December 17, 2018

Dear Colleague,

Thank you for taking the time to complete the survey for The Solar Foundation's National Solar Jobs Census 2018. 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.

You have received a copy of this report as a token of our appreciation.

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SEIA and Wood Mackenzie 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 www.seia.org/join, email membership@seia.org or call (202) 556-2907 to learn more about how joining SEIA can help your solar business grow.

Best Regards.

Sincerely,

Justin Baca
Vice President of Markets & Research
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The Solar Foundation

U.S. SOLAR MARKET INSIGHT

Full Report

2017 Year in Review

CONTENTS

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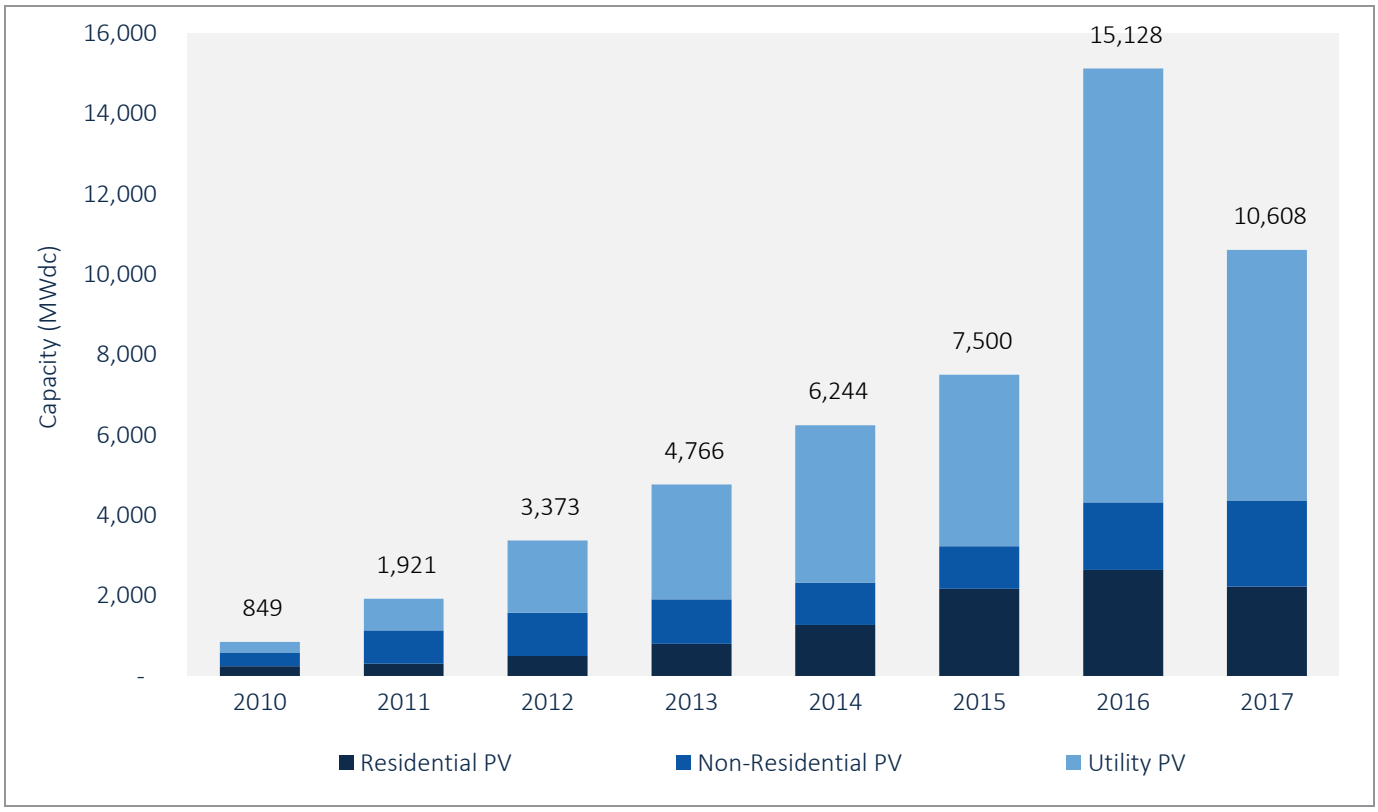
Author's Note: Revision to U.S. Solar Market Insight report title

Wood Mackenzie, Limited, and SEIA have changed the naming convention for the U.S. Solar Market Insight report series. Starting with the report released in June 2016 onward, the report title will reference the quarter in which the report is released, as opposed to the most recent quarter in which installation figures are tracked.

1. INTRODUCTION

In 2017, the U.S. solar market installed 10.6 gigawatts direct current (GW_{dc}). Despite installing 30% less solar than what was installed in a unique and record-breaking 2016, the market still grew 40% over 2015 levels. In line with previous years, 59% came from the utility PV segment, while distributed solar accounted for the remainder of installations.

Figure 1.1 U.S. Annual PV Installations, 2010-2017



2017 bucked many historical trends in what proved to be a transitional year for the solar market. All segments experienced role reversal, as residential and utility PV – long the growth segments of the solar market – both saw installations fall on an annual basis for the first time since the first edition of Solar Market Insight in 2010, marking a "reset" year for both segments. Meanwhile, the long-beleaguered non-residential PV segment was the only market to experience growth in 2017.

For residential PV, the downturn in 2017 stems from segment-wide customer acquisition challenges that are constraining growth across most major state markets. Amidst other variables such as NEM reform, loss of state incentives, and competitive landscape trends, we are also monitoring the relationship between increasing customer penetration and low installation growth as the pool of attractive early-adopter customers grows increasingly thin in certain markets. While

the relationship between market penetration and growth does not fully explain the market downturn, GTM Research believes it is increasingly becoming a factor in constraining growth amongst major state markets

Meanwhile, the year-over-year downturn for utility PV in 2017 was largely expected, due to the massive influx of projects trying to leverage the 30% federal Investment Tax Credit (ITC) in 2016. However, uncertainty surrounding the Section 201 tariffs caused many projects to be shelved this year, while PURPA project cancellation and interconnection delays resulted in many projects spilling over into 2018.

Finally, both closing regulatory windows and the realization of a robust community-solar pipeline drove substantial growth in non-residential solar in 2017. This is the second consecutive year for such growth after the space essentially remained flat from 2012-2015.

1.1. Federal Policy Spotlight: Section 201 and Corporate Tax Reform

Federal policy reared its head not once, but twice, via corporate tax reform and the prospect of Section 201 tariffs (finally announced January 22, 2018). Together, these two major federal policy developments will have long-lasting implications for the market and our base-case outlook.

Section 201 Tariffs

On January 22, President Trump announced a 30% ad valorem year-one tariff on imported c-Si cells and modules. These tariffs will decline 5 percentage points per year for a period of four years, resulting in a 15% tariff in 2021, after which the tariff will expire unless extended by the president. Based on current pricing trends, the 30% tariffs result in a roughly $0.10/W increase in year 1 module prices.

The decision on loose cell imports functions as a tariff rate quota, with the first 2.5 gigawatts of imported crystalline-silicon (c-Si) cells excluded from the tariff in each of the four years. This mechanism is designed to allow domestic module manufacturers without cell manufacturing capacity to continue importing inexpensive cells for module manufacturing purposes. Additionally, the Trump administration excluded nearly all Generalized System of Preferences beneficiary countries, except for Thailand and the Philippines. Any excluded GSP beneficiary country will be subject to the tariff if it exceeds 3% of total imports of c-Si PV products, or all excluded GSP countries will become subject to the tariff if they collectively account for more than 9% of imports.

When accounting for additional changes to the state policy landscape, utility procurement plans, and the competitive landscape, GTM Research's updated base-case forecast between 2018 and 2022 is now 13% lower than what was projected in the last edition of the U.S. Solar Market Insight report.

Corporate Tax Reform

The Tax Cuts and Jobs Act of 2017 introduces a handful of changes to tax law that will have varying implications for the solar industry. Of the multitude of changes made to the tax code, the most impactful provisions to solar are:

- Corporate Tax Rate Reduction: At its core, the law lowers the top corporate tax rate from 35% to 21%. In theory, this could reduce the availability of tax equity financing given that overall corporate tax liability will be lower. However, elimination of the corporate alternative minimum tax could offset some of this reduction. While there are no public announcements of major banks exiting the solar tax equity market altogether, a couple of possible outcomes are that tax equity investors will account for a smaller share of the capital stack or require additional cash returns. If tax equity pricing goes up, one additional possible outcome is downward pressure on solar asset owners' returns, given that they or lenders will have to take on a higher share of the capital stack. Another impact of the lower tax rate is a decrease in the effective value of depreciation. Depending on the degree to which investors elect for 100% expensing (see below), this could be somewhat offset by the time-value effects.
- Base Erosion Anti-Abuse Tax: The BEAT provision effectively puts in place a new corporate minimum tax if a company's income tax liability falls below 11% of its U.S. income, when adjusted for tax credits and certain cross-border payments not previously counted as income. This provision could diminish the supply of tax equity from investors with high levels of offshore income who are at risk of falling short of the 11% minimum tax threshold. However, 80% of the solar Investment Tax Credit is excluded from determining the tax liability under the BEAT provision, which means 20% of the ITC is at risk of being lost if an investor is noncompliant with BEAT. To date, our survey of tax equity providers and legal teams suggests that the BEAT provision only affects a limited number of tax equity investors and corporates with significant cross-border payments.
- 100% Bonus Depreciation: Beginning in 2019 (and potentially in 2018), investors will have the option to take 100% bonus depreciation – a change from the optional 50% bonus deprecation schedule in effect before the tax legislation passed. Though relatively few investors took advantage of 50% bonus depreciation, it's unclear whether investors will opt in or out of full bonus depreciation in 2018 for two reasons. First, the law does not specify whether projects put into service in 2018 are actually eligible to elect out of 100% bonus depreciation, and second, tax equity investors' risk appetite for taking on full bonus depreciation in the lower tax rate environment is untested and thus has yet to be determined.

To be clear, there are a number of changes to corporate tax law that are likely to have implications for the market that have not been elucidated here. For instance, lower tax rates also mean that business and utilities have more expendable income to divert toward capital investment. However, we've highlighted the most relevant aspects into which we currently have visibility.

Figure 1.2 State PV Installation Rankings by 2017 Installations

	Rank			Installations (MW_{dc})		
State	**Cumulative**	**2016**	**2017**	**Cumulative**	**2016**	**2017**
California	1	1	**1**	19,817.7	5,225.2	**2,603.8**
North Carolina	2	4	**2**	4,308.3	1,014.3	**1,201.3**
Florida	10	9	**3**	1,355.2	404.7	**748.8**
Texas	7	6	**4**	1,874.2	676.9	**654.0**
Massachusetts	6	8	**5**	2,011.1	460.3	**461.4**
Minnesota	15	14	**6**	744.4	268.5	**436.8**
Arizona	3	7	**7**	3,116.5	656.4	**416.6**
South Carolina	18	20	**8**	510.5	105.6	**395.9**
Nevada	4	5	**9**	2,421.3	1,001.9	**386.3**
Virginia	17	17	**10**	619.5	192.4	**381.3**
New Jersey	5	10	**11**	2,389.9	392.7	**356.6**
New York	11	12	**12**	1,252.9	294.2	**319.4**
Maryland	13	13	**13**	899.5	276.9	**233.1**
Oregon	19	18	**14**	461.5	123.9	**223.5**
Mississippi	26	37	**15**	228.4	7.1	**218.2**
Idaho	21	16	**16**	407.4	224.6	**179.9**
Alabama	24	22	**17**	257.6	103.4	**151.9**
Hawaii	14	19	**18**	807.8	107.5	**142.8**
Utah	8	2	**19**	1,599.0	1,240.5	**110.0**
Connecticut	20	21	**20**	420.5	105.3	**94.6**
Georgia	9	3	**21**	1,566.4	1,067.2	**90.4**
Tennessee	25	26	**22**	247.2	42.0	**79.6**
Colorado	12	11	**23**	997.5	373.8	**78.9**
Michigan	32	32	**24**	110.4	15.9	**75.0**
Pennsylvania	22	25	**25**	361.9	43.5	**60.5**
New Mexico	16	15	**26**	697.0	261.5	**59.8**
Indiana	23	23	**27**	275.6	80.7	**58.8**
Montana	37	41	**28**	55.3	2.3	**50.4**
Ohio	28	36	**29**	164.7	12.0	**40.1**
Oklahoma	41	44	**30**	32.0	0.4	**27.8**
Rhode Island	40	40	**31**	39.1	2.7	**23.4**
Vermont	27	24	**32**	212.5	76.4	**22.7**
Wisconsin	38	39	**33**	50.4	5.0	**20.9**

	Rank			Installations (MW_{dc})		
Washington	31	28	**34**	111.1	26.5	**20.4**
Iowa	36	35	**35**	60.2	13.7	**19.3**
Delaware	30	30	**36**	113.6	16.9	**18.3**
New Hampshire	35	27	**37**	70.5	30.8	**18.3**
Washington DC	39	31	**38**	48.6	16.4	**15.7**
Missouri	29	29	**39**	162.7	19.2	**15.6**
Illinois	33	38	**40**	83.8	5.2	**13.5**
Kentucky	42	34	**41**	31.9	13.9	**12.0**
Louisiana	34	33	**42**	82.0	14.9	**6.3**
Arkansas	43	42	**43**	21.4	0.9	**2.4**
Wyoming	44	43	**44**	1.6	0.5	**0.6**

Source: GTM Research

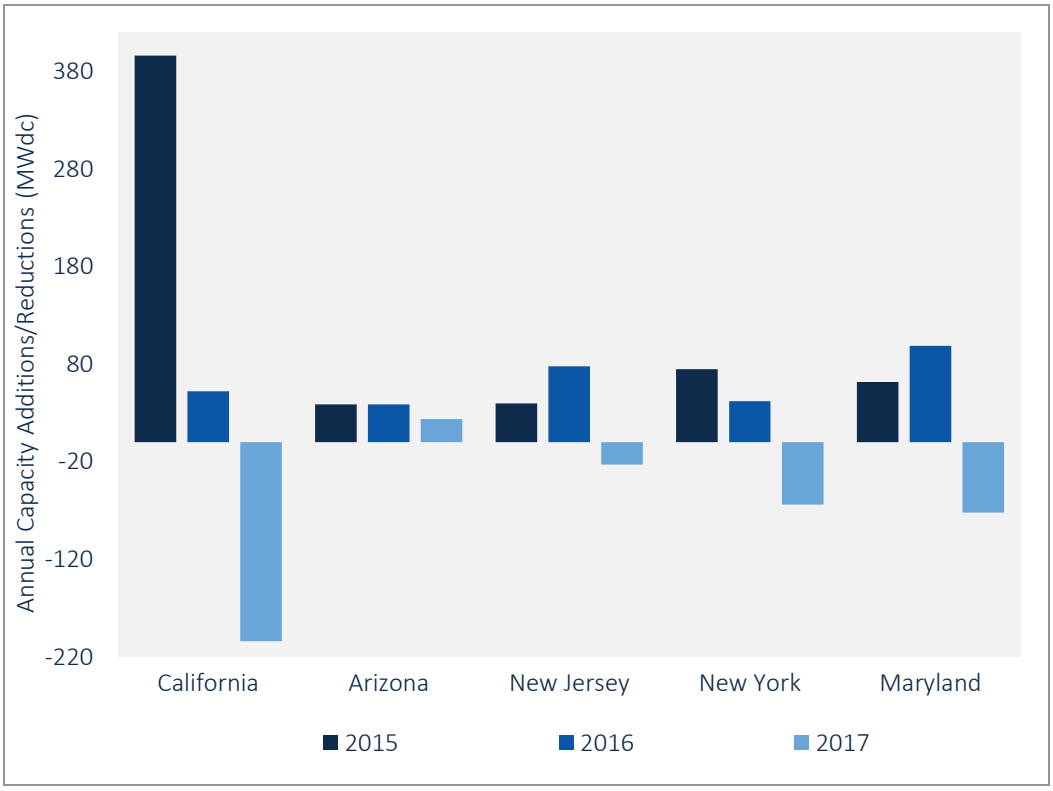
2. RESIDENTIAL PV

2.1. National Installations

- 2,227 MW_{dc} installed in 2017
- Down 16% from 2016

For the first time since GTM Research began tracking the market, residential PV saw an annual contraction from 2016. The downturn was primarily driven by continued weakness in established state markets, while persistent customer-acquisition challenges across top national installers continued to hamper growth. California's performance in 2017 to date has heavily influenced the overall national residential market, as the market accounted for nearly 40% of the residential market while accounting for half of the losses in megawatts relative to 2016. Meanwhile, all major Northeast markets experienced annual contractions. Arizona was only one of two top-10 state markets that added residential installations compared to 2016, though this was primarily a function of regulatory demand pull-in as the state transitions to a lower export credit for solar. In total, the top 10 state markets lost nearly 475 MW relative to 2016.

