7	0.3	2.1	1.4

California

- 124.2 MW_{dc} installed in Q4 2014, up 45% over Q4 2013
- 307 MW_{dc} installed in 2014, up 5% over 2013

The non-residential market in California has long mirrored non-residential solar's national level trend of lumpy development cycles. In 2014, Q4 alone accounted for 40.5% of non-residential installations brought on-line in California. Amidst this lumpy development, California is finally beginning to see a meaningful share of non-residential capacity come on-line outside of the CSI program. In fact, a record 72% of non-residential installed capacity in Q4 2014 came outside the CSI program, which serves as a hopeful sign for California's growth trajectory in 2015, as incentive funding via CSI comes to a close.

Figure 2.28 Share of IOUs' Non-Residential Installed Capacity With and Without CSI Funding, 2012-2014



While a growing share of capacity came on-line outside of CSI in 2014, 2015 is expected to continue to benefit from a significant backlog of CSI-funded projects. During the second half of 2014, 191 MW of non-residential installations reserved incentive funding under the final incentive step.

Nevertheless, the growth narrative in California's non-residential market is finally beginning to extend beyond the role of incentive funding to other drivers of attractive project economics, most notably, rate design. To date, commercial customers have been accepting deals from third-party financiers that have typically ranged between 10% and 20% annual net savings. But now, developers are tapping into alternative solar-friendly tariffs in California that allow for additional savings opportunities more akin to residential rate structures within the state. Additional details about the three IOUs' solar-friendly rate tariffs can be found below.

- Southern California Edison: In December 2014, SCE agreed to add 250 MW of new non-residential capacity to its Option R tariff.
- Pacific Gas and Electric: In December 2014, the CPUC voted to create an equivalent Option R program for large commercial customers that fall under E-19 and E-20 tariff schedules. Unlike SCE's Option R, PG&E's program has no cap on participation.
- San Diego Gas and Electric: SDG&E offers a solar-friendly time-of-use rate, which also has no program capacity limit. However, SDG&E has recently proposed to push the peak period of the rate schedule later into the day, which if approved, would lower the value proposition of NEM under this tariff.

Under all of the aforementioned commercial rate tariffs, customers can take advantage of rate structures with lower demand charges and higher consumption rates, which developers note can allow solar to offer annual net savings of between 20% and 30%. In addition to that, a number of small and medium-sized commercial customers (i.e., those with average monthly peak demands of 200 kW or less) across the IOUs' territories are now transitioning away from flat rates to time-of-use (TOU) rate structures. The switch to time-of-use rate tariffs is expected to increase monthly bills for these low-usage customers, who as a result will be attractive targets for developers as well. Collectively, California's non-residential market is poised to grow 42% in 2015 as the market benefits from both the final wave of CSI-funded installations and a growing pool of projects that leverage attractive rate structures with lower demand charges.

Massachusetts

- 43.9 MW_{dc} installed in Q4 2014, down 53% over Q4 2013
- 224 MW_{dc} installed in 2014, up 31% over 2013

Massachusetts ranked as the second-largest non-residential market in 2014, as the second half of the year benefited from the spillover of projects eligible under SREC I, alongside the initial ramp-up of SREC II projects. Under the terms of SREC I, systems larger than 100 kW_{dc} that expended more than 50% of project costs by December 31, 2013 were granted a six-month extension to complete construction and receive an authorization to interconnect by June 30, 2014. However, completed projects that can prove that interconnection was delayed by the utility after that deadline have been granted an additional extension. The utilities in Massachusetts have been extremely sluggish in accepting interconnection requests from non-residential projects under SREC I. In fact, 40.6 MW of non-residential systems qualified for SREC I have been waiting more than half a year to interconnect.

In the summer of 2014, Massachusetts' solar PV market saw the proposal of a comprehensive but controversial bill that included eliminating the net metering caps, replacing SRECs with performance-based incentives, and revising rates downward for virtually net-metered systems. However, the bill failed to pass before the end of the legislative session. Instead, stopgap legislation was passed that raised net metering caps from 3 percent to 5 percent for public projects and to 4 percent for private projects. Additionally, a Net Metering and Solar Task Force was assembled to advise the state legislature on matters relating to the future of net metering in Massachusetts.

In the near term, the revised aggregate NEM caps are not expected to be a bottleneck to growth, given that 181 MW remain available under the private cap and 156 MW remain available under the public cap. Instead, rules surrounding the SREC II program, which officially began on April 25, 2014, will be the primary driver of future growth opportunities for the non-residential segment in the state.

Most non-residential systems greater than 650 kW_{dc}, which accounted for the majority of non-residential installed capacity in 2014, are now classified under the Managed Growth sector and are limited to a varying annual capacity. Developers note that they have had to become increasingly creative to maintain a sufficient pipeline of larger ground-mount systems. Most notably, developers are ramping up development of projects sited on former landfills and brownfields that do not fall under the Managed Growth category. Nevertheless, 2015 is poised to dip slightly as the market is increasingly made up of mid-scale non-residential installations under 1 MW.

New York

- 16.5 MW_{dc} installed in Q4 2014, down 39% over Q4 2013
- 49 MW_{dc} installed in 2014, up 29% over 2013

In 2014, New York emerged as the fifth-largest non-residential state market as the pipeline of projects awarded incentives under NYSERDA's NY-Sun and PSEG Long Island's incentive programs came to fruition. While New York's broader non-residential market grew 29% over 2013, a number of underlying challenges hampered additional growth opportunities for the state's large commercial PV segment in 2014.

In the latter half of 2014, late-stage developers consistently noted that there is a waning pool of "economically feasible" projects being awarded incentives under NYSERDA's Competitive PV Program, which targets systems greater than 200 kW in size. A number of large non-residential projects that received incentives from NYSERDA as far back as 2012 were expected to come on-line in 2014, but have been canceled altogether. Late-stage developers claimed that numerous early-stage developers submitted overly aggressive bid prices to NYSERDA in their initial incentive applications, based on unrealistic assumptions about all-in development costs. When these project originators tried selling systems to late-stage developers, the incentive funding the projects received was simply too low to allow project economics to pencil out. In turn, this disconnect between early- and late-stage developers played a major role in limiting development opportunities throughout the second half of 2014.

In 2015, however, the market is expected to grow 78%, with 87 MW brought on-line. The growth that will occur is a function of two factors. First, there still remains a backlog of viable projects in development under the Competitive PV program, which will fuel the majority of new installations. Second, the rollout of NYSERDA's MW Block Incentive Program in the first half of 2015 for systems greater than 200 kW will become a growing driver of non-residential demand. NYSERDA has proposed that the three-year PBI for non-residential PV systems greater than 200 kW start at $0.105/kWh in Con Edison territory, and at $0.09/kWh for the rest of the state.

However, non-residential developers have expressed concerns that Step 1 incentive rates are too low, considering a recent decision by the New York Public Service Commission (PSC) to revise remote net metering. In December 2014, the PSC revised remote NEM roles such that the NEM credits will no longer be valued according to the host customer's rate schedule, but rather the remote offtakers' rate schedules. Oftentimes in New York, the remote offtaker will be a large commercial customer, while the host customer site will be eligible for a small commercial rate structure that can value NEM credits at a 50% higher value than under the remote customers' rates. Developers subsequently submitted a wave of petitions communicating their opposition to this ruling. However, assuming the PSC's decision stands, this revision to remote NEM would serve as a major barrier to growth in New York's large commercial market – an issue that GTM Research will monitor and with which SEIA will engage over the ensuing months.

Community Solar Market Opportunities: Colorado and Minnesota

- Colorado: 25 MW_{dc} installed in 2014, down 8% over 2013
- Minnesota: 4.5 MW_{dc} installed in 2014, up 29% over 2013

While accounting for a minor share of demand to date, in 2015 and 2016, community solar is poised to drive a growing portion of Colorado and Minnesota's non-residential solar markets. Through 2014, Colorado has added 18.8 MW of community solar installations, while Minnesota has added less than 1 MW of community solar. However, in 2015, approximately 50% of Colorado's non-residential market is expected to stem from community solar. Meanwhile, an eye-popping 431 MW of community solar projects submitted applications in December 2014 as part of Xcel Energy's community solar program in Minnesota.

As is the case across the rest of the distributed generation market in Colorado and Minnesota, the primary driver of demand for community solar stems from Xcel Energy's Solar*Rewards programs. In Colorado, Xcel is required to fund at least 6.5 MW of new community solar projects for its 2015 and 2016 RPS compliance years, with maximum annual incentive allocations of 30 MW. Meanwhile, Xcel's program in Minnesota has no annual cap, which subsequently led to an application gold rush once the program took effect at the end of 2014.

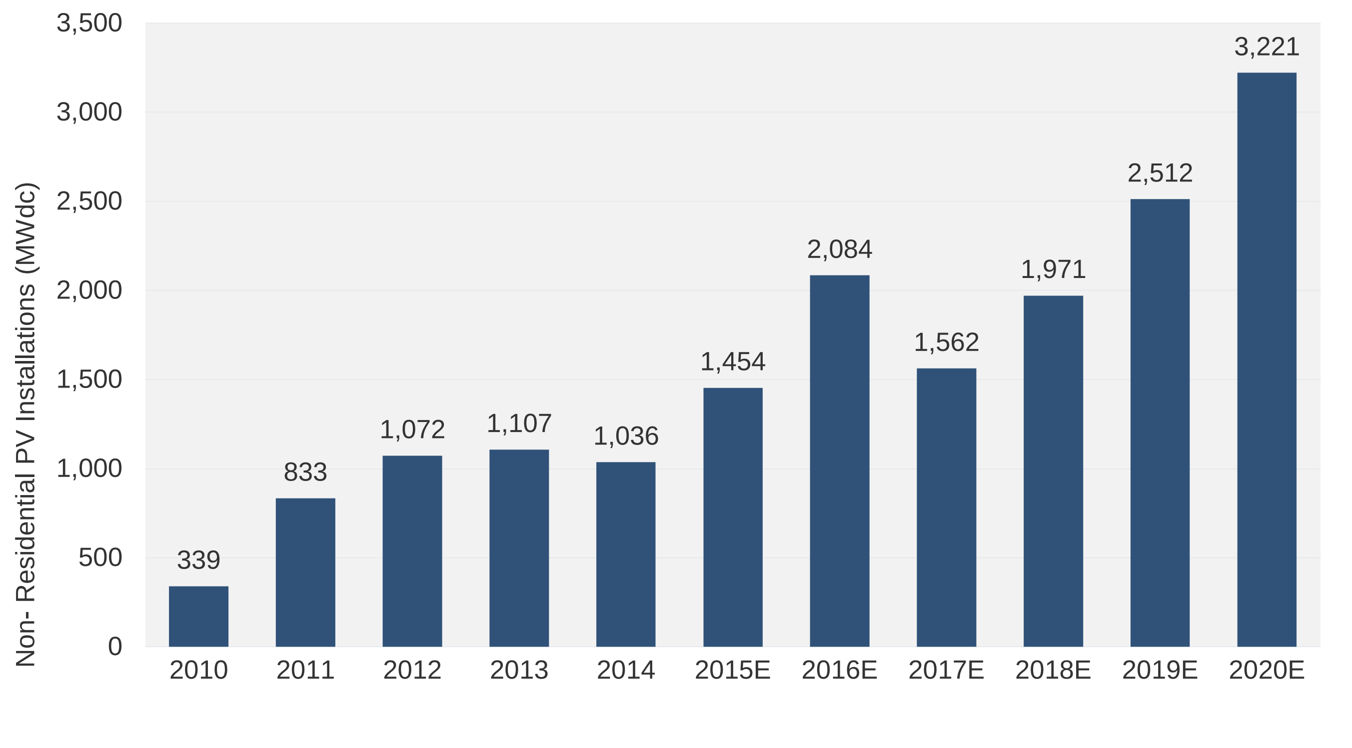
In Colorado, developers note that subscribers of community solar projects involve a diverse cross-section of commercial, government, nonprofit, and residential customers. Each community solar project requires a minimum of 10 subscribers, while in Minnesota, the minimum number of subscribers per project is only five. But for both community solar markets, the individual cap on subscriber participation is 40% of a project's total capacity. In Minnesota, developers have taken advantage of Xcel's community solar market design by parceling out 10 MW+ utility-scale projects into 1 MW project sites, which has led to a subscriber base primarily comprising large commercial, government, and nonprofit entities that subscribe to 40% of multiple 1 MW projects. While Minnesota's community solar market holds more upside than Colorado's in terms of total MW potentially installed, ongoing regulatory proceedings in 2015 are poised to shed light on whether utility-scale projects split into multiple sites will still qualify for Xcel's community solar program in Minnesota.

2.2.5. Non-Residential Market Outlook

Our non-residential market forecast has largely remained steady this quarter. But given the lower-than-expected total for the market in 2014, this implies a strong growth rate of 40% in 2015, followed by 45% in 2016. We expect this growth to come from a variety of markets, but much of it is attributable to an expansion in California beyond the California Solar Initiative, a resumption of growth in New Jersey driven by more stable SREC pricing, and a still-strong Massachusetts market. New York is also a key growth market, but our outlook has been somewhat tempered by rule revisions that could negatively impact the virtual net energy metered sector.

The biggest forecast revision is a larger 2017 downturn, which is now forecasted to be 25%. This stems from both the timelines of a number of individual projects and programs, as well as the generally tight economics for commercial solar in the U.S.

Figure 2.29 Non-Residential PV Installation Forecast, 2010-2020E



2.3. Utility PV

2.3.1. Operating Capacity vs. Project Pipeline

- 1,500 MW_{dc} installed in Q4 2014, up 4% over Q4 2013
- 3,934 MW_{dc} installed in 2014, up 38% over 2013

The utility PV sector remains the bedrock of demand within the U.S. solar market, accounting for 63% of all PV installations brought on-line in 2014. Most notably, First Solar's 550 MW_{ac} Topaz Solar and Desert Sunlight projects achieved full commercial operation at the end of 2014, ranking as the largest solar projects currently on-line in the world. But by the end of 2015, Desert Sunlight and Topaz Solar Farm will cede their top spot to SunPower's 579 MW_{ac} Solar Star project, which is slated for full commercial operation in 2015. 2015 and 2016 will be highlighted by a number of large-scale project completions alongside those below that are only partially on-line. In fact, there are 38 additional projects in development that are 100 MW_{dc} or larger, all of which have yet to bring an initial phase on-line.

