Title

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Publication Date

2014-09-17

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Lawrence Berkeley National Laboratory

September 2014

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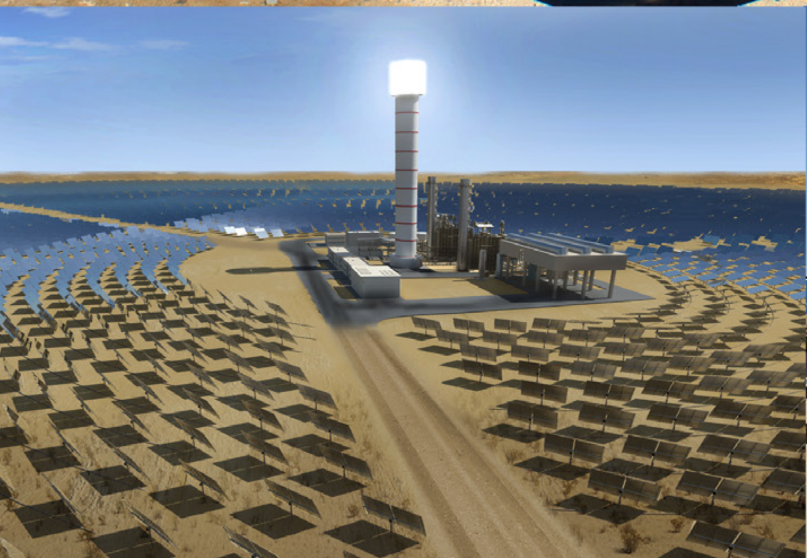

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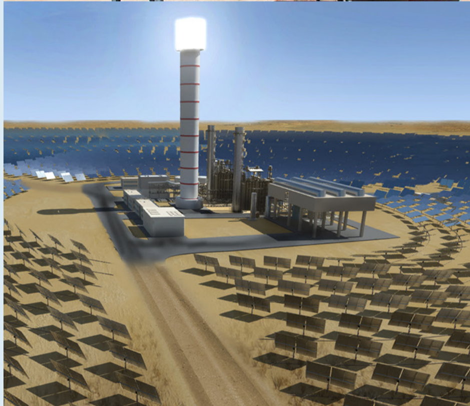

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Executive Summary

Other than the SEGS I-IX parabolic trough projects built in the 1980s, virtually no large-scale or "utility-scale" solar projects – defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar power ("CSP" or solar thermal) project larger than 5 MW_{AC} – existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in 2013 and that is expected to continue for at least the next few years.[1] Over this same short period, CSP also experienced a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including storage – either achieving commercial operations or entering the commissioning phase.

With this critical mass of new utility-scale projects now online and in some cases having operated for several years (generating empirical data in addition to electricity), the rapidly growing utility-scale sector is ripe for analysis. This report, the second in what is envisioned to be an ongoing annual series, meets this need through in-depth, annually updated, data-driven analysis of not just installed project costs or prices – i.e., the traditional realm of solar economics analyses – but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects in the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though more balanced coverage is expected in future editions as the new CSP projects that have recently or soon will come online start to generate usable data.

Some of the more-notable findings from this year's edition include the following:

- ***Technology Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn,[2] several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and price data analyzed later. For example, an increasing proportion of projects over time are using crystalline silicon ("c-Si") rather than thin-film (including cadmium telluride, or CdTe) modules, and in conjunction with tracking devices rather than mounted at a fixed tilt. The quality of the solar resource in which PV projects are being built in the United States has increased on average over time, and most of the projects in the total population (84% in MW terms) are located in the Southwest where the solar resource is the strongest. The average inverter loading ratio – i.e., the ratio of a project's DC array rating to its AC inverter rating – has also increased among more recent project vintages, as oversizing the array can boost revenue when time-of-delivery pricing is used. In combination, these trends should drive capacity factors higher among more recently built PV projects (a hypothesis confirmed by the capacity factor data analyzed in Chapter 5).
- ***Installed Prices:*** Installed project prices within a sizable sample have fallen by more than one-third since the 2007-2009 period, from around \$5.8/W_{AC} to \$3.7/W_{AC} (or \$5.0/W_{DC} to \$3.0/W_{DC}, all in 2013 dollars) on average for projects completed in 2013. Most of this decline occurred through 2012, however, as the average installed price for projects completed

[1] Highlighting just how young the utility-scale PV market is, 92% of the 3,016 MW_{AC} of utility-scale PV capacity installed by the end of 2013 came online in just the preceding three years (2011-2013).
[2] The CPV and CSP project populations are too small to identify trends worthy of mention in this executive summary.

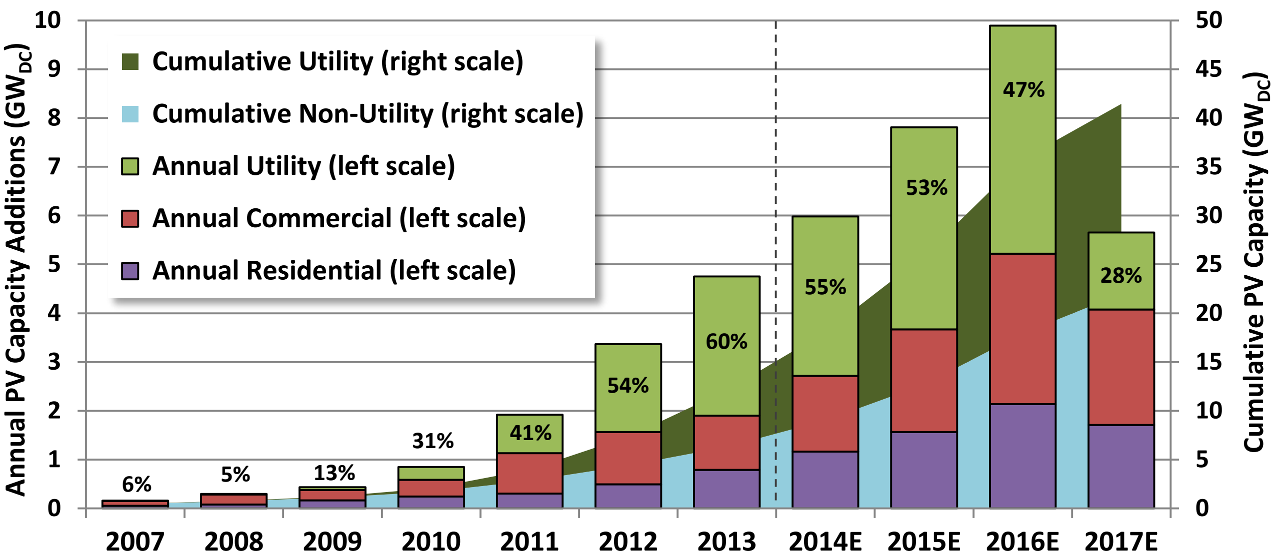
in 2013 ($3.7/W$_{AC}$) was down only slightly from the prior year ($3.8/W$_{AC}$). The decline has been concentrated among projects using c-Si modules.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are available suggest that actual costs have largely been in line with pro forma operating cost projections gleaned from several bond offering prospectuses. For PV, O&M costs appear to be in the neighborhood of $20-$40/kW$_{AC}$-year, or $10-$20/MWh. CSP O&M costs are higher, due to plumbing and thermal components, and come in around $60/kW$_{AC}$-year.
- ***Capacity Factors:*** The capacity-weighted average cumulative capacity factor across the entire PV project sample is 27.5% (median = 26.9% and simple average = 25.9%), but individual project-level capacity factors exhibit a wide range (from 16.6% to 32.8%) around these central numbers. This variation is based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site; whether the array is mounted at a fixed-tilt or on a tracking mechanism; the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio); and the type of modules used (e.g., c-Si versus thin film). Changes in the first three of these factors have driven the average capacity factor among 2012 projects sharply higher (to nearly 30%) relative to the average capacity factors achieved by projects built in either 2011 or 2010 (just under 25% in either case). Among CSP projects, parabolic trough systems that have been operating in the U.S. for more than 20 years are still (in 2013) achieving capacity factors in the range of 20% (solar portion only, no storage), which is comparable to the only recent trough project in our sample. All of these CSP projects have lower capacity factors than similarly situated (i.e., located at similarly good sites and using single-axis tracking) PV projects. Likewise, the two CPV projects in our sample seem to be underperforming both relative to similarly situated PV projects and ex-ante expectations.
- ***PPA Prices:*** Driven primarily by lower installed project prices (which, in turn, have been driven primarily by declining module prices), levelized PPA prices (levelized using a 7% real discount rate) have fallen dramatically over time, by a steady $25/MWh per year on average since 2007, though this trend shows signs of slowing in 2014. Some of the most-recent PPAs in the southwestern United States have levelized PPA prices as low as (or even lower than) $50/MWh (in 2013 dollars), which, in some cases, is competitive with wind power projects in that same region. Solar appears to be particularly competitive in that region when considering its time-of-delivery pricing advantage over wind (which amounts to roughly $25/MWh in California at current levels of penetration).

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry over the next few years. For example, at the end of 2013, there was at least 39.5 GW of utility-scale solar power capacity – i.e., roughly eight times the installed capacity in our entire project population at that time – making its way through interconnection queues across the nation (though concentrated in California and the Southwest). Though not all of these projects will ultimately be built, presumably those that are built will most likely come online prior to 2017, given the scheduled reversion of the 30% investment tax credit ("ITC") to 10% at the end of 2016. Even if *only half* of the solar capacity in these queues meets that deadline, it will still mean an unprecedented amount of new construction in 2014, 2015, and 2016 – as well as a massive amount of new data to collect and analyze in future editions of this report.

1. Introduction

The term "utility-scale solar" refers both to large-scale concentrating solar power ("CSP") projects that use several different technologies to produce steam and generate electricity for sale to utilities,[3] and to large photovoltaic ("PV") and concentrating photovoltaic ("CPV") projects that typically sell wholesale electricity directly to utilities, rather than displacing on-site consumption (as has been the more-traditional application for PV in the commercial and residential markets). Although utility-scale CSP has a significantly longer history than utility-scale PV (or CPV),[4] and has recently experienced a renaissance,[5] the utility-scale solar market in the United States is now largely dominated by PV: there are currently five times as much PV as CSP capacity either operating (4.1x), under construction (6.1x), or under development (5.2x) in utility-scale projects (SEIA 2014). PV's dominance follows explosive growth in recent years: utility-scale PV has been the fastest-growing sector of the PV market since 2007, and since 2012 has accounted for the largest share of the overall PV market in terms of new MW installed (see Figure 1), a distinction that is projected to continue through 2016 (GTM/SEIA 2014).[6]



Source: GTM/SEIA 2014

Figure 1. Historical and Projected PV Capacity by Sector in the United States

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[3] Operating CSP projects most commonly use either parabolic trough or, more recently, power tower technology. CSP projects using other technologies, including compact linear Fresnel lenses and Stirling dish engines, have also been built in the United States, but largely on a pre-commercial prototype basis.

[4] Nine large parabolic trough projects totaling nearly 400 MW_{AC} have been operating in California since the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.

[5] In 2013/2014 alone, more than twice as much CSP capacity has or will come online in the United States than in the previous 28 years combined.

[6] GTM/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box – *Defining "Utility-Scale"* – on page 3 for a discussion of different definitions of "utility-scale"). In addition, the capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box – *AC or DC?* – on page 5 discusses why AC capacity ratings make more sense than DC for utility-scale projects). Despite these two inconsistencies, the data are nevertheless useful (and so are included here) for the basic purpose of providing a general sense for the size of the utility-scale market (both historical and projected) and demonstrating relative trends between market segments.

This rapidly growing utility-scale sector of the solar market is ripe for analysis. Historically, empirical analyses of solar economics have focused primarily on up-front installed costs or prices (see, for example, Barbose et al. 2014), and principally within the residential and commercial PV sectors. But as more utility-scale projects have come online and begun to acquire an operating history, a wealth of other empirical data has begun to accumulate as well. Utility-scale solar projects can be mined for data on not only installed prices, but also project performance (i.e., capacity factor), operations and maintenance ("O&M") costs, and power purchase agreement ("PPA") prices ($/MWh) – all data that are often unavailable publicly, and are also somewhat less meaningful,[7] within the residential and commercial sectors.