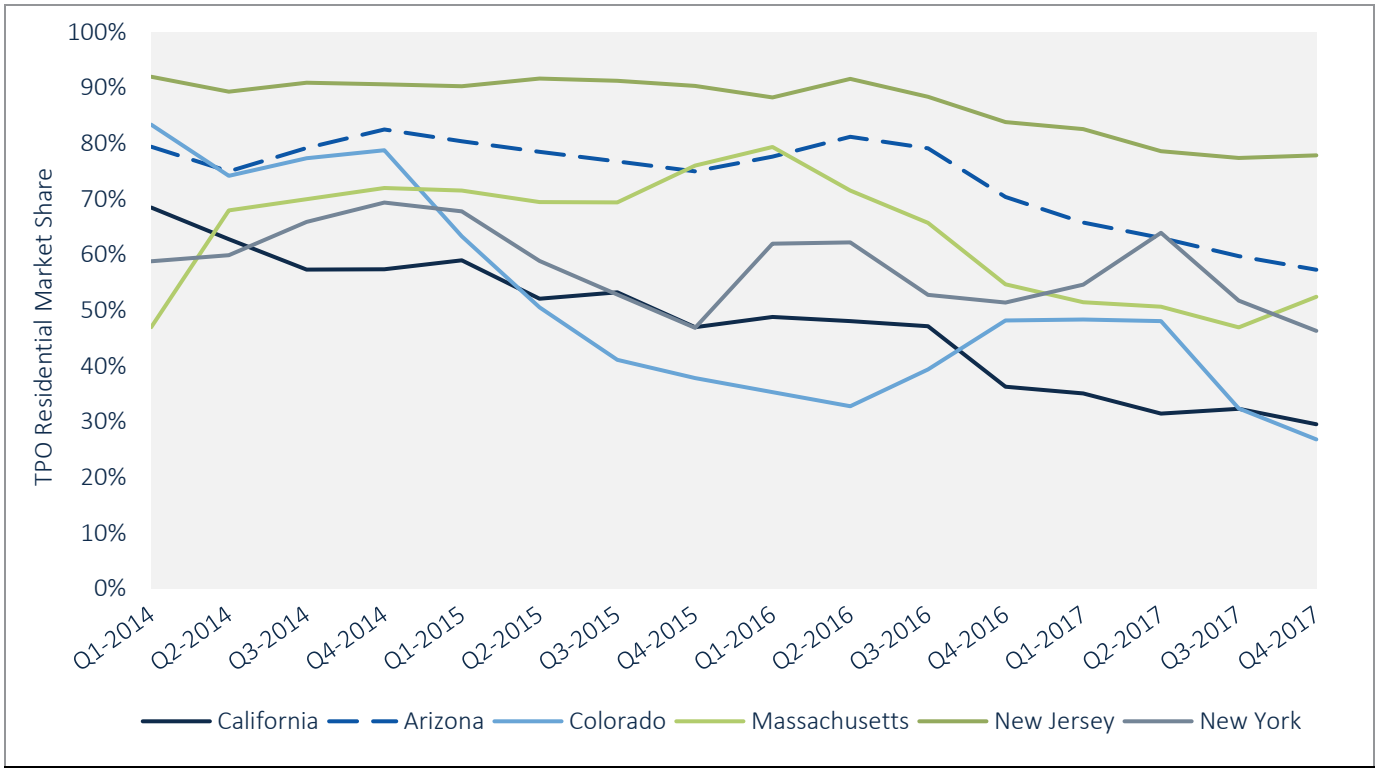
Figure 2.1 Year-over-year Change in Capacity Additions Across Top Five Markets, 2017 (MW_{dc})



Source: GTM Research

2.1.1. Trends in Consumer Finance

Figure 2.2 Percentage of New Residential Installations Owned by a Third Party in Major State Markets, Q1 2014-Q4 2017



State	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015	Q3 2015	Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
CA	68%	63%	57%	57%	59%	52%	53%	47%	49%	48%	47%	36%	35%	31%	32%	30%
AZ	79%	75%	79%	83%	80%	78%	77%	75%	78%	81%	79%	70%	66%	63%	60%	57%
CO	83%	74%	77%	79%	63%	51%	41%	38%	35%	33%	39%	48%	48%	48%	32%	27%
MA	47%	68%	70%	72%	72%	69%	69%	76%	79%	72%	66%	55%	51%	51%	47%	52%
NJ	92%	89%	91%	91%	90%	92%	91%	90%	88%	92%	88%	84%	83%	79%	77%	78%
NY	59%	60%	66%	69%	68%	59%	53%	47%	62%	62%	53%	51%	55%	64%	52%	46%

The national trend away from third-party ownership continued in Q4 2017, during which only 37 percent of new installed capacity was third-party owned. This is especially true of California, which had another record-low rate of third-party ownership of just 30 percent in the quarter. This decrease in third-party ownership has been especially pronounced in the last three quarters as some of the largest national installers have made a point of rejiggering their product offerings to improve their cash positions. The transition to a direct-ownership model is not an easy one, as companies must retrain their sales teams, which can be a multi-month process; this is affecting installers across the board.

The share of third-party ownership (TPO) in the market is expected to drop to about a quarter of the market by 2022, as growth expectations for small and medium installers drive the market and national firms shift away from PPAs/leases. As this transition occurs, the financiers (both loan providers and TPO providers) that partner with small and medium installers will gain share, just as they have been recently. To date, the successes (or failures) of residential financing companies have been largely dependent on the successes (or failures) of their installer partners.

The transition of the market away from TPO is also partly driven by the sheer abundance of solar loan companies. With the emergence of numerous solar loan providers, many installers are able to offer financing for the first time. (However, access to TPO financing can be limited for certain installers who do not meet TPO providers' criteria.) Over the past year, many lenders have emerged to service the residential solar industry, creating an extremely crowded and competitive loan space in which consolidation is likely.

In addition to competition among solar-only loan providers, companies also face increasing competition from direct-to-consumer lending through banks and credit unions outside of existing dealer networks. Credit unions can often offer the lowest interest rates to consumers, though they tend to be less technologically advanced than solar lending companies and often do not provide instant credit approval. The benefits and drawbacks of lending through installers, as well as direct to consumers, are outlined below.

Lending Through Dealer Networks (Solar Lending Companies)

Pros:

- Dealer maintains control of the entire sale
- Dealer can close the sale immediately with instant credit approval
- One-stop shopping for consumers
- Many lenders provide training and other forms of support to installer sales teams
- Lenders can help installers get better terms on equipment purchases

Cons:

- Dealer fees can be high for installers
- Installment payments are late in the cycle; dealer must find additional sources of working capital
- Fewer loan options available for a given installer

Lending Directly to Consumers (Banks and Credit Unions)

Pros:

- Transparency with rates and no dealer fees, which can mean cheaper borrowing for consumers
- Installers get entire payment upfront; no issues with working capital
- Easy bundling of products, such as solar with energy efficiency or storage

Cons:

- Installers do not have as much control over the sale
- Slow process – can take up to several days for credit approval
- Many banks and credit unions have a limit to the amount of solar lending they can do

There are benefits and drawbacks to both consumers and installers of using solar lenders versus direct-to-consumer lending through banks and credit unions. But considered together, the abundance of loan financing options in the residential solar space, along with the intentional pivot by national installers, has driven the market away from third-party ownership.

2.2. State Market Overview

Figure 2.3 Top 10 Residential PV State Markets, Q4 2017: Key Installation Figures

Installations (MW_{dc})	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
California	279.1	247.4	252.0	199.0	228.6	199.8	231.2
Arizona	53.1	36.6	45.6	44.2	50.0	50.1	51.1
New Jersey	47.0	49.9	44.9	46.8	34.6	35.7	37.8
New York	55.6	46.7	44.7	36.6	37.8	32.3	35.4
Maryland	41.5	51.0	57.5	42.8	37.0	24.9	26.9
Massachusetts	43.2	35.8	35.6	23.4	20.7	19.6	18.5
Texas	21.1	18.8	20.6	19.2	17.2	13.8	15.7
Utah	16.6	21.4	23.9	29.4	16.8	15.5	14.8
Florida	5.6	6.8	8.1	12.2	15.9	13.8	14.6
South Carolina	8.1	11.9	13.6	18.6	12.4	11.5	12.8

2.3. State Market Spotlights

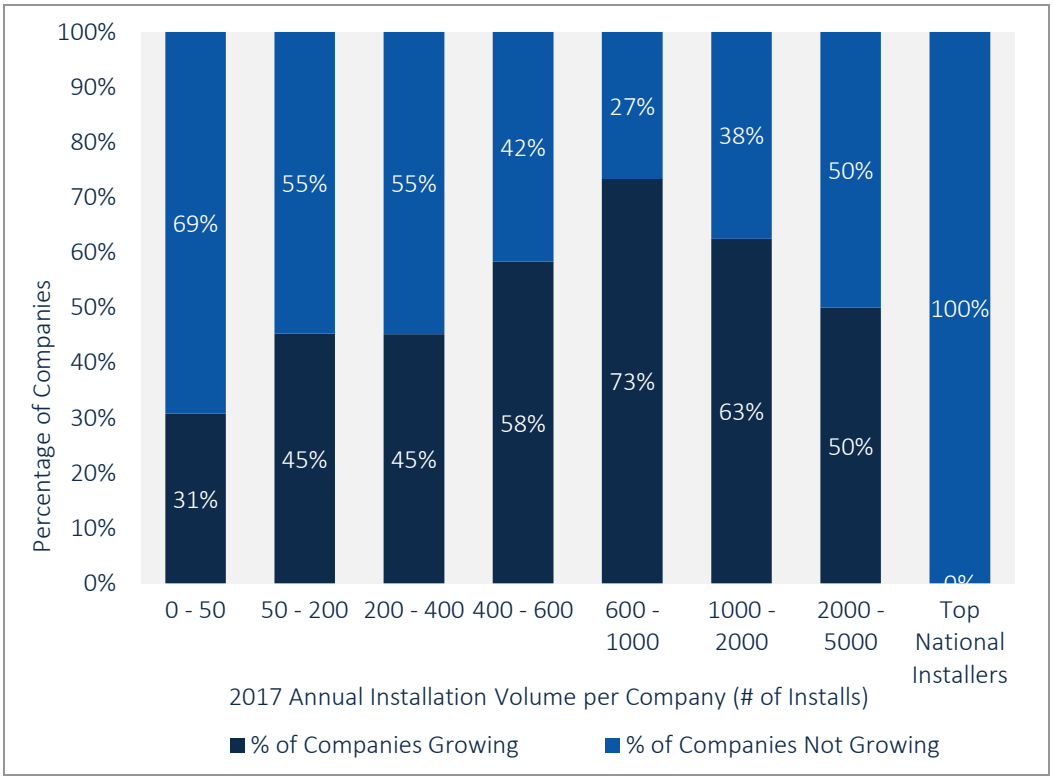
2.3.1. California

- 858.7 MW_{dc} installed in 2017
- Down 19% over 2016

While 2017 included the transition of the state's three investor-owned utilities to NEM 2.0, moderate demand pull-in prior to those transitions were not enough to mute the impact of large firms' pullback nor segment-wide customer-acquisition challenges plaguing the market.

While the largest installation declines were seen by the national installers that are working to bring customer-acquisition costs down, difficulties in the California market go beyond just the largest national installers. Even small and medium installers, who collectively have been gaining market share each quarter, saw smaller installations volumes in 2017 than in 2016. This group includes large regional players, small local installers, and hundreds of electricians and builders who also install solar. But the impacts of customer acquisition challenges were not uniformly felt across the installer landscape.

Figure 2.4 Share of California Solar Installers Growing, by Installer Size, 2017 over 2016



Source: GTM Research

In fact, more than half of all solar installers doing more than 200 annual installations that were active in both 2016 and 2017 grew this year. And if we dig deeper, the sweet spot for installation growth in California appears to be for companies in the 600 to 1,000 annual installation range (between about 4 MW and 7 MW of capacity installed annually). For companies larger than this, the prospect for growth diminishes incrementally, though the majority of companies installing 400 to 5,000 systems per year are still seeing growth, suggesting that the mid-sized installers may be the core of California's market going forward.

Among the growing solar installers discussed above, no one product offering is dominant; for some companies leases and PPAs represent 98% of their sales while other companies do not offer leases or PPAs at all. Still others pursue a more diverse mix of finance options. The key to healthy growth in California and other major markets is much more a function of how installers are selling their products as opposed to the products themselves. The particular success of companies in the 600 to 1,000 annual installation range indicates that it is difficult to scale companies that are either very small or very large. While it is challenging for a small solar installer to build brand awareness and acquire customers (especially given reduced marketing efforts by the national installers), after a certain size threshold has been reached, the company has built a strong referral network and as

such has a good chance at growth – that is, if it can keep customer-acquisition costs low and design a sales channel mix that works for that particular business.

These customer-acquisition challenges exist despite the economic attractiveness of solar for consumers in the state. Even in the NEM 2.0 environment, customers who own their systems can see payback periods in the five- to eight-year range, while customers who lease systems are able to save up to 20 percent to 50 percent on their energy bills each month. These savings can be achieved in spite of higher-than-average system prices due to high retail electricity rates in California. And with these high prices, installers are able to achieve up to 20 percent gross margins on installations.

Looking forward, GTM Research expects the California residential solar market to resume a rate of 5% growth in 2018. Installation volumes among national installers are expected to level out, while small and medium installers are expected to grow moderately as it continues to navigate customer acquisition in a saturated market with decreased national installer presence. The California market will remain relatively insulated from the effects of Section 201 tariffs in 2018 due to early procurement undertaken by many companies, though the tariffs will have a greater effect on the market in 2019, when we expect to see flat growth in California. Beyond 2019, GTM Research expects high-single to double-digit percentage growth for each of the next three years. However, the looming NEM 3.0 transition presents downside risk to the incremental recovery of installation growth, as installers address customer-acquisition challenges in yet another new regulatory framework.

2.3.2. Massachusetts

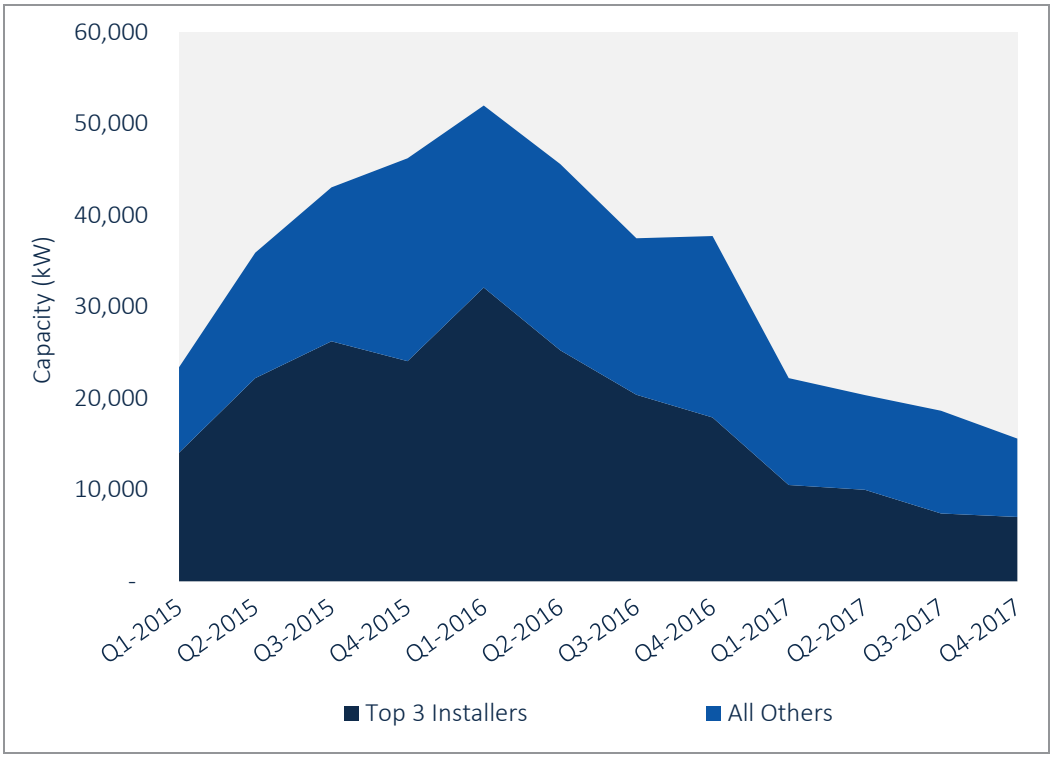
- 82.2 MW_{dc} installed in 2017
- Down 49% from 2016

2017 was a rough year for Massachusetts residential solar. With only 82 MW_{dc} installed, the state saw its lowest installation levels since 2014. Though a changing policy environment is underway in the state, the lucrative SREC-II program was largely intact throughout the year, with the various incentive stepdowns appearing to have little impact on deployments. Instead, much of this downturn can be pegged to the pull-back of top national TPO providers, in addition to the bankruptcies and market exits of many larger regional players. However, unlike in other state markets where small and medium installers have partially offset the growth trajectory of national TPO providers, growth in 2017 was hard to come by across residential installers of all shapes and sizes in Massachusetts.

In 2016 the top three national installers accounted for 55% of Massachusetts' market. In 2017, those same installers collectively shrunk to 45% of the market despite seeing a 63% volume reduction over 2016; this speaks to both the shifts of national installers and the relative decline of the rest of the market. Smaller-scale regional and local installers likewise saw a 46% reduction in

volume throughout 2017, suggesting that the decline in growth was not limited to just national TPO providers, though clearly TPO providers saw disproportionate volume reductions.

Figure 2.5 Total Installations – Top 3 Installers vs. Rest of Market Q1 2015 – Q4 2017



Source: GTM Research, Q1 2018 U.S. PV Leaderboard

2017 is notable for also seeing a reversal of customers' preference back to direct ownership, with cash and loan sales increasing from 31% of purchases in 2016 to 53% in 2017. Conversations with installers suggest that on a company level, the transition from offering primarily power-purchase agreements (PPAs) and leases to cash/loan sales was difficult to execute while maintaining volume, particularly in the domain of maintaining sales commissions. Additionally, our channel checks suggest that cash sales have typically resulted in longer lead times than do leases and PPAs, further exacerbating the slowdown. For many major national installers, this volume erosion ultimately resulted in increased pricing, while smaller, more cost-efficient installers were able to maintain competitive pricing.

In the immediate near term, we do not expect conditions to improve markedly for the Massachusetts residential market. In addition to the continued pull-back of national installers, many policy-related developments are set to impact the market beginning in 2018. While Q1 may experience some demand pull-in from the closure of SREC-II by March 31, the results of the initial competitive RFP for SMART, the declining block successor incentive program to SREC-II, moves the state one step closer to rollout. Though base compensation rates will remain relatively close to the

ceiling price of $.34/kWh for residential systems, this will be a modest, but manageable, reduction to the pre-existing NEM + SREC revenue stream that consumers are familiar with. However, the state's well-educated consumer base is unlikely to tolerate an increase in payback periods. This, in tandem with 30% ad valorem tariffs on cells and modules, will exacerbate the difficulties of selling in an already competitive market. For this reason, coupled with a beleaguered installer landscape, we expect the market to remain essentially flat in 2018.

In 2019, policy-related hiccups will continue to constrain the Massachusetts market. The introduction of a demand charge by Eversource beginning in 2019 ranging from $2.20 to $2.70/kW and the expected step-down of the SMART tariff (to decline 4% per incentive block) will chip away at the value proposition for residential customers. Taking into account the impact of Section 201 tariffs, the SMART incentive decline, the Eversource demand charge – all near- to mid-term bottlenecks – we expect the state to align with local installer growth rates of less than 10%, with the market not expected to reach 2016 installation levels again in our existing five-year forecasts.

2.3.3. North Carolina

- 7.9 MW_{dc} installed in 2017
- Down 2% from 2016

Since the passing of HB 589 in July, the North Carolina residential solar market has seen modest growth as installers ramp up operations to take advantage of newly legal third-party ownership and recently proposed rebates in the state. With implementation of the new law at the beginning of the year, Duke Energy proposed a new $62 million rebate program for residential and commercial customers. Under the proposed program, which is set to be approved by the North Carolina Utilities Commission in late Q1 or early Q2 2018, annual rebates of up to 10 MW will be available for residential customers in Duke Energy Carolinas and Duke Energy Progress territories, for a total of 50 MW through 2022. The residential rebate will be $0.60 per watt of installed capacity, up to $6,000 (on 10 kW) per residential installation. Given GTM Research's near-term forecast, the rebate is expected to support more than 75% of North Carolina's residential solar market in 2018.

Prior to the passing of HB 589, North Carolina's residential market was dominated by a handful of local installers who were able to offer breakeven or modest bill savings to customers who purchased their systems. With the proposed rebate and ability to offer leases and PPA financing, installers expect to be able to pass on greater bill savings to customers. Several large regional players, particularly those with strong operations already established in nearby South Carolina, are looking to expand into the state. However, it is unlikely that the largest TPO providers will do so despite the legalization of leases/PPAs, given that the economics will still be tight. According to installers in the area, breakeven economics in an area like North Carolina can be enough to incentivize a customer to go solar due to the desire for "energy independence" from the utility.