Figure 2.30 10 Largest PV Projects Currently in Operation

Project Name	Developer	Capacity (MWdc)	State	Offtaker	Owner(s)	On-Line Date
Desert Sunlight	First Solar	673.0	CA	Southern California Edison, Pacific Gas & Electric	NextEra Energy Resources, GE Energy Financial Services, Sumitomo Corp.	2013-2014
Topaz Solar Farm	First Solar	673.0	CA	Pacific Gas & Electric	MidAmerican Energy Holdings	2013-2014
Solar Star: Phase 1-5	SunPower	535.7	CA	Southern California Edison	MidAmerican Energy Holdings	2013-2014
Agua Caliente Solar	First Solar	333.4	AZ	Pacific Gas & Electric	NRG Energy, MidAmerican Energy Holdings	2012-2014
California Valley Solar Ranch: Phase I-V	SunPower	287.4	CA	Pacific Gas & Electric	NRG Energy	2012-2013
Antelope Valley Solar Ranch One: Phase 1-3	First Solar	283.7	CA	Pacific Gas & Electric	Exelon Corporation	2012-2014
Sempra Copper Mountain 3: Phase 1-6	Sempra Generation	272.7	NV	Southern California Public Power Authority	Sempra Generation, Con Edison	2014
Mount Signal Solar Farm	8minutenergy, Silver Ridge Power	260.0	CA	San Diego Gas & Electric	Riverstone Holdings, SunEdison	2014
Centinela Solar	LS Power	215.9	CA	San Diego Gas & Electric	LS Power	2013-2014
SolarGen2	First Solar	194.7	CA	San Diego Gas & Electric	Southern Company, First Solar	2014

Source: GTM Research U.S. Utility PV Tracker

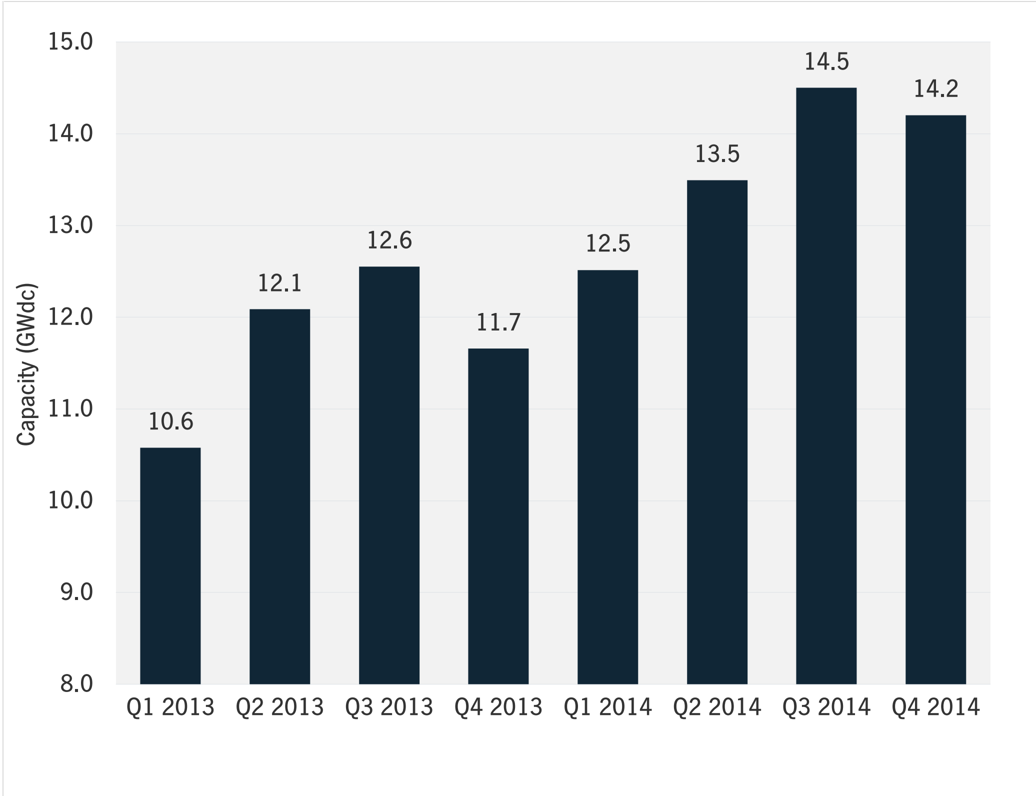
2.3.2. Trends in Utility PV Procurement

In 2012 and 2013, the U.S. utility PV market experienced two divergent trends. On one hand, installations were growing at a rapid clip, outpacing the also-growing distributed PV market in the U.S. In 2013, the utility market installed 2,855 MW_{dc} of capacity and accounted for 60% of the overall solar market – up from just 58 MW_{dc} and 13% in 2009. But while installations expanded, the project pipeline – defined as projects with a utility PPA or equivalent contract – began to stagnate. Virtually all utility procurement had been enabled by state renewable portfolio standards, and utilities in key Western states including California, Arizona and Colorado had signed up enough capacity to meet their near-term requirements. As a result, new procurement dried up and developers were left with stranded assets.

That procurement valley resulted in hard times for a number of project developers and fostered M&A activity that involved both companies and projects. But 2014 deviated from a longstanding lull in procurement, as utilities ramped up procurement opportunities to optimize the number of projects eligible to come on-line before the federal ITC is scheduled to drop at the end of 2016.

This rush was not only born out of meeting RPS obligations, but was also due to utility PV's growing economic competitiveness in the broader electricity market. As mentioned, by year's end, more than 4 GW_{dc} of centralized PV capacity had been procured by utilities based on solar's competitiveness with natural gas alternatives. Looking ahead to the rest of 2015, we expect utility procurement efforts to slow down, as developers double down on efforts to complete ambitious project pipelines before the end of 2016.

Figure 2.31 Utility PV Contracted Pipeline, Q1 2013-Q4 2014

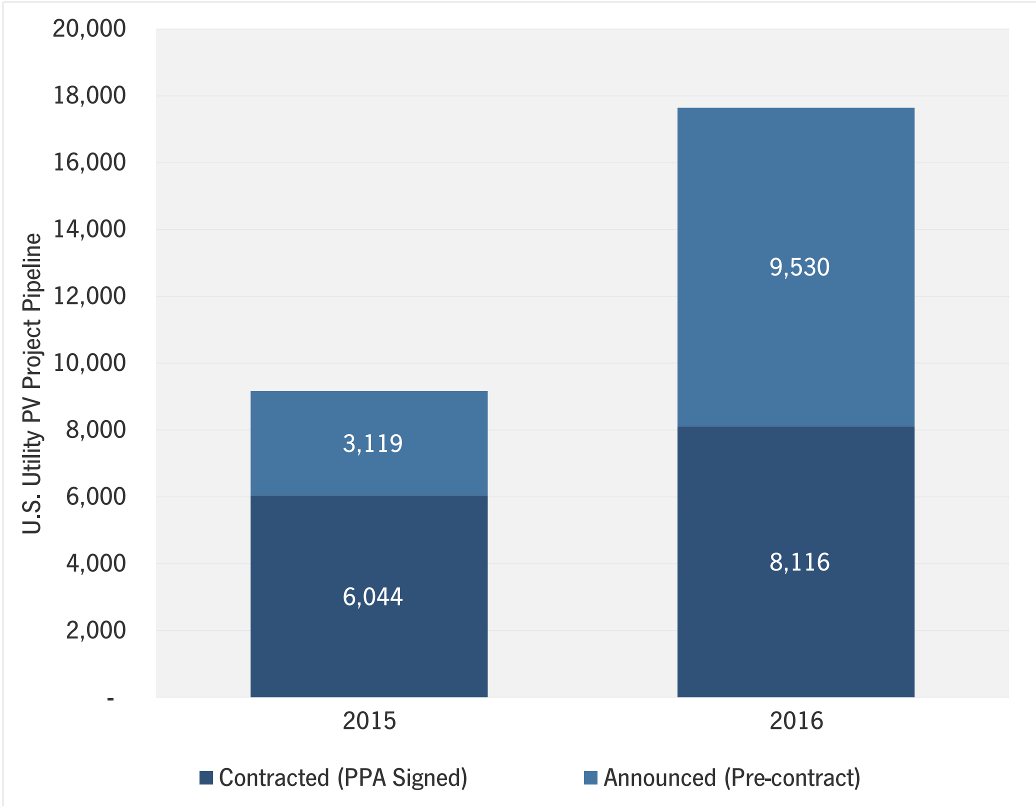


Source: GTM Research, U.S. Utility PV Tracker

2.3.3. Utility PV Market Outlook

2015 and 2016 will be all about pipeline build-out in the utility-scale PV market. There are currently 14.2 GW of utility-scale PV projects with PPAs in place and expected completion before the scheduled ITC expiration, so developers and EPCs will be operating at full capacity to bring these projects on-line. Additionally, GTM Research is tracking 12.6 GW projects still seeking PPAs for projects with similar timelines.

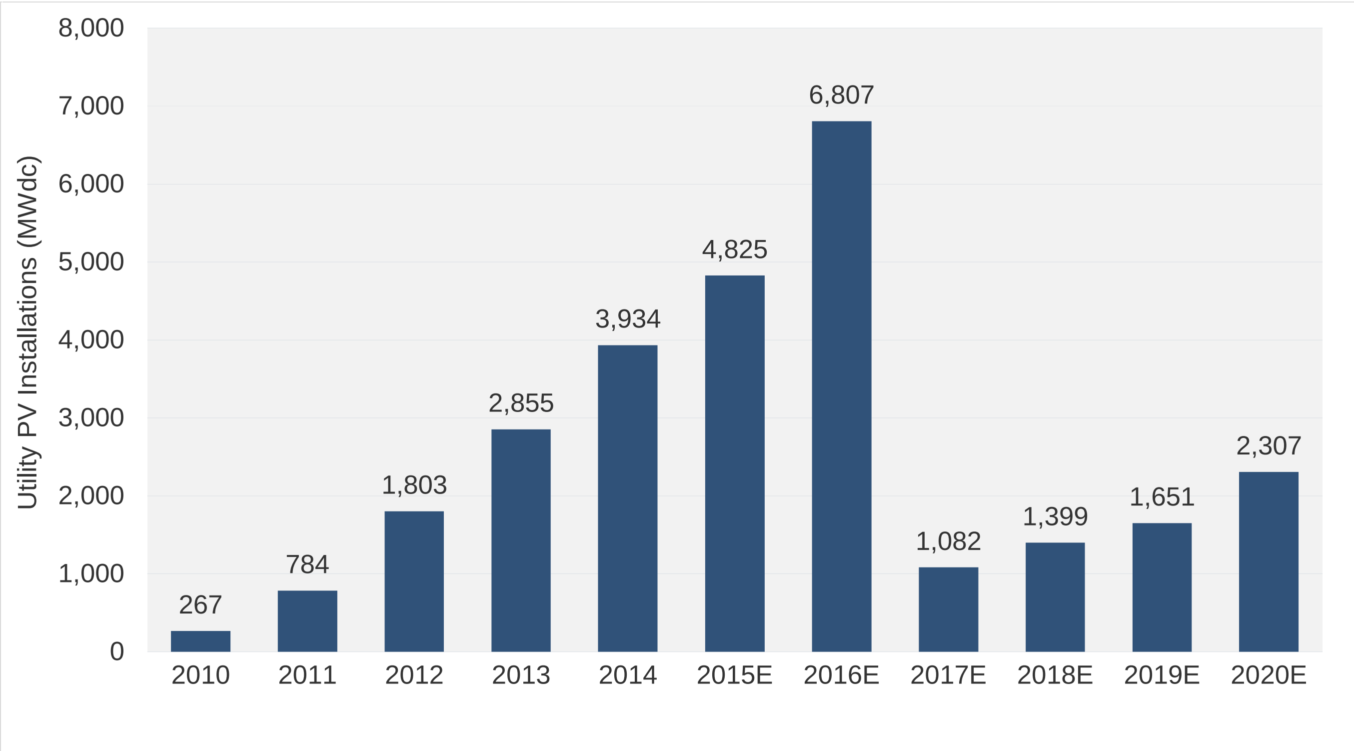
Figure 2.32 Current Utility-Scale PV Project Pipeline



Source: GTM Research U.S. Utility PV Market Tracker

After 2016, all bets are off in the utility market. As of now, virtually no developers are planning projects that will begin operation in 2017 or soon thereafter, as the loss of the ITC drives the majority of these projects into the red. As the ITC expiration date looms and developers seek to replenish their pipelines, we will see whether the economics of projects can pencil out in a post-30% ITC market. If a group of new PPAs are signed for post-2016 projects over the next year, the longer-term forecast could increase.