This report is the second edition in what is envisioned as an ongoing annual series that will, each year, compile and analyze the latest empirical data from the growing fleet of utility-scale solar projects in the U.S. In this second edition, we revise our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC}, up from 2 MW_{AC} in the first edition (the text box on the next page describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). Within this subset of projects, the relative emphasis on different solar technologies within the report largely reflects the distribution of those technologies in the broader market – i.e., most of the data and analysis naturally focuses on PV given its large market share, but CPV and CSP projects are also included where data are available.

The report proceeds as follows. First, a new Chapter 2 describes key characteristics of the overall utility-scale solar project population from which the data samples that are analyzed in later chapters are drawn, with a goal of identifying underlying technology trends that could potentially influence trends in the data analyzed in later chapters. The remainder of the report analyzes the cost, performance, and price data samples in a logical order: up-front installed costs or prices are presented in Chapter 3, followed by ongoing operating costs and performance (i.e., capacity factor) in Chapters 4 and 5, all of which influence the PPA prices that are reported and analyzed in Chapter 6. Chapter 7 concludes with a brief look ahead.

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[7] For example, even if performance data for residential systems were readily available, they might be difficult to interpret given that residential systems are often partly shaded or otherwise constrained by roof configurations that are at sub-optimal tilt or azimuth. Utility-scale projects, in contrast, are presumably less-constrained by existing site conditions and better able to optimize these basic parameters, thereby generating performance data that are more normalized and easier to interpret. Similarly, even if known, the price at which third-party owners of residential PV systems sell electricity to site hosts is difficult to interpret, because residential PPAs are often priced only as low as they need to be in order to present an attractive value proposition relative to retail rates (this is known as "value-based pricing"). In contrast, utility-scale solar projects must often compete (policy incentives notwithstanding) for PPAs against other generating technologies within competitive wholesale power markets, and therefore tend to offer PPA prices that reflect the minimum amount of revenue needed to recoup the project's initial cost, cover ongoing operating expenses, and provide a normal rate of return (this is known as "cost-plus" pricing). Whereas cost-plus pricing data provide useful information about the amount of revenue that solar needs in order to be economically viable in the market, value-based PPA price data are somewhat less useful in this regard, in that they often reflect the "price to beat" more so than the lowest possible price that could be offered.

Defining "Utility-Scale"

Determining which electric power projects qualify as "utility-scale" (as opposed to commercial- or residential-scale) can be a challenge, particularly as utilities begin to focus more on distributed generation. For solar PV projects, this challenge is exacerbated by the relative homogeneity of the underlying technology. For example, unlike with wind power, where there is a clear difference between utility-scale and residential wind turbine technology, with solar, the same PV modules used in a 5 kW residential rooftop system might also be deployed in a 100 MW ground-mounted utility-scale project. The question of where to draw the line is, therefore, rather subjective. Though not exhaustive, below are three different – and perhaps equally valid – perspectives on what is considered to be "utility-scale":

- The Energy Information Administration ("EIA") does not explicitly distinguish between utility-scale and other types of generation projects, but nevertheless draws a de facto line by collecting and reporting data for all projects larger than 1 MW in capacity (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA ("GTM/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it on site) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FIT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 20 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: **utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC}.**

This definition is grounded in consideration of the four types of data analyzed in this report: installed prices, O&M costs, capacity factors, and PPA prices. For example, setting the threshold at 5 MW_{AC} (rather than 2 MW_{AC}, as used in last year's inaugural edition of this report) helps to avoid smaller projects that are arguably more commercial in nature, and that make use of net metering and/or sell electricity through FITs or other avoided cost contracts (any of which could skew the sample of PPA prices reported in Chapter 6). A 5 MW_{AC} limit also helps to avoid specialized (and therefore often high-cost) applications, such as carports or projects mounted on capped landfills, which can skew the installed price sample. Meanwhile, ground-mounted systems are more likely than roof-mounted systems to be optimally oriented in order to maximize annual electricity production, thereby leading to a more homogenous sample of projects from which to analyze performance, via capacity factors. Finally, data availability is often markedly better for larger projects than for smaller projects (in this regard, even our increased threshold of 5 MW_{AC} might be too small).

Some variation in how utility-scale solar is defined is natural, given the differing perspectives of those establishing the definitions. Nevertheless, the lack of standardization does impose some limitations. For example, GTM/SEIA's projections of the utility-scale market (shown in Figure 1) may be useful to readers of this report, but the definitional differences noted above (along with the fact that GTM/SEIA reports utility-scale capacity in DC rather than AC terms) makes it harder to synch up the data presented herein with their projections. Similarly, institutional investors may find some of the data in this report to be useful, but perhaps less so if they are only interested in projects larger than 20 MW_{AC}.

Until consensus emerges as to what makes a solar project "utility-scale," a simple best practice is to be clear about how one has defined it (and why), and to highlight any important distinctions from other commonly used definitions – hence this text box.

Data sources are diverse and vary by chapter depending on the type of data being presented, but in general include the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA"), state and federal incentive programs, state and federal regulatory commissions, industry news releases, and trade press articles. Sample size also varies by chapter, and relatively few projects have sufficiently complete data to be included in all four data sets. All data involving currency are reported in constant or real U.S. dollars – in this edition, 2013 dollars[8] – and all PPA price levelization uses a 7% real discount rate.

Finally, we note that this report complements several other related studies and ongoing research activities, all funded as part of the DOE's SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020. Most notable is LBNL's long-standing *Tracking the Sun* series (e.g., Barbose et al. 2014), which focuses on trends in PV installed prices with a primary emphasis on the residential and commercial sectors (but also including some of the utility-scale data presented in this report). In addition, LBNL and the National Renewable Energy Laboratory (NREL) jointly issue an annual briefing that summarizes historical, current, and projected PV installed prices, drawing upon data from *Tracking the Sun* along with modeled installed price benchmarks and projections of near-term system pricing developed through research efforts underway at NREL (Feldman et al. 2014).

[8] Conversions between nominal and real dollars use the implicit GDP deflator. Historical conversions use the actual GDP deflator data series from the U.S. Bureau of Economic Analysis, while future conversions (e.g., for PPA prices) use the EIA's projection of the GDP deflator in *Annual Energy Outlook 2014*.

2. Technology Trends Among the Project Population

Before diving into project-level data on installed prices, operating costs, capacity factors, and PPA prices, this chapter (new to this second edition of the report) analyses trends in utility-scale solar project technology and configurations among the *entire population* of projects from which later data samples are drawn.[9] The basic idea is to explore underlying trends in the characteristics of the entire fleet of projects that could potentially influence the cost, performance, and/or price data presented and discussed in later chapters.[10] As with the data samples explored in later chapters, the total project population is broken out here by technology type – PV, CPV and CSP – and, for reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms.

AC or DC? AC Capacity Ratings Make More Sense for Utility-Scale Solar

Because PV modules are rated in DC terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale solar projects, however, the AC capacity rating – measured by the combined AC rating of the project's inverters – is more relevant than DC, for two reasons. First, all other conventional and renewable utility-scale generation sources to which utility-scale solar is compared are described in AC terms – with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors. Second, as described in this chapter and as shown in Figure 4, utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (i.e., they've increased the "inverter loading ratio") as a way to boost revenue (and, as a side benefit, boost AC capacity factors). In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the AC capacity rating is the more appropriate rating to use. Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($\$/W_{AC}$), operating costs ($\$/kW_{AC}$-year), and capacity factor.

PV (126 projects, 3,023 MW_{AC})

At the end of 2013, there were 126 PV projects totaling 3,023 MW_{AC} that were fully online and that met the definition of utility-scale used in this report (ground-mounted and larger than 5 MW_{AC}).[11] These 126 projects, the first of which were installed as recently as 2007, make up the total population of PV projects from which data samples are drawn in later chapters of this report.

Figure 2 breaks out this capacity by the year in which it came online. Highlighting just how young the utility-scale PV market is, 92% of the 3,023 MW_{AC} of utility-scale PV capacity

[9] Because Chapter 6 analyzes PPA prices by the date on which the contract was executed rather than by the project's commercial operation date, the Chapter 6 contract sample includes some PPAs for projects that have not yet been built, and therefore are not included in the project population described in this chapter.
[10] Though describing these project characteristics here, in a separate chapter, isolates the discussion from the data presented in later chapters, it nevertheless makes sense (in order to guard against the possibility that sample characteristics are not fully representative of the population as a whole) to analyze these trends on a fleet-wide basis, rather than only within the smaller sample of projects for which we have cost, performance, and/or price data.
[11] Because of differences in how "utility-scale" is defined (e.g., see the text box on page 3 of the previous chapter), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM/SEIA 2014) of the amount of utility-scale PV capacity online at the end of 2013.

installed by the end of 2013 came online in just the preceding three years (2011-2013). Extending this period back one more year through 2010 boosts the percentage to 98%, as only five PV projects (totaling 75 MW_{AC}) were built in the 2007-2009 period.

Figure 2 also breaks out this capacity by module type and project configuration – i.e., projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium telluride or CdTe[12]) modules, and projects mounted at a fixed-tilt instead of tracking the sun. Though thin-film modules power two-thirds of the new utility-scale PV capacity installed in 2010, c-Si projects began to dominate starting in 2011 and continued through 2013, accounting for roughly three quarters of all new utility-scale PV capacity installed in those three years. There has also been a noticeable trend towards the use of tracking, particularly in 2013, when tracking projects – all of them using c-Si modules – accounted for nearly 60% of the record amount of new utility-scale PV capacity installed that year.[13]

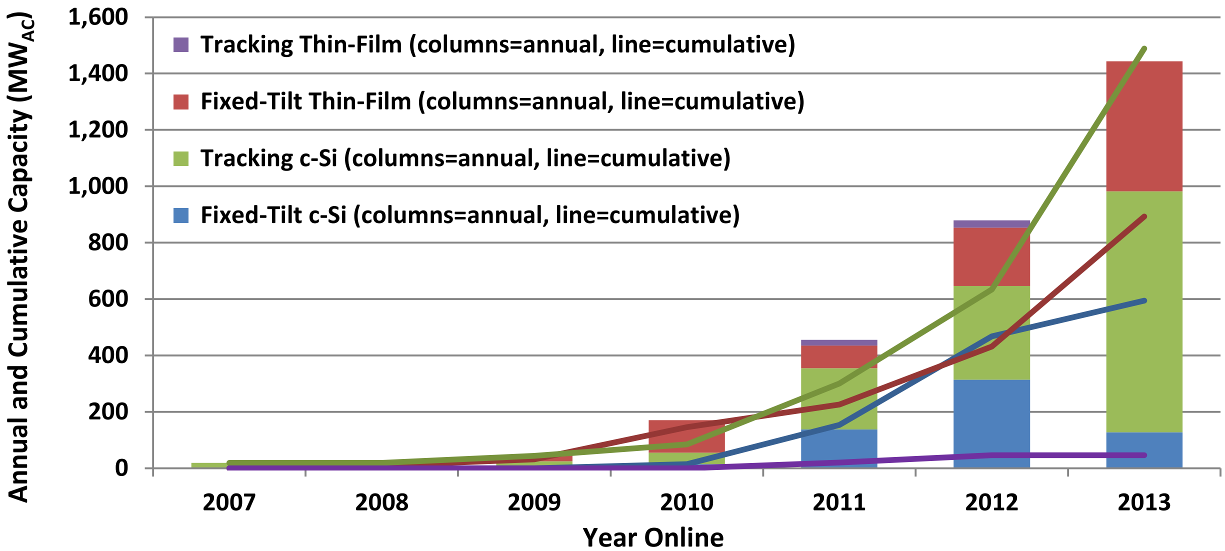


Figure 2. Historical Utility-Scale PV Capacity by Module Type and Project Configuration

As a result of these trends in annual installations, tracking c-Si projects had a commanding lead on a cumulative basis at the end of 2013 (1,489 MW_{AC}), followed by fixed-tilt thin-film (893 MW_{AC}), fixed-tilt c-Si (595 MW_{AC}), and tracking thin-film (47 MW_{AC}) projects.[14] Overall, the

[12] Module manufacturer First Solar, which makes CdTe modules, accounts for 85% of the 939 MW_{AC} of thin-film capacity in the project population.