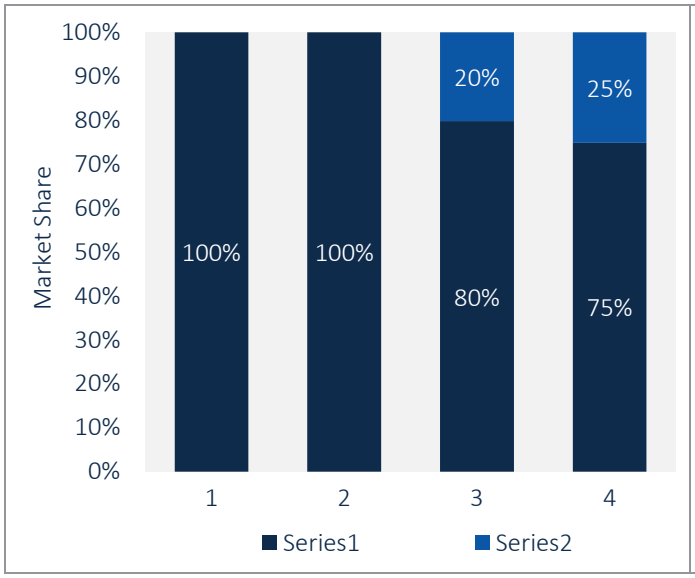
Looking forward, our forecast hinges on the ability of regional installers to move into the state to take advantage of the Duke Energy rebates. Given the new rebate, the legalization of third-party ownership, and the state's limited reliance on sometimes-volatile large national installers, GTM Research expects between 40% and 60% annual growth for each of the next five years.

2.3.4. Sustainable Growth in Emerging Markets: Pennsylvania vs. Florida Case Study

2017 was a big growth year for many emerging state markets, including Pennsylvania and Florida. At 52 MW installed in 2017, Pennsylvania saw a doubling of installations over 2016. Similarly, Florida also experienced a high-growth year, exceeding our own forecasts by installing 58 MW and also doubling over 2016 installations. But the path to achieve growth differed substantially between the two states. While Florida's market has been driven primarily by local and regional players, Pennsylvania's growth has largely come from national firms. Given the growth trajectory of other emerging state markets – in particular, the reliance on national installers vs. local/regional players – Pennsylvania's market may prove an instructive example of what constitutes unmanageable growth, while Florida may provide the blueprint for sustainable growth via local installers gradually scaling up operations.

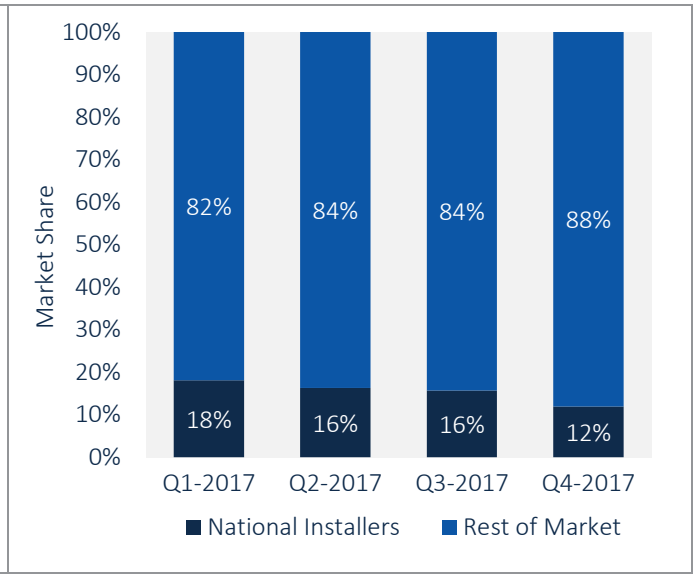
National installers accounted for nearly 100% of capacity additions in Pennsylvania in 2017. This is in stark contrast to other emerging markets such as Florida, where growth has come primarily from local installers. While GTM Research makes no value judgement as to the composition of a state's installer base, it should be noted that of the major state markets that saw a significant reduction in installation volumes in 2017 – Mass., New York, Calif. – national installers account for between 30% and 50% of their installed capacity, and all experienced significant market downturns as a function of pull-back from the national installers. Given the state's high penetration of national installers that exhibited signs of sales weakness in 2017, we consider Pennsylvania's significant exposure to national installers as a sign of potential risk.

Figure 2.6 2017 Pennsylvania Residential PV Market Share



Source: December 2017 EIA Form 861M

Figure 2.7 2017 Florida Residential PV Market Share



Source: December 2017 EIA Form 861M. Only 2 of the 3 national installers are active in Florida.

Further, with relatively low utility rates of approximately $.13/kWh it appears difficult to achieve profitability in Pennsylvania. Our survey of installers found that PPAs that provide 10% year-one savings are difficult to sell with any significant profit margin, suggesting that growth is coming at the expense of profitability in order to secure market share. This leaves the market particularly susceptible to price fluctuations, as increased costs are unable to be absorbed in reduced margins and are difficult to pass along to customers.

Pennsylvania – and other emerging markets with relatively low electricity rates that have recently achieved grid parity – is particularly sensitive to system-cost increases due to higher module prices. As such, we forecast a lull in demand in response to Section 201 and we have reduced our residential forecast by 32% for 2018-2022. Though the state is still sensitive to tariffs, we have only reduced our Florida forecast by 19% for the period 2018-2022 since the Q4 2017 edition of the *U.S. Solar Market Insight* report.

Looking ahead, we expect emerging state markets with a higher share of local installers to see more sustainable growth and less installation volatility as national growth begins to align with the gradual growth rates of local installers in the 10% to 15% range.

2.3.5. Overheard at Solar Power Northeast

- **New Jersey**'s legislature is seeking to accelerate the state's renewable portfolio standard by pulling forward compliance requirements in an effort to maintain existing price levels and reduce the amount of SREC oversupply. SB 877 would increase the solar carve-out to 4.3% (from the current 3.3%) in 2019, increasing gradually to 5.1% by 2023. This would help to immediately fix the pending SREC supply-demand imbalance, which would provide significant upside to our long-term forecasts. Additionally, the bill would also set megawatt targets for distributed generation carve-outs and establish a community solar program. The bill does not establish community solar capacity targets but does direct the Board of Public Utilities to establish a pilot program. Projects would be limited to 5 MW, and the BPU would have to establish a permanent community solar program after three years with a goal of at least 50 MW per year.
- **Pennsylvania** solar stakeholders are similarly pushing for a community solar program, though the timeline remains nebulous, with some stakeholders suggesting a 2018-2019 timeframe. Separately, SREC prices have doubled to $10/MWh since it closed its borders, though significant oversupply remains.
- **Rhode Island** launched a single, statewide permit application. As a patchwork permitting process is commonly cited as a significant pain point among installers, the market welcomes permitting uniformity among the many Rhode Island municipalities.
- **Connecticut** regulators released its annual *Comprehensive Energy Study*, which recommended that the legislature's successor to the ZREC program be constrained to an annual budget of $35 million, as well as combining energy and incentive values – much like neighboring Massachusetts' SMART program. Regulators forecasts that this will result in the deployment of about 900 MW of distributed solar.
- **South Carolina's** NEM cap is expected to be hit soon. At the current run-rate, Duke would hit sometime in Q2 2018, while SCE&G may last until 2019. Though there are talks to extend the NEM cap, there is currently no transition plan once caps have been hit.
- While no major state markets have fully dismantled net metering in 2017, many utilities are still seeking ways in which to recover revenue losses from the increase in distributed generation. Some notable strategies in 2017 include:
  - **El Paso Electric (Texas)**: EPE consistently saw 2 MW/quarter installed throughout 2017, but growth in the utility territory is set to slow in 2018 as regulators approved a 20% increase to customer-wide residential fixed charges (for a total of $8.25) to monthly bills, while also approving a minimum monthly bill of $30.00 for new residential solar customers.
  - **Eversource (MA)**: Set to implement a residential demand charge ($2.20-2.70/kW) for customers beginning in 2019.
  - **Xcel (WI)**: Wisconsin's PSC approved a fixed charge amounting to $17.00.

2.4. Residential PV Market Outlook, 2018-2023

In 2017, residential solar fell year-over-year for the first time this decade. This downturn largely stems from persistent sales challenges and customer-acquisition difficulties across the installer landscape in major state markets. Throughout the year, it became clear that the rising costs of customer acquisition represent a significant pain point in the residential space. Though installers of all sizes struggled to grow in major states, the scaling back of operations by national residential solar companies significantly affected national installation levels.

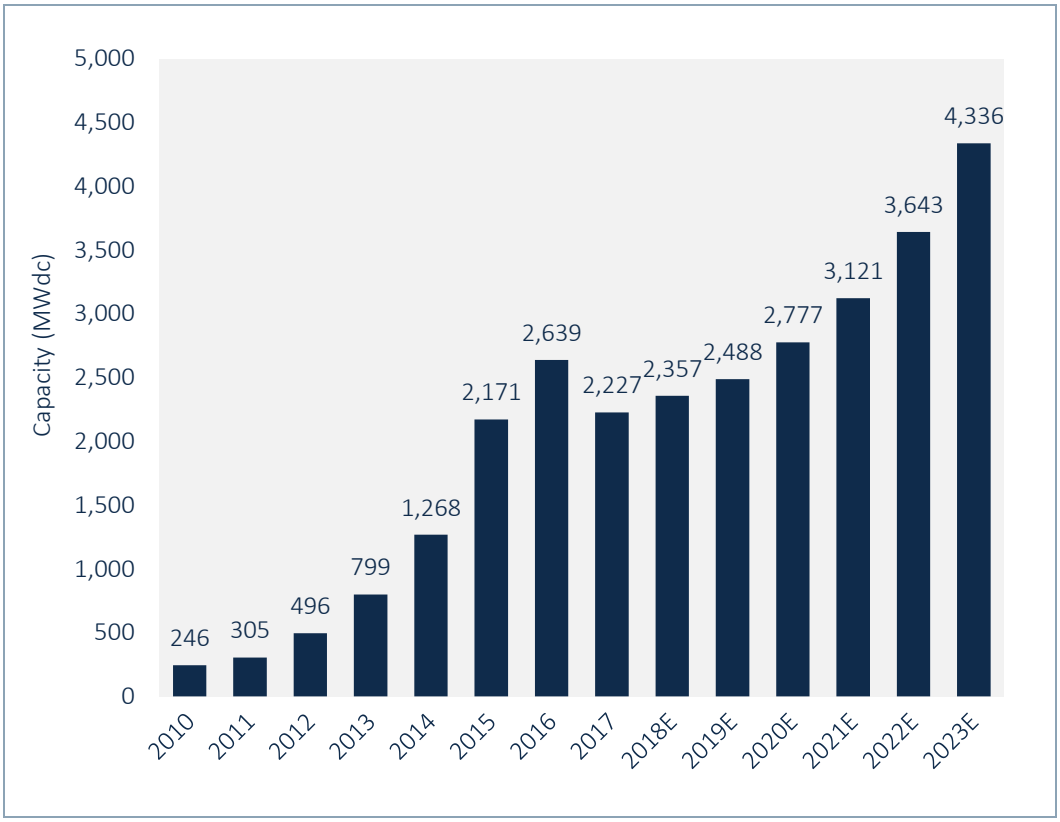
We largely expect these competitive landscape trends that defined 2017 to continue to a lesser extent in 2018. Pressure to decrease customer acquisition costs will be further exacerbated by the recently imposed cell and module tariffs and a depleting pool of early-adopter customers in major state markets. With 2017 representing a transition year in which national installers bottom out, 2018 will see the shifts toward a majority of growth being driven by smaller, local and regional installers. Consequently, **major state markets are expected to be essentially flat in 2018** after a year in which most of these same states experienced contraction.

Over the next few years, as installer business models mature, loan product offerings proliferate, and tariffs gradually step down, residential PV is expected to begin to range between 6% and 12%, with upside contingent on the extent and speed with which national installers can scale new sales solutions. The residential PV market's ability to achieve that growth amidst headwinds within the competitive landscape stems from strong near-term policy fundamentals. While various incentive and rate-design battles are underway or anticipated in several key states, in most major markets, retail-rate NEM is expected to continue to drive demand. The exceptions to this in 2018 are Massachusetts, which will be transitioning to the SMART program; Arizona, which will begin to feel the effects of a reduced export credit, and California, which will be transitioning to NEM 3.0 in 2019.

Conversely, we expect emerging state markets to play an increasingly important role in our long-term outlook as states continue to achieve grid parity. However, the introduction of module tariffs disproportionately affects emerging state markets that have recently hit – or were poised to hit – grid parity within the next few years. While major state markets see the largest megawatt reductions relative to our Q4 forecasts, emerging state markets see the largest percentage reductions under our revised forecasts, as tariffs push out the point at which certain states are able to offer 10% or more year-one savings. Pennsylvania exemplifies this trend, as growth has largely been a function of major installer presence driven by market share capture at the expense of profitability. The effectiveness of such an approach is limited in an increased pricing environment.

Starting in the early parts of the next decade, we will begin to see the impacts of demand pull-in related to the federal Investment Tax Credit. 2022 benefits from being the first post-tariff year to realize pent-up demand, though the ITC step-downs soften the impacts of demand buildup, while an increasing number of emerging markets begin to scale in 2023.

Figure 2.8 Annual Residential PV Installation Forecast, 2010-2023E



Source: GTM Research

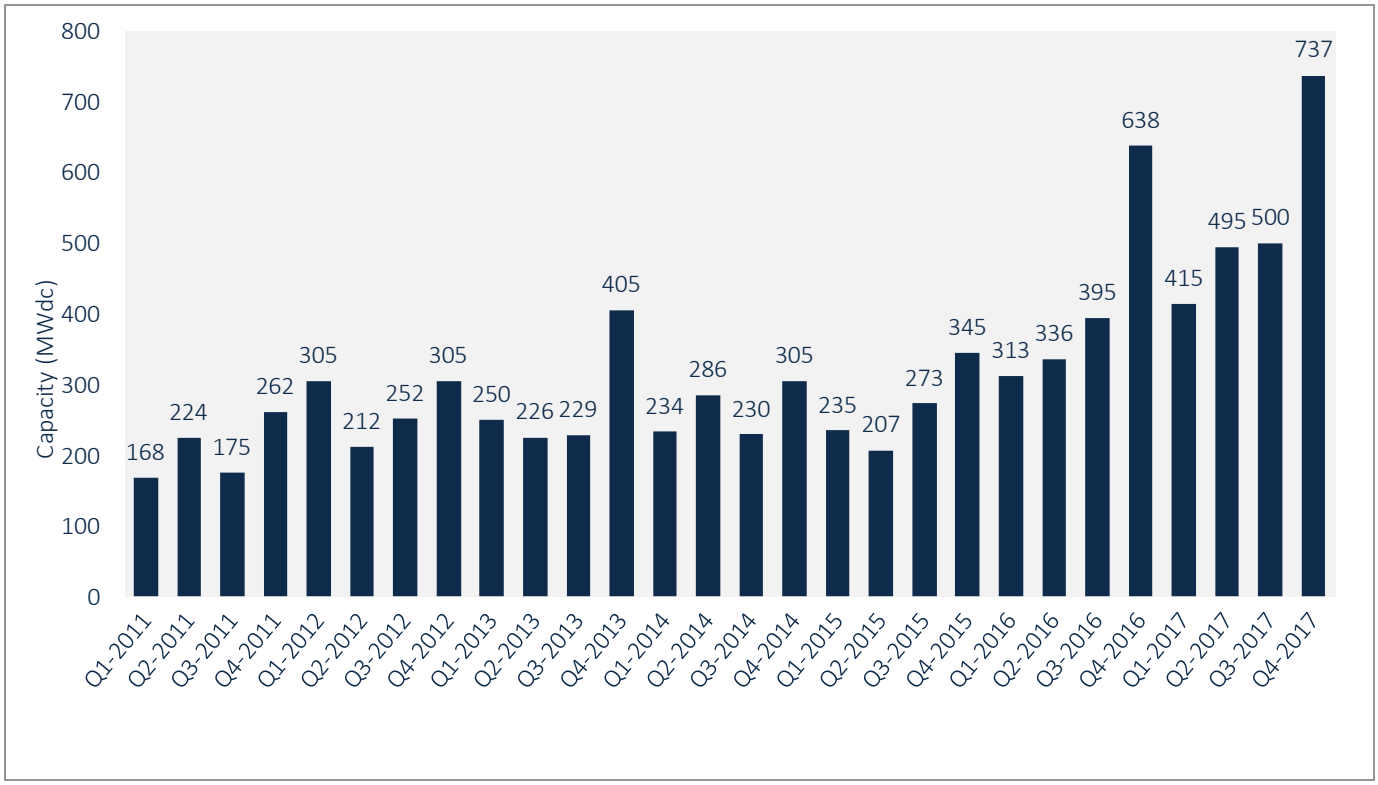
3. NON-RESIDENTIAL PV

3.1. National Installations

- 2,147 MW_{dc} installed in 2017
- Up 28% from 2016

Regulatory demand pull-in and community solar were the primary market movers in 2017 and combined to make non-residential PV the only segment to see growth. California benefited from developers rushing to install projects to meet a (since-lifted) year-end deadline to be grandfathered into more favorable solar-friendly time-of-use periods. In the Northeast U.S., developers in Massachusetts rushed to get projects installed under the SREC-II program, while New York saw record-breaking installations as developers likewise rushed to install projects to maintain eligibility for remote net metering. Meanwhile, the buildout of Xcel Energy's robust community solar pipeline vaulted Minnesota to the rank of third-largest non-residential market in 2017.