Figure 2.33 U.S. Utility PV Market Forecast, 2010-2020



2.4. Detailed Installations by State and Segment

Figure 2.34 PV Installations by State and Segment (MW_{dc})

	Q4				Annual 2014				Cumulative			
	Res.	Comm.	Util.	Total	Res.	Comm.	Util.	Total	Res.	Comm.	Util.	Total
Arizona	29.9	9.5	100.6	140.0	94.2	49.8	102.6	246.6	316.5	289.2	1,180.3	1,786.0
California	181.3	124.2	873.6	1,179.1	614.8	306.6	2,627.6	3,549.0	1,698.3	1,650.1	5,372.3	8,720.7
Colorado	12.9	7.6	-	20.5	41.8	25.4	-	67.2	135.8	156.1	106.6	398.4
Connecticut	6.1	2.8	6.8	15.7	16.6	21.5	6.8	44.8	41.7	62.7	14.2	118.6
Delaware	0.6	0.6	-	1.3	2.2	5.3	-	7.5	8.0	19.6	33.1	60.7
Florida	2.5	2.4	-	4.9	9.7	11.9	-	21.6	29.9	61.7	67.6	159.2
Georgia	0.1	0.0	19.6	19.7	1.2	2.2	42.1	45.5	3.4	26.2	131.6	161.2
Hawaii	19.6	10.0	-	29.6	60.7	32.2	14.0	106.9	238.5	160.5	41.4	440.5
Illinois	0.3	0.4	-	0.7	0.7	5.0	0.6	6.3	4.3	13.1	36.7	54.0
Indiana	0.3	0.4	21.5	22.2	0.7	2.4	55.4	58.5	1.2	5.1	106.2	112.5
Louisiana	5.1	0.2	-	5.3	29.8	0.9	-	30.7	63.1	2.2	-	65.3
Maryland	17.1	11.4	-	28.5	39.6	33.0	-	72.6	66.9	118.1	30.0	215.0
Massachusetts	23.0	43.9	-	66.9	64.4	224.2	19.7	308.2	122.7	550.6	78.0	751.2
Minnesota	0.8	1.4	-	2.1	1.4	4.5	-	5.9	4.1	13.8	2.3	20.1
Missouri	1.9	4.4	6.1	12.4	20.4	36.5	15.7	72.6	38.3	57.0	15.7	111.1
Nevada	0.8	7.9	124.0	132.7	2.3	18.6	318.4	339.3	10.1	63.7	651.1	725.0
New Hampshire	0.9	0.4	-	1.2	2.4	0.8	-	3.2	4.9	2.6	-	7.5
New Jersey	18.8	19.5	43.5	81.8	60.5	102.3	77.1	239.8	225.8	984.8	240.6	1,451.1
New Mexico	1.5	2.4	1.8	5.7	5.2	16.3	66.7	88.2	22.1	45.3	257.2	324.6
New York	41.6	16.5	0.6	58.7	89.3	48.8	9.3	147.4	163.2	171.5	62.2	396.9
North Carolina	1.6	0.6	213.4	215.6	4.3	2.7	389.5	396.6	14.0	99.5	839.7	953.2
Ohio	0.4	2.9	-	3.4	1.3	13.3	-	14.6	6.2	71.9	24.4	102.4
Oregon	2.7	0.5	-	3.2	6.5	1.7	-	8.2	31.7	36.9	15.8	84.5
Pennsylvania	0.4	1.6	-	2.0	1.9	8.3	-	10.2	51.8	171.4	21.6	244.8
South Carolina	0.2	0.06	-	0.3	0.8	0.2	-	1.0	2.01	5.4	3.7	11.1
Tennessee	0.5	0.4	52.0	52.9	1.5	2.1	52.4	56.1	9.1	50.8	70.1	130.0
Texas	4.4	6.6	19.3	30.2	14.6	15.5	98.8	128.9	43.8	41.7	244.5	330.0
Utah	2.0	0.2	-	2.2	4.4	6.0	-	10.4	11.6	18.7	-	18.2
Vermont	2.1	3.3	11.4	16.7	6.4	4.1	27.1	37.5	14.5	11.5	43.9	69.9
Virginia	0.7	0.1	1.0	1.8	2.1	2.4	1.2	5.6	3.7	6.3	1.2	11.2
Washington	3.9	0.2	-	4.1	12.0	1.8	-	13.8	29.5	9.2	-	38.6
Washington, D.C.	0.4	0.2	-	0.6	1.8	0.9	-	2.7	6.6	2.8	-	9.3
Wisconsin	0.6	0.4	-	1.0	1.3	1.1	-	2.4	7.2	11.5	1.1	19.8
Other	4.5	9.7	5.0	19.2	14.2	27.7	9.0	50.8	55.8	95.4	51.2	202.4
Total	390	293	1,500	2,182	1,231	1,036	3,934	6,201	3,486.1	5,086.8	9,744.2	18,305.0

2.5. Number of Installations

Figure 2.35 PV Installations by State and Segment

	Q4				Annual 2014				Cumulative			
	Res	Comm.	Util.	Total	Res	Comm.	Util.	Total	Res	Comm.	Util.	Total
Arizona	3,698	54	3	3,755	12,329	205	6	12,540	45,305	2,032	103	47,440
California	29,368	566	45	29,979	101,162	2,231	99	103,492	315,405	13,580	227	329,212
Colorado	1,972	20	-	1,992	6,346	155	0	6,501	23,178	1,732	7	24,917
Connecticut	823	18	2	843	1,747	95	2	1,844	5,675	438	3	6,116
Delaware	66	10	-	76	271	36	0	307	1,337	225	4	1,566
Florida	381	108	-	489	1,367	325	0	1,692	6,715	1,375	7	8,097
Georgia	13	2	68	83	45	28	142	215	463	281	185	929
Hawaii	3,136	138	-	3,274	10,720	538	2	11,260	49,817	2,412	9	52,238
Illinois	32	11	-	43	102	47	1	150	956	205	5	1,166
Indiana	48	6	4	58	109	42	28	179	178	68	32	278
Louisiana	1,176	13	-	1,189	5,325	33	0	5,358	7,698	59	0	7,757
Maryland	1,708	45	-	1,753	4,066	124	0	4,190	8,380	743	2	9,125
Massachusetts	3,363	86	-	3,449	9,380	341	6	9,727	18,953	1,977	28	20,958
Minnesota	118	49	-	167	211	111	0	322	673	393	1	1,067
Missouri	175	135	1	311	1,786	1,496	3	3,285	3,446	2,205	3	5,654
Nevada	134	14	2	150	330	152	4	486	1,817	740	13	2,570
New Hampshire	113	17	-	130	302	40	0	342	684	116	0	800
New Jersey	2,244	47	5	2,296	7,892	269	12	8,173	27,910	5,689	86	33,685
New Mexico	290	16	1	307	904	85	2	991	4,388	363	24	4,775
New York	5,320	140	4	5,464	10,616	498	28	11,142	22,346	3,238	40	25,624
North Carolina	315	12	26	353	853	60	72	985	2,462	286	198	2,946
Ohio	50	12	-	62	172	42	0	214	972	377	6	1,355
Oregon	468	14	-	482	1,200	51	0	1,251	7,941	677	6	8,624
Pennsylvania	54	44	-	98	277	175	0	452	7,067	2,407	4	9,478
South Carolina	43	2	-	45	161	10	0	171	402	66	1	469
Tennessee	59	15	2	76	183	68	4	255	763	611	11	1,385
Texas	639	57	2	698	2,272	186	5	2,463	7,437	881	22	8,340
Utah	329	8	-	337	816	60	0	876	2,811	97	0	2,908
Vermont	325	33	4	362	1,000	80	10	1,090	2,436	284	20	2,740
Virginia	118	3	3	124	377	30	4	411	1,703	207	4	1,914
Washington	517	8	-	525	1,773	49	0	1,822	5,384	294	0	5,678
Washington, D.C.	57	6	-	63	301	14	0	315	788	44	0	832
Wisconsin	115	23	-	138	247	51	0	298	1,443	511	1	1,955
Other	665	60	1	726	2,197	251	4	2,452	11,316	1,206	24	12,546
Total	57,932	1,792	173	59,897	186,839	7,978	434	195,251	598,249	45,819	1,076	645,144

2.6. Detailed Forecast Tables

Figure 2.36 Residential PV Installation Forecast (MW_{dc}), 2010-2020

State	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	2020E
Arizona	32	32	62	73	94	120	160	140	168	216	278
California	104	128	196	410	615	966	1,593	1,356	1,843	2,320	2,996
Colorado	19	14	18	28	42	60	82	71	74	87	102
Connecticut	3	3	6	7	17	22	30	23	29	37	44
Delaware	1	2	1	1	2	6	11	8	12	18	28
Florida	3	1	5	7	10	16	31	26	37	51	76
Georgia	0	1	1	0	1	3	7	4	6	10	14
Hawaii	8	21	57	83	61	48	67	60	75	97	136
Illinois	0	1	1	1	1	3	5	3	6	11	17
Indiana	-	-	-	0	1	3	7	5	8	12	16
Louisiana	-	-	-	21	30	40	51	42	39	42	47
Maryland	2	6	8	9	40	56	67	59	69	85	94
Massachusetts	2	5	15	30	64	86	98	86	97	118	141
Minnesota	1	0	1	0	1	4	9	6	8	13	17
Missouri	-	1	3	14	20	25	32	28	32	37	45
Nevada	1	1	0	1	2	10	22	18	25	44	61
New Hampshire	-	-	1	1	2	4	10	7	9	12	17
New Jersey	20	35	43	38	60	75	95	79	94	132	176
New Mexico	3	5	4	4	5	11	21	16	22	31	50
New York	12	8	15	27	89	125	188	165	200	256	343
North Carolina	0	2	1	2	4	9	20	13	19	30	41
Ohio	0	1	1	2	1	4	11	8	13	19	26
Oregon	4	4	6	6	7	14	23	16	29	35	43
Pennsylvania	14	17	7	10	2	6	13	8	14	28	44
South Carolina	-	0	0.1	0.2	1	3	8	5	11	17	27
Tennessee	-	1	3	2	2	6	8	5	9	15	19
Texas	3	5	8	9	15	25	41	34	42	61	84
Utah	-	0.04	0	1	4	12	19	15	20	29	38
Vermont	-	2	2	5	6	14	24	19	26	30	41
Virginia	-	-	-	1.6	2	3	7	5	8	11	15
Washington	2	3	3	8	12	18	27	19	24	31	35
Washington, D.C.	1	1	1	1	2	6	14	9	14	22	29
Wisconsin	1	2	0	1	1	4	6	4	7	10	12
Other	7	5	21	8	14	30	56	49	58	71	90
Total	246	304	494	814	1,231	1,837	2,862	2,411	3,147	4,037	5,242

Figure 2.37 Non-Residential PV Installation Forecast (MW_{dc}), 2010-2020

State	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	2020E
Arizona	22	76	64	58	50	39	44	36	41	49	65
California	90	216	307	293	307	436	704	510	575	665	806
Colorado	16	33	24	28	25	38	53	40	46	53	64
Connecticut	2	2	5	23	21	26	37	31	37	43	57
Delaware	2	8	2	1	5	8	13	10	15	20	28
Florida	5	5	14	19	12	14	19	14	17	21	28
Georgia	4	7	9	4	2	5	7	3	5	8	11
Hawaii	7	18	38	49	32	38	49	37	48	55	67
Illinois	0	1	4	1	5	12	30	22	25	29	35
Indiana	-	-	-	3	2	5	9	6	8	11	16
Louisiana	-	-	-	1	1	4	7	5	6	10	15
Maryland	5	16	41	20	33	51	63	44	57	79	94
Massachusetts	14	23	108	171	224	190	225	195	235	273	300
Minnesota	1	1	3	3	4	20	55	20	24	31	40
Missouri	-	3	4	14	36	40	43	30	36	43	55
Nevada	5	18	7	8	19	50	30	23	29	38	48
New Hampshire	-	-	1	1	1	5	8	4	7	11	16
New Jersey	89	226	300	189	102	160	265	210	288	410	589
New Mexico	5	4	4	14	16	21	29	24	31	41	55
New York	10	15	34	42	49	87	136	111	146	194	277
North Carolina	4	26	2	57	3	71	31	24	30	35	41
Ohio	7	20	13	17	13	10	16	12	17	22	33
Oregon	5	10	11	2	2	6	11	7	10	13	18
Pennsylvania	32	70	30	28	8	14	21	17	26	46	51
South Carolina	-	3	0.05	0.12	0	1	4	2	5	8	12
Tennessee	1	12	15	18	2	8	13	9	12	28	35
Texas	3	5	7	6	16	24	37	24	33	41	51
Utah	-	0	0	2	6	10	18	14	25	30	34
Vermont	-	3	2	2	4	6	11	8	12	19	31
Virginia	-	-	-	4	2	5	12	7	10	25	32
Washington	0	2	1	1	2	5	12	7	11	15	19
Washington, D.C.	0	1	0	1	1	5	10	9	14	21	30
Wisconsin	2	3	1	1	1	4	7	4	15	20	24
Other	6	6	23	26	28	36	55	43	75	105	144
Total	337	833	1,072	1,107	1,036	1,454	2,084	1,562	1,971	2,512	3,221

Figure 2.38 Utility PV Installation Forecast (MW_{dc}), 2010-2020

State	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	2020E
Arizona	9	182	592	290	103	107	115	29	36	49	66
California	22	233	542	1,918	2,628	2,077	3,932	442	470	605	706
Colorado	19	45	34	-	-	1	151	38	57	91	145
Connecticut	-	-	-	7	7	3	14	5	9	20	78
Delaware	-	11	15	7	-	5	-	-	-	-	-
Florida	27	8	5	-	-	1	121	42	72	50	80
Georgia	-	2	1	86	42	172	181	27	35	50	76
Hawaii	1	1	14	11	14	91	157	39	59	74	92
Illinois	10	-	26	-	1	40	-	-	-	-	-
Indiana	-	-	-	51	55	31	41	-	-	-	-
Louisiana	-	-	-	-	-	-	-	-	-	-	-
Maryland	-	-	30	-	-	30	-	-	-	-	-
Massachusetts	5	3	11	39	20	67	25	5	7	8	12
Minnesota	-	-	-	2	-	1	178	62	80	-	90
Missouri	-	-	-	-	16	-	-	-	-	-	-
Nevada	55	24	191	38	318	499	528	50	100	-	-
New Hampshire	-	-	-	-	-	-	-	-	-	-	-
New Jersey	24	52	76	9	77	144	80	16	22	27	38
New Mexico	35	114	15	26	67	59	71	25	42	57	98
New York	-	37	14	2	9	58	20	4	6	7	9
North Carolina	26	27	121	276	390	720	129	32	48	60	91
Ohio	12	-	11	1	-	6	-	-	-	-	-
Oregon	2	3	10	-	-	20	13	4	7	10	17
Pennsylvania	1	-	18	-	-	31	-	-	-	-	-
South Carolina	-	0.3	-	3	-	20	-	-	-	-	-
Tennessee	3	5	9	5	52	9	-	-	-	-	-
Texas	16	34	36	60	99	215	297	100	140	200	235
Utah	-	-	-	-	-	104	344	121	80	100	125
Vermont	-	-	8	9	27	12	-	-	-	81	119
Virginia	-	-	-	-	1	8	10	-	60	70	75
Washington	-	-	-	-	-	15	-	-	-	-	-
Washington, D.C.	-	-	-	-	-	-	-	-	-	-	-
Wisconsin	-	-	-	1	-	7	-	-	-	-	-
Other	2	3	25	13	9	272	399	40	68	92	156
Total	269	784	1,803	2,855	3,934	4,825	6,807	1,082	1,399	1,651	2,307