[13] All of the PV projects in the sample that use tracking systems use single-axis trackers, whereas the three CPV projects and one CSP power tower project (described later) use dual-axis trackers. For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis) often does not outweigh the incremental costs (and risk of malfunction), depending on the PPA price.

[14] The use of tracking has not been as common among thin-film systems because the lower efficiency of thin-film relative to c-Si modules requires more land area per nameplate MW – an expense that is exacerbated by the use of trackers, which require *even more* land area to avoid shading as the modules move throughout the day. In addition, thin-film modules have historically been cheaper than c-Si modules, perhaps making array over-sizing a more-viable alternative to tracking as a means to boost capacity factor (Figure 4, discussed later, supports this notion). Looking ahead, however, the number of projects using thin-film modules in conjunction with tracking is likely to increase,

total project population as of the end of 2013 is split almost evenly (in capacity terms) between fixed-tilt and tracking projects, while the c-Si/thin-film split is less even, at 69%/31%, respectively.

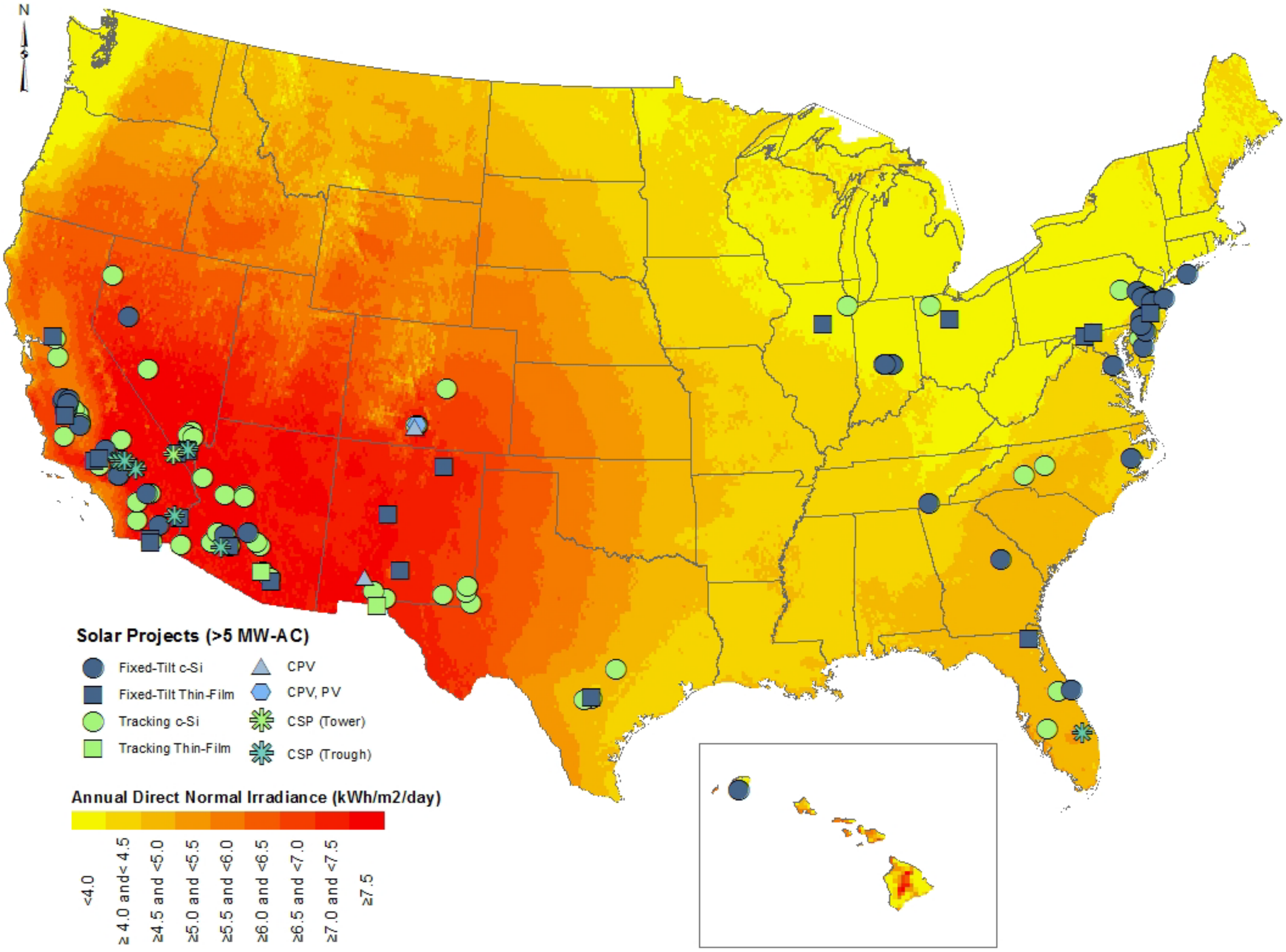


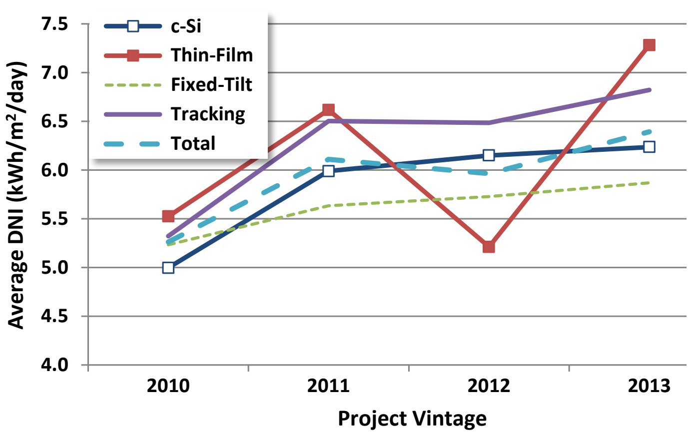
Figure 3. Map of Direct Normal Irradiance (DNI) and Utility-Scale Solar Project Locations in the U.S.

Figure 3 overlays the location of every utility-scale solar project in the population (also including CPV and CSP projects in this case) on a map of solar resource strength, as measured by direct normal irradiance (or "DNI," the measure most relevant to utility-scale projects, particularly those using tracking). Not surprisingly, most of the projects in the population (84% in MW terms) are located in the Southwestern United States (defined here as CA, NV, AZ, UT, CO, and NM), where the solar resource is the strongest and where state-level policies (such as renewable portfolio standards, and in some cases state-level tax credits) encourage utility-scale solar development. As shown, however, utility-scale solar projects have also been built in various

following the 2011 acquisition of a single-axis tracking manufacturer by First Solar (by far the largest supplier of thin-film – in this case CdTe – modules).

states along the east coast and in the Midwest, where the solar resource is not as strong; these installations have largely been driven by state renewable portfolio standards.

While Figure 3 provides a static view of *where* and in what type of solar resource regime utility-scale solar projects within the population are located, knowing *when* each of these projects was built – and hence how the average resource quality of the project fleet has evolved over time – is also useful, for example, to help explain any observed trend in project-level capacity factors by project vintage (explored later in Chapter 5). The left-hand graph of Figure 4 addresses this question by showing the average DNI (in kWh/m^2/day) among PV projects built in a given year, broken out by module type and project configuration. Among the entire PV project population, the average DNI has increased over time (notwithstanding a slight reversion in 2012). Not surprisingly, systems that track the sun – and therefore benefit from higher DNI – are built (on average) in higher DNI locations than fixed-tilt systems. And with the exception of 2012 (which saw a number of thin-film projects built in the Midwest and Mid-Atlantic regions), thin-film projects have been built in higher DNI locations than c-Si projects on average; this also makes sense, given the superior temperature coefficient of thin-film (CdTe in particular) modules, and their predominant use in the Desert Southwest.[15]



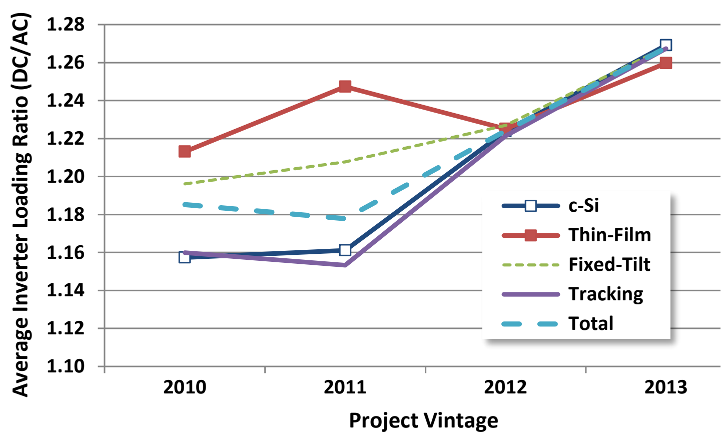


Figure 4. Trends in Direct Normal Irradiance and Inverter Loading Ratio by PV Project Vintage

A second project-level characteristic that can also influence time trends in capacity factor (as well as the spread between $/W installed project costs or prices expressed in DC versus AC terms) is the ratio of a project's DC capacity rating (based on the DC capacity of the array) to its aggregate AC inverter rating – known as the inverter loading ratio ("ILR").[16] With the cost of PV modules having dropped precipitously in recent years, and with some utilities (particularly in California) offering time-varying PPA prices that favor peak solar periods, many developers

[15] The vast majority – 85% – of thin film capacity in the population uses CdTe panels from First Solar. On its web site (http://www.firstsolar.com/Home/Technologies-and-Capabilities/PV-Modules/First-Solar-Series-3-Black-Module), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at module temperatures above 25° C (77° F) – i.e., conditions routinely encountered by PV systems located in the high-DNI Desert Southwest region.

[16] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014, Fiorelli and Zuercher-Martinson 2013). This report uses inverter loading ratio, or ILR.

have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which – like tracking – boosts capacity factor,[17] at least in AC terms (this practice will actually *decrease* capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production periods[18]).

The right-hand graph in Figure 4 shows the average ILR among projects built in each year, broken out by module type and project configuration. Among the entire population, the average ILR has increased significantly over time, from around 1.18 for projects built in 2010 and 2011 to 1.27 in 2013. Sub-populations broken out by module type and project configuration also show a few interesting trends. For example, thin-film projects had the highest ILRs on average in 2010 and 2011, perhaps reflecting thin-film modules' early pricing advantage (now largely gone – see Chapter 3) over c-Si modules in the early years. Similarly, until 2012, fixed-tilt projects had a noticeably higher average ILR than tracking projects, consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, "tracking-like" daily production profile. Both of these distinctions largely disappeared in 2012 and 2013 as ILR's converged across sub-categories, perhaps driven by declining module prices and greater recognition of the economic benefit of a higher ILR.

In combination, and along with the previously mentioned trend towards greater use of tracking, both graphs in Figure 4 suggest that project-level capacity factors should increase among more recently built PV projects. This hypothesis is explored further (and confirmed) in Chapter 5.

CPV (2 projects, 35 MW_{AC})

There are only two CPV projects – the 5.04 MW_{AC} Hatch project in New Mexico (online in late 2011) and the 30.24 MW_{AC} Cogentrix Alamosa project in Colorado (online in early 2012) – in the project universe.[19] Both use the same high-concentration CPV technology from Amonix, are sited in similarly high solar resource areas (~7.6-7.7 kWh/m^2/day DNI) and have relatively low inverter loading ratios of 1.17 (which makes sense in light of the high-concentration technology).

[17] This is analogous to the boost in capacity factor achieved by a wind turbine when the size of the rotor increases relative to the turbine's nameplate capacity rating. This decline in "specific power" (W/m^2 of rotor swept area) causes the generator to operate closer to (or at) its peak rating more often, thereby increasing capacity factor.

[18] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently (Advanced Energy 2014, Fiorelli and Zuercher-Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even sees the excess DC power – rather, it is simply not generated in the first place.