Figure 3.1 U.S. Non-Residential PV Installations, Q1 2011-Q4 2017



Source: GTM Research

3.2. Community Solar Market Update: 2017

- **Cumulative operating capacity:** 768 MW_{dc}
  - Third-Party Led: 512 MW_{dc} (67%)
  - Utility Led: 256 MW_{dc} (33%)
- **2017 capacity additions:** 408 MW_{dc}

Figure 3.2 Annual Community Solar Installations by State (MWdc), Pre-2010 to 2017

State	Pre-2010 Cumulative	2010	2011	2012	2013	2014	2015	2016	2017	Cumulative
Arkansas	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
Arizona	0.0	0.0	24.4	3.2	0.0	0.0	0.0	0.0	0.0	27.6
California	1.2	0.0	0.0	0.0	0.0	5.7	0.0	66.3	6.0	78.0
Colorado	0.0	0.2	2.1	2.9	4.7	9.3	16.1	1.5	9.4	46.1
Delaware	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.2
Florida	0.0	0.1	0.0	0.0	0.4	0.0	0.5	0.0	20.0	21.0
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.2	0.0	2.2
Iowa	0.0	0.0	0.0	0.0	0.0	0.1	1.2	1.5	5.9	8.6
Idaho	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Illinois	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1
Indiana	0.0	0.0	0.0	0.0	0.0	0.1	0.2	2.6	0.0	2.8
Kansas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	8.6
Massachusetts	0.0	0.0	0.0	0.3	0.0	3.5	19.7	63.8	92.4	177.0
Maine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Michigan	0.0	0.0	0.0	0.0	0.1	0.0	0.0	4.0	1.5	5.6
Minnesota	0.0	0.0	0.0	0.0	0.1	1.5	0.5	42.0	240.9	285.1
Missouri	0.0	0.0	0.0	0.0	0.0	5.0	0.1	0.1	0.0	5.2
Montana	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
North Carolina	0.0	0.0	0.0	0.2	0.0	0.0	0.2	2.0	0.0	2.5
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Nebraska	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0
New Hampshire	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1
New Mexico	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
Nevada	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	17.5
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	3.4	4.0
Oklahoma	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Oregon	0.1	0.0	0.0	0.0	0.1	0.0	3.4	0.2	0.0	3.7
South Carolina	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.5	1.6
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.9	4.8
Texas	0.0	0.0	0.0	0.0	0.0	0.0	3.9	2.0	8.1	14.0

State	Pre-2010 Cumulative	2010	2011	2012	2013	2014	2015	2016	2017	Cumulative
Utah	0.1	0.3	0.0	0.0	0.0	0.0	0.0	26.0	0.0	26.2
Virginia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.6
Vermont	0.0	0.0	0.2	0.1	0.4	0.9	0.8	0.2	0.0	2.6
Washington	0.0	0.1	0.1	0.1	0.4	0.2	0.9	0.3	0.0	2.2
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.9	1.5	0.0	4.1	6.5
Other	0.0	0.0	0.0	0.1	0.0	0.1	1.2	6.0	1.4	8.7
Total	1.46	0.61	26.67	7.13	6.20	27.50	48.89	241.47	408.16	768.10

Source: GTM Research

3.2.1. Minnesota

- 241 MW_{dc} of community solar installed in 2017

After a period of delayed development and uneven progress, 2017 officially stands as the breakout year for community solar, with Minnesota leading the pack. With 241 MW_{dc} installed last year, Minnesota is by far the largest community solar market in the U.S., and it will remain the largest community solar market as the remainder of the state's robust pipeline is built out in 2018. We continue to see projects delay their energization dates to 2018; none of the 48 projects originally scheduled for Q4 2017 energization were completed. Many sites did not meet the requirements for witness testing, resulting in a doubling of the number of projects scheduled to be energized in Q1 2018. With over 200 MW anticipated to be installed in 2018, this year is likely to surpass 2017 as Minnesota's biggest year for community solar.

Once Minnesota's current community solar pipeline is built out in 2018, the pace of installations is expected to slow dramatically. Community solar subscriptions have become much less attractive under Minnesota's Value-of-Solar Tariff (VOST) and even less so under the new Value-of-Solar Vintage Bill Credit Rates (VOS), which range from $0.0944 to $0.1006/kWh for projects with applications in 2018 ($0.0027/kWh less than VOST rates in 2017). Residential subscribers continue to make up an increasingly small share of subscriber capacity (just 7% as of January 2018), but the residential subscriber base will become an increasingly important target demographic as the pool of C&I customers is exhausted. On December 14, the Minnesota Public Utility Commission ordered that Xcel perform additional analysis on the economic impacts of a proposed residential subscriber adder that would start at $0.025/kWh in the first year and decline by $0.01/kWh over the following two years. The commission also proposed a residential subscriber capacity carve-out for community solar projects, requiring that a certain portion of a community solar project's capacity be allocated to residential customers. The adder could provide a modest boost to developers dealing with high customer-acquisition costs in the reduced bill credit environment. However, on February 1, Xcel's analysis reiterated its preference for the residential subscriber carve-out, which would saddle developers with the added costs of acquiring residential customers for their projects.

In conjunction with the ongoing residential subscriber adder, the imposition of Section 201 cell tariffs has pushed an already price-sensitive sub-segment further into the red in a challenging and costly customer-acquisition landscape. Our current post-2018 base-case outlook for Minnesota is diminished as tariffs make it that much more challenging for VOST projects to pencil out economically. But if the commission decides to approve residential subscriber adders, it would provide upside growth to our outlook.

3.2.2. Maryland

April 2018 marks the one-year anniversary of the official program launch of Maryland's pilot community solar pilot program. Though the state's community solar program has experienced its fair share of issues related to program design, interconnection, legal issues and economic attractiveness of bill credits, the state's current community solar bottlenecks are unrelated to the program structure. Instead, land-use constraints – in the form of restrictive local and county-level zoning laws – are the biggest roadblock to community solar deployment in Maryland. Despite these constraints, nearly 25% of the program's 196 MW have been allocated.

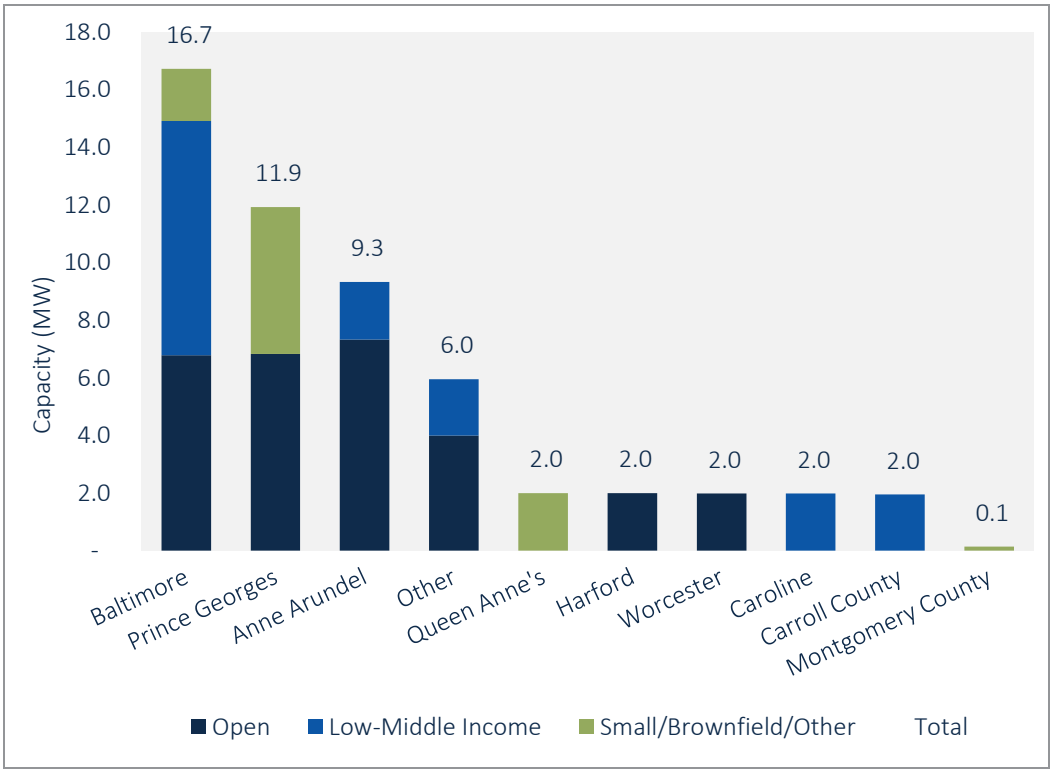
Throughout 2017, many counties have put land-use moratoriums on community solar or ground-mount solar more broadly. Further, these counties sit squarely within Pepco and Baltimore Gas & Electric territory – the state's largest utilities. Among the counties with zoning restrictions:

- Anne Arundel County – In December 2017, county officials instituted an eight-month moratorium on the approval and development of solar facilities as city officials address the impact of solar gardens on the surrounding rural residential and agriculture community. Five solar garden projects in the county are currently in limbo because of the decision.
- Montgomery County – One of the best counties in Maryland for community solar (higher income, densely populated, lots of usable land, etc.), development is limited by the county's archaic zoning rules, limiting property owners from hosting solar to "accessory use," meaning that solar systems must be built in support of another structure. These rules effectively disqualify the ground-mount structures that most community solar gardens employ. Zoning codes also limit solar usage to on-site consumption, as rules state that systems must be sized to produce a maximum of 120% of on-site consumption – a difficult, if not impossible, restriction for community solar site that exports all production. This has effectively halted ground-mount development in Montgomery County, limiting development to rooftop systems. However, recently introduced legislation would revise zoning standards to allow for solar gardens of up to 2 MW in non-agricultural zones, which would allow development to move forward if ultimately passed. Legislation will proceed through the spring.
- Prince George's County – While many developers are proceeding with projects, county-level officials are attempting to make zoning laws more restrictive for siting projects on land zoned for open space and residential-agricultural usage. Examples of proposals would include requiring grazing livestock, poultry and crop production to persist beneath ground-mounted

systems. Many of the current proposals are cumbersome and would require extensive additional siting costs. Close to half of the project applications are sited in lands zoned for agricultural use, so zoning restrictions would significantly hamper growth opportunities.

Taking these issues into account, we have adjusted our 2018 forecasts to reflect project delays for sites that have applied to the program in counties affected by land-use moratoriums. However, our midterm outlook for the state is still strong as developers are largely content with many aspects of the program structure and administration. Baltimore County leads the way in capacity allocations, with most projects designated as "low-middle income" – a project category which requires 30% of the project's output to be allocated to customers on low-middle income rate schedules – an encouraging sign. Further, though subscriber organizations have just begun to start customer acquisition, conversations with developers suggest that product offerings can offer bill savings of 5%-20% based on current project economics. While this may change due to module pricing pressure in response to Section 201 tariffs, the upper end of this range suggests that Maryland's community solar market will see stable growth through the life of the three-year community solar pilot program.

Figure 3.3 Year 1 Community Solar Capacity Allocations by County and Project Category



Source: Maryland IOU Program Capacity Updates

Looking beyond 2018, year 2 of the community solar pilot program will open up in April 2018. Due to the first-come, first-served basis of the community solar application process – which requires developers to submit a conditional approval of interconnection from the utility – there is widespread concern that many projects currently on the waitlist for capacity allocations may not receive allocations again, as utilities have been directed to clear out their interconnection queues. While this is frustrating for developers, it doesn't appear to be substantially slowing down the rate of applications.

Consequently, our outlook for Maryland is still largely supported by the 196 MW pilot program through 2021. Longer-term, the PSC is required to conduct a study to inform the legislature on the results of the program to be completed by July 1, 2019. As we gain more clarity on the design and ultimate results of that study, we will have more insight into the long-term trajectory of Maryland's community solar program. Until then, we will be monitoring the outcomes of the various county-level zoning disputes currently impacting our near-term forecast.

3.3. State Market Overview

Figure 3.4 Top 10 Non-Residential PV State Markets by Q4 2017: Key Installation Figures

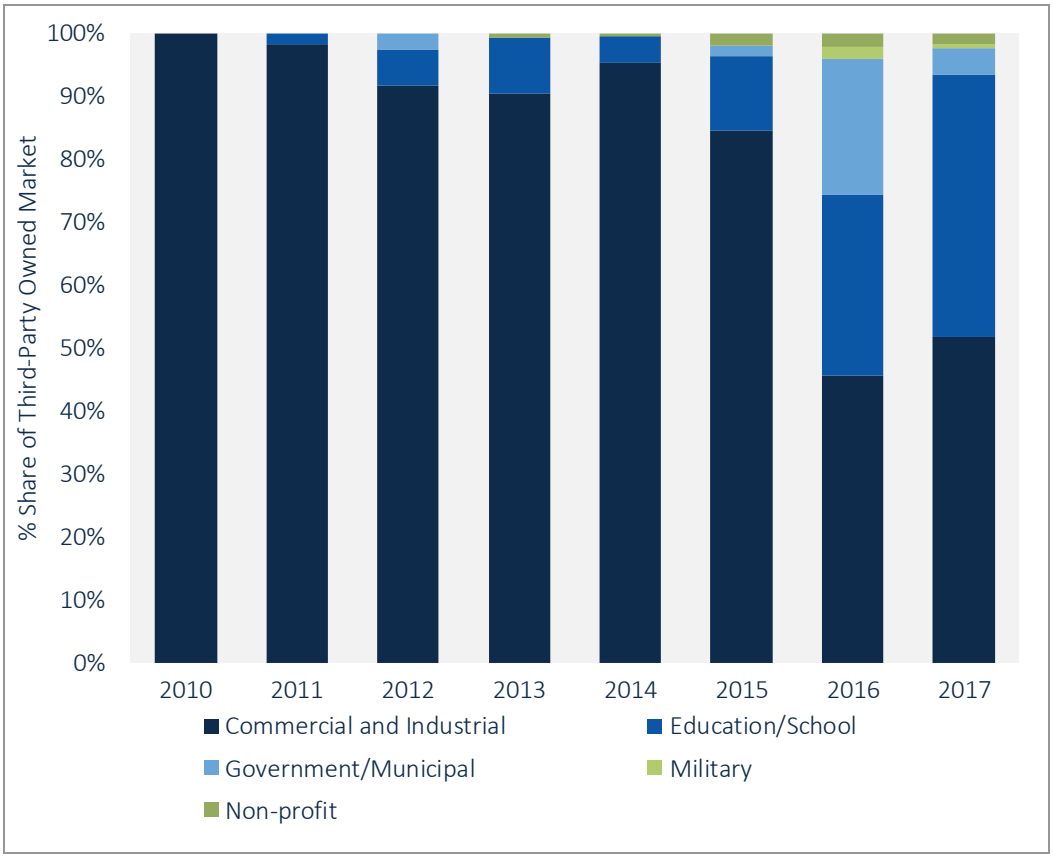
Installations (MW_{dc})	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
California	151.2	193.6	218.7	140.8	193.4	177.1	262.4
Minnesota	2.1	2.3	43.8	45.7	14.6	64.4	125.2
Massachusetts	55.8	29.9	157.2	58.4	140.5	93.8	86.5
New Jersey	12.9	18.9	48.2	26.4	15.5	26.2	56.0
New York	20.4	14.4	27.3	37.3	44.7	46.5	34.7
Florida	3.8	2.4	1.2	6.5	1.0	3.4	23.8
Connecticut	9.9	14.6	7.3	9.1	7.2	10.8	21.2
Alabama	0.7	0.1	0.3	0.2	0.2	0.2	13.2
Arizona	10.3	8.1	11.3	2.3	9.6	5.6	12.9
Rhode Island	0.4	0.2	1.0	0.4	1.3	1.6	11.1

Source: GTM Research

3.1. Non-Residential Finance Trends – California

The share of California's non-residential solar market that is third-party-financed has not changed dramatically in recent years. Since 2015, the share of third-party-owned systems has increased slightly from 22% to 30%. But as California's commercial solar customers have become more diverse, new customer types have been acquired, predominantly through power-purchase agreements. The market for customer-owned solar in California remains dominated by C&I customers that have large tax appetites and can take advantage of tax credits and depreciation benefits. Third-party-owned solar, unsurprisingly, accommodates tax-exempt public-sector and nonprofit customers.

Figure 3.5 California's non-residential, third-party owned solar installations by customer type



Source: GTM Research

Non-residential customers tend to be the prime mover in deciding between contracting with a third party or owning their system outright. This differs from residential solar, where company-specific preferences for product offerings can drive trends in residential consumer finance. Developers report that non-residential customers typically want to see several financing options to weigh the tradeoffs of various ownership structures. There are several top California solar

developers that tend to sell systems directly to customers (such as REC Solar and Baker Solar), while others almost exclusively sell third-party-owned systems (such as SunPower, Borrego and PFMG). Developers that have strong relationships with third-party financiers will be well positioned to capture a growing portion of customers who are interested in offsite solar but are turned off by increasing market complexity and policy risk. As several major non-residential solar markets transition to new compensation schemes and incentive structures (such as new time-of-use rates in California, the Value of Distributed Energy Resources proceeding in New York, or the SMART program in Massachusetts), customers would rather let third-party owners manage those complexities.

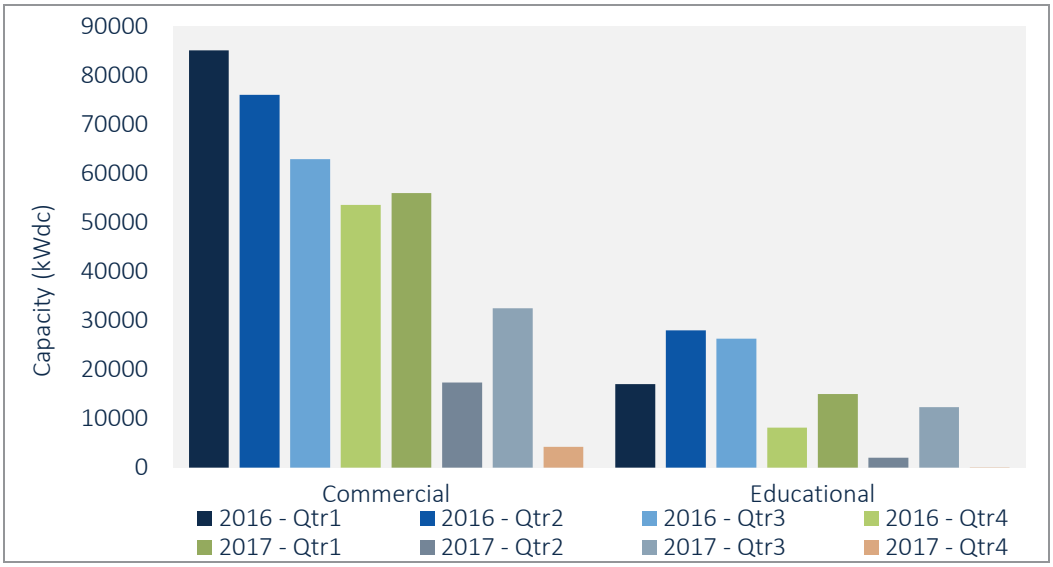
3.2. Non-Residential PV State Market Spotlights

3.2.1. California

- 773.7 MW_{dc} installed in 2017
- Up 13% from 2016

2017 was a record-breaking year for California's non-residential market as a number of policy-related deadlines pulled in many projects that sought to be grandfathered in under more favorable rates and time-of-use periods. A decision by the California Public Utilities Commission in early 2017 initially stated that projects needed to have submitted completed interconnection applications by the end of January and complete projects by December 2017 in order to be grandfathered in under more favorable time-of-use periods that align with peak PV production. Though the CPUC eventually lifted the December completion requirement, many developers rushed to get installations completed before the end of the year, which partly led to the influx of build-out in 2017. While 2018 will benefit from the since-lifted December 2017 project completion requirement, we have seen a substantial decline in NEM applications since the CPUC first announced the decision to limit grandfathering to projects that had submitted their applications before January 2017.

Figure 3.6 NEM Interconnection Application Submission Queue by Segment, Q1 2016-Q4 2017



Source: California Distributed Generation Statistics, NEM Interconnection Applications Data Set as of Dec. 31, 2017

In August the CPUC approved of SDG&E's proposal to shift peak time-of-use periods from 11:00 a.m.-6:00 pm to 4:00 p.m.-9:00 p.m., a move that will substantially impact the value of non-residential projects going forward as exports will now be compensated at lower, off-peak rates. Our conversations with developers suggest that the shifting peak periods can extend the payback period for a cash sale by as much as 6-12 months. Though payback periods are not still expected to exceed five years under new peak periods, the stark drop-off in NEM applications suggest that the reform is substantial enough for customers to second-guess their decision to go solar. With the CPUC expected to approve proposals by PG&E and SCE in H1 2018 that have similarly requested the pushing out of on-peak time-of-use periods – moving to 5:00 p.m.-10:00 p.m. from 12:00 p.m.-6:00 p.m. – developers have already begun talking to customers about seeing reduced savings.