Figure 2.39 Total PV Installation Forecast (MW_{dc}), 2010-2020

State	2010	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	2020E
Arizona	63	290	719	421	247	266	319	205	245	313	408
California	216	577	1,046	2,621	3,549	3,478	6,229	2,308	2,888	3,590	4,508
Colorado	54	92	76	56	67	99	286	149	177	231	311
Connecticut	5	4	11	37	45	51	81	59	75	100	179
Delaware	2	20	18	9	7	19	24	18	27	38	56
Florida	35	14	24	26	22	31	171	82	126	122	184
Georgia	4	10	11	91	45	180	195	34	46	68	101
Hawaii	16	40	109	144	107	177	273	136	182	226	295
Illinois	11	1	30	2	6	55	35	25	31	40	52
Indiana	-	-	-	54	59	39	57	11	16	23	32
Louisiana	-	-	-	22	31	44	58	47	45	52	62
Maryland	8	22	79	29	73	137	130	103	126	164	188
Massachusetts	22	31	134	240	308	343	348	286	339	399	453
Minnesota	2	2	4	6	6	25	242	88	112	44	147
Missouri	-	3	7	28	73	65	75	58	68	80	100
Nevada	61	44	198	47	339	559	580	91	154	82	109
New Hampshire	-	-	2	2	3	9	18	11	16	23	33
New Jersey	132	313	419	236	240	379	440	305	404	569	803
New Mexico	43	123	24	45	88	91	121	65	96	129	203
New York	23	60	63	72	147	270	344	280	352	457	629
North Carolina	31	55	124	335	397	800	180	69	97	125	173
Ohio	19	21	25	21	15	20	27	20	30	41	59
Oregon	11	18	27	7	8	40	47	27	46	58	78
Pennsylvania	47	88	54	38	10	51	34	25	40	74	95
South Carolina	-	3	0	4	1	24	12	7	16	25	39
Tennessee	3	18	27	25	56	23	21	14	21	43	54
Texas	23	44	51	75	129	264	375	158	215	302	370
Utah	-	0	1	2	10	126	381	150	125	159	197
Vermont	-	5	12	16	38	32	35	27	38	130	191
Virginia	-	-	-	6	6	16	29	12	78	106	122
Washington	3	5	4	9	14	38	39	26	35	46	54
Washington, D.C.	1	2	1	2	3	11	24	18	28	43	59
Wisconsin	3	5	1	3	2	15	13	8	22	30	36
Other	15	13	69	47	51	338	510	132	201	268	390
Total	852	1,922	3,369	4,776	6,201	8,116	11,754	5,055	6,517	8,200	10,770

2.7. National System Pricing

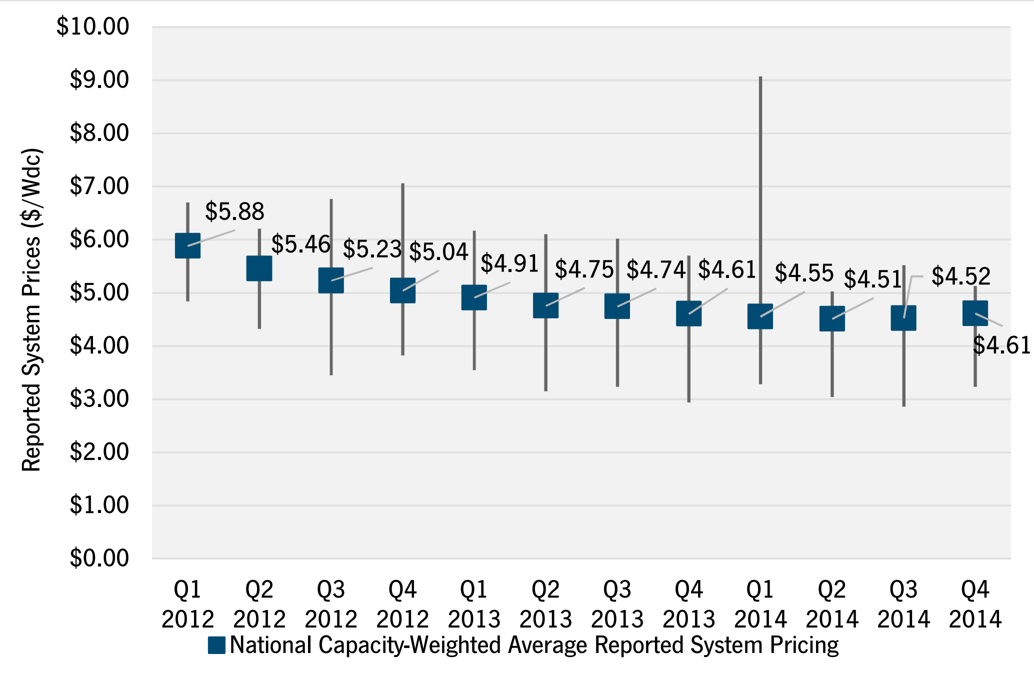
In the Q1 2014 *U.S. Solar Market Insight*, we introduced a new methodology of capturing and reporting national system pricing. Our previous methodology used weighted average system pricing directly from utility and state incentive programs, but we have long felt that the data was not an ideal reflection of the current state of system pricing, as it often represented systems quoted in quarters well prior to the installation and connection date, and much of the reported data was based on fair-market value assessments for third-party-owned systems.

Our new bottom-up methodology is based on tracked wholesale pricing of major solar components and data collected from major installers, with national average pricing supplemented by data collected from utility and state programs. Continuing with the previous quarter's change, we will no longer be reporting system prices on a state-by-state basis.

2.7.1. National Residential System Pricing

Reported residential system pricing from state and utility incentive programs averaged $4.61/W_{dc}$ on a capacity-weighted basis, with major state markets like California, Arizona and New York reporting figures of $4.69/W_{dc}$, $4.15/W_{dc}$, and $4.68/W_{dc}$, respectively. The lowest reported pricing came from programs in Florida ($3.23/W_{dc}$), Delaware ($3.35/W_{dc}$), Wisconsin ($3.50/W_{dc}$) and Texas ($3.50 W_{dc}$), whereas the highest reported pricing came from Massachusetts ($4.91/W_{dc}$), New York ($5.13/W_{dc}$), and Washington ($4.86/W_{dc}$).

Figure 2.40 Reported Capacity-Weighted Average Residential System Prices, Q1 2012-Q4 2014



As stated, these figures are subject to a number of factors that render the analysis insufficient for determining the actual industry costs during the quarter reported. These include:

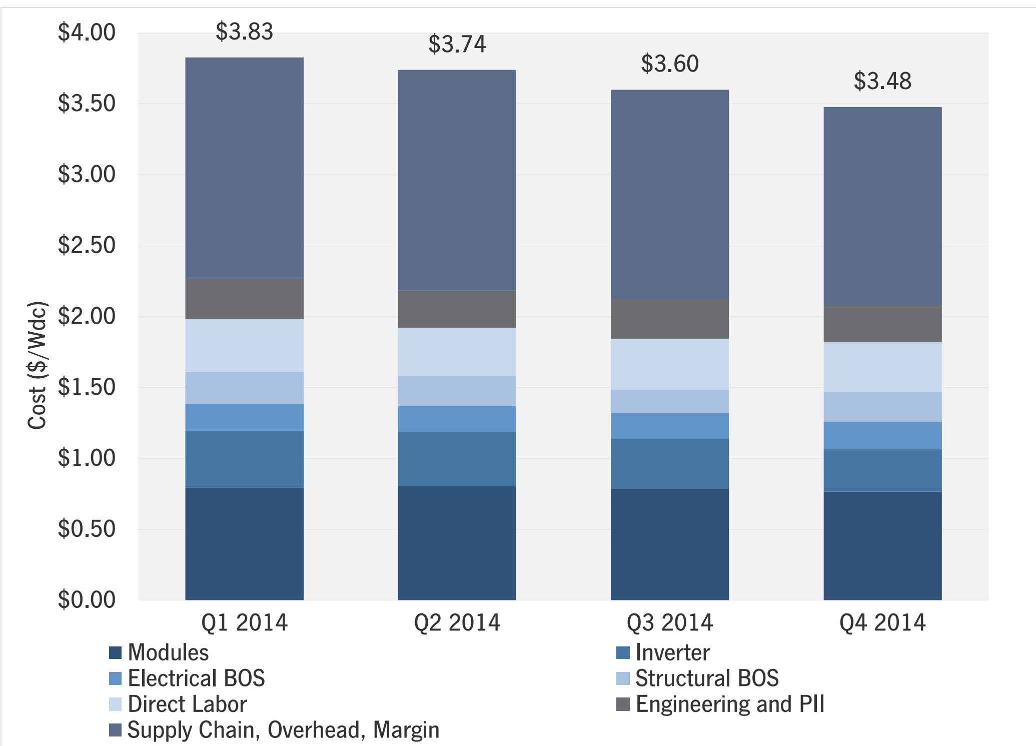
- Various definitions of "cost" that may or may not be inclusive of fair-market valuation and other components that do not necessarily reflect the true cost of solar installations
- Dated reporting of system pricing, reflecting quotes from as much as a year prior to the installation date
- Pricing for systems installed outside of state and utility incentive programs are not accounted for

As such, we have supplemented this reported data with more formal inquiries on system pricing with major PV system installers and investors. With this data, we have built a bottom-up model of residential system costs that better elucidates component and categorical costs for PV systems built during the quarter. Due to the data sources for this information, these costs are more reflective of turnkey pricing on standard systems for firms installing a total of more than 1 MW (~150 systems) per quarter. In line with the previous quarter, we amend our residential cost breakdowns to reflect a blend of systems using microinverters and string inverters to home in on a better "average" price.

We continue to see system pricing falling as installers reach scale and focus their attention on improving installation speed and reaping the resulting cost savings. Competition has also played a major role in forcing installers to be leaner in their bids to potential residential customers. This has led to cost declines across the entire balance-of-system value chain, even as module pricing and inverter pricing has stayed relatively flat, the latter due to a shifting mix toward module-level power electronics.

Our modeled costs for residential solar land at \$3.48/W_{dc} in Q4 2014 versus the modeled costs of \$3.83/W_{dc} in Q1 2014. While we did not model quarterly costs in 2013, the implied weighted average of \$3.64/W_{dc} in 2014 represents a 10% year-on-year decline from our modeled \$4.08/W_{dc} weighted average estimate for 2013.

Figure 2.41 Modeled Residential Turnkey EPC Pricing With Breakdown, Q1 2014-Q4 2014



Residential	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Modules	$0.79	$0.81	$0.79	$0.77
Inverter	$0.40	$0.38	$0.35	$0.30
Electrical BOS	$0.19	$0.18	$0.18	$0.19
Structural BOS	$0.23	$0.21	$0.16	$0.21
Direct Labor	$0.37	$0.34	$0.36	$0.35
Engineering and PII	$0.28	$0.27	$0.28	$0.26
Supply Chain, Overhead, Margin	$1.56	$1.55	$1.48	$1.40
National Average Turnkey Pricing	$3.83	$3.74	$3.60	$3.48
National Average Reported Pricing	$4.55	$4.52	$4.55	$4.61

Large disparities in system pricing often exist due to the size of projects, the size of the installation company, and, significantly, what the local market will bear. In regions with high electricity retail rates, overall system pricing may be higher despite similar hardware costs. In terms of hardware costs, three major differences drive the divergences in hardware costs:

- Premium PV module-based systems, including high-efficiency modules, that can command 25% to 35% more than standard efficiency crystalline silicon modules
- Microinverters, which lead to a 8% to 20% premium on the overall system due to additional hardware costs
- Structural balance-of-system requirements, especially in high wind zone areas or on clay tile roofs, which can drive the materials and cost of racking and mounting hardware up by 50%

Fire safety and grid integration have emerged as key topics in the early part of 2015. More states are adopting and moving to the 2014 NEC standard, increasing the need to meet rapid shutdown requirements – and to finally adopt long-mandated but previously seldom-enforced arc-fault circuit interruption requirements. The regulations have pushed some installers to adopt module-level power electronics solutions in order to maximize functionality from additional installed electrical equipment; however, traditional, non-DC-optimized string inverter architectures still have a slight advantage in the residential market.

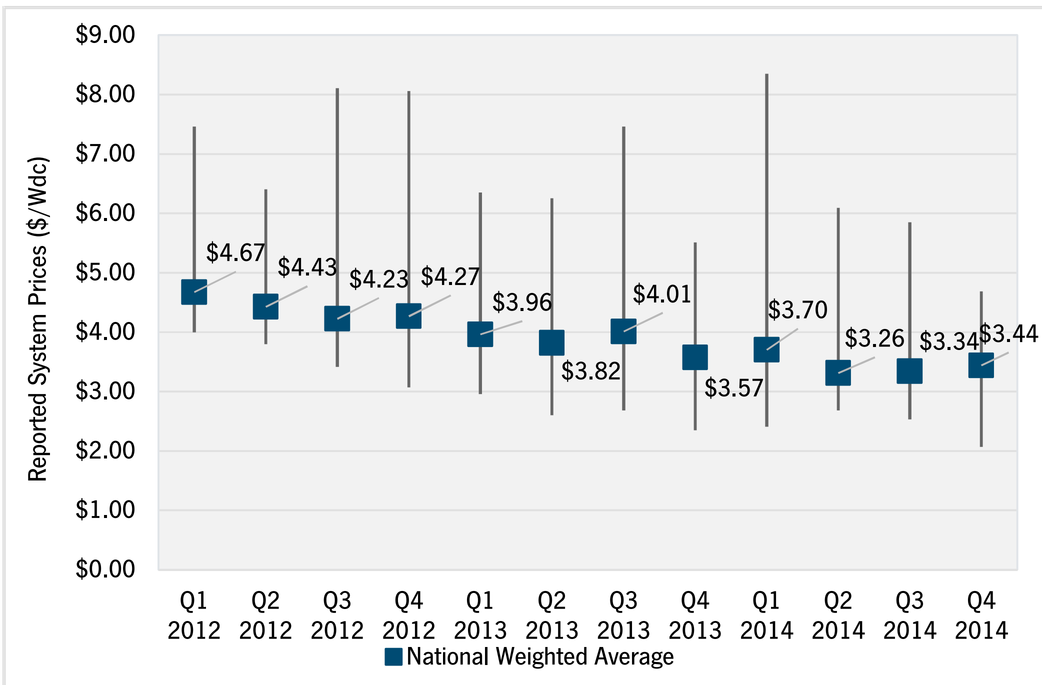
In addition, the California CPUC recently approved revisions to the California Grid interconnection code Rule 21, making the adoption of "smart inverters" mandatory for California PV systems installed by the latter of December 31, 2015 or 12 months after UL approves the applicable standards. Prior to the requirement, California utilities can allow the use of "smart inverters." Furthermore, existing interconnected inverters are grandfathered and will not be required to conform to new standards. Functionality for Rule 21 focuses on changing anti-islanding requirements to allow for low-voltage ride-through, establishing new standards for fault ride-through, volt/VAR operations, ramp rates and soft start reconnection. Many inverter manufacturers are confident in their ability to provide these new features. The next phase of Rule 21 will center on standardizing communication protocols to allow for remote monitoring, signaling and control.