[19] A third project – the 6.9 MW_{AC} SunE Alamosa project built in 2007 – uses both CPV (from SOLON) and PV technology, but is classified in this chapter and elsewhere in this report as a PV project (tracking c-Si) because CPV only makes up about 12% of the project's total capacity.

CSP (16 projects, 1,848 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough build-out in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed by the 75 MW_{AC} Martin project in 2010 (also a trough system, feeding steam to a co-located combined cycle gas plant in Florida), and then a slew of CSP projects built in 2013/2014, including three parabolic trough projects (one with 6 hours of built-in thermal storage) totaling roughly 800 MW_{AC} and two power tower projects (one with 10 hours of built-in thermal storage) totaling roughly 500 MW_{AC}.[20] The two power tower projects are the first commercial deployment of this technology in the United States.[21] As shown earlier in Figure 3, except for the Martin trough project in Florida, all of the CSP projects in the population are located in high-DNI areas of California, Nevada, and Arizona.

[20] Although not all of these projects were completely online at the end of 2013, there are few enough of them – and the project universe is otherwise quite small – that we have decided to include all 2013/2014 CSP projects in the total CSP project population, whether or not they were fully online by the end of 2013. Some data (e.g., estimates of installed costs or prices) are already available for these projects.

[21] Commercial power tower projects have been operating in several overseas countries, including Spain and Israel, for a number of years now.

3. Installed Prices

Berkeley Lab has gathered installed price data[22] for 105 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) solar projects totaling 3,575 MW_{AC} and built between 2007 and 2013. The sample consists largely of PV projects – 98 projects totaling 2,599 MW_{AC}, or 78% and 86% of the total number of projects and capacity in the overall project population described in Chapter 2 – but also includes two CPV projects totaling 35 MW_{AC} and five CSP projects totaling 1,066 MW_{AC}.

In general, only fully operational projects for which all individual phases were in operation at the end of 2013 are included in the sample[23] – i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels in 2014 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an "Engineering, Procurement, and Construction" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent reductions in component costs or other changes in market conditions.[24] For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV, and may differ from the average installed prices reported elsewhere (e.g., in GTM/SEIA 2014).

This chapter analyzes installed price trends among the sample of utility-scale projects described above. It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by module type (c-Si vs. thin-film vs. CPV), project configuration (fixed-tilt vs. tracking), and system size. The chapter then provides an overview of installed prices for the five CSP projects in the sample. Sources of installed price information include the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, FERC Form 1 filings, trade press articles, and data previously gathered by the National Renewable Energy Laboratory (NREL). All prices are reported in real 2013 dollars.

PV (98 projects, 2,599 MW_{AC}) and CPV (2 projects, 35 MW_{AC})

Figure 5 shows installed price trends for PV (and CPV) projects completed since 2007 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is most often

[22] Installed "price" is reported (as opposed to installed "cost") because in many cases, the value reported reflects either the price at which a newly completed project was sold (e.g., through a sale/leaseback financing transaction), or alternatively the fair market value of a given project – i.e., the price at which it would be sold through an arms-length transaction in a competitive market.

[23] In contrast, later chapters of this report do present data for individual phases of projects that are online, or (in the case of Chapter 6 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

[24] This reasoning may partially explain why the decline in installed prices presented in this chapter has seemingly not kept pace with the decline in PPA prices reported later in Chapter 6.

reported in $/W$_{DC}$ terms as well (see, for example, Barbose et al. 2014 and GTM/SEIA 2014). As noted in the text box (*AC or DC?*) on page 5 of the previous chapter, however, AC terms are more appropriate for utility-scale solar. Figure 5 shows installed prices both ways (in both $/W$_{DC}$ and $/W$_{AC}$ terms) as a way to provide some continuity between this report and others (namely Barbose et al. 2014). The remainder of this chapter, however, as well as the rest of this document, report data exclusively in AC terms.

As shown in Figure 5, average installed prices among the sample of utility-scale PV projects have declined by more than one-third from the 2007-2009 period through 2013, as capacity-weighted average prices dropped from $5.8/W$_{AC}$ to $3.7/W$_{AC}$ over that timeframe. Most of this decline occurred through 2012, however, as capacity-weighted average prices within the sample were little changed from 2012 ($3.8/W$_{AC}$) to 2013 ($3.7/W$_{AC}$).

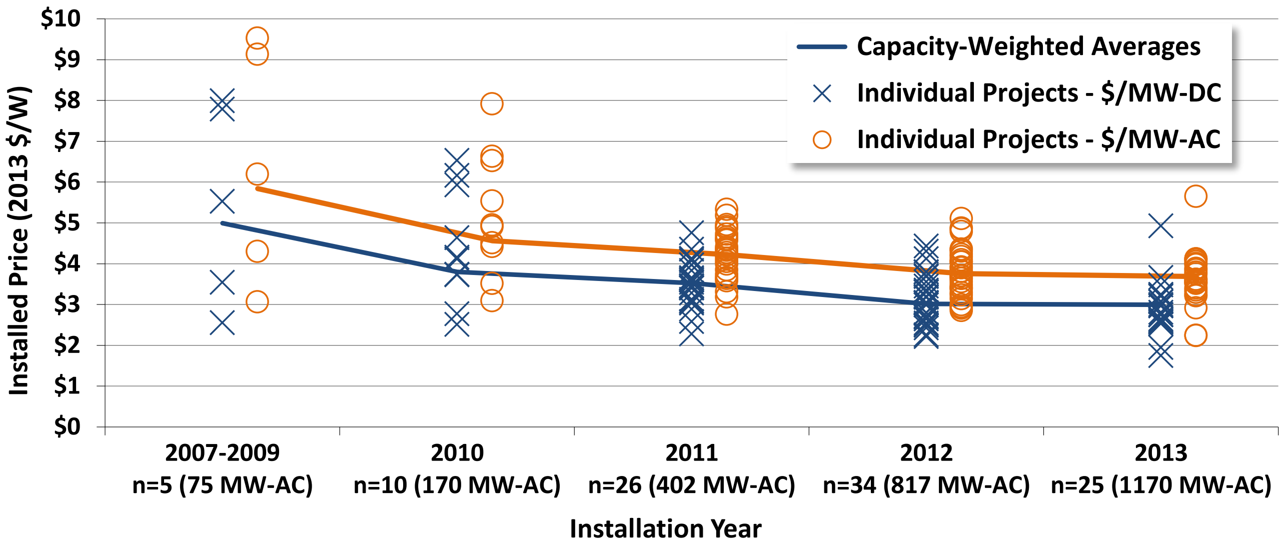


Figure 5. Installed Price of Utility-Scale PV (and CPV), 2007-2013

Anecdotally, a similar pattern of slowing price declines is evident in a recent Public Service Company of New Mexico ("PNM") filing for regulatory approval of 40 MW$_{AC}$ of utility-scale PV that it intends to build in 2015 as two separate 20 MW$_{AC}$ projects. The company expects this new turnkey capacity to cost $1.98/W$_{AC}$, which is down only slightly from the $2.03/W$_{AC}$ it is currently paying for another 23 MW$_{AC}$ being built this year (in 2014). Both of these prices (of ~$2/W$_{AC}$) are down more substantially from the $2.25/W$_{AC}$ that PNM paid for another 20 MW$_{AC}$ built in 2013 and the $3.99/W$_{AC}$ that it paid for an initial 22.5 MW$_{AC}$ built in 2011 (O'Connell 2014).[25]

Though capacity-weighted average prices in the sample have declined over time (at least through 2012), there remains a considerable spread in individual project prices. Among the 25 PV projects in the sample that were completed in 2013, for example, installed prices range from $2.2/W$_{AC}$ to $5.6/W$_{AC}$, and prior years show similar levels of variability. This price variation is

[25] Battery storage reportedly added an additional $0.20/W$_{AC}$ to the 22.5 MW$_{AC}$ built in 2011, bringing the total cost to $4.19/W$_{AC}$ (O'Connell 2014). PNM's 2011 price point of roughly $4/W$_{AC}$ is fairly consistent with the capacity-weighted average price for 2011 shown in Figure 4, while PNM's 2013 price point of $2.25/W$_{AC}$ is the low end of the overall range for 2013.

partially attributable to differences in module type and project configuration – i.e., whether PV projects use c-Si or thin-film modules, and whether those modules are mounted at a fixed-tilt or on a tracking system. Figure 5 breaks out installed prices over time among these four combinations (and also includes the two CPV projects in the sample); the solid lines denote trends in the capacity-weighted average installed price over time.

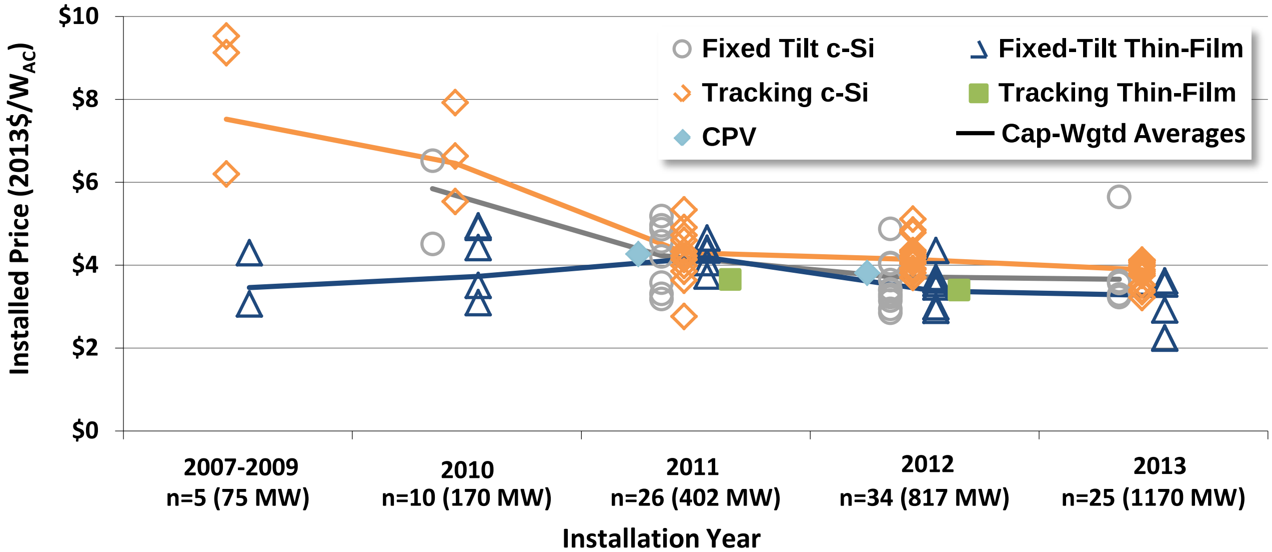


Figure 6. Installed Price of Utility-Scale PV (and CPV) by Module Type and Project Configuration, 2007-2013

Trends of particular note include:

- Although projects using c-Si modules have historically been significantly more expensive than projects using thin-film modules (e.g., by \$2.1/W$_{AC}$ on average in 2010 – though based on a very small sample), the average installed price of c-Si and thin-film projects has converged over time, to just \$0.4/W$_{AC}$ on average in 2013 (among fixed-tilt projects). This convergence has been led by the falling price of c-Si modules over time, driven by a decline in the price of silicon as well as a global excess of c-Si module manufacturing capacity (at least through 2012 – both drivers have since stabilized or even reversed). As the price of c-Si projects has converged with thin-film, the number of c-Si projects in both the installed price sample and the broader population has grown significantly as well, as noted earlier in Chapter 2 (see Figure 2).[26]
- Tracking systems remain slightly more expensive than fixed-tilt systems within the sample – a difference of about \$0.2/W$_{AC}$ in 2013 among c-Si projects. As shown later in Chapter 5, this higher up-front cost provides a benefit in terms of greater energy production, and hence likely lower \$/MWh costs over a project's life.