With SDG&E already transitioning to new TOU periods and the remaining investor-owned utilities set to follow suit in 2018, developers are only targeting customers who maintain attractive savings under the revised rates. In particular, though reductions to gross savings range anywhere from 10%-25% under the new on-peak periods, hotels across all system size ranges see a considerable decline in bill savings under revised time-of-use periods. In general, customer types with significant evening load and high daytime exports are the most impacted by the shift. Going forward, we expect 2018 to fall over 2017 as the pipeline of grandfathered TOU projects is gradually depleted. With developers seeking to build out grandfathered projects this year, the years 2018-2020 are poised to be a period of transition as the rebooted origination cycle this year and next year coincide with NEM 3.0 in 2019. With little knowledge of how those proceedings will result, we don't expect California's non-residential market to experience annual growth again until 2021, at which point growth will be increasingly driven by solar-plus-storage deployments.

3.2.2. New York

- 163 MW_{dc} installed in 2017
- Up 111% from 2016

Across the non-residential segment, community solar is among the most sensitive sub-segments to the Section 201 tariffs. This is especially true for states with programs that require a significant share of the project's energy be allocated to residential subscribers given the added cost of customer acquisition.

New York in particular is among the most sensitive states to the 30% module tariff. This is primarily because the foundation of our five-year outlook is based on community solar, but the impact is exacerbated because the state's program highly incentivizes projects to subscribe residential and small commercial (i.e., non-demand rate) customers. Only these "mass-market" customers are eligible for a fixed Market Transition Credit (MTC) that helps true up the value of the bill credit closer to the retail rate. Medium and large C&I (demand rate) customers are not eligible for such a credit. The credit declines every tranche so that Tranche 3 of the program credits subscribers at an MTC that would be roughly equivalent to 90% of the full retail rate. However, given the high costs of customer acquisition and retention specifically for New York, which requires projects to have residential subscribers to be eligible for the MTC, additional 10-12 cents/watt module costs eat into developers' ability to offer attractive savings to residential customers. Because of this, **community solar tranches with lower-credit value are most sensitive to the impact of pricing as it inhibits the ability to offer attractive savings to customers.**

Furthermore, our base-case forecast in the previous U.S. Solar Market Insight report assumed that that the upstate utility tranches with lower credit values that have yet to be subscribed would eventually become economic as system-cost reductions enabled developers to offer attractive savings in our long-term base-case forecast in 2021-2022E. However, **artificially inflated module cost increases now push out the viability of upstate community solar projects past 2022E.**

On January 18, the PSC approved the implementation of an additional Tranche 4 for community solar projects that have exceeded – or will soon exceed – their capacity allocation for Tranche 3 of the CDG program. These projects will effectively be credited at a lower value than projects that fell under Tranche 3 – around 75% of the base retail rate for Orange and Rockland Utilities and 85% of the base retail rate for Central Hudson. It remains to be seen whether Tranche 4 projects will be viable going forward due to the expected reduced credit, but the expectation is that these projects are still more attractive than projects that would be sited in upstate utilities' territories given higher rates in downstate utilities. Additionally, the recent PSC approval of 5 MW project sizes – up from 2 MW – provides additional upside to our base-case forecasts for higher tranche allocations, as additional economies of scale may permit projects with lower MTCs to pencil out economically, though this could potentially be offset by higher interconnection costs.

Separate from community solar, NYSERDA has introduced a proposal to fix certain elements of the MW Block program that have thus far hampered on-site C&I development in the state. In short, NYSERDA's proposal would essentially take well-functioning elements of the small C&I program and apply these to the large C&I blocks.

For Con Edison, the NYSERDA proposal would combine the small and large C&I programs into one incentive program while changing the basis of the program to a capacity-based incentive paid out fully at commissioning, while also providing adders for certain project types. Utilities in the rest of the state would similarly see changes to their MW Block structure, with NYSERDA proposing to increase project size eligibility for the small C&I program from 200 kW to 750 kW. The proposal would also change project maturity requirements by mandating all projects to pay 25% of their interconnection upgrade costs in order to receive an incentive.

In aggregate, developers are highly optimistic about all of these changes. In particular, shifting to a capacity-based incentive for the majority of the Block program with a higher share of the incentive paid out at commissioning is expected to ease the financing of projects. Looking forward, the fixes would provide additional upside to our C&I forecasts if ultimately approved. NYSERDA has filed a petition to the Department of Public Service. If approved, NYSERDA would begin to implement program changes in May.

3.2.3. Illinois

- 8.7 MW_{dc} installed in 2017
- Up 425% over 2016

On December 4, the Illinois Power Agency (IPA) officially filed its first Long-Term Renewable Resources Procurement Plan (LTRRP) as a part of the Illinois Future Energy Jobs Act, which came into effect on June 1, 2017. The implementation of the Adjustable Block Program, whereby the IPA procures RECs from new distributed solar projects, is expected to expand the state's non-residential solar market from less than 10 MW a year in 2017 to over 150 MW a year in 2022. In the official LTRRP filed in December, the IPA defined the sizes of the program blocks at 222 MW each, with 74 MW each allocated to large commercial projects (between 10 kW and 2,000 kW) and community solar projects of the same size.

With more clarity about the incentive program, developers are beginning to get control of prospective sites in Illinois by securing land lease options, while other developers are offering preliminary quotes to customers. The IPA still needs to release final prices for the RECs procured through the Adjustable Block Program. But the initial prices reported in the LTRRP appear favorable, particularly for community solar projects, which earn $52-$99/MWh for 15 years depending on the size of the project and utility territory. Furthermore, all non-residential projects are eligible for REC adders based on project size, and community solar projects can earn more adders based on their shares of residential subscribers.

Figure 3.7 Illinois Block 1 REC Prices and Adders as of December 2017

Group	Solar Project Type	Project Size	Preliminary REC Prices ($/MWh)
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Large Non-Residential Projects (10 kW-2,000 kW)	>10 - 25 kW	$74.75
		>25 - 100 kW	$58.51
		>100 - 200 kW	$45.75
		>200 - 500 kW	$39.87
		>500 - 2,000 kW	$37.57
	Community Solar Projects	>10 - 25 kW	$99.88
		>25 - 100 kW	$79.17
		>100 - 200 kW	$65.76
		>200 - 500 kW	$59.55
		>500 - 2,000 kW	$56.93
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Large Non-Residential Projects (10 kW – 2,000 kW)	>10 - 25 kW	$67.58
		>25 - 100 kW	$52.62
		>100 - 200 kW	$39.87
		>200 - 500 kW	$33.98
		>500 - 2,000 kW	$31.69
	Community Solar Projects	>10 - 25 kW	$94.24
		>25 - 100 kW	$73.52
		>100 - 200 kW	$60.12
		>200 - 500 kW	$53.91
		>500 - 2,000 kW	$51.29

Source: GTM Research, IPA Long Term Renewable Resources Procurement Plan

Once the rates are finalized by the IPA, developers of community solar projects will have a lot to think about. They'll need to balance the additional customer-acquisition costs for residential customers with the available adders for projects, while also structuring product offerings and customer bill crediting via three disparate revenue streams: an on-bill supply charge, an upfront rebate, and five-year fixed REC contracts that accrue to the system owner. Nonetheless, the non-residential solar market in Illinois is forecast to be one of fastest growing markets in the next five years, particularly for community solar.

In light of the recently imposed Section 201 tariffs, Illinois is one of the few non-residential markets that may be insulated from increased module prices. The IPA is scheduled to finalize distributed generation REC prices in April and has authority to increase prices by up to 25% without requiring legislative approval. Accordingly, the industry is hopeful that the IPA will take the pricing impacts of tariffs into account in the finalized REC prices though we have not accounted for such an increase in our base-case forecast. Thus, we expect Illinois' program to roll out in H2 2018, with robust deployment growth to follow in 2019.

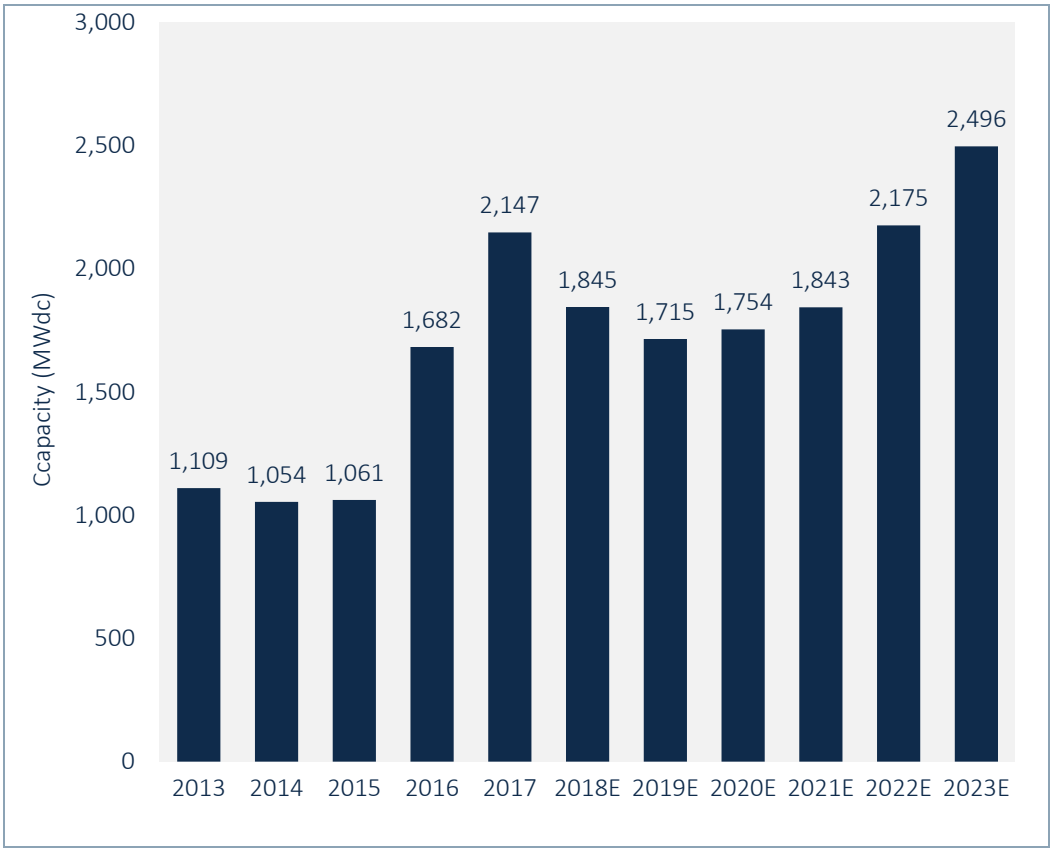
3.3. Non-Residential Market Outlook, 2018-2023

With 2016 and 2017 benefiting from regulatory and policy deadlines that led to demand pull-in across major state markets, 2018 is forecasted to fall by 14% as two major non-residential state markets see transitions in their policy environments. First, California has a dwindling pipeline of projects grandfathered in under solar-friendly time-of-use periods. Meanwhile, Massachusetts faces NEM cap constraints that will limit additional greenfield origination until the new SMART program takes effect in mid-2018. Though we still forecast a contraction in 2018, our revised forecasts are actually 5% *higher* than those in our Q4 report, due to increased visibility into project pipelines as grandfathering of projects partially insulates the segment from the impacts of the tariffs.

Given that, the tariffs impact demand to a greater extent in 2019 and 2020 as new policies with lower compensation for solar take effect in major state markets, including SMART in Massachusetts and the successor bill credit program to NEM in New York. Amidst the slew of policy reforms across major state markets, community solar still represents an important cushion to support incremental growth. On one hand, community solar faces additional soft costs via subscriber acquisition and retention that, paired with tariffs, make community solar economics more sensitive than residential rooftop solar, but still a more attractive segment than onsite C&I. At the same time, the roll out of emerging state markets for community solar, including Maryland, Illinois and Oregon, position community solar to account for more than one-third of annual demand by 2020.

Beyond 2020, growth will incrementally resume, stemming from the sub-1 MW_{dc} non-residential PV market, as third-party financing solutions expand into the small and medium-sized commercial customer bases. By 2022, we expect the market to resume double-digit growth as the ITC expiration pulls in demand, while pent-up demand from module tariffs begins to be realized. But in the initial out years, community solar and solar-plus-storage adoption will be increasingly important drivers of growth, and leading commercial states are already working toward policy designs that incentivize both project types.

Figure 3.8 Annual Non-Residential PV Installation Forecast, 2010-2023E



Source: GTM Research

4. UTILITY PV

4.1. Operating Capacity vs. Project Pipeline

Key Figures

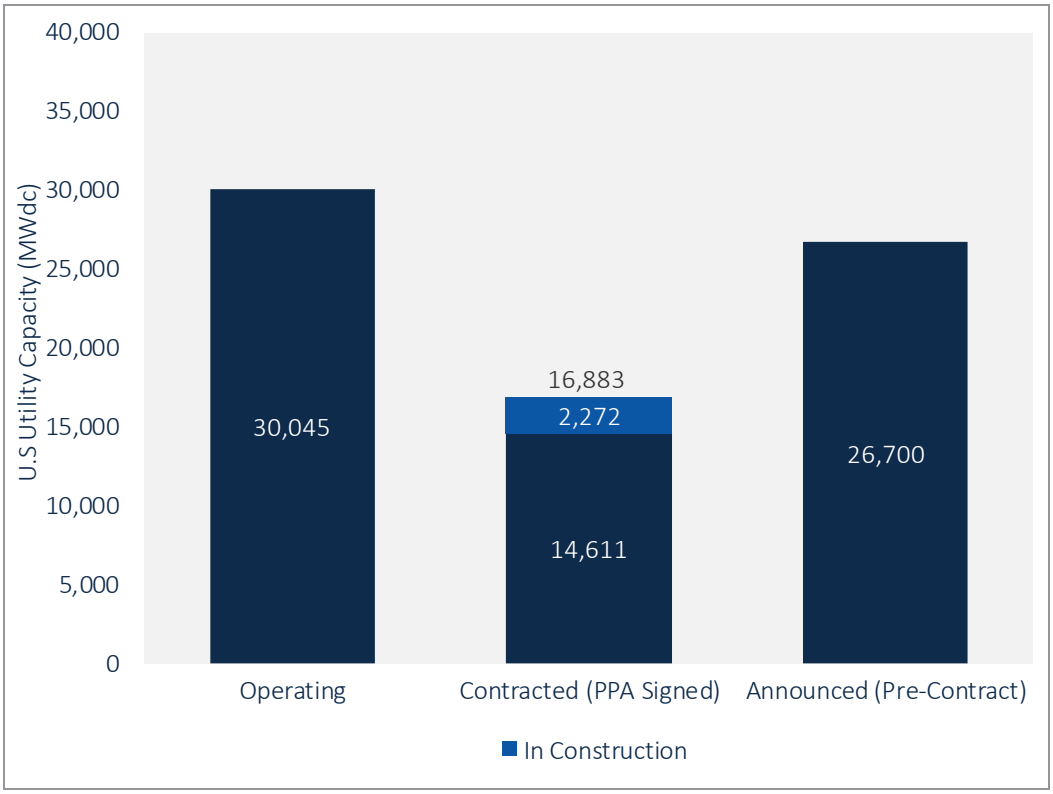
- 6,234 MW_{dc} installed in 2017
- Contracted utility PV pipeline currently totals 16.8 GW_{dc}

Utility PV continues hold the largest share of installations in the U.S. Solar market. A total of 2.6 GW_{dc} came online in Q4 2017, accounting for 67% of PV capacity installed this quarter. In total, 6.2 GW_{dc} were installed in 2017, making up 59% of annual capacity additions. A total of 2.0 GW_{dc} of projects are in construction for 2018, with 6.5 GW_{dc} expected throughout the year. Lower-than-expected installation volumes in H2 2017 can be attributed to both delay and consequent spillover of projects into 2018 due to the uncertainty surrounding tariffs on imported cells and modules, along with delay and cancellation of PURPA projects in markets like Idaho, Montana and South Carolina.

The utility PV pipeline sits at 16.9 GW_{dc}. Despite several utilities like NV Energy and AEP Ohio announcing RFPs or plans for solar procurement, offtakers remained hesitant to sign new PPAs before the tariffs were announced. While no utility has canceled or modified previously announced plans to procure additional utility PV capacity, GTM Research expects some utilities will adjust procurement timelines and delay target commercial operation dates to better leverage tariff step-downs.

Despite the contraction in the development pipeline, there is an underlying low-price environment for utility PV. Prior to the announcement of module tariffs, the low end of PPA pricing has now dropped below $22 per MWh levelized. With tariffs now in place, existing PPAs for 2019 and 2020 that structured contracts with module pricing assumptions below $0.35/W to $0.40/W will be at a high risk of cancellation. While utility PV's economic competitiveness is weakened by tariffs, the prospect of falling prices should allow PPA pricing to remain competitive.

Figure 4.1 U.S. Utility PV Pipeline



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

4.2. Trends in Utility PV Procurement

Only 1.8 GW_{dc} worth of new projects was procured in Q4 2017. Many utilities delayed signing new power-purchase agreements until the Section 201 decision was announced, and GTM Research expects an uptick in new PPAs in H1 2018. Long-term, the addition of tariffs still creates some uncertainty as developers continue determining how to strike a balance between leveraging commence-construction rules to achieve a higher ITC and delaying module procurement to obtain lower module tariff rates. Developers are exploring how to leverage liquidated damages and push projects, resulting in consistent spillover from Q4 into H1 in 2019 and 2020.