2.7.2. National Non-Residential System Pricing

Tracking non-residential system pricing presents an even bigger challenge than with residential systems due to the large variation of system sizes, customer types, and system types within the non-residential sector. As one might expect, a 10 kW carport system for a small elementary school in Arizona will have a much different price point than a 5 MW ground-mount project on abandoned land in Massachusetts. Nevertheless, in Q4 2014, reported system pricing from state and utility incentive programs averaged to $3.44/W$_{dc}$ on a capacity-weighted average basis – an increase from last quarter's $3.34/W$_{dc}$.

Reported weighted average system pricing in major non-residential markets such as California and Massachusetts came in at $3.80/W$_{dc}$, and $2.57/W$_{dc}$, respectively. Massachusetts ($2.57/W$_{dc}$), Maryland ($2.07/W$_{dc}$), New Jersey ($2.63/W$_{dc}$) and Texas ($2.79/W$_{dc}$) were the lowest-priced markets, whereas Minnesota ($4.38/W$_{dc}$), Delaware ($5.85/W$_{dc}$) and New York ($4.69/W$_{dc}$) appeared as high-priced markets. Note that in commercial markets, states with low volumes and incentive programs that limit the size of commercial projects will show higher-than-average commercial pricing.

Figure 2.42 Reported Capacity-Weighted Average Non-Residential System Prices, Q1 2012-Q4 2014



Once again, reported pricing from major EPCs, integrators and developers indicates that standard construction costs for the market within the quarter were lower than what is ultimately reported by state and utility agencies.

System characteristics that will drastically affect pricing, among others, include:

- Geographical differences, in particular,
  - Weather-related building codes (e.g., snow and wind loading)
  - Labor pricing regulations (e.g., requirements for prevailing wage)
  - Building occupancy regulations (i.e., safety factors)
- System type (i.e., rooftop, carport, ground mount)
- Customer type and electricity tariff structure

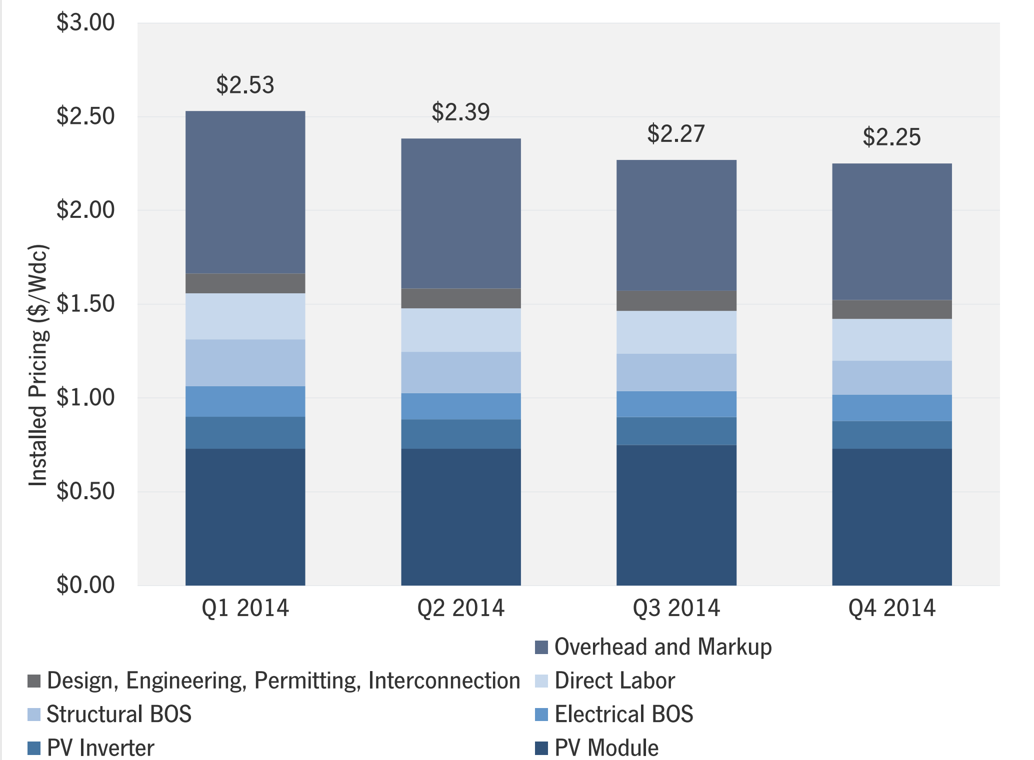
As with residential PV systems, we performed a bottom-up cost analysis of non-residential PV, specifically focusing on the example of a ballasted flat-roof system. Once again, our inputs come from larger EPCs and integrators that likely have better-than-average pricing relative to the strict industry mean. In order to ensure our bottom-up model reflects industry trends going forward, we have standardized around a minimalist flat-roof non-residential system, with the caveat that commonplace issues such as roof obstructions can significantly affect system costs. Our bottom-up model assumes:

- 300 kW low-slope ("flat") roof system
- Standard multicrystalline silicon PV modules
- String inverter-based design topology
- Fully ballasted, aluminum-based mounting structure
- Rectangular array on membrane roof
- PV module and inverters reflect "factory-gate" pricing with distribution and low volume markups reflected in the supply chain category

Our model shows flat-roof non-residential system costs at $2.25/W_{dc}$, representing a 1% decrease quarter-over-quarter – which means prices essentially remained flat during the quarter.

"Overhead and margins" remains the largest cost category at $0.73/W_{dc}$. While considerably less than residential soft costs, commercial supply chain, overhead, and margins are similarly the single largest cost category. With additional competition amongst project buyers, we have seen stronger margins for good commercial projects over the last quarter.

Figure 2.43 Modeled Non-Residential Turnkey System Pricing With Breakdown, Q1 2014-Q4 2014



Commercial	Q1 2014	Q2 2014	Q3 2014	Q4 2014
PV Module	$0.73	$0.73	$0.75	$0.73
PV Inverter	$0.17	$0.16	$0.15	$0.15
Electrical BOS	$0.16	$0.14	$0.14	$0.14
Structural BOS	$0.25	$0.22	$0.20	$0.18
Direct Labor	$0.25	$0.23	$0.23	$0.22
Design, Engineering, Permitting, Interconnection	$0.11	$0.11	$0.11	$0.10
Overhead and Markup	$0.87	$0.80	$0.70	$0.73
Turnkey Pricing	$2.53	$2.39	$2.27	$2.25
Reported Pricing	$3.70	$3.31	$3.34	$3.44

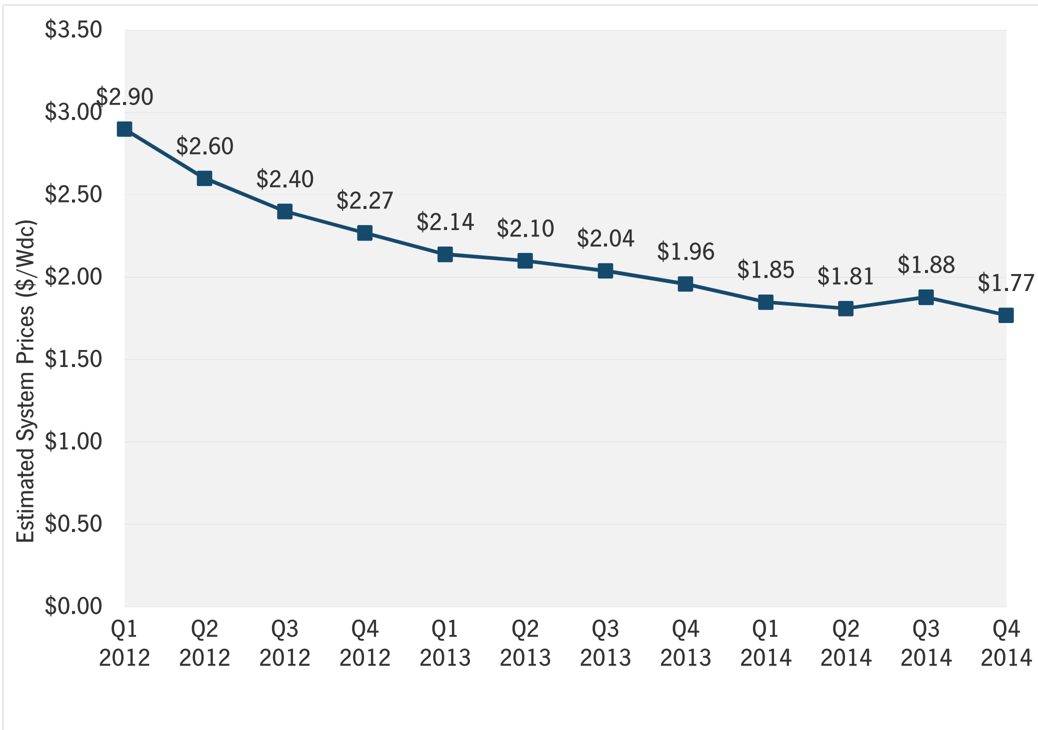
Once again, shifting rules in California are sending module and balance-of-systems manufacturers scrambling. In particular, new International Building Code (IBC) requirements around fire safety have required module and racking manufacturers to seek additional testing. The IBC in California now requires module and racking systems to attain a fire class rating that measures the PV systems' resistance to spreading a rooftop fire. The fire class rating must be equal or above that of the host rooftop. These rules were originally intended to go into effect in 2014, but after determining that the standards would be disruptive to the PV market, California regulators pushed the enforcement to January 1, 2015. While no other states currently have similar requirements, manufacturers expect that others will look toward California for guidance and implement similar, if not identical, requirements.

2.7.3. National Utility System Pricing

Unlike residential and non-residential systems, utility system pricing is rarely reported. As a result, our national capacity-weighted average incorporates publicly reported pricing where available, as well as input from utility developers and EPCs. National weighted-average system pricing for utility systems in Q4 2014 came in at $1.77/W$_{dc}$, a 6% decrease from Q3 2014, but a year-over-year decline of 10%.

We also find that costs for systems installed in Q4 2014 came in as low as $1.40/W$_{dc}$, specifically in Southeastern markets, and as high as $2.10/W$_{dc}$. Low pricing reflects strong competition in new markets that has pushed component and EPC margins significantly downward. High pricing reflects systems with legacy PPAs and higher-cost components such as single-axis tracking.

Figure 2.44 Capacity-Weighted Average Utility PV System Prices, Q1 2012-Q1 2014



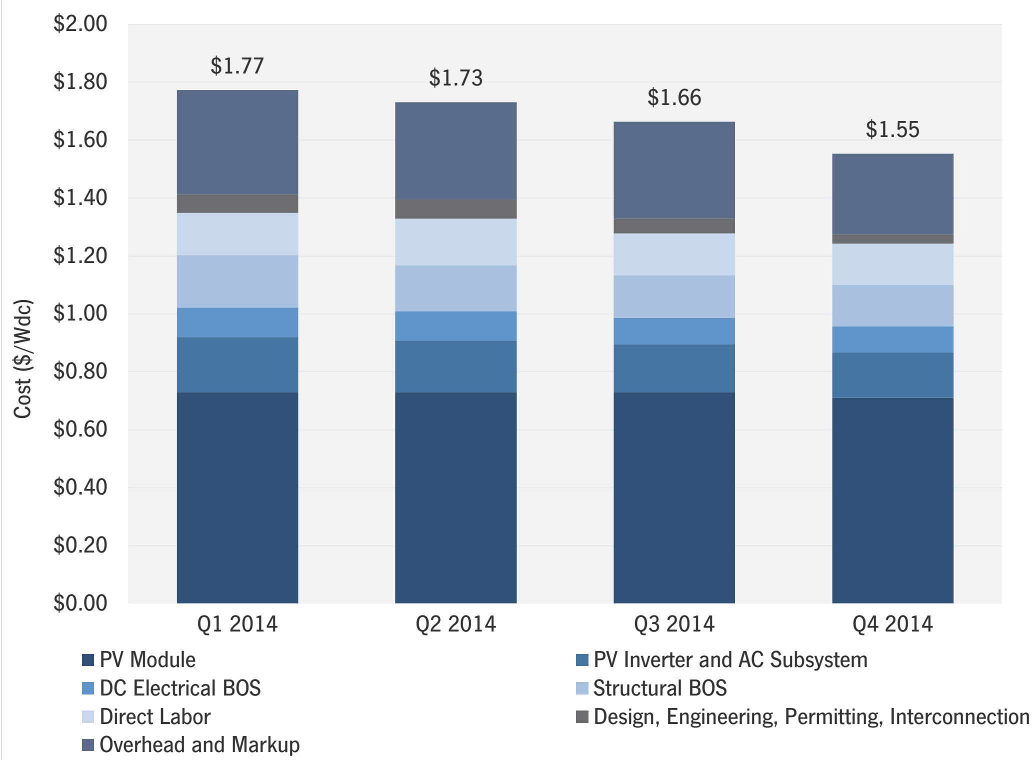
In modeling our utility PV system costs, we employ the following assumptions:

- 10 MW$_{dc}$ utility system in California
- Standard multicrystalline silicon PV modules
- 1.3 DC-to-AC ratio
- Steel-based fixed-tilt system with pile-driven foundations and horizontal single-axis tracking
- Square array with minimal site grading
- PV module and inverters reflect “factory-gate” pricing

Modeled costs of a fixed-tilt utility system land at $1.55/W$_{dc}$, reflecting a significant drop from last quarter's $1.66/W$_{dc}$ pricing. In particular, we have witnessed strong pressure on racking pricing, with lowest costs under $0.10/W$_{dc}$.