[26] This shift towards c-Si can be illustrated anecdotally by the Copper Mountain projects in Nevada, the first three phases (built from 2008-2012) of which use thin-film modules, while the fourth phase (planned for 2015) will use c-Si modules. In a similar nod to the increasing cost-competitiveness of c-Si, PNM's 40 MW$_{AC}$ slated for 2015 (referenced above) will use c-Si modules, in contrast to its previous projects (built in 2011, 2013, and 2014), all of which use thin-film modules. In its recent regulatory filing, PNM states "The most important reason for the selection of the polycrystalline system for this procurement was cost. Projects bid into PNM's renewable RFP that proposed polycrystalline modules were lower in cost than bids based on thin-film technology" (O'Connell 2014).

- The two high-concentration CPV projects built in 2011 and 2012 exhibit installed prices that are comparable to the average PV pricing in the sample (yet, as shown later in Chapter 5, these two CPV projects have not performed as well as the average PV project). One or more low-concentration CPV projects (e.g., using SunPower's new C7 technology) may enter the sample in 2014, providing additional data points.

Differences in project size may also explain some of the variation in installed prices, as PV (and CPV) projects in the sample range from 5.1 MW_{AC} to 250 MW_{AC}. Figure 7 investigates price trends by project size to see whether scale economies potentially allow the larger projects in the sample to achieve lower costs. In order to minimize the potentially confounding influence of price reductions over time, Figure 7 focuses on just those PV (and CPV) projects in the sample that were installed in 2012 and 2013 – i.e., two years of relatively consistent prices, according to Figures 5 and 6.

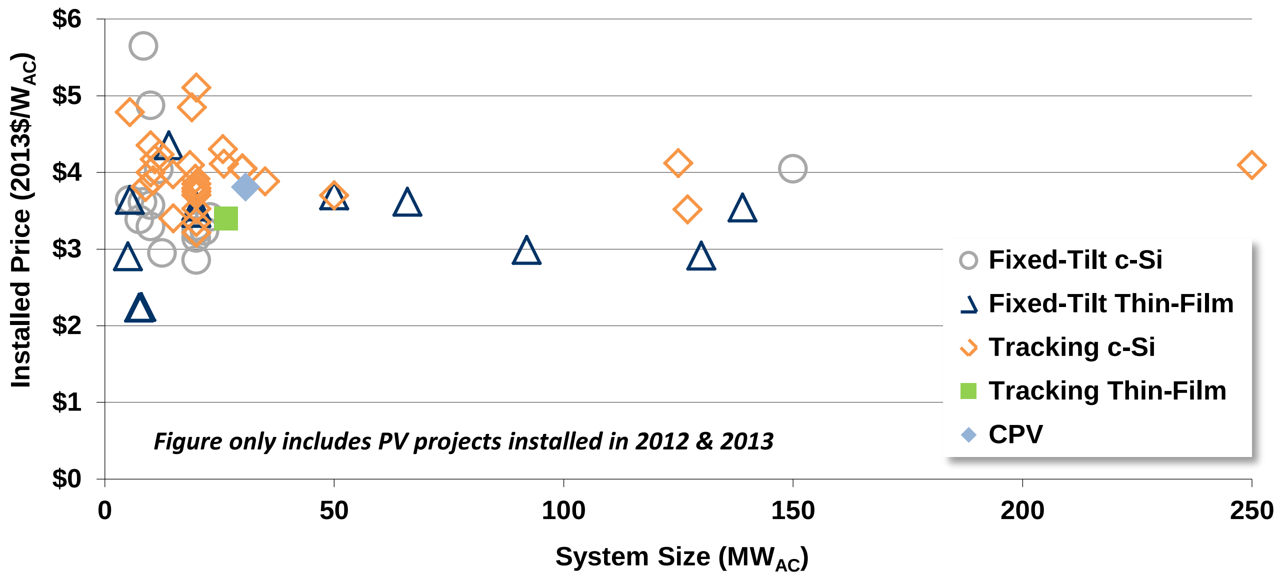


Figure 7. Installed Price of Utility-Scale PV (and CPV) by Module Type, Project Configuration, and Size: 2012 & 2013 Projects Only

Although the overall variation in installed prices does appear to narrow as project size increases (perhaps indicative of scale economies, at least at the upper end of the price range), the average price level does *not* exhibit obvious signs of scale economies – either for the sample as a whole or when broken out by module type and project configuration. Although the reasons for this somewhat counterintuitive finding are not clear, one potential explanation is that evidence of PV scale economies is perhaps most visible among projects of less than 5 MW_{AC} in size – none of which are included in our sample.[27]

[27] For example, if projects commonly make use of the modular "power blocks" offered by module manufacturers such as SunPower (e.g., its 1.5 MW Oasis power block) and First Solar, then perhaps those standardized solutions have largely wrung out any existing economies of scale that one might otherwise expect to capture through larger projects. Alternatively, larger projects may encounter more significant (and more expensive) barriers to development than smaller projects, which could also offset any scale economies that might otherwise be achieved.

CSP (5 projects, 1,066 MW_{AC})

The installed price sample also includes five CSP projects totaling 1,066 MW_{AC}: three parabolic trough projects, one parabolic trough project with 6 hours of thermal storage, and one power tower project. Figure 7 breaks down these various CSP technologies by project size and installation year (from 2007 through 2013), and also compares their installed prices to the capacity-weighted average installed price of PV (from Figure 5) in each year from 2010 through 2013.

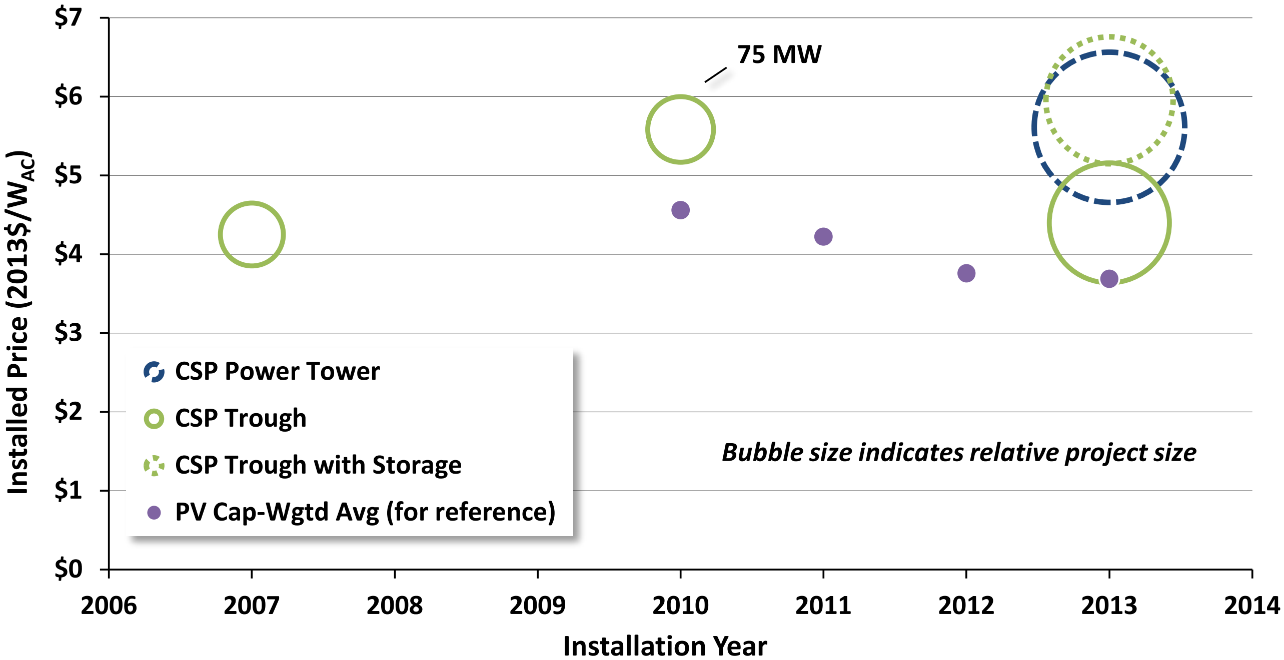


Figure 8. CSP Installed Price and Project Size by Installation Year, 2007-2013

The small sample size makes it difficult to discern any trends. Focusing just on 2013, the single power tower project (which does not include storage) falls in between the two trough projects (the trough project with six hours of storage is priced $1.55/$W_{AC}$ higher than the trough project without storage), and all three projects are above the capacity-weighted average PV price in that year. Additional CSP installed price data points will become available in next year's edition of this report, following the 2014 completion of another large trough project (without storage) and one additional power tower (including ten hours of storage).

4. Operations and Maintenance Costs

In addition to up-front installed project costs or prices, utility-scale solar projects also incur ongoing operations and maintenance ("O&M") costs. This section reviews and analyzes the limited data on O&M costs that are in the public domain. It starts with a review of *projected* O&M (as well as total operating[28]) costs from three large projects that have financed a portion of their capital costs through public bond offerings, thereby necessitating the disclosure of detailed project information. Then it turns to empirical historical data from a very limited sample of projects that are owned by investor-owned utilities and, as such, are required to report O&M costs for those projects each year on FERC Form 1.

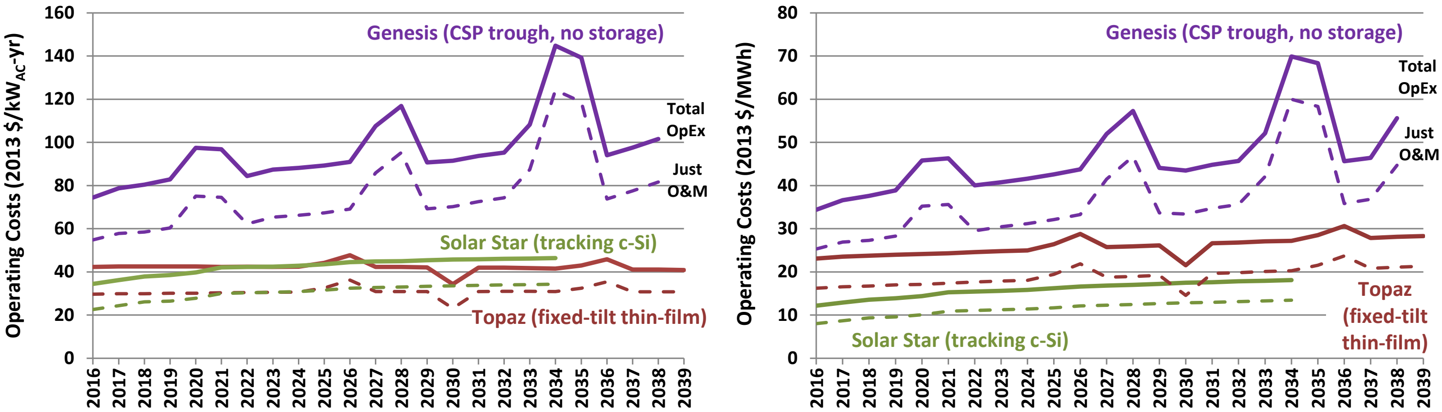
Projected O&M Costs Are Similar for Different PV Configurations, Higher for CSP

In the past few years, there have been at least three utility-scale solar projects in the U.S. that have issued bonds to finance a portion of their construction. The 550 MW Topaz project is a fixed-tilt thin-film PV system; the 579 MW Solar Star projects (formerly known as the Antelope Valley Solar Projects) are two adjacent PV projects that will utilize c-Si with single-axis tracking; and the 250 MW Genesis project is a parabolic trough CSP project without storage. All three projects are located in California, and only one – the Genesis CSP project – was fully online at the time of writing, although the Solar Star and Topaz Solar projects were under construction and delivering energy from early phases.

Though not empirical data, projected O&M costs for these three projects are nevertheless instructive, not only because the projects are all very large (i.e., indisputably utility-scale), but also because they represent a diversity of technologies that happens to be highly representative of the majority of utility-scale solar installations in the United States today, ranging from fixed-tilt thin-film PV to tracking c-Si PV to parabolic trough CSP without storage. That said, it is important to keep in mind that these three projects (and the data available for them) may not be entirely representative of their respective technology configurations. For example, given that these projected O&M costs are obtained from documentation intended to support a credit rating, they may be conservatively high in order to provide comfort to potential bond buyers. In fact, in its published research on each project, the credit rating agency Fitch noted the robust nature of operating cost projections, referring in particular to long-term, fixed-price O&M contracts with experienced operators covering both routine maintenance and major repair and replacement costs, as well as the allocation of additional funds for any O&M contingencies that might arise (FitchRatings 2013, 2012, 2011). For this reason, actual O&M costs (among these projects, as well as others that fall into these three technology categories) might tend to be lower than shown in the figures below. On the other hand, these are all large projects, and smaller projects might experience higher per-unit O&M costs.