At the beginning of the year, PURPA was expected to be the largest driver of utility PV in 2017. While 1.6 GW_{dc} of PURPA projects came online in 2017, representing 25% of the total annual capacity, it was still the second-largest driver, behind only voluntary procurement. Going forward, PURPA will drive less than 15% of new procurement, with only two states, Massachusetts and Michigan, seeing more than 200 MW_{dc} of new Qualifying Facility development in 2018. Through the SMART program, Massachusetts is expected to see ~400 MW of 1,600 MW_{dc} allocated over

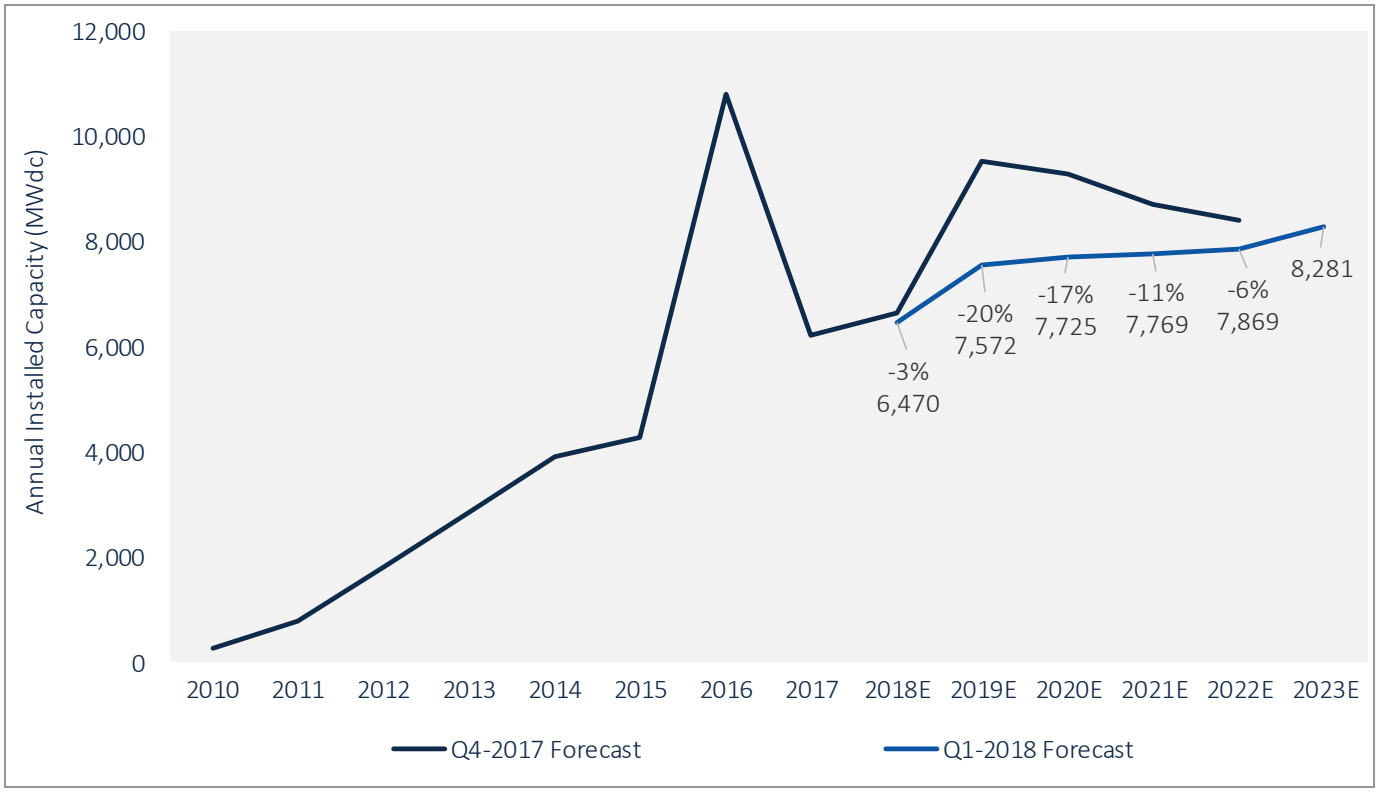
several years by QFs, with the rest of the program served by behind-the-meter solar. Michigan, specifically Consumers Energy (CE), has stated that in seven months it has received 296 MW_{dc} of interconnection requests; it has asked the Michigan Public Service Commission to intervene and allow CE to reject additional QF contracts on the grounds that no additional capacity is needed. This continues the trend of utilities petitioning for reprieve from PURPA at the state level that has been seen in Montana, Utah, Idaho, Oregon and many other states. At the federal level, HR 4476, The PURPA Modernization Act of 2017, was introduced in the House of Representatives and aims to stem development of additional QF renewables by allowing utilities to challenge the 1-mile rule and reject QF contracts based on having access to wholesale markets. It faces an uncertain fate in the Senate.

While voluntary procurement will drive over 60% of new procurement in 2018, corporate procurement of utility PV through green tariffs, direct energy purchases, or virtual PPA contracts will likely see the largest growth in market share of any driver. A total of 1.0 GW_{dc} of projects with a corporate offtaker came online in 2017, representing 16% of 2017's cumulative capacity. New green tariff programs, like Public Service Co. of New Mexico's green tariff, will be the largest driver of new corporate offtake agreements by helping utilities retain customers and prevent customer defection, while also helping corporate entities meet sustainability targets. The number of virtual PPAs with corporate offtakers remains small. Developers report that it is still a multi-year sales cycle with few corporations understanding the long-term risks of virtual PPAs.

4.3. Utility PV State Market Spotlights – Module Tariff Impacts

Of the three sectors, utility solar is most heavily affected by tariffs on imported cells and modules. With modules accounting for 40% (single-axis tracking) and 45% (fixed tilt) of utility PV installation costs, any existing PPAs with module pricing assumptions below $0.35/W to $0.40/W are at risk of cancellation. While the U.S. solar market as a whole will face a 12.1% decline over GTM's Q4 2017 forecast, individual state-level sensitivities to tariffs are most strongly influenced by the primary driver of new projects in each state and whether utilities in each state have previously outlined procurement targets.

Figure 4.2 Annual Utility PV Installed Capacity Under Tariff Free and Tariff Conditions



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

- **RPS and Policy-Driven States**: Utilities in states like Hawaii, Oregon and California with RPS mandates are still beholden to hitting near- and long-term targets. Consequently, states with RPS targets still in place appear to be among the markets least sensitive to tariffs. Despite the risk of tariffs being approved, several utilities in each of these RPS-driven state markets released RFPs in late 2017 or early 2018. For example, Hawaii's HECO released an RFP on February 27 for 300 MW_{ac} of renewable resources across Oahu, Maui and Hawaii that can come online before 2022. In Oregon, PacifiCorp issued an RFP for up to 300 MW_{ac} of new utility PV. And in California, community-choice aggregators including Peninsula Clean Energy, Marin Clean Energy and Silicon Valley Clean Energy have issued solicitations in early 2018.
- **PURPA/QF-Driven States**: In most PURPA markets, such as Montana and Utah, utilities have already tried to stem PURPA development by lowering the rate and length of standard offer contracts. With project margins already slim, developers have reported that portions of their near-term pipeline will not pencil out with tariffs above $0.05/W, stemming further project development and putting current project pipelines at risk for being canceled.
- **Emerging State Markets**: State markets outside of the top 10 account for 53% of demand loss compared to GTM Research's Q4 forecast. Emerging state markets like Louisiana, Iowa and

Washington where utility PV's levelized cost of electricity was expected to begin being competitive with wind and other generation resources are now expected to see reduced or delayed procurement to 2019-2021. However, procurement in emerging markets is expected to pick up in 2021 for projects that can leverage commence-construction rules in 2021 and take advantage of tariffs being removed after February 2022.

- Long-Term Procurement/Resource Plans: Since the start of the Section 201 trade case, several utilities such as Duke Energy North Carolina, Tampa Electric Company, AEP Ohio and NV Energy have announced or updated resource plans that include utility PV or released RFPs for new projects. While project developers and utilities have stated they have not fully measured how tariffs will affect long-term development and procurement, no utility has changed or altered previously outlined procurement targets. Particularly in regulated markets where changes would have to be approved by the state utility commission, these plans are least likely to see changes in procurement volume but are still exposed to project delay by developers looking to push out projects that can leverage lower tariff rates.

4.4. Utility PV Market Outlook, 2018-2023

The U.S. utility PV forecast remains geographically diverse, with 20 state markets expecting to see over 500 MW_{dc} of new capacity between 2018 and 2023. The Southeast is still expected to drive 38% of U.S. cumulative capacity, the largest of any region. GTM Research expects the Midwest and Texas to see 44% and 36% CAGR, respectively, over the next five years.

There is lingering uncertainty surrounding how corporate tax reform will change project economics. While it appears the Base Erosion Anti-Abuse Tax provision will have minimal effect on tax equity demand, reduction in the corporate tax rate may change investor returns and result in changes to the capital stacks of new projects. Again, some of these changes are offset by elimination of the corporate alternative minimum tax and, potentially by 100% bonus depreciation. By Q2 2018, we expect to get clarity on how tax reform will change returns for developers and project investors.

Despite utility PV seeing a 12% reduction to our base-case forecast through 2022 due to the Section 201 decision, GTM now expects to see year-over-year growth through 2023. This is partly driven by demand in 2019, and to a lesser extent in 2020, being pushed out to later years. The 2018 forecast has remained less sensitive to module tariff impacts. While uncertainly around the impact of tariffs led to a reduction in procurement for 2018 projects, both spillover of projects into 2018 along with more than half a gigawatt of tariff-free module supply for 2018 projects has cushioned the downturn. As a result, GTM's 2018 forecast has only seen a modest reduction of 3% to 6.5 GW_{dc}.

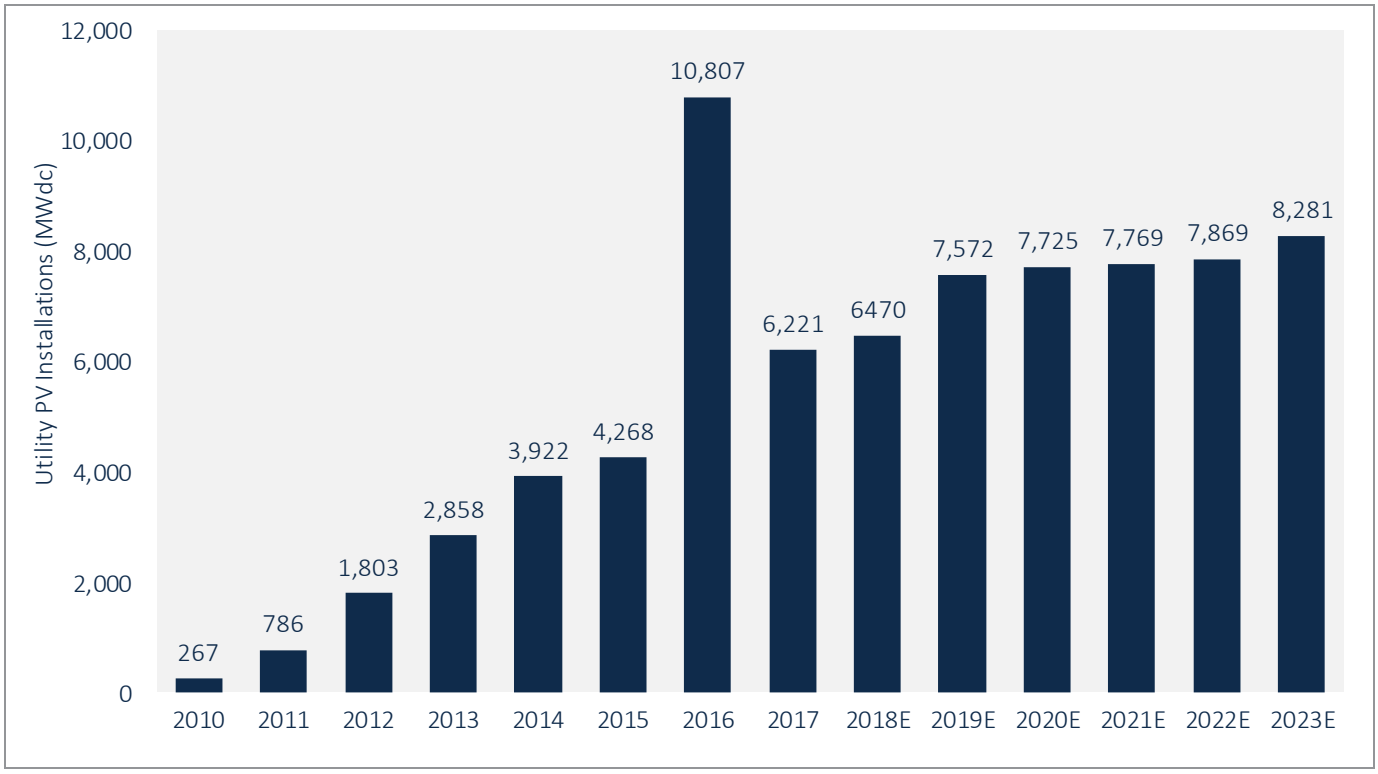
2019 and 2020 are most impacted by module tariffs and respectively see a 20% and 17% reduction in expected capacity additions compared to GTM's Q4 utility PV forecast. While both years will see

over 7.5 GW of annual capacity additions, projects currently in development for 2019 are at risk of pushing out target completion dates to 2020 or later in order to leverage lower tariff rates.

For 2019 through 2022, U.S. utility PV will grow at a 1.3% CAGR as developers balance the complementary impacts of the step-down of the ITC with the step-down of module tariffs. Prior to the announcement of tariffs, both developers and offtakers were incentivized to bring projects online in 2019 or 2020 to leverage the full 30% ITC. Some developers reported exploring bridge PPAs that would enable projects to come online 12 to 36 months early. Now that there is clarity around tariff rates, GTM Research expects procurement to pick up in H1 2018, with projects slightly favoring CODs in 2021 and 2022 rather than 2019 and 2020.

Long-term, 2023 is expected to grow 5% over 2022, increasing to 8.3 GW_{dc}. While some 2023 projects in development will be leveraging Investment Tax Credit levels above 10%, 2023 will be the first year where the majority of projects utilize the 10% ITC. In 2018, the levelized cost of energy of 20 MW of utility PV is lower than the LCOE of onshore wind in 13 states. By 2022 and 2023, the number rises to 30 and 43 state markets, respectively. With the tariffs scheduled to expire in February 2022, we expect emerging markets, including those traditionally driven by wind, such as Wyoming and Iowa, to see an increase in procurement that translates into 2023 capacity additions.

Figure 4.3 Annual Utility PV Installation Forecast, 2010-2023E



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

5. NATIONAL SYSTEM PRICING

5.1. National Reported System Pricing

We utilize a bottom-up modeling methodology to capture and report national average PV system pricing for the major market segments. Though we continue to solicit weighted-average system pricing directly from utility and state incentive programs, we believe that this data no longer accurately reflects the current state of system pricing, as more systems are forgoing local incentives, and data from these sources often represents pricing quoted well prior to the installation and connection date.

Our bottom-up methodology is based on tracked wholesale pricing of major solar components and data collected from interviews with major installers and supplemented by data collected from utility and state programs.

5.2. Modeled National PV Installed Price Estimates With Component Costs

Figures reported by state and utility agencies are subject to several 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, non-residential rooftop, ground-mount fixed-tilt and ground-mount tracking PV system costs that better elucidates component and category 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 medium-sized and large installation and EPC firms.

In Q4 2017, system pricing fell only in the non-residential market segment. System pricing increased by 0.5%, 1.4% and 0.4% in the residential, utility fixed-tilt and utility single-axis tracking markets, respectively. This is the second quarter in a row where we have seen increases in pricing in the majority of market segments.

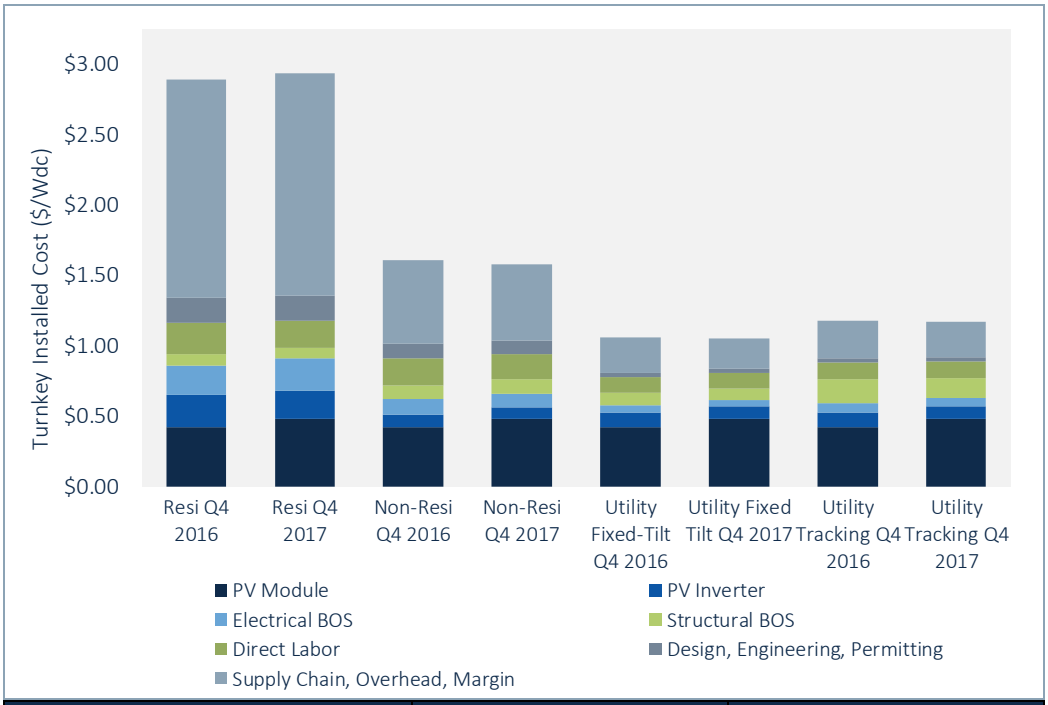
2017 is a story of two halves. Quarter-over-quarter, both Q1 and Q2 saw average decreases in system pricing by 2.2% and up to 3.9% depending on the market segment. In Q3 and Q4, however, average system pricing rose by 2% and up to 5.6% depending on the market segment. This stark

contrast between the first and second half of the year is due almost entirely to the increase of U.S. module prices.

The rush for module delivery before the Trump administration's final decision on Suniva's Section 201 case severely impacted the trajectory of system pricing in 2017. In past Q4s, depending on the market segment, we have seen system pricing fall as much as 23% and on average by 16% year-over-year. Comparing Q4 2016 to Q4 2017, prices fell by an average of only 0.5%, with prices increasing by 2% in for residential systems. This means that system pricing in Q4 2017 was almost equal to pricing in Q4 2016. However, despite prices for modules increasing by 14% in 2017, system prices for most market segments were still able to fall. Factors including pricing for racking, inverters, further adoption of 1,500-volt system architectures, improved operational efficiencies, and likely margin compression were able to mitigate much of the impact. Thus, without the rush for modules in the second half of the year, system pricing across all market segments would have been substantially lower.

System pricing does not change uniformly in each state market: Differences in the cost of labor, permitting requirements and geographical characteristics can affect system prices by as much as 20% on a state-by-state basis.