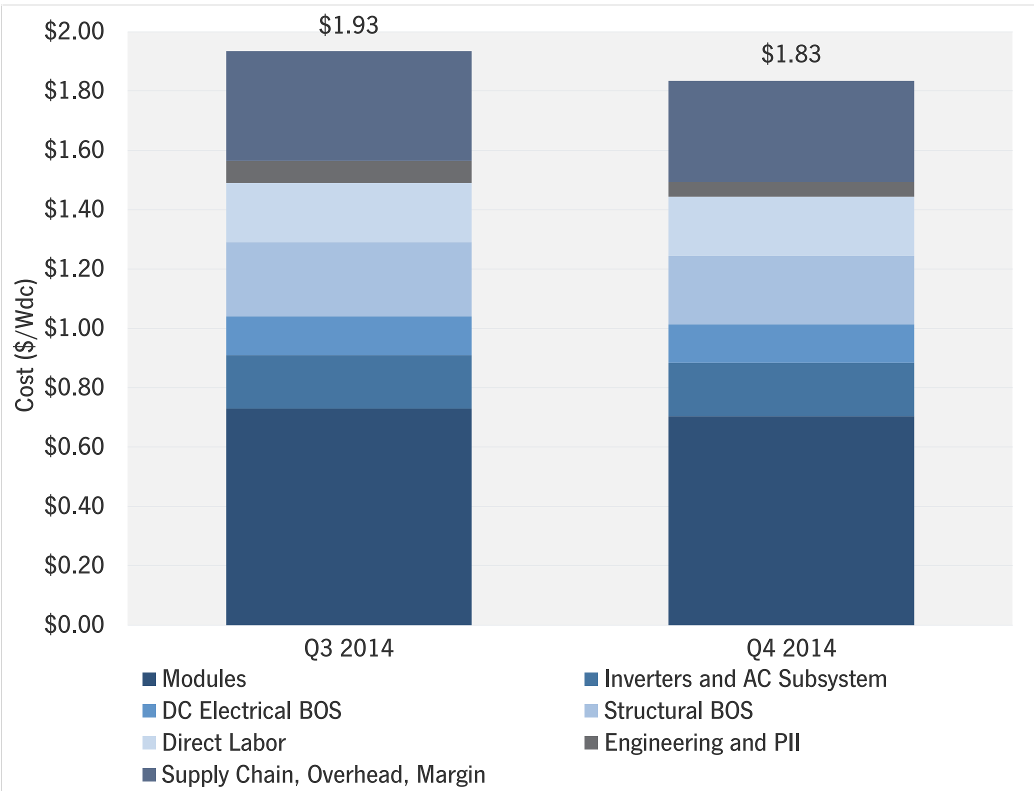
Meanwhile, we began publishing our models for single-axis tracking systems in last quarter's edition of this report. In Q4 2014, single-axis tracking projects came in at $1.83/W$_{dc}$ – a 5% drop from the $1.93/W$_{dc}$ reported the quarter before. We continue to see single-axis tracking projects expand in the ground-mount sector, with capacity-weighted share reaching 60% in 2014. In addition, due to the compression of the price differential between fixed-tilt and single-axis systems, project developers have proposed tracking projects in nontraditional markets such as North Carolina and Georgia.

Figure 2.45 Modeled Utility Turnkey Fixed-Tilt PV System Pricing With Cost Breakdown, Q1 2014-Q4 2014



U.S. Fixed-Tilt PV Modeled Costs ($/Wdc)	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Modules	$0.73	$0.73	$0.73	$0.71
Inverters and AC Subsystem	$0.19	$0.18	$0.17	$0.16
DC Electrical BOS	$0.10	$0.10	$0.09	$0.09
Structural BOS	$0.18	$0.16	$0.15	$0.14
Direct Labor	$0.15	$0.16	$0.14	$0.14
Engineering and PII	$0.06	$0.07	$0.05	$0.03
Supply Chain, Overhead, Margin	$0.36	$0.34	$0.34	$0.28
National Average Turnkey Pricing	$1.77	$1.73	$1.66	$1.55

Figure 2.46 Modeled Utility Turnkey Single-Axis Tracking PV System Pricing With Cost Breakdown, Q3 2014-Q4 2014



Utility	Q3 2014	Q4 2014
Modules	$0.73	$0.70
Inverters and AC Subsystem	$0.18	$0.18
DC Electrical BOS	$0.13	$0.13
Structural BOS	$0.25	$0.23
Direct Labor	$0.20	$0.20
Engineering and PII	$0.07	$0.05
Supply Chain, Overhead, Margin	$0.37	$0.34
Turnkey EPC Pricing	$1.93	$1.83

2.8. Manufacturing

2014 was a notable year for U.S. manufacturers. Though shipment growth out of U.S. manufacturing facilities was minimal when compared to those in other solar manufacturing hubs, for the first time in years, domestic factories started to experience capacity strain, some reaching fully booked capacities.

This growth was driven by a healthy supply-demand balance and uncertainty regarding the final tariff rates for Chinese-produced modules. Strong performance in 2014 and a positive demand outlook for 2015 ultimately allowed leading U.S. firms to announce and construct new manufacturing capacity, most notably:

- SolarWorld: The company plans to expand module capacity from 390 MW to 530 MW with completion and ramp-up by Q3 2015. The investment will enable the line to be expanded to as much as 630 MW. PERC cell production will increase by 100 MW in Q1 2015, growing from 335 MW to 425 MW.
- Suniva: Started construction on new 200 MW PV facility in Michigan in August 2014, claiming production would begin in Q4 2014.
- First Solar: In addition to restarting idled lines at its Malaysia facility, the company will deploy existing toolsets to add two new lines of capacity at its Perrysburg, Ohio facility. The additional lines will be operational mid-2015 and provide >100 MW of output in 2015.

2.8.1. Polysilicon

The global solar polysilicon industry is highly consolidated. This applies to the U.S. as well, where there are only three major facilities of note; each is individually owned by Hemlock, SunEdison or REC. Together, these three facilities were responsible for 49,059 MT of solar polysilicon in 2014. This represented a 19% increase over production in 2013. The significant year-over-year increase can be attributed to a much stronger pricing environment and a tighter overall supply-demand balance in 2014.

Looking ahead, 2015 could see significant capacity expansions in the U.S., with REC adding capacity in Washington, and Wacker Chemie planning to commence operation of a new 15,000 MT facility in Tennessee in the second half of the year. However, the antidumping tariffs on U.S. polysilicon exports to China are a definite threat to the growth of the U.S. polysilicon sector in 2015. In January 2014, China applied final antidumping duty rates of up to 57 percent on polysilicon produced by U.S. manufacturers. The duties are effective for five years. In August, China's Ministry of Commerce declared that it would suspend applications from solar companies looking to import polysilicon under so-called processing trade rules. In the case of solar, processing trade rules enable polysilicon used in domestic manufacturing to be exempt from import duties if the finished product – solar cells – is then exported. This had a disproportionate effect on U.S. polysilicon producers, since import duties on their products are much steeper than duties applied to polysilicon coming from other markets.

Figure 2.47 U.S. Polysilicon Production, Q4 2013-Q4 2014

Polysilicon (Metric Tons)	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Capacity	13,640	13,856	14,071	14,287	14,503
Production	11,455	11,155	11,981	12,859	13,064

2.8.2. Wafers

We estimate that 21 MW of wafers were produced in the U.S. in Q4 2014, down 72% from 2013's total of 76 MW. Year-end capacity stood at 310 MW, which was flat when compared to 2013, but the top-level number belies the reality that very little of this capacity is currently active and being utilized for commercial production. Presently, there remain only two wafer manufacturing facilities in the U.S. One is owned by SunEdison, a monocrystalline wafer fab in Oregon operating below its nameplate capacity of 60 MW, and the other is owned by SolarWorld, which has yet to re-ramp its 250 MW Oregon facility after announcing it would close in 2013 for upgrades.

Figure 2.48 U.S. Wafer Production, Q4 2013-Q4 2014

Wafer (MW)	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Capacity	78	78	78	78	78
Production	5	4	5	6	7

2.8.3. Cells

Note: Thin film facilities producing modules through monolithic integration are not defined as producing cells in this report series.

U.S. crystalline silicon cell production was estimated to be 400 MW in 2014, down 1% over 2013. Year-end capacity fell slightly, dropping 5% year-over-year to an estimated 400 MW. U.S. solar cell capacity and production is driven by SolarWorld in Oregon (the largest U.S. cell producer), Suniva in Georgia, and, when its greenfield facility fully ramps, Mission Solar Energy in Texas.

Figure 2.49 U.S. Cell Production, Q4 2013-Q4 2014

Cell (MW)	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Quarterly Capacity	125	125	131	138	144
Production	100	92	98	100	111

2.8.4. Modules

U.S. PV module production grew 4% year-over-year, reaching 997 MW in 2014. The year-over-year uptick was primarily due to healthier supply-demand balance in 2014, as well as the new trade litigation relating to imports of Chinese- and/or Taiwanese-produced cells and modules, which diverted a meaningful portion of sales to the best-positioned U.S. producers.

In terms of technology trends, the majority of modules produced in the U.S. in 2014 were crystalline silicon (52%). With regard to thin-film technologies, cadmium telluride (all First Solar) and CIGS (mostly MiaSolé and Stion) had a production share of 31% and 17%, respectively. Overall, U.S. thin film production share stood at 48%, which is much higher than the global average (10% in 2014).

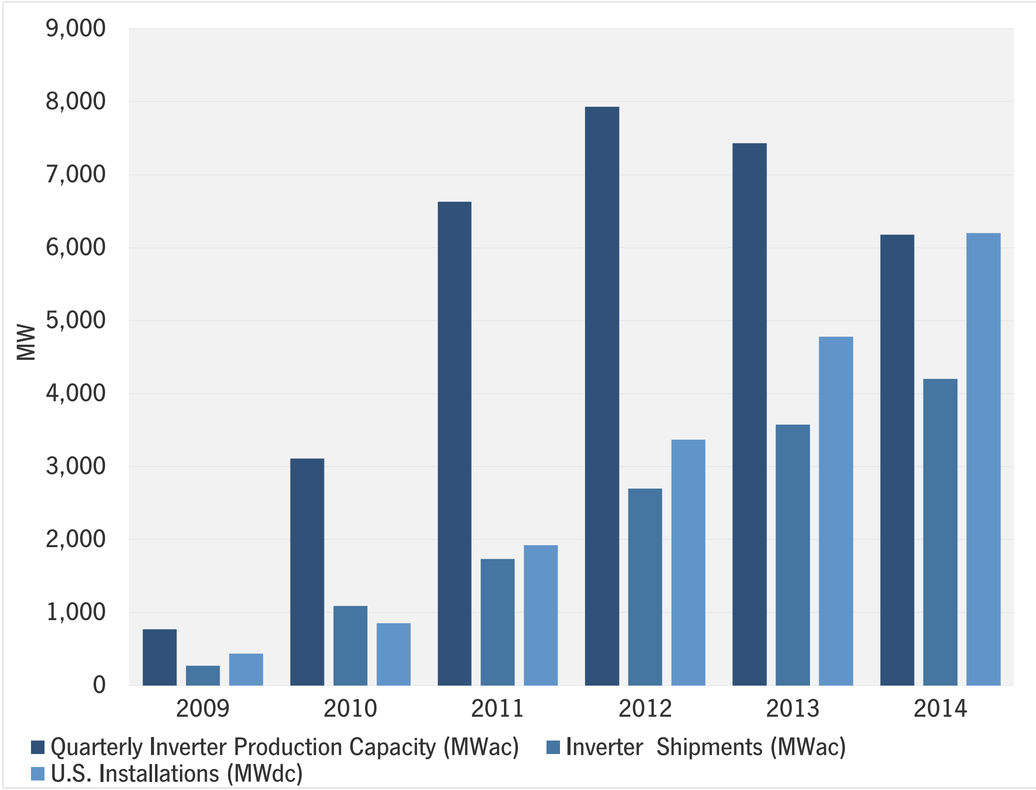
Figure 2.50 U.S. Module Production by Technology, Q1 2014-Q4 2014

Module (MWp)	Q1 2014		Q2 2014		Q3 2014		Q4 2014	
	Capacity	Production	Capacity	Production	Capacity	Production	Capacity	Production
Crystalline Si	204	131	171	116	174	136	184	140
CdTe	91	68	93	74	94	80	96	82
CIGS	75	33	76	41	76	47	77	48
a-Si	5	1	3	1	0	0	1	0
Total	375	232	342	232	344	263	358	269

2.8.5. Inverters

Production capacity based on Q4 run rates from U.S. facilities exceeded 6.1 GWac at the end of 2014 – a 17% decline from the end of 2013 and a 23% drop from the peak in 2012. Still, domestic production capacity represents eightfold growth since 2009. More importantly, while capacity has fallen, actual production and shipment of PV inverters increased by 17% over the past year. In fact, domestic production of PV inverters has grown at a 73% CAGR in the past five years, representing more than 15-fold growth. While the emergence of the U.S. market in 2010-2012 encouraged significant capacity investment, much of the exuberance faded as foreign manufacturers faced significant bankability hurdles. In combination with well-publicized inverter bankruptcies and troubles, a slow divestment of U.S. manufacturing capacity by struggling manufacturers has dominated headlines – despite a quiet but extremely promising growth by domestic market leaders.