[28] In addition to O&M costs – i.e., those costs incurred directly to operate and maintain the generating plant itself – total operating expenses also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (FitchRatings 2013, 2011).

Figure 9 shows projected O&M costs (dashed lines) and total operating expenses ("OpEx" – shown by the solid lines) for all three projects over time, expressed both in $/kW$_{AC}$-year (on the left) and $/MWh (on the right). Since the vast majority of O&M expenses for solar projects are fixed (i.e., incurred regardless of how much electricity the system generates),[29] $/kW$_{AC}$-year is seemingly a more appropriate metric than $/MWh, but the latter is included for ease of comparison to PPA prices (presented later in Chapter 6).



Source: FitchRatings 2013, 2012, 2011

Figure 9. Projected O&M and Total Operating Costs for Three Utility-Scale Solar Projects

Although one might expect tracking systems to have higher O&M costs than fixed-tilt systems on a $/kW-year basis, the two PV projects have very similar O&M and total operating cost projections, with O&M costs in the $22 to $36/kW$_{AC}$-year range. Given Solar Star's expected capacity factor advantage from tracking, however, its projected O&M costs are lower than Topaz's on a $/MWh basis – increasing from $8-$13/MWh over time, compared to $16-$21/MWh for Topaz.[30] For both projects, O&M costs account for ~75% of total operating costs.

Perhaps not surprisingly (given not only the solar tracking components, but also the rest of the infrastructure needed for a CSP project – e.g., plumbing for the heat-transfer fluid, heat exchangers, condensers, steam turbines, etc.), O&M and operating expenses for the Genesis project are projected to be considerably higher than for either of the PV projects, and with a recurring spike every seven years related to scheduled maintenance and/or overhaul of the steam turbines (full inspection, tune-up, re-blading as necessary).

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[29] Of the three projects in question, only Genesis – the parabolic trough CSP project, which includes a gas turbine component – broke out O&M expenses into fixed and variable costs, with fixed costs accounting for 96%-98% of total O&M costs each year. PV projects presumably have even fewer variable O&M costs.

[30] The projected O&M costs for Solar Star are consistent with information on PV tracking systems from the Public Service Company of New Mexico's Renewable Energy Portfolio Procurement Plan for 2015 (referenced earlier in Chapter 3). That plan projects that annual O&M costs (which, in addition to O&M contract costs, also include costs associated with vegetation and animal management, vandalism, and other property damage) for 40 MW$_{AC}$ (split into two 20 MW$_{AC}$ projects) of tracking c-Si projects that it plans to build in 2015 will be approximately $21/kW-year, or $7.25/MWh based on an expected 33.1% capacity factor (O'Connell 2014).

Limited Sample of Empirical O&M Costs Seems to Conform to Projections

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Not only have relatively few utility-scale solar projects been operating for more than a year, but even fewer of those projects are owned by investor-owned utilities, which are required by FERC to report on Form 1 the O&M costs of the power plants that they own.[31] And even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful.[32] As a result of this disparity in how utilities report (or not, as the case may be) O&M costs, the sample of projects for which O&M cost data are available (eight projects totaling 136 MW_{AC}) is only about half as large as the total population of projects for which such data *should be* available (18 projects totaling 237 MW_{AC}).

Despite these limitations, Figure 10 shows historical O&M costs for this small sample of utility-scale solar projects in both \$/kW-year and \$/MWh terms.[33] Three of these projects have historical data for more than two years; the other five have data for only 2012 and 2013. Despite the extremely limited sample, reported costs are seemingly in line with the projected O&M costs in the early years of Figure 9 above – i.e., in the neighborhood of \$20-\$40/kW_{AC}-year or \$10-\$20/MWh for PV, and \$40-\$60/kW_{AC}-year for the lone CSP parabolic trough project.

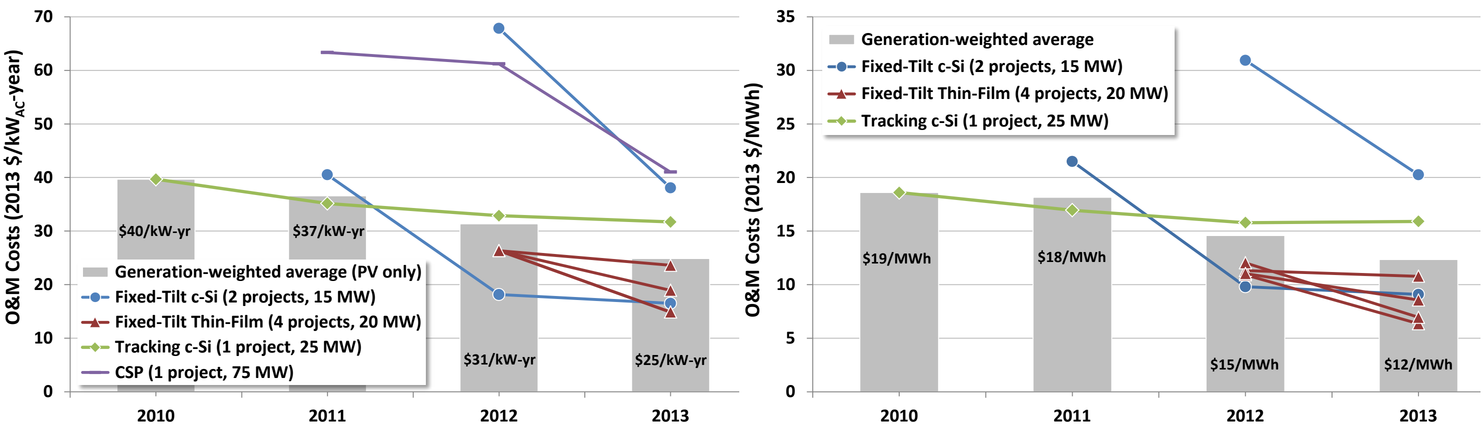

Figure 10. Empirical O&M Costs by Project Type

As utility ownership of operating solar projects increases in the years ahead (and as those utilities that already own substantial solar assets but do not currently report operating cost data hopefully begin to do so, as required in FERC Form 1), the sample of projects reporting O&M costs will grow, potentially allowing for more interesting analyses in future editions of this report.

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[31] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses" – namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. As such, the FERC Form 1 data are more closely aligned with, and therefore more comparable to, the projected O&M costs (rather than the total operating expenses) reported in Figure 9.

[32] For example, the two investor-owned utilities that own by far the most solar capacity (PG&E and APS) either do not report operating costs for their solar projects on Form 1 at all (PG&E), or else report them in an aggregated manner that does not readily lend itself to analysis (APS).

[33] O&M costs for the single CSP project (a 75 MW parabolic trough project) are only shown in \$/kW-year terms because this project provides steam to a co-located combined cycle gas plant (i.e., the solar plant acts as a natural gas fuel saver). The amount of generation attributed to the solar plant is not tracked separately (or at least not reliably); instead, the solar plant serves to reduce the heat rate of the combined cycle gas plant.

5. Capacity Factors

At the close of 2013, more than 75 utility-scale solar projects (again, ground-mounted projects larger than 5 MW_{AC}) had been operating for at least one full year (and in some cases for several or even many years), thereby enabling the calculation of capacity factors.[34] Sourcing net generation data from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and state regulatory filings, this chapter presents net capacity factor data for 64 PV projects totaling 1,532 MW_{AC}, two CPV projects totaling 35 MW_{AC}, and ten CSP projects (all parabolic trough without storage) totaling 461 MW_{AC} (and for which only the solar generation is reported here – no gas or oil augmentation is included). This sample size should increase significantly in next year's edition, as the large amount of new utility-scale solar capacity that came online in 2013 will have its first full operating year in 2014.[35]

PV (64 projects, 1,532 MW_{AC})

Project-level capacity factors for utility-scale PV projects can vary considerably, based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site (measured in DNI with units $kWh/m^2/day$); whether the array is mounted at a fixed-tilt or on a tracking mechanism; the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or "ILR"); and the type of modules used (e.g., c-Si versus thin-film). Other factors such as tilt and azimuth will also play an obvious role, though since we focus only on ground-mounted utility-scale projects, our operating assumption is that these fundamental parameters will be equally optimized to maximize energy production across projects.

One might also expect project vintage to play a role – i.e., that newer projects will have higher capacity factors because the efficiency of PV modules (both c-Si and thin-film) has increased over time. As module efficiency increases, however, developers simply either use fewer of them to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well) or, alternatively, use the same number of them to boost the amount of capacity installed on a fixed amount of land (which directly reduces at least $\$/W_{DC}$ costs, if not also $\$/W_{AC}$ costs). In other words, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is therefore most likely attributable to a time trend in one of the other variables noted above – e.g., towards higher inverter loading ratios or greater use of tracking.

Figure 11 illustrates and supports this hypothesis, by breaking out the average net capacity factor ("NCF") by project vintage across the sample of projects built in 2010, 2011, or 2012 (and by noting the relevant average project parameters within each vintage). The capacity factors

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[34] Because solar generation is seasonal (generating more in the summer and less in the winter), capacity factor calculations should only be performed in full-year increments.

[35] Net generation data for 2013 from annual respondents to form EIA 923 – which were not available at the time of writing, but will be in time for next year's edition – should expand the number of 2012 projects in the sample as well.

presented in Figure 11 represent *cumulative* capacity factors – i.e., calculated over as many years of data as are available for each individual project (a maximum of three years, from 2011-2013, in this case), rather than for just a single year (though for projects completed in 2012, only a single year of data exists at present) – and are expressed in *net*, rather than *gross*, terms (i.e., they represent the output of the project net of its own use). Notably, they are also calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[36] which results in higher capacity factors than if reported in DC terms,[37] but allows for direct comparison with the capacity factors of other generation sources (e.g., wind energy or conventional energy), which are also calculated in AC terms.

As shown, the average capacity factor does not differ much on average between 2010- and 2011-vintage projects, which is perhaps not surprising given virtually no change in the average ILR across vintages, in conjunction with the opposing influences of a lower DNI and higher proportion (in capacity terms) of projects using tracking among 2011-vintage projects. Projects built in 2012, however, have notably higher capacity factors on average, likely driven by a significant increase in both average ILR and DNI.

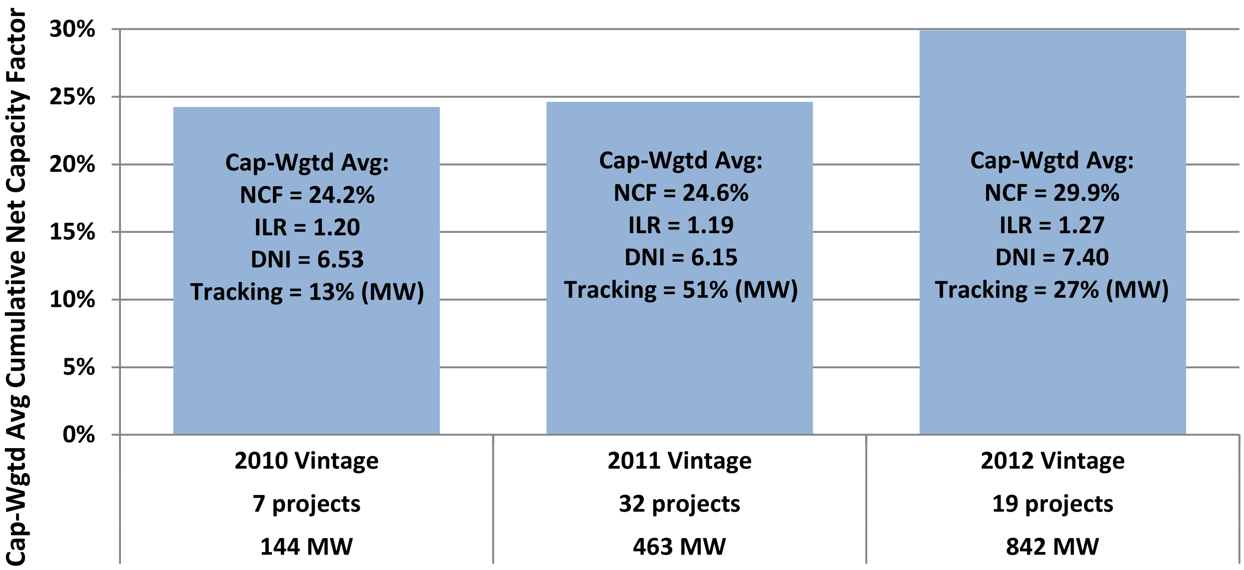

Figure 11. Cumulative PV Capacity Factor by Project Vintage: 2010-2012 Projects Only

To the extent that this observable time trend in net capacity factor by project vintage is, in fact, attributable to a time trend in one or more of the other variables noted, it is perhaps best to measure the impact of those other variables directly. Figure 12 does just that, by categorizing the entire data sample in four different ways: by solar resource strength (in DNI terms), by fixed-tilt versus tracking systems, by the inverter loading ratio, and by module type (c-Si versus thin-film). The capacity-weighted average capacity factor across the entire sample is 27.5%, the median is 26.9%, and the simple average is 25.9%, but there is a wide range of individual project-level capacity factors (from 16.6% to 32.8%) around these central numbers.