Figure 5.1 Modeled U.S. National Average PV System Pricing by Market Segment, Q4 2016 and Q4 2017



National Average Turnkey PV Installation/EPC Price ($/Wdc)	Q4 2016	Q4 2017
Residential	$2.89	$2.94

National Average Turnkey PV Installation/EPC Price ($/Wdc)	Q4 2016	Q4 2017
Non-Residential	$1.61	$1.58
Utility Fixed-Tilt	$1.06	$1.05
Utility Tracking	$1.18	$1.17

5.3. Modeled National Residential PV System Pricing

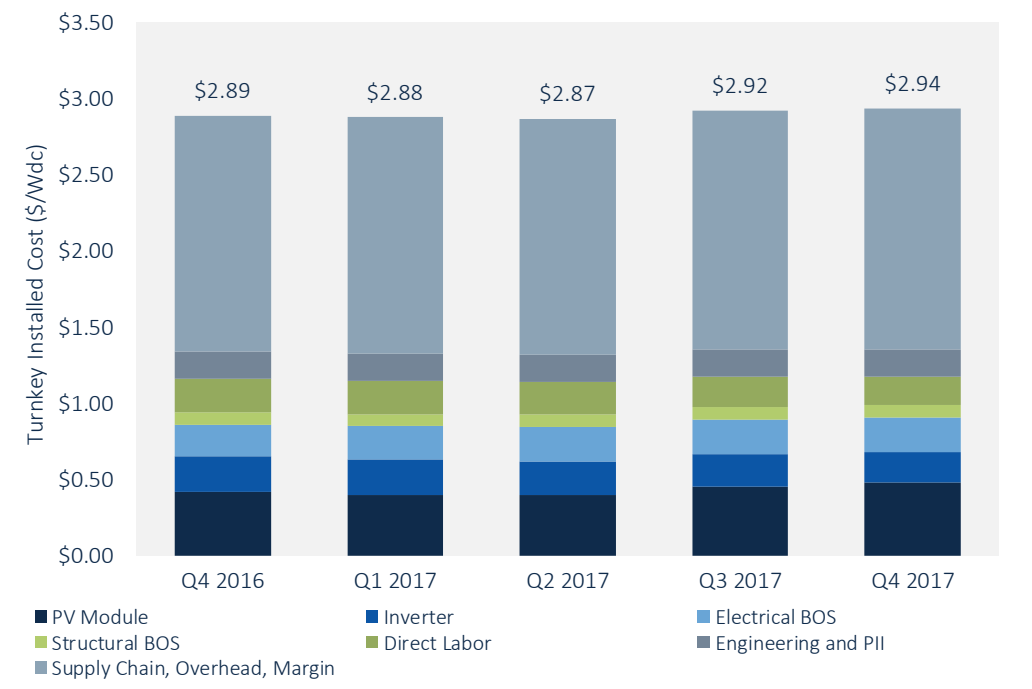
In Q4 2017, average pricing for residential rooftop systems landed at $2.94/$W_{dc}$ – a 0.5% increase from Q3 2017. As in all market segments, higher module pricing in Q4 drove increases in overall system pricing.

In 2017, residential system prices increased by 2%. While module prices drove much of this increase, 2017 also saw rising customer-acquisition costs. Broadly speaking, while major national installers have scaled back their operations in 2017 to maintain positive cash flow, decrease customer-acquisition costs and manage growth sustainably, this has left a gap in the market. In order to fill this gap, many medium-sized regional installers increased investment in customer-acquisition strategies to position them for greater growth in the long term. Therefore, while major national players' costs have fallen, the number of smaller companies that increased their spending on customer acquisition has produced an increase in the overall average costs.

Though residential system pricing is $2.94/$W_{dc}$ nationally, significant pricing variation is a fundamental element of the residential PV market. Appreciable disparities in residential system pricing exist due to the size of projects, differences in installation companies, and the dynamics of local markets. Additionally, in regions with high retail electricity rates, overall system pricing may be higher despite similar hardware costs. In terms of installation hardware, three significant variations drive estimated differences:

- Premium PV module-based systems, including high-efficiency modules, which can command prices 25% to 35% higher than standard-efficiency crystalline silicon modules.
- Microinverters and DC optimizers, which lead to a premium on the overall system cost due to higher hardware costs.
- Structural balance-of-system requirements, especially in high-wind-zone areas or on clay tile roofs, which can drive the cost of racking materials and mounting hardware up by 50%. Rail-less racking solutions also carry a significant premium over rail-based systems.

Figure 5.2 Modeled Residential Turnkey EPC Installed Costs With Breakdown, Q4 2016-Q4 2017



Residential Installed Costs	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Modules	$0.42	$0.40	$0.40	$0.45	$0.48
Inverter	$0.23	$0.23	$0.22	$0.21	$0.20
Electrical BOS	$0.21	$0.22	$0.23	$0.23	$0.23
Structural BOS	$0.08	$0.08	$0.08	$0.08	$0.08
Direct Labor	$0.22	$0.22	$0.21	$0.20	$0.19
Engineering and PII[1]	$0.18	$0.18	$0.18	$0.18	$0.18
Supply Chain, Overhead, Margin	$1.55	$1.55	$1.55	$1.57	$1.58
National Average Turnkey Pricing	$2.89	$2.88	$2.87	$2.92	$2.94

Note: Assumes a 5-10 kW_{dc} rooftop system, standard crystalline silicon modules, blended string, microinverter and DC optimizer

[1] PII: Permitting, interconnection and inspection

5.4. Modeled National Non-Residential PV System Pricing

In the non-residential sector, reported pricing from major EPCs, integrators and developers indicates that standard construction costs for the market within the quarter were lower than what was ultimately reported by state and utility agencies.

System characteristics that 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)
  - Site-specific topographical challenges (e.g., soil conditions)
- System type (i.e., rooftop, carport, ground mount)
- Customer type and electricity tariff structure

As with residential PV systems, we utilize a bottom-up cost analysis for non-residential PV, specifically modeling ballasted flat-roof systems. Once again, our inputs come from larger EPCs and integrators that likely have better-than-average pricing relative to the industry mean. In order to ensure our bottom-up model reflects industry trends going forward, we have standardized around the model of 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:

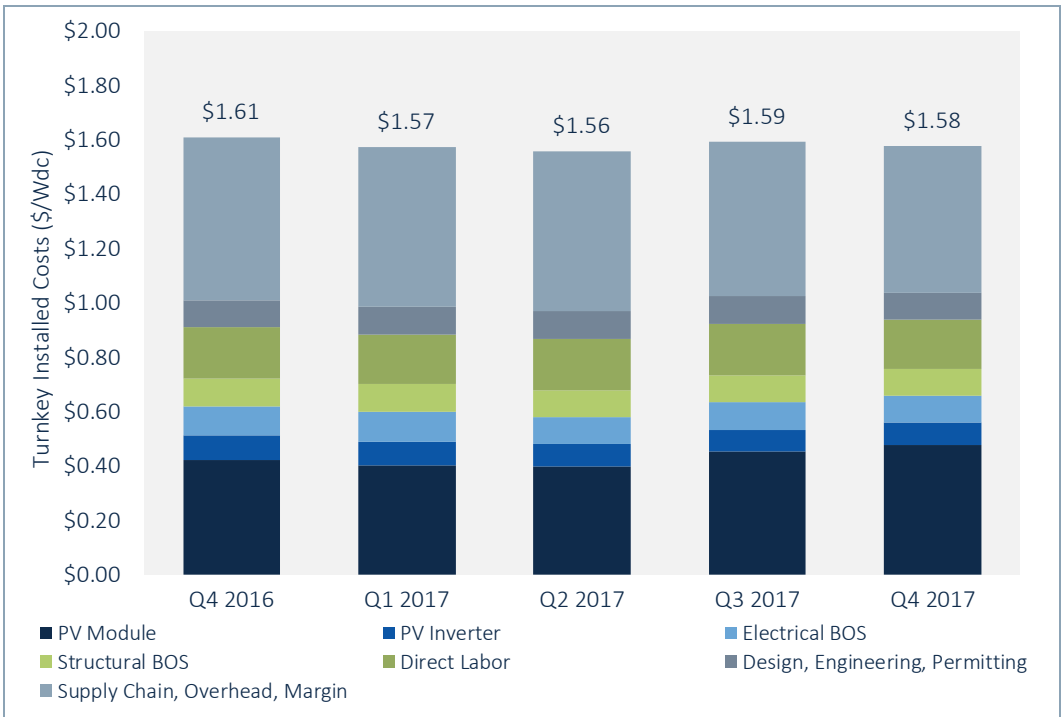
- 300 kW low-slope ("flat") roof system
- Standard multicrystalline silicon PV modules
- String inverter-based design topology
- Fully ballasted, aluminum-based mounting structure
- Rectangular array on membrane roof
- PV module and inverters reflect "factory-gate" pricing with distribution and low volume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

The non-residential sector saw a 1% decrease in pricing this past quarter. In Q4 2017, flat-roof non-residential system pricing landed at $\$1.58/W_{dc}$. The non-residential market segment was the only market to see quarter-over-quarter decreases in system pricing.

In 2017, non-residential system pricing fell by 2%. While this segment, like all markets in the U.S., saw module prices increase, improvements in construction efficiency were able to mitigate the impact. Equally as important, in preparation for the Trump administration's ruling on Section 201, commercial EPCs began decreasing margin and reducing overhead. However, soft costs still make up 52% of non-residential PV system pricing. Any long-term cost reduction trajectory will require further increases in construction efficiency, improved logistics, and truncating the project lifecycle.

Soft costs can be even higher for projects in areas with strict labor requirements, and particularly in jurisdictions with stringent permitting and interconnection requirements – including California and many states in the Northeast. Moreover, in several markets, a significant portion of non-residential projects are on municipal or state property, adding another layer of complexity and cost to execution.

Figure 5.3 Modeled Non-Residential Turnkey System Pricing With Breakdown, Q4 2016-Q4 2017



Non-Residential	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
PV Module	$0.42	$0.40	$0.40	$0.45	$0.48
PV Inverter	$0.09	$0.09	$0.08	$0.08	$0.08
Electrical BOS	$0.11	$0.11	$0.10	$0.10	$0.10
Structural BOS	$0.10	$0.10	$0.10	$0.10	$0.10
Direct Labor	$0.19	$0.19	$0.19	$0.19	$0.18
Design, Engineering, Permitting, Interconnection	$0.10	$0.10	$0.10	$0.10	$0.10
Supply Chain, Overhead, Margin	$0.60	$0.59	$0.59	$0.57	$0.54
Turnkey Pricing	$1.61	$1.57	$1.56	$1.59	$1.58

5.5. Modeled National Utility PV System Pricing

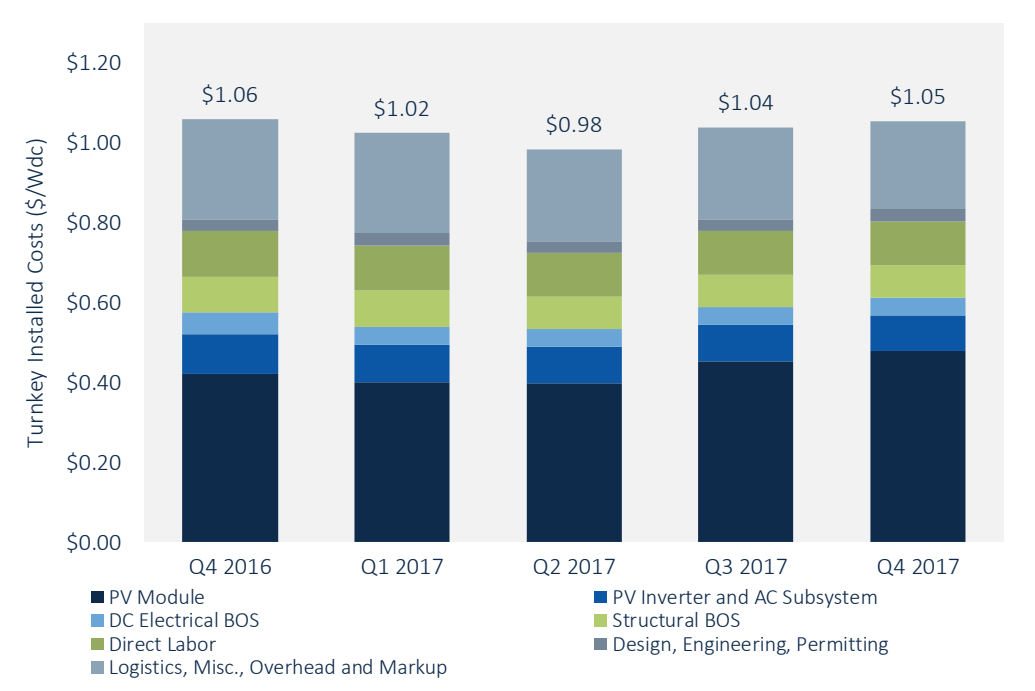
In modeling our utility PV system costs, we employ the following assumptions:

- 10 MW_{dc} utility system
- 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

Utility fixed-tilt and single-axis tracking projects in Q4 2017 saw average pricing of $1.05/$W_{dc}$ and $1.17/$W_{dc}$, respectively. That represents a 1.4% and 0.4% price increase from last quarter. Due to the increase in U.S. module pricing for fixed-tilt and single-axis tracker ground-mount systems, hardware costs increased by 4% and 2% this quarter. As hardware costs make up approximately 62% of utility PV system pricing, this market segment is most sensitive to dynamics in the hardware market. As a result, the quarter-over-quarter increases in system pricing were the largest in the utility market.

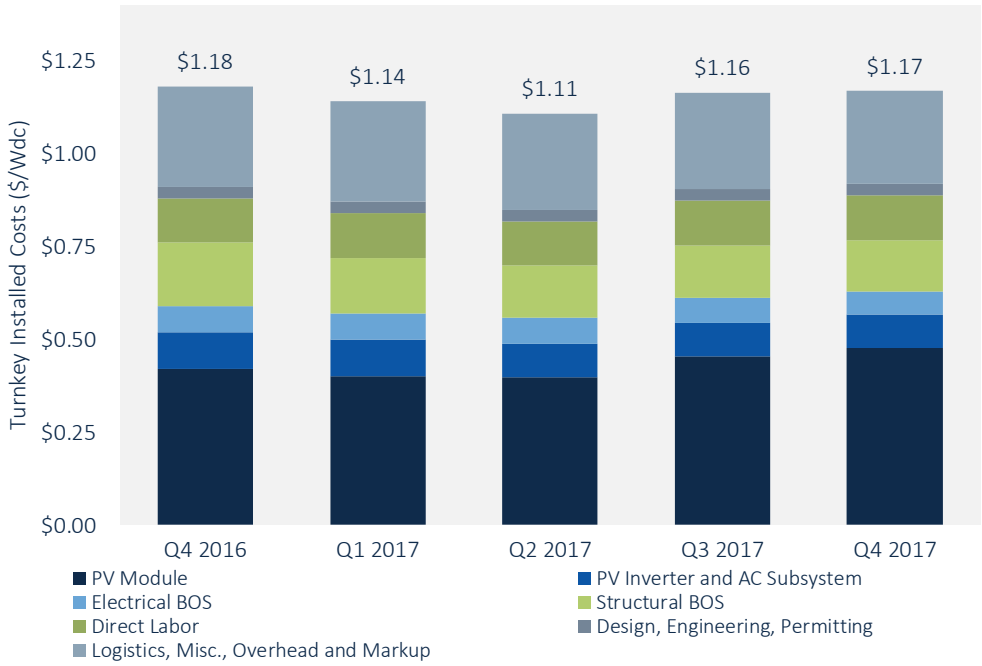
Beyond the major inverter price declines, the shift to 1,500-volt systems has reduced the costs of electrical balance of systems. For utility-scale projects, margin compression is the key driver for lower soft costs. Reduction in deployment volume from 2016 levels, coupled with the rise in module pricing, is forcing many EPCs to bring their margins back to early-2016 levels.

Figure 5.4 Modeled Utility Turnkey Fixed-Tilt PV System Pricing With Cost Breakdown, Q4 2016-Q4 2017



U.S. Fixed-Tilt PV Modeled Costs ($/Wdc)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
PV Module	$0.42	$0.40	$0.40	$0.45	$0.48
PV Inverter and AC Subsystem	$0.10	$0.10	$0.09	$0.09	$0.09
DC Electrical BOS	$0.05	$0.05	$0.05	$0.05	$0.05
Structural BOS	$0.09	$0.09	$0.08	$0.08	$0.08
Direct Labor	$0.11	$0.11	$0.11	$0.11	$0.11
Design, Engineering, Permitting	$0.03	$0.03	$0.03	$0.03	$0.03
Logistics, Misc., Overhead and Margin	$0.25	$0.25	$0.23	$0.23	$0.22
Turnkey Installed Costs	$1.06	$1.02	$0.98	$1.04	$1.05

Figure 5.5 Modeled Utility Turnkey Single-Axis Tracking PV System Pricing With Cost Breakdown, Q4 2016-Q4 2017



U.S. One-Axis Tracking PV Modeled Costs ($/Wdc)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
PV Module	$0.42	$0.40	$0.40	$0.45	$0.48
PV Inverter and AC Subsystem	$0.10	$0.10	$0.09	$0.09	$0.09
DC Electrical BOS	$0.07	$0.07	$0.07	$0.07	$0.06
Structural BOS	$0.17	$0.15	$0.14	$0.14	$0.14
Direct Labor	$0.12	$0.12	$0.12	$0.12	$0.12
Design, Engineering, Permitting	$0.03	$0.03	$0.03	$0.03	$0.03
Logistics, Misc., Overhead and Margin	$0.27	$0.27	$0.26	$0.26	$0.25
Turnkey Installed Costs	$1.18	$1.14	$1.11	$1.16	$1.17

6. MANUFACTURING

6.1. 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: Hemlock, REC Silicon and Wacker. Together, these three facilities were responsible for 5,850 MT of solar polysilicon production in Q4 2017. This represented a 20% decrease compared to production in Q3 2017 and a 27% decrease from production in Q4 2016.

In January 2014, China applied final antidumping duty rates of up to 57% on polysilicon produced by U.S. manufacturers. The duties are effective for five years. Looking forward, U.S. polysilicon production growth will likely be limited due to low polysilicon prices, import tariffs, and limited sales markets outside of China. In addition, low production in Q4 was also driven by temporary shutdown of Wacker's Tennessee facility after an explosion in early September 2017.

Figure 6.1 U.S. Polysilicon Production, Q4 2016-Q4 2017

Polysilicon (Metric Tons)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Quarterly Capacity	17,075	17,075	17,075	17,075	17,075
Production	7,973	8,430	8,172	7,325	5,850

Source: GTM Research

6.2. Wafers

In February 2016, SunEdison announced it would consolidate its Oregon facility into an R&D and technology demonstration and training center for future licensees of the company's Continuous Czochralski Process silicon ingot technology, thus causing wafer production in the U.S. to halt – there has been no word to date as to whether the facility will remain an R&D facility given SunEdison's bankruptcy proceedings. And while SolarWorld maintains a 250 MW integrated ingot-to-module plant (also in Oregon), ingot and wafer production were discontinued, possibly permanently, in mid-2013.

Figure 6.2 U.S. Wafer Production, Q4 2016-Q4 2017

Wafer (MW)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Quarterly Capacity	0	0	0	0	0
Production	0	0	0	0	0

Source: GTM Research

6.3. Cells

Note: In this report series, thin film facilities producing modules through monolithic integration are not defined as producing cells.

U.S. crystalline silicon cell production was 37 MW in Q4 2017, up 3% quarter-over-quarter and down 77% year-over-year. Domestic production has been impacted by low prices and margins as well as by low utilization rates. Only one firm continues to produce cells c-Si cells in the U.S.

In 2017, there were two cell producers of any scale in the U.S., SolarWorld, and Suniva, In April 2017, Suniva filed for chapter 11 bankruptcy and has not produced cells or modules in the U.S. for nearly a year. Following this, SolarWorld America's parent company filed for insolvency, with SolarWorld Americas later announcing that it would join the Section 201 petition initiated by Sunvia amid layoffs at its Hillsboro, Oregon plant.

While SolarWorld and Suniva's production fell in 2017, Solaria ramped up its domestic cell production. The company announced in June that it plans to increase its U.S. cell and module capacity to 40 MW.