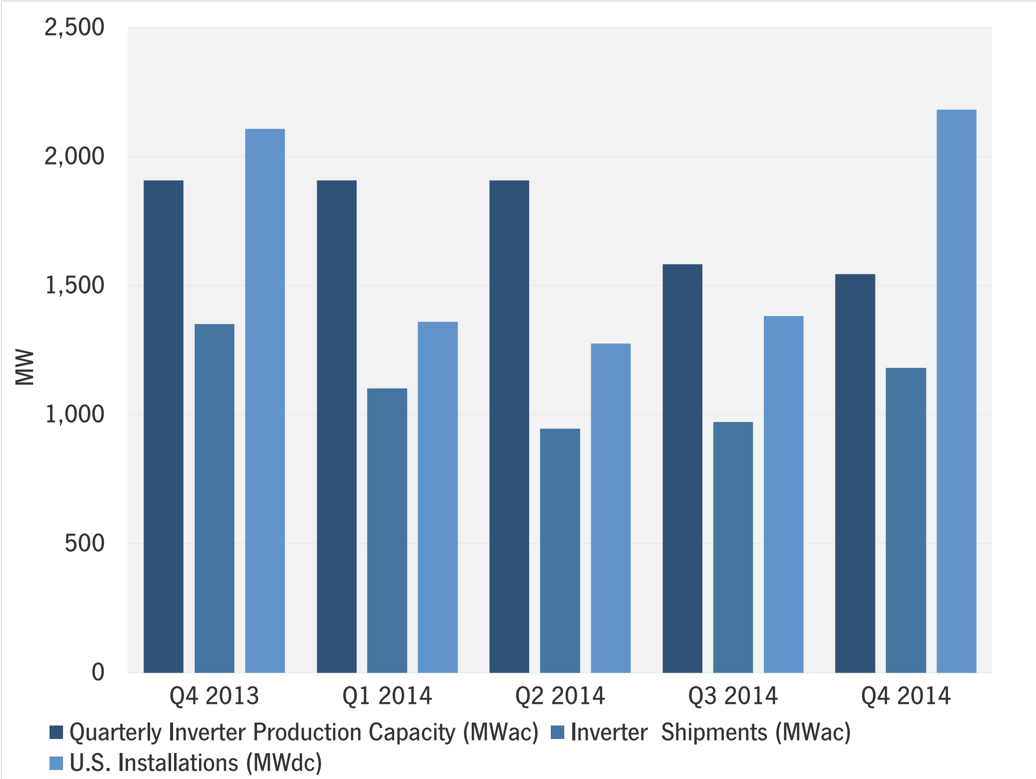
Figure 2.51 Annual U.S. Inverter Production Capacity, Shipments, and U.S. Installations, 2009-2014



	2009	2010	2011	2012	2013	2014
Inverter Production Capacity (MWac)	769	3,108	6,627	7,932	7,432	6,176
Inverter Shipments (MWac)	271	1,087	1,737	2,699	3,577	4,201
U.S. Installations (MWdc)	435	852	1,922	3,369	4,776	6,201

Seasonality continues to be a strong force, as shipments spiked in the latter part of Q3 and early in Q4 to meet the end-of-year rush. Quarter-over-quarter growth jumped by 22% but shipments actually dropped by 12% on a year-over-year basis, in large part due to the retirement of U.S. production capacity by a major inverter supplier. Domestically produced inverters continue to dominate in the commercial and utility sectors, with all but a couple of leading manufacturers owning significant U.S. production capability. While two residential market leaders produce their power electronics through contract manufacturers in China, the remaining inverter manufacturers produce through U.S. capacity.

Figure 2.52 Quarterly Domestic Inverter Capacity and Shipments (MWac) vs. Installations (MWdc)



	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Quarterly Inverter Production Capacity (MWac)	1,908	1,908	1,908	1,583	1,544
Inverter Shipments (MWac)	1,351	1,102	945	972	1,182
U.S. Installations (MWdc)	2,108	1,361	1,276	1,382	2,182

While U.S. inverter manufacturing saw a significant upswing throughout 2014, the industry was nevertheless marked by growing troubles due to a broader global shakeout of inverter companies, as well as suppliers struggling to adapt to newly enforced NEC requirements and rapidly changing requirements for grid interconnection in Hawaii. Inverter manufacturers must be prepared for continued changes in 2015, with the adoption of new California interconnection standards (Rule 21), as well as a continued question mark on requirements in Hawaii and other high-penetration PV states.

2.9. Component Pricing

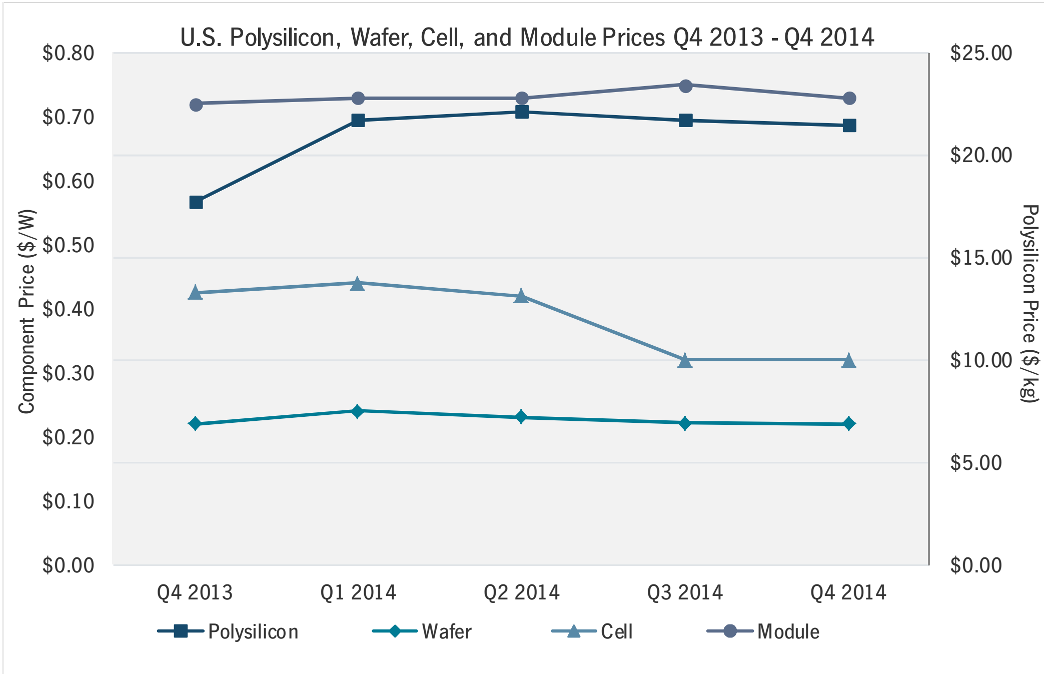
2.9.1. Polysilicon, Wafers, Cells, and Modules

Blended pricing for polysilicon was up year-over-year, growing 21% at $21.5/kg in Q4 2014. Significant polysilicon price growth was driven by polysilicon demand recovery in 2014, as well as favorable supply-demand dynamics. In contrast to dramatic polysilicon price growth, end-of-year multi wafer prices stayed static compared to 2013 year-end levels at $0.22/W. Multi cell prices were the one component in which prices fell, down 25% year-over-year at $0.32/W. It should be noted that following the U.S. imposition of antidumping duties on Taiwanese cells and modules, Chinese producers switched from using Taiwanese cells in U.S.-bound modules to using Chinese cells. In the past, prices for Taiwanese-produced cells had been relevant to determining the price for a U.S.-bound, Chinese-produced module (Q2 2012-Q3 2014), while prices and tariffs on Chinese-produced cells currently drive module prices.

Module pricing in the U.S. differs widely based on order volume, producer region and individual firm. During the fourth quarter, delivered prices for Chinese modules ranged from $0.69/W on the low side (corresponding to order volumes greater than 10 MW) to $0.73/W on the high side (order volumes of less than 1 MW). The blended delivered price for Chinese-produced multi modules is estimated to have risen 1% year-over-year to $0.73/W in Q4 2014. This upward trend contrasts with the downward global module price trend, and, in fact, is unique to the U.S. with its imposition of new tariffs on Chinese- and Taiwanese-produced modules. Pricing by firms in the U.S. and rest of Asia countries (Korea, Malaysia, Singapore) selling into the residential and commercial sector were in the range of low to mid-$0.80/W, largely in sync with price levels throughout the year.

In 2015, U.S. module prices will be driven by the tariff on Chinese cells. Currently, the most popular sourcing strategy utilized by Chinese suppliers to mitigate cost increases from these new tariffs involves shipping all-Chinese product to the U.S. and paying the 2012 tariff on Chinese cell imports (30.7% for most firms). At the end of 2014, the U.S. Department of Commerce filed its preliminary review of the import tariffs on Chinese cells into the U.S. The review called for tariffs on Chinese cells to be reduced to a 1.82% AD rate and 15.68% CVD rate (a sum of 17.5%). New rates don't apply until the final review, which comes in either early spring (without an extension) or early summer (with an extension). Regardless of the date, this change in tariff will allow prices to drop.

Figure 2.53 U.S. Polysilicon, Wafer, Cell and Module Prices, Q4 2013-Q4 2014

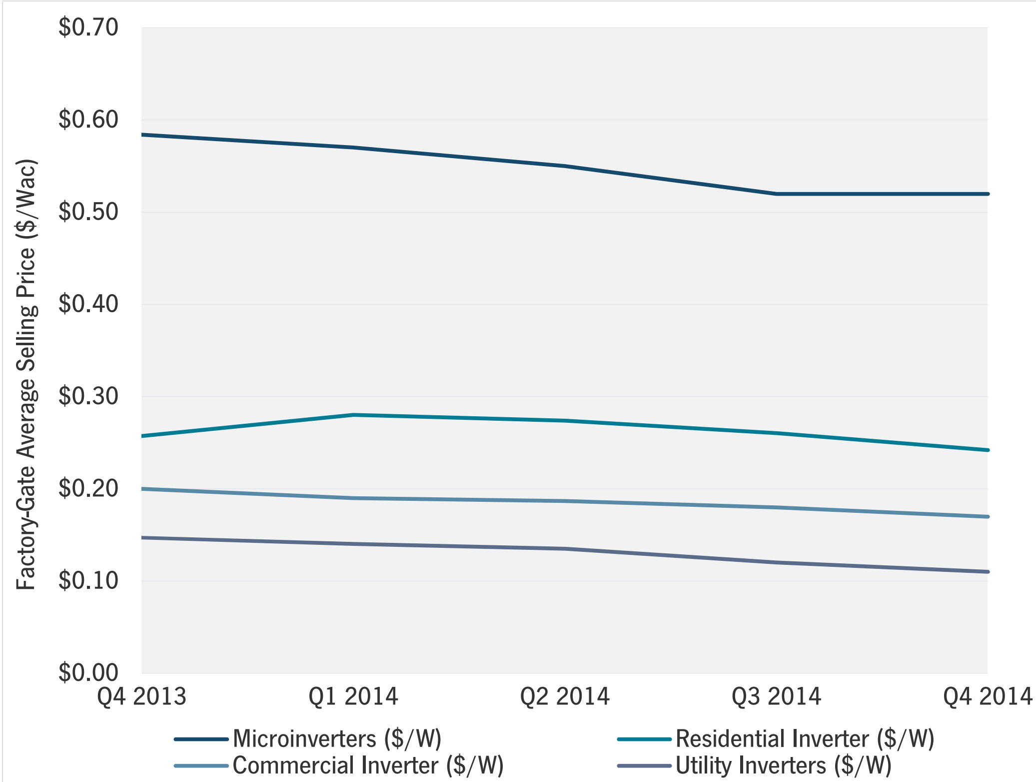


	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Polysilicon ($/kg)	$17.72	$21.70	$22.13	$21.69	$21.47
Wafer ($/W)	$0.22	$0.24	$0.23	$0.22	$0.22
Cell ($/W)	$0.43	$0.44	$0.42	$0.32	$0.32
Module ($/W)	$0.72	$0.73	$0.73	$0.75	$0.73

2.9.2. Inverter Pricing

Factory gate pricing remained relatively steady in the U.S., albeit with small declines in Q4 2014. Utility central inverters and three-phase string inverters have experienced the heaviest pressure, as new entrants have forced incumbents to compete more aggressively on price. Pricing has fallen year-over-year by 6% to 25% depending on market segment. Furthermore, as global demand outside of the U.S. continues to be insulated or weak, we expect to see a continued focus by foreign manufacturers on breaking into the U.S. market.

Figure 2.54 Factory-Gate PV Inverter Pricing, Q4 2013-Q4 2014



National Average Pricing	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Microinverters ($/W)	$0.58	$0.57	$0.55	$0.52	$0.52
Residential Inverter ($/W)	$0.26	$0.28	$0.27	$0.26	$0.24
Commercial Inverter ($/W)	$0.20	$0.19	$0.19	$0.18	$0.17
Utility Inverters ($/W)	$0.15	$0.14	$0.14	$0.12	$0.11

2.9.3. Mounting Structure Prices

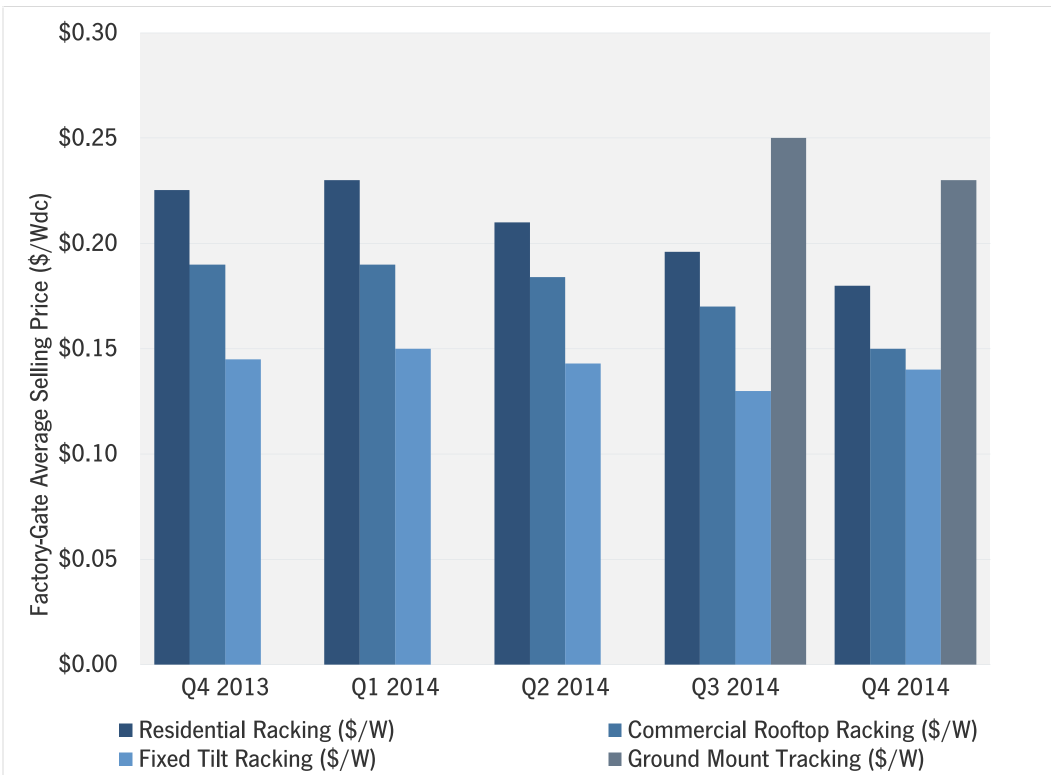
We continue to note that factory-gate pricing for PV mounting structures differ heavily depending on market segment, geography, configuration, layout and project size, all of which complicate the calculation of an "average" cost. For example, manufacturers reported costs in the second quarter for commercial rooftop systems of anywhere between $0.11/W and $0.19/W. Although single-axis tracking structures come at a significant premium over fixed-tilt structures, overall system costs are only impacted by 12%. Furthermore, beneficial project economics in the form of time-of-use pricing and enhanced performance often justify the additional expenditure on single-axis tracking systems.