[36] The formula is: Net Generation (MWh_{AC}) over Single- or Multi-Year Period / [Project Capacity (MW_{AC}) * Number of Hours in that Same Single- or Multi-Year Period].
[37] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

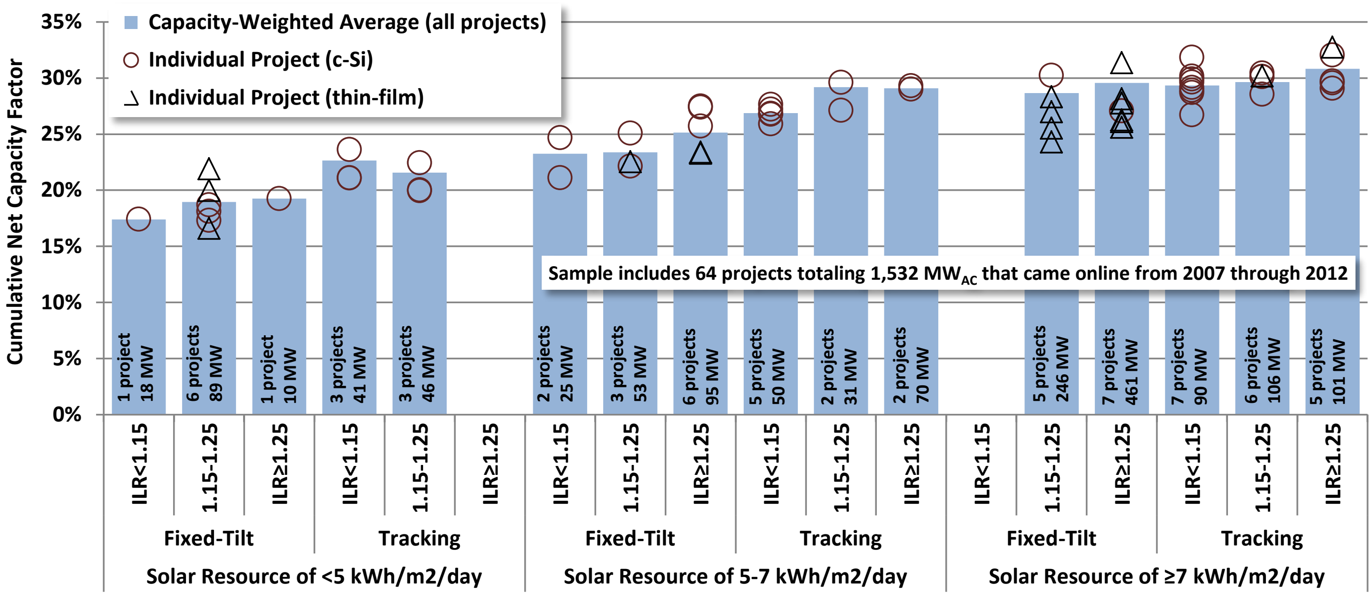

Figure 12. Cumulative PV Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, Inverter Loading Ratio, and Module Type

Each of the four variables explored in Figure 12 is discussed in turn below.

- **Solar Resource:** Each project in the sample is associated with a direct normal irradiance ("DNI") value derived from the map shown earlier in Figure 3. Solar resource bin thresholds (<5, 5-7, and ≥7 kWh/m^2/day DNI) were chosen to ensure that a sufficient number of projects fall within each bin.[38] Not surprisingly, projects sited in stronger solar resource areas have higher capacity factors, all else equal. The difference can be substantial: the capacity-weighted average capacity factors in the highest resource bin, for example, range anywhere from 30-54% higher (depending on whether fixed-tilt or tracking and inverter loading ratio) than their counterparts in the lowest resource bin.
- **Fixed-Tilt vs. Tracking:** Tracking (all single-axis in our sample) boosts average capacity factor by roughly 19% on average in the two lowest solar resource bins (with the boost ranging from 14% to 30% depending on the inverter loading ratio bin). Within the highest solar resource bin, however, the boost from tracking is muted, at roughly 4% on average (with a range of 3-4% across inverter loading ratio bins). One potential explanation (other than fairly limited sample size) is that, compared to the two lower resource bins, the fixed-tilt projects in the highest resource bin have relatively higher average inverter loading ratios (within each inverter loading ratio bin) than their tracking counterparts (this is evident in Figure 13, below). In other words, these fixed-tilt projects have achieved, at least on average, a capacity factor that more closely resembles that of a tracking project simply by oversizing the DC PV array relative to the AC inverter rating; as such, the incremental boost from tracking is smaller than one might expect.

[38] Fourteen projects totaling 203 MW fall into the lowest resource category of less than 5 kWh/m^2/day, 20 projects totaling 324 MW fall into the middle resource category of between 5 and 7 kWh/m^2/day, and 30 projects totaling 1,005 MW fall into the highest resource category of at least 7 kWh/m^2/day. Not surprisingly, the highest resource category also has the highest average system size of 33 MW, compared to 15-16 MW in the other two categories.

- **Inverter Loading Ratio (ILR):** Figure 12 breaks the sample down further into three different inverter loading ratio bins: <1.15, 1.15-1.25, and ≥1.25. The effect on average capacity factor is noticeable: within each resource bin and fixed/tracking bin, the capacity factor difference between the highest and lower inverter loading ratio bin ranges from 5-11%.
- **Module Type:** Figure 12 differentiates between projects using c-Si and thin-film modules by the shape and color of the markers denoting individual projects (the capacity-weighted averages, meanwhile, include *both* c-Si and thin-film projects). Though somewhat difficult to tease out, the differences in project-level capacity factors by module type are generally small (smaller than for the other variables discussed above), and do not necessarily exhibit any sort of pattern.

Focusing only on those projects within the highest resource bin (≥7 kWh/m^2/day DNI) of Figure 12, Figure 13 breaks this sub-sample down by project vintage (for projects built from 2010-2012 only) in order to take a closer look at the notion explored earlier in Figure 11 that time trends in PV capacity factors are primarily attributable to underlying project characteristics like ILR and DNI. Although small sample size becomes an issue when breaking down the sample to this degree (e.g., some vintage bins in Figure 13 consist of just a single project), an upward time trend in capacity factor is nevertheless generally evident among this sub-sample. The data are empirical and so are not perfect in conforming to theory, but in general – and particularly among the tracking projects – more recent project vintages do have higher DNIs and ILRs supporting their higher capacity factors.

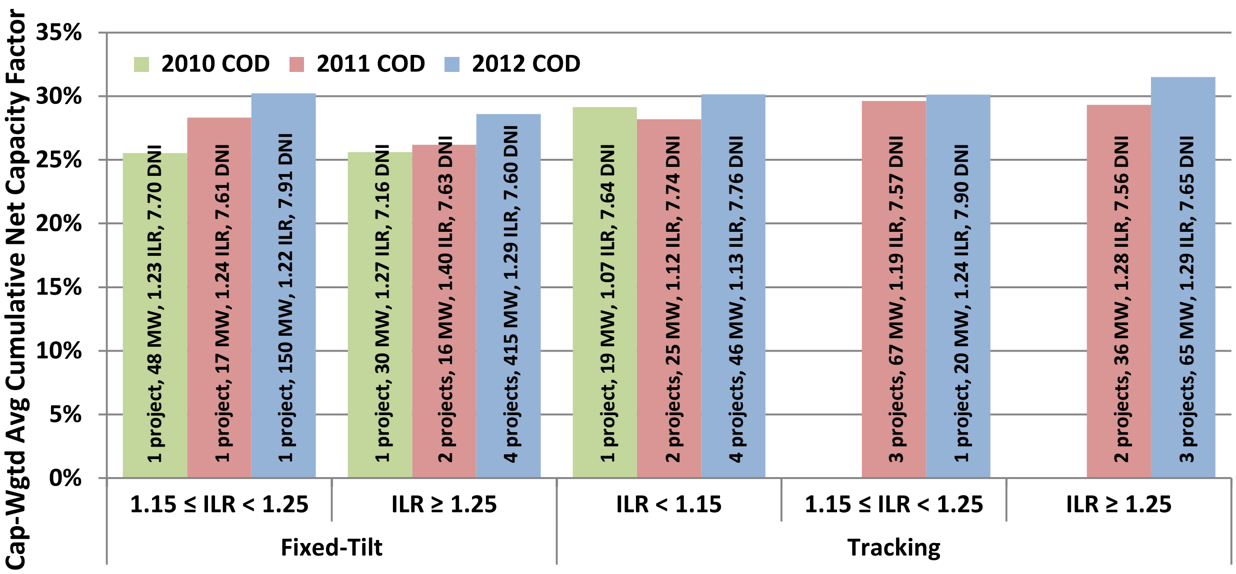

Figure 13. Average Cumulative PV Capacity Factor by Project Vintage, Inverter Loading Ratio, and Fixed-Tilt vs. Tracking: Solar Resource ≥ 7 kWh/m^2/day

CPV (2 projects, 35 MW_{AC})

The two CPV-only projects in the sample (the 5 MW_{AC} Hatch and the 30 MW_{AC} Cogentrix Alamosa projects) use virtually the same high-concentration technology (from Amonix), and both appear to be underperforming – both relative to publicly stated expectations and to how a single-axis tracking PV project would likely have performed in similar conditions. In November 2011 (a few months after Hatch came online and a few months before Alamosa went online), a conference presentation from Amonix suggested a 31.5% capacity factor for Hatch and a 32.5% capacity factor for Alamosa (Pihowich 2011).[39] This 31.5-32.5% range is consistent with the empirical PV capacity factors seen in the second column from the right in Figure 12, which – except for the fact that they feature dual-axis, rather than single-axis, tracking – is where these two CPV projects would otherwise fall based on resource strength and inverter loading ratio. Actual experience to date, however, has been below this range: Hatch's 20.9% capacity factor in 2012 dropped to 18.5% in 2013, while Cogentrix Alamosa posted a 24.7% capacity factor in 2013.[40] The 2013 capacity factors may have been reduced somewhat by the reportedly below-average insolation levels in the southwestern United States during the summer of 2013 (3TIER 2013).