Even in the face of new import tariffs, a massive boom in new domestic suppliers is unlikely. This is because the tariff is not high enough to make the economics of building domestic cell production work. In addition, existing domestic suppliers have at 2.5 GW cell quota with zero tariff, which exceeds recent annual U.S. cell imports and current domestic crystalline silicon module capacity, but that 2.5 GW may provide insufficient headroom for significant new domestic module assembly.

Figure 6.3 U.S. Cell Production, Q4 2016-Q4 2017

Cell (MW)	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Quarterly Capacity	173	223	225	228	230
Production	161	155	35	36	37

Source: GTM Research

6.4. Modules

U.S. PV module production increased 8% quarter-over-quarter and was down 44% year-over-year, reaching 240 MW in Q4 2017. While production trends in the past few quarters were driven by lower utilization, layoffs at Suniva's and SolarWorld's module processing facilities and First Solar's Series 6 product ramp, as well as new domestic module capacity (Tesla, Solaria, China Sunergy, Itek), allowed production to increase in Q4.

In terms of technology trends, most modules produced in the U.S. in Q4 2017 were crystalline silicon (69%). With regard to thin-film technologies, cadmium telluride (all First Solar) and CIGS (mostly MiaSolé and Stion) had a production share of ~22% and ~9%, respectively.

Figure 6.4 U.S. Module Production by Technology, Q1 2017-Q4 2017

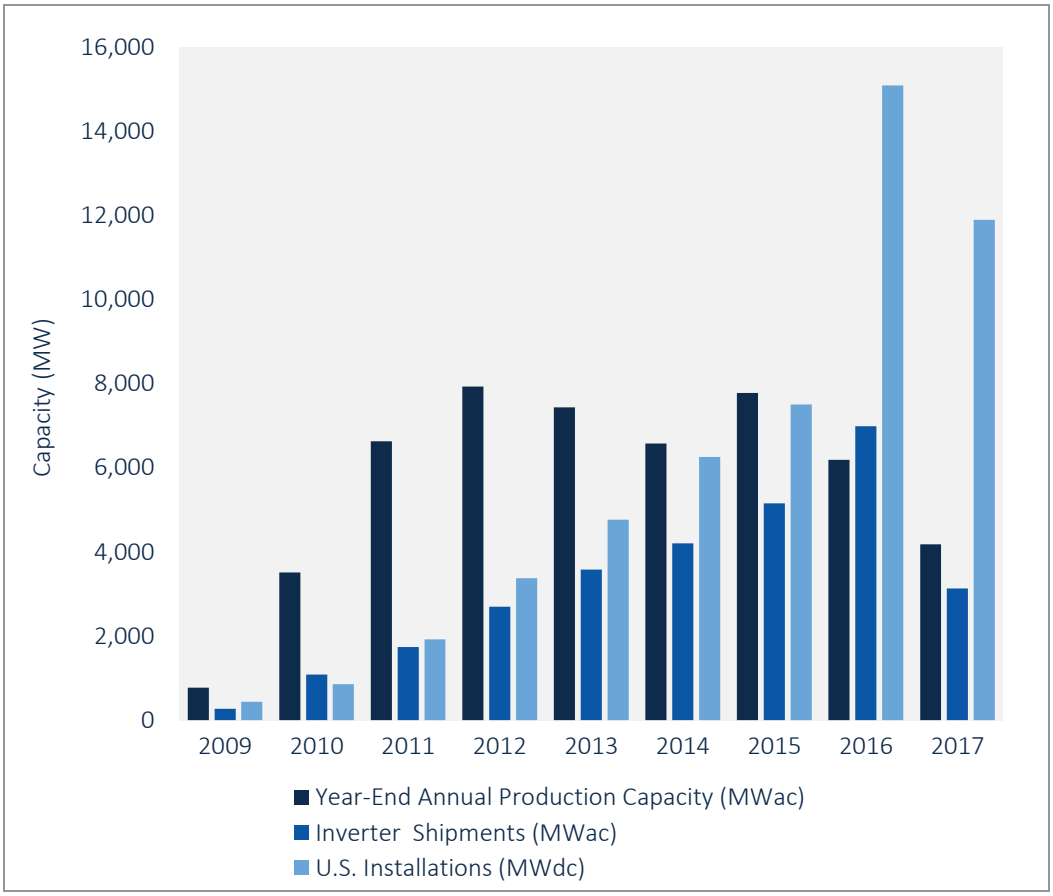
Module (MWp)								
	Q1 2017		Q2 2017		Q3 2017		Q4 2017	
	Capacity	Production	Capacity	Production	Capacity	Production	Capacity	Production
Crystalline Si	355	250	327	123	359	145	403	161
CdTe	50	35	50	40	50	50	50	50
CIGS	88	41	81	33	73	21	66	21
a-Si	-	-	-	-	-	-	-	-
Total	493	326	457	196	482	216	519	232

Source: GTM Research

6.5. Inverters

U.S. solar inverter production capacity fell to a five-year low in 2017. This was primarily due to SMA and ABB shutting down their U.S. inverter manufacturing facilities to consolidate production in their European plants. Both remain major players in the U.S. market.

Figure 6.5 Annual U.S. Inverter Production Capacity (MW_{ac}), Shipments (MW_{ac}), and Installations (MW_{dc})

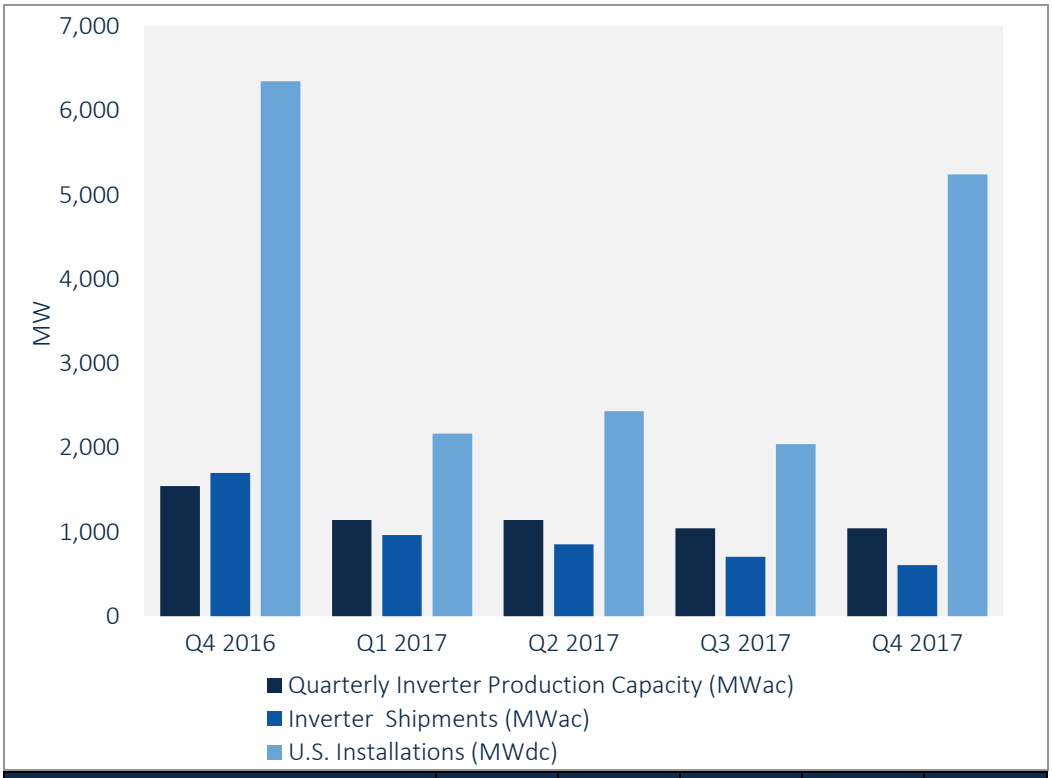


Source: GTM Research

	2011	2012	2013	2014	2015	2016	2017
Inverter Production Capacity (MWac)	6,627	7,932	7,432	6,576	6,696	5,176	4,176
Inverter Shipments (MWac)	1,737	2,699	3,577	4,201	5,155	6,985	3,132
U.S. Installations (MWdc)	1,920	3,371	4,764	6,253	7,501	15,088	11,888

In addition to those facility closures, shipments of U.S. produced inverters were also depressed by declines in market share of many U.S.-based inverter companies. Vendors of module-level power electronics were the main gainers in 2017, and the great majority of these products are built by contract manufacturers outside of the United States. Solar inverter vendors Yaskawa-Solectria Solar, KACO New Energy, Fronius, General Electric, TMEIC, Enphase Energy and Ingeteam each continue to manufacture inverters in the U.S.

Figure 6.6 Quarterly U.S. Inverter Production Capacity (MW_{ac}), Shipments (MW_{ac}), and Installations (MW_{dc}), Q4 2016-Q4 2017



	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Inverter Production Capacity (MWac)	1,546	1,144	1,144	1,044	1,044
Inverter Shipments (MWac)	1,700	965	855	707	605
U.S. Installations (MWdc)	6,349	2,167	2,434	2,042	5,244

7. COMPONENT PRICING

7.1. Polysilicon, Wafers, Cells and Modules

Price trends varied by component in Q4 2017, with differences driven by component-level demand and inventory levels.

- For polysilicon, the quarterly average price increased 8% quarter-over-quarter to $18.0/kg in Q4 2017. Polysilicon price growth has been driven by low supply as select firms operated at lower utilizations, some undergoing annual maintenance and others undergoing environmental inspections.
- Multi-wafer and cell prices fell slightly quarter-over-quarter, to a respective $0.15/W and $0.22/W. Price trends were driven by low demand and buyer pressure to reduce prices.
- In the past few years, U.S. module price trends were largely driven by antidumping and countervailing duties on Chinese suppliers. But recently the main driver has shifted; current module price trends are largely a result of supply-demand tightness, with prices increasing to an average of $0.48/W for standard multi modules as the U.S. becomes a seller's market in the wake of the result of the Section 201 trade case.

7.1 U.S. Polysilicon, Wafer, Cell, and Module Prices, Q4 2016-Q4 2017

	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Polysilicon ($/kg)	$14.98	$16.93	$14.39	$16.69	$18.03
Wafer ($/W)	$0.15	$0.15	$0.14	$0.15	$0.15
Cell ($/W)	$0.21	$0.21	$0.21	$0.23	$0.22
Module ($/W)	$0.39	$0.38	$0.40	$0.45	$0.48

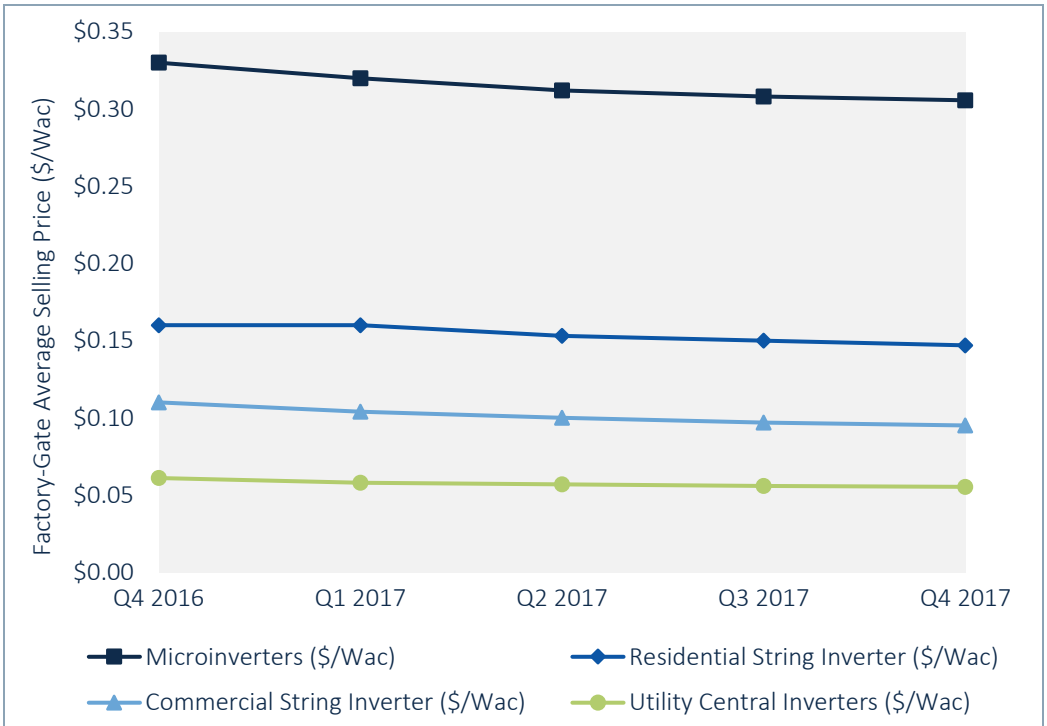
Source: GTM Research

7.2. Inverter Pricing

Pricing continues to trend downward for PV inverters, though it stabilized significantly in the second half of the year. We expect price declines to reaccelerate across all product segments in 2018 due to the proliferation of low-cost 1,500-volt string inverters, as well as the introduction of new products in the residential market.

An inverter component shortage also persisted through 2017. Industry checks indicate that the shortage is due to growth in the electric vehicle and computer industries. Most expect the shortage to last through mid- to end-of-year 2018. The shortage has affected all inverter suppliers, though so far it has not impacted product pricing.

Figure 7.2 Factory-Gate PV inverter Pricing, Q4 2016-Q4 2017 ($/$W_{ac}$)



National Average Pricing	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Microinverters ($/Wac)	$0.33	$0.32	$0.31	$0.30	$0.30
Single-Phase String Inverter ($/Wac)	$0.16	$0.15	$0.15	$0.15	$0.15
Three-Phase String Inverter ($/Wac)	$0.11	$0.10	$0.10	$0.10	$0.10
Central Inverters ($/Wac)	$0.07	$0.06	$0.06	$0.06	$0.06

Source: GTM Research

7.3. Mounting Structure Pricing

We continue to note that factory-gate pricing for PV mounting structures differs significantly depending on market segment, geography, configuration, layout and project size, all of which complicate the calculation of determining an "average" cost. For example, in Q4 2017, manufacturers reported racking pricing for residential rooftop systems ranging anywhere from $0.06/W to $0.14 /W.

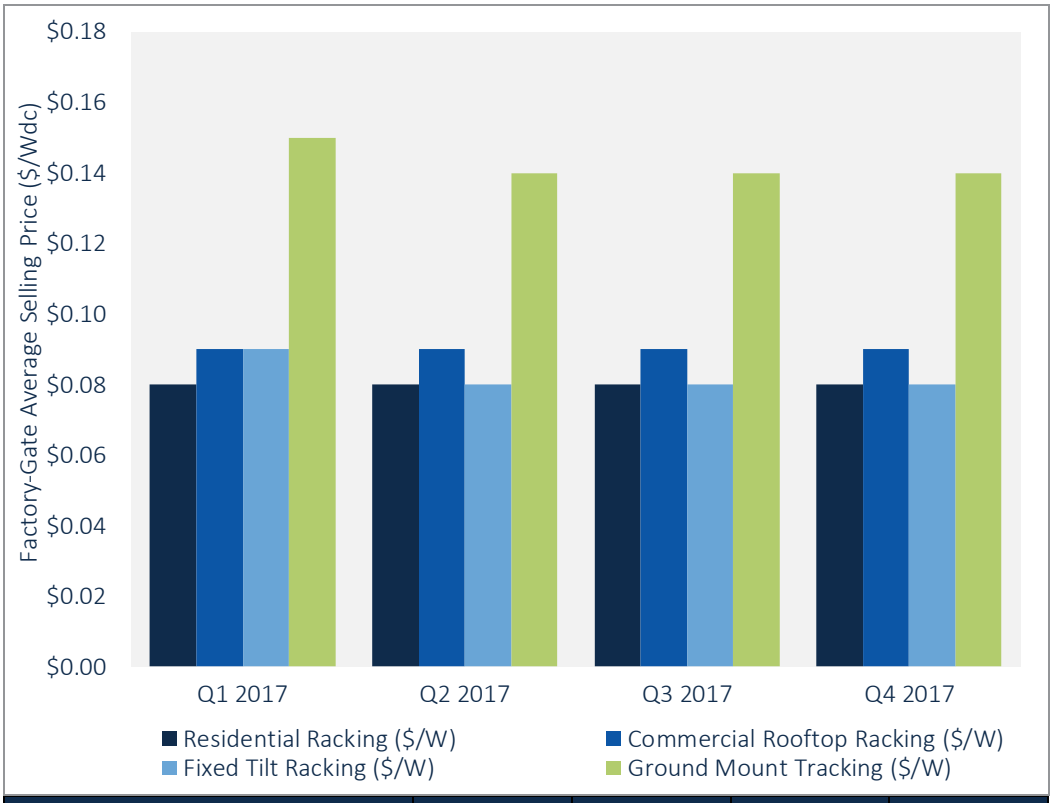
For simplicity's sake, we note that the values reported below reflect the mounting-structure-only costs of the following system types:

- 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 one-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 procurers should consider the full implied cost of individual manufacturers rather than relying on quotes versus the national average. Differences in racking materials and design have varied implications for labor costs, grounding requirements and the need for additional structural support. Also note that we have revised our historical pricing in previous quarters given significant feedback that our values represented higher-than-market values.

The extent to which newly announced tariffs on steel and aluminum will impact racking costs is still unclear as the announcement is fresh and the implications of the Canada and Mexico exclusions have not yet been evaluated.

Figure 7.3 Factory-Gate PV Racking Pricing, Q1 2017-Q4 2017



Average Price (National Aggregate)	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Residential Racking ($/W)	$0.08	$0.08	$0.08	$0.08
Commercial Rooftop Racking ($/W)	$0.09	$0.09	$0.09	$0.09
Fixed-Tilt Ground Mount Racking ($/W)	$0.09	$0.08	$0.08	$0.08
1-Axis Tracking ($/W)	$0.15	$0.14	$0.14	$0.14

8. APPENDIX A: METRICS AND CONVERSIONS

8.1. 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 MW_{ac} and a 77% DC-to-AC derate factor for systems greater than 10 MW_{ac} based on data from existing systems, conversations with installers, and averages from California Solar Initiative data.

8.2. Residential Photovoltaic System

A residential PV installation is defined as a project in which the offtaker of the power is a single-family household. 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.

8.3. 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.

Further, 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. Within the segment we distinguish between utility-led and third-party-led community solar with the following distinctions:

Utility-Led Community Solar – A regulated utility manages the community solar project and program subscriptions directly or outsources to third parties. The physical projects may be self-developed, co-developed with a third-party, or owned by third parties that sell energy directly to the regulated utility.

Third-Party-Led Community Solar – An individual entity or collection of non-utility entities develops and manages the community solar subscriptions. Projects are developed and owned by non-utility entities. While utilities may offtake electrons and renewable credits, subscribers often benefit via a bill credit mechanism and pay electricity tariffs to the third party.

8.4. 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.

9. 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.

9.1. 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).

PV	State incentive program administrators, utility companies, state public utilities commissions, PUC filings, GTM Research Utility PV Project Database, Larry Sherwood/IREC

9.2. 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 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

Components in the national cost breakdown categories include:

- PV modules: 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)

9.3. Manufacturing Production and Component Pricing

GTM Research maintains databases of manufacturing facilities for PV components.

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

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