For simplicity, we note that the values reported below reflect the mounting-structure-only costs of the following system types:

- Residential rooftop: 5 kW to 10 kW sloped roof in California using a clamp-and-rail-based system
- Commercial rooftop: 100 kW to 500 kW flat-roof ballasted system in low wind areas requiring no additional structural support
- Ground-mount fixed-tilt: 1 MW to 5 MW fixed-tilt ground-mount system in low wind areas, not including foundation structures
- Ground-mount single-axis tracking: 1 MW to 5 MW horizontal single-axis tracking ground-mount system in low wind areas, not including foundation structures

Even with these baselines, PV mounting structure purchasers should consider the full implied costs of individual manufacturers rather than relying on quotes versus the national average. Differences in racking materials and design have different implications for labor costs, grounding requirements and the need for additional structural support. Note that we have revised our historical pricing in previous quarters given significant feedback that our values represented higher than market values.

Figure 2.55 PV Mounting Structure Prices, Q4 2013-Q4 2014



Average Price (National Aggregate)	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Residential Racking ($/W)	$0.23	$0.23	$0.21	$0.20	$0.18
Commercial Rooftop Racking ($/W)	$0.19	$0.19	$0.18	$0.17	$0.15
Fixed-Tilt Racking ($/W)	$0.15	$0.15	$0.14	$0.13	$0.14
1-Axis Tracking ($/W)	-	-	-	$0.25	$0.23

3. Concentrating Solar Power

3.1. Introduction

In the U.S., concentrating solar thermal power plants experienced a burst of project activity in California in the 1980s and then remained largely inactive for two decades. Several years ago, procurement of concentrating solar projects was revitalized across the Southwest and West, primarily in California, where investor-owned utilities launched aggressive procurement plans in response to large RPS obligations. However, concentrating solar has not been immune to the turmoil of the larger solar industry, and the past few quarters have seen a number of CSP projects shelved or delayed.

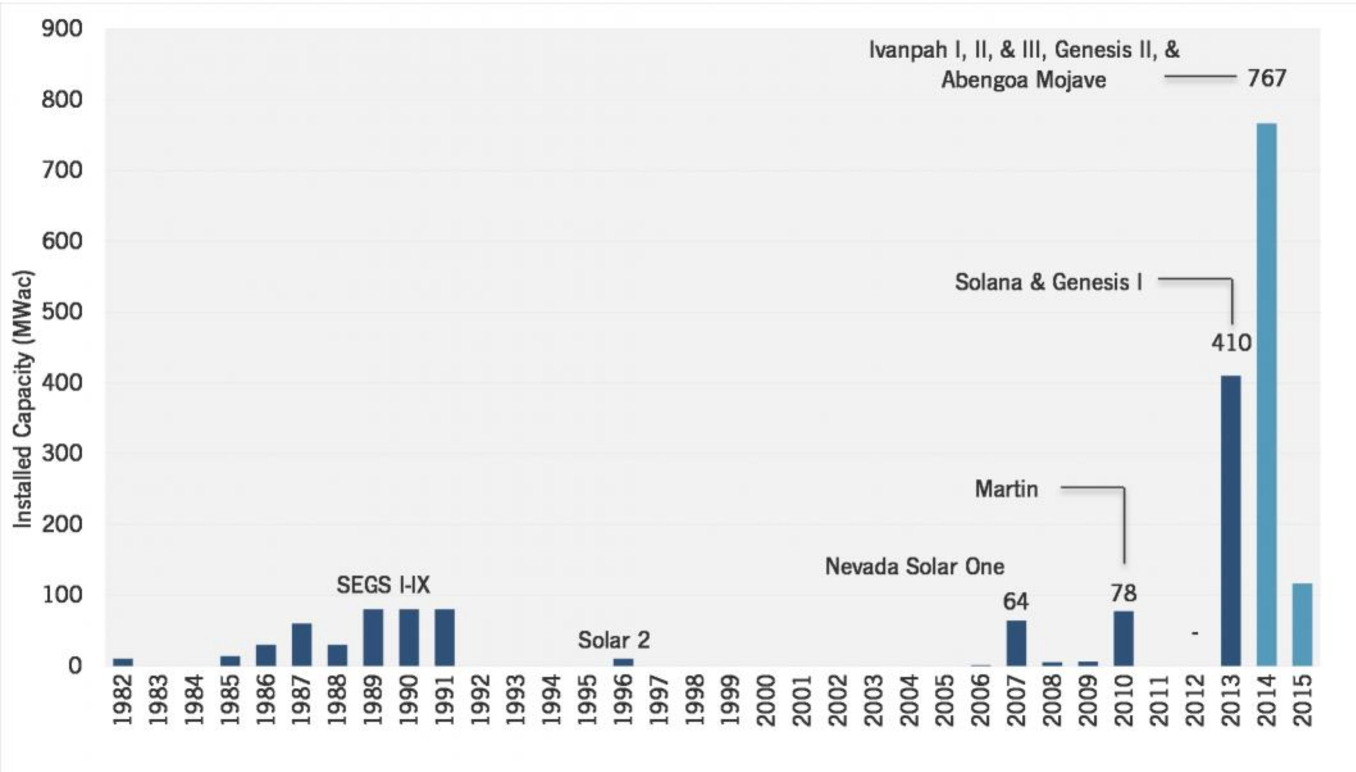
3.2. Installations

Figure 3.1 Concentrating Solar Installations, 2010-2014

Capacity Installed by State (MWac)	2010 Total	2011 Total	2012 Total	2013 Total	2014 Total	Cumulative
Arizona	3	-	-	280	-	283
California	-	-	-	125	767	1,256
Florida	75	-	-	-	-	75
Hawaii	-	-	-	5	-	7
Nevada	-	-	-	-	-	64
Total	77	-	-	410	767	1,685

3.3. Installation Forecast

Figure 3.2 CSP Installation Forecast, 1982-2015E



As shown in Figure 3.2, the concentrating solar industry in the U.S. was effectively dormant from 1992 to 2006. In 2007, there was one project of scale: a 64 MW_{ac} trough plant in Nevada. Following that was the construction of several small demonstration plants for various technologies, including a 5 MW_{ac} compact linear Fresnel reflector (CLFR) plant in California in 2008, a 5 MW_{ac} tower plant in California in 2009, and a 1 MW_{ac} micro-CSP plant in Hawaii in 2009. The 75 MW_{ac} FP&L Martin Solar plant in Indiantown, Florida came on-line in the fourth quarter of 2010.

While the 5 MW_{ac} Kalaeloa Solar One project was the only concentrating solar power project to come on-line during the first three quarters of 2013, in Q4 the first wave of mega-scale CSP projects began to come on-line, starting with Abengoa's 280 MW_{ac} Solana Generating Station and the first 125 MW_{ac} phase of NextEra's Genesis solar project. Q1 2014 built on that momentum, with 517 MW_{ac} brought on-line. This includes BrightSource Energy's 392 MW_{ac} Ivanpah project and the second and final 125 MW_{ac} phase of NextEra's Genesis solar project.

While Q2 2014 and Q3 2014 did not see any CSP project activity, Abengoa finished commissioning its 250 MW_{ac} Mojave Solar project in December 2014. In turn, 2014 ranks as the largest year ever for CSP, with 767 MW_{ac} brought on-line. The next notable project slated for completion is SolarReserve's 110 MW_{ac} Crescent Dunes project, which entered the commissioning phase in February 2014 and is now expected to become fully operational before the end of March 2015.

In 2016, growth prospects for the CSP market in the U.S. are bleak. On one hand, CSP when paired with storage represents an attractive generation resource for utilities, offering a number of ancillary and resource adequacy benefits. However, due to extensive permitting hurdles that have confronted CSP projects, developers are putting their CSP pipelines on hold given the short window to bring projects on-line before the federal ITC is scheduled to expire at the end of 2016. Most notably, Abengoa's Palen Solar project, BrightSource's Hidden Hills project and SolarReserve's Rice Solar project are all delayed indefinitely.

Beyond 2016, the outlook for the CSP market will depend on further progress made toward mitigating early-stage development hurdles, lowering hardware costs, and strengthening the ancillary and capacity benefits provided by CSP paired with storage.

4. Appendix A: Metrics and Conversions

4.1. Photovoltaics

We report PV capacity data in watts of direct current (DC) under standard test conditions (STC). This is the metric most commonly used by suppliers, developers and program administrators. However, some program administrators report data in alternating current (AC) watts, and some utility-scale systems are measured in AC watts. Given that, we assume an 87% DC-to-AC derate factor for systems of less than 10 MWac and a 77% DC-to-AC derate factor for systems greater than 10 MWac based on data from existing systems, conversations with installers, and averages from California Solar Initiative data.

4.2. Residential Photovoltaic System

A residential PV installation is defined as a project in which the offtaker of the power is a single-family household. Second, any PV system installed on a homeowner's property that participates in a feed-in tariff program is considered residential despite the offtaker of the power being a utility.

4.3. Non-Residential Photovoltaic System

A non-residential PV installation is defined as a project in which the offtaker of the power is neither a homeowner nor a utility. The spectrum of non-residential offtakers typically includes commercial, industrial, agricultural, school, government, and nonprofit customers. Second, a "community solar" system is defined as non-residential as well. Although homeowners and apartment tenants unable to install solar are the typical subscribers to community solar systems, the fact that the system has multiple offtakers of power categorizes community solar as non-residential.

4.4. Utility Photovoltaic System

A utility PV installation is a project in which the offtaker of the power is a utility or wholesale power market. This definition also includes any PV system installed on a non-residential customer's property that participates in a feed-in tariff program, in which the system's power is sold to a utility.

4.5. Concentrating Solar Power

We report CSP capacity data in watts of alternating current (AC), which is the metric most commonly used in the CSP industry. As a result, capacity comparisons for CSP and PV should not be considered on an apples-to-apples basis.

5. Appendix B: Methodology and Data Sources

Please note that data from previous quarters is sometimes updated as a result of improved or changed historical data.

Data for this report comes from a variety of sources and differs by data item, technology, and granularity. Below we outline our methodology and sources.

5.1. Historical Installations

PV: Quarterly state-by-state data on PV installations is collected primarily from incentive program administrators. These administrators include state agencies, utility companies, and third-party contractors. For larger projects not included in these programs, GTM Research maintains a database that tracks the status of all operating and planned utility PV projects in the United States. In some cases, program administrators report incentive application and award dates rather than installed dates. In these instances, we use the information that most closely approaches the system's likely installed date. For annual and cumulative installations prior to 2010, 2010 data for "Other States" and smaller utilities, GTM Research also utilized data collected by Larry Sherwood at the Interstate Renewable Energy Council (IREC).

CSP: GTM Research maintains a database that tracks the status of all operating and planned CSP projects in the United States.

PV	State incentive program administrators, utility companies, state public utilities commissions, PUC filings, GTM Research Utility PV Project Database, Larry Sherwood/IREC
CSP	GTM Research CSP Project Database, announcement tracking, state public utilities commissions, conversations with developers/manufacturers

5.2. Average System Price

PV: Prior to Q1 2014, the methodology used to estimate average system prices was based on weighted average system pricing received directly from utility and state incentive programs, but GTM Research and SEIA have long felt that the data was not an ideal reflection of the current state of system pricing, as it often represented systems quoted in quarters well prior to the installation and connection date, and much of the reported data was based on fair-market value assessments for TPO systems.

As of Q1 2014, GTM Research and SEIA have switched to a bottom-up methodology based on tracked wholesale pricing of major solar components and data collected from major installers, with national average pricing supplemented by data collected from utility and state programs.

PV	GTM Research manufacturing facility databases, announcement monitoring, conversations with manufacturers
CSP	Announcement monitoring, conversations with manufacturers

Components in the national cost breakdown categories include:

- PV module: National average delivered pricing for Chinese crystalline silicon modules
- PV inverters: National average factory-gate pricing with product as specified in the respective breakdown sections
- Electrical balance of systems (EBOS): Includes all additional electrical components necessary for the system, including DC and AC wiring, system and equipment grounding, conduit, disconnects, fuses, circuit breakers, and data monitoring
- Structural balance of systems (SBOS): Includes all additional equipment necessary to support the PV system structurally, including mounting systems, foundations, ballast, racking, and clamps
- Direct labor: Includes all the necessary labor related to PV system installation including site setup/preparation, installation, in-field logistics, and system commissioning
- Engineering, design, permitting, interconnection, inspection: Includes all labor and fees not directly related to preparing or installing PV system, including system engineering, design, permitting inspection and fees, interconnection labor and fees, and project management
- Supply chain, logistics, customer acquisition, overhead and markup: Includes all other costs directly associated with the project, including supply chain costs (distribution markups, volume markups, taxes), logistics (shipping and handling), customer acquisition (direct sales and marketing, site visits), overhead (project-related office costs) and markup (margin)

5.3. Manufacturing Production and Component Pricing

GTM Research maintains databases of manufacturing facilities for PV and CSP components.

PV	GTM Research manufacturing facility databases, announcement monitoring, conversations with manufacturers
CSP	Announcement monitoring, conversations with manufacturers

Disclaimer of Warranty and Liability

Greentech Media and SEIA have used their best efforts in collecting and preparing each report.

GTM Research, SEIA, their employees, affiliates, agents, and licensors do not warrant the accuracy, completeness, correctness, non-infringement, merchantability, or fitness for a particular purpose of any reports covered by this agreement. Greentech Media, SEIA, their employees, affiliates, agents, or licensors shall not be liable to user or any third party for losses or injury caused in whole or part by our negligence or contingencies beyond Greentech Media's or SEIA's control in compiling, preparing or disseminating any report or for any decision made or action taken by user or any third party in reliance on such information or for any consequential, special, indirect or similar damages, even if Greentech Media or SEIA was advised of the possibility of the same. User agrees that the liability of Greentech Media, SEIA, their employees, affiliates, agents and licensors, if any, arising out of any kind of legal claim (whether in contract, tort or otherwise) in connection with its goods/services under this agreement shall not exceed the amount you paid to Greentech Media for use of the report in question.

U.S. SOLAR MARKET INSIGHT

Full Report

2014 Year in Review