CSP (10 projects, 461 MW_{AC})

Although several new large CSP projects (both troughs and power towers) either achieved commercial operations or entered the commissioning phase in late 2013 or early 2014, it will be at least another year before empirical capacity factor data from those projects are available for analysis. Until then, there are still only eleven CSP projects in the U.S. that are larger than 5 MW_{AC} and that have been operating for one or more years. These include the nine parabolic trough SEGS plants (totaling 392 MW_{AC}) that have been operating in California for more than twenty years, the 68.5 MW_{AC} Nevada Solar One parabolic trough project that has been operating in Nevada since mid-2007, and the 75 MW_{AC} Martin parabolic trough project in Florida that, since 2011, has been feeding steam to a co-located combined cycle gas plant. Figure 14 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with

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[39] Although the Amonix presentation (Pihowich 2011) lists expected generation numbers that equate to a 31.5% capacity factor for Hatch, the slide itself states a slightly lower capacity factor estimate of 29.4% – which is still higher than actual experience. Meanwhile, the web site of El Paso Electric (the offtaker) lists 9,189 MWh, or a 20.8% capacity factor, as the expected output of Hatch (the project met this expectation in 2012, but fell short in 2013). For Cogentrix Alamosa, an April 2011 environmental assessment prepared for the DOE's Loan Program Office assumed a 29% capacity factor, although the current Loan Program Office project description notes annual generation of 58,000 MWh, which equates to just 21.9% (well below the 24.7% achieved in 2013). The reason for these disparate expectations (for both projects) is not clear, though one potential explanation might have to do with timing – i.e., the current El Paso Electric and Loan Program Office numbers might be more recent, therefore potentially reflecting some degree of actual experience.

[40] A third project that includes a mix of PV and CPV technologies – the 6.9 MW_{AC} SunE Alamosa project – has performed better than the two CPV-only projects, having logged a 28.9% cumulative capacity factor over six full years of operations (from 2008-2013). The CPV portion of the project, however, only accounts for about 12% of the project's total capacity (the rest being PV with diurnal (~80%) or seasonal (~7%) tracking), and unfortunately, the project-level net generation data are not granular enough to enable a determination of how the CPV and PV portions of this project have performed independently.

natural gas or fuel oil is included in Figure 14) of ten of these eleven projects (the Martin project is omitted from Figure 14 due to data complications), going back to 2001.

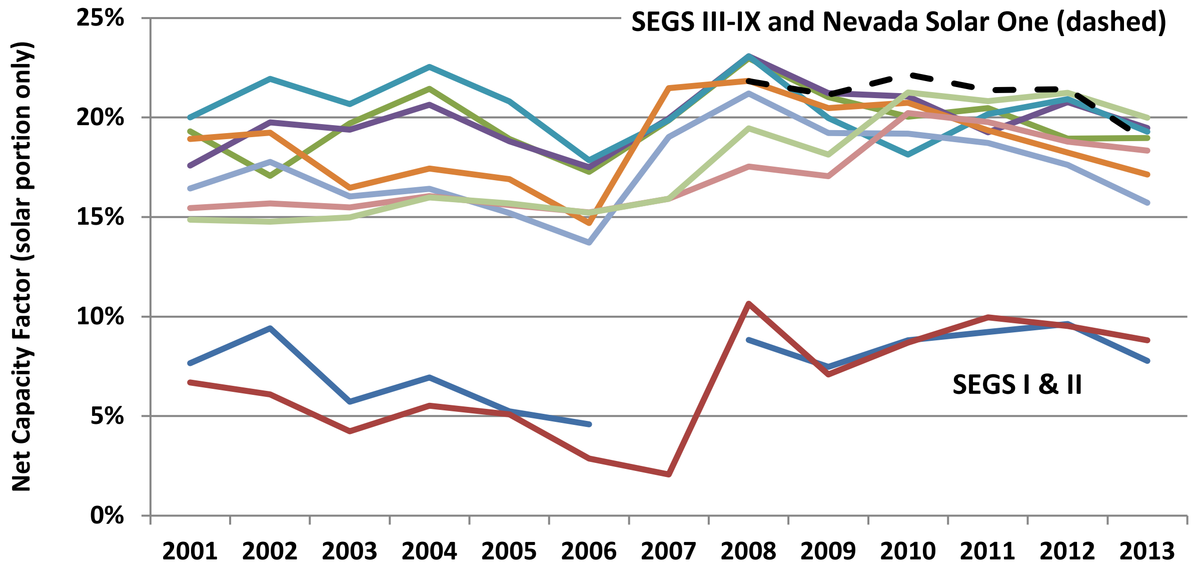

Figure 14. Capacity Factor of CSP Thermal Projects (Solar Portion Only) Over Time

Notable findings include the following:

- The projects fall into two groupings: SEGS III-IX and Nevada Solar One in one grouping, and SEGS I and II in the other. SEGS I and II are owned and operated separately from SEGS III-IX, and have reportedly been used as somewhat of a test-bed for new collector technologies in recent years, which could explain their lower capacity factors. Other potential drivers include the size of the collector field relative to the generator's nameplate capacity – which tends to be a lower ratio for SEGS I and II than the other projects – along with generator efficiency (also potentially lower for SEGS I and II).
- Capacity factors among SEGS III-IX have converged somewhat in recent years (at least relative to the pre-2010 period), in part as a result of refurbishments and upgrades. For example, SEGS VIII and IX, which prior to 2010 regularly had the lowest capacity factors within this grouping, upgraded (with the help of the Section 1603 grant program) their heat collection elements in early-2010 to make the projects more efficient. The resulting improvement in their capacity factors is evident.
- Nearly all of these projects saw significantly lower solar-only capacity factors in 2013. This decline is potentially attributable to inter-year variations in the solar resource, which was reportedly well below average in the southwestern United States (i.e., where these projects are located) during the summer of 2013 (3TIER 2013), with summer typically being the peak production period for solar projects.
- Figure 14 reflects only the net capacity factor attributable to the sun. Most of these projects also use gas-fired turbines to supplement their output (e.g., during shoulder months, into the evening, or during cloudy weather). In the case of Nevada Solar One,

for example, gas-fired generation has boosted historical capacity factors by twenty to forty basis points depending on the year (e.g., from 20.1% solar-only to 20.5% gas-included in 2013), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 180-240 basis points in 2013, depending on the project.

- Finally, the capacity factors for even the highest-performing CSP projects in Figure 14 (e.g., Nevada Solar One) are lower than many of the PV capacity factors shown earlier in the chapter. For example, as noted earlier, the capacity-weighted average capacity factor across the entire PV sample is 27.5% (with a range from 16.6% to 32.8%), whereas none of the CSP projects in Figure 14 have exceeded 23% in recent years.

With three new parabolic trough projects (Genesis, Mojave, Solana) and two new power tower facilities (Ivanpah and Crescent Dunes) – all of them sizable, and two of them utilizing storage – having come online or entered commissioning in recent months, the availability of CSP performance data will improve in future years.

6. Power Purchase Agreement ("PPA") Prices

The cost of installing, operating, and maintaining a utility-scale solar project, along with its capacity factor – i.e., all of the factors that have been explored so far in this report – are key determinants of the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale solar projects in the U.S. The sample includes a total of 80 contracts totaling 6,493 MW_{AC} and broken out as follows: 73 PV PPAs totaling 5,747 MW_{AC}, two CPV PPAs totaling 35 MW_{AC}, one 7 MW_{AC} PPA that is a mix of PV and CPV, and 4 CSP PPAs (three parabolic trough, one power tower) totaling 704 MW_{AC}.

The population from which this sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that sell electricity directly to end-users (i.e., on a retail basis, and often in conjunction with net metering), are therefore not included in the sample. We also exclude those projects that unbundle and sell RECs separately from the underlying electricity, because in those instances the PPA price alone is not indicative of the project's total revenue requirements (at least on a post-incentive basis). PPAs resulting from feed-in tariff ("FIT") programs are excluded for similar reasons – i.e., the information content of the pre-established FIT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable,[41] and as such, the PPA sample comes entirely from utility-scale projects that sell bundled energy, capacity, and RECs to utilities (both investor-owned and publicly-owned utilities) through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[42]

For each of the contracts in the sample,[43] we have collected the contractually locked-in PPA price data over the full term of the PPA,[44] and have accounted for any escalation rates and/or

[41] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs.

[42] Because all of the PPAs in the sample include RECs (i.e., transfer them to the power purchaser), we need not worry too much about REC price trends in the unbundled REC market. It is, however, worth noting that some states (e.g., Colorado) have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for RPS compliance purposes), while others have implemented solar "set-asides" or "carve-outs" (requiring a specific portion of the RPS to be met by solar) as a way to specifically encourage solar power development. In these instances, it is possible that utilities might be willing to pay a bit more for solar through a bundled PPA than they otherwise would be, either because they need to in order to comply with a solar set-aside, or because they know that each bundled solar REC has added value (in the case of a multiplier). So even though REC prices do not directly impact the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases – presumably to the upside.

[43] In general, each PPA corresponds to a different project, though in some cases a single project sells power to more than one utility under separate PPAs, in which case there may be two or more PPAs tied to a single project.

[44] The minimum PPA term in the sample is 10 years (though the two 10-year contracts in the sample are effectively 4-year "bridge" PPAs with a California municipality, whereby the buyer takes 100% of the output for the first four years and then, once a long-term contract with an investor-owned utility begins in 2019, just 1% of the output in the

time-of-delivery ("TOD") pricing factors employed (see the text box – *Estimating PV's TOD Value* – on page 32).[45] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum amount of revenue required by[46]) these projects over the life of the contract – at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation)[47] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[48,49] As such, the levelized PPA prices presented in this section should *not* be equated with a project's levelized cost of energy ("LCOE").

Figure 15 shows trends in the levelized (using a 7% real discount rate) PPA prices from the entire sample (not all of which is yet operational) over time. Each bubble in Figure 15 represents a single PPA, with the area of the bubble corresponding to the size of the contract in MW and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[50] Different solar technologies (e.g., PV versus CPV versus CSP) are denoted by different colors and patterns.

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last six years), the maximum is 34 years, the mean is 23.2 years, the median is 25 years, and the capacity-weighted average is 23.4 years.

[45] In cases where PPA price escalation rates are tied to inflation, the EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2014* is used to determine expected escalation rates. For contracts that use time-of-delivery pricing and have at least one year of operating history, each project's average historical generation profile is assumed to be replicated into the future. For those projects with less than a full year of operating history, the generation profiles of similar (and ideally nearby) projects are used as a proxy until sufficient operating experience is available.

[46] In a competitive "cost-plus" pricing environment – where the PPA price is just sufficient to recoup initial capital costs, cover ongoing operating costs, and provide a normal rate of return – PPA prices will represent the minimum amount of revenue required by a project. In contrast, "value-based" pricing occurs when the project developer or owner is able to negotiate a higher-than-necessary PPA price that nevertheless still provides value to the buyer.

[47] In addition to the other federal incentives listed, nine projects within the sample also received DOE loan guarantees through the Section 1705 program. In all nine cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee had no impact on the PPA price.

[48] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher (i.e., 30%/(1-federal tax rate)) if there were no federal investment tax credit ("ITC"). Without the ITC, however, the resulting increase in PPA prices would be limited by the fact that sponsors with tax appetite could then leverage their projects up more heavily with cheap debt, while sponsors without tax appetite would be able to forego expensive third-party tax equity in favor of cheaper forms of capital, like debt. Because of these financing shifts, the PPA price would likely not increase by 50%, but rather more like 35-40% in the case of a sponsor with tax appetite, and by roughly 20% in the case of a sponsor without tax appetite that currently relies on third-party tax equity to monetize the ITC (Bolinger 2014).

[49] Though there is too much variety in state-level incentives to try and systematically quantify their impact on PPA prices here, one example is New Mexico's refundable Production Tax Credit, which provides a credit of varying amounts per MWh (averaging $27/MWh) of solar electricity produced over a project's first ten years. One PPA for a utility-scale PV project in New Mexico allows for two different PPA prices – one that is $43.50/MWh higher than the other, and that goes into effect only if the project does not qualify for the New Mexico PTC. Based on New Mexico's top corporate tax rate of 7.6%, a $43.50/MWh price increase due to loss of New Mexico's PTC seems excessive (a more appropriate 20-year adjustment would seemingly have been roughly half that amount), but nevertheless, this is one tangible example of how state incentives can reduce PPA prices.

[50] Because PPA prices reflect market conditions at the time a PPA is executed – which could be two years or more in advance of when the project achieves commercial operations – the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices. In contrast, installed prices (and, to a lesser extent, capacity factors) are more closely tied to when a project achieves commercial operations; hence, commercial operation date is used in earlier chapters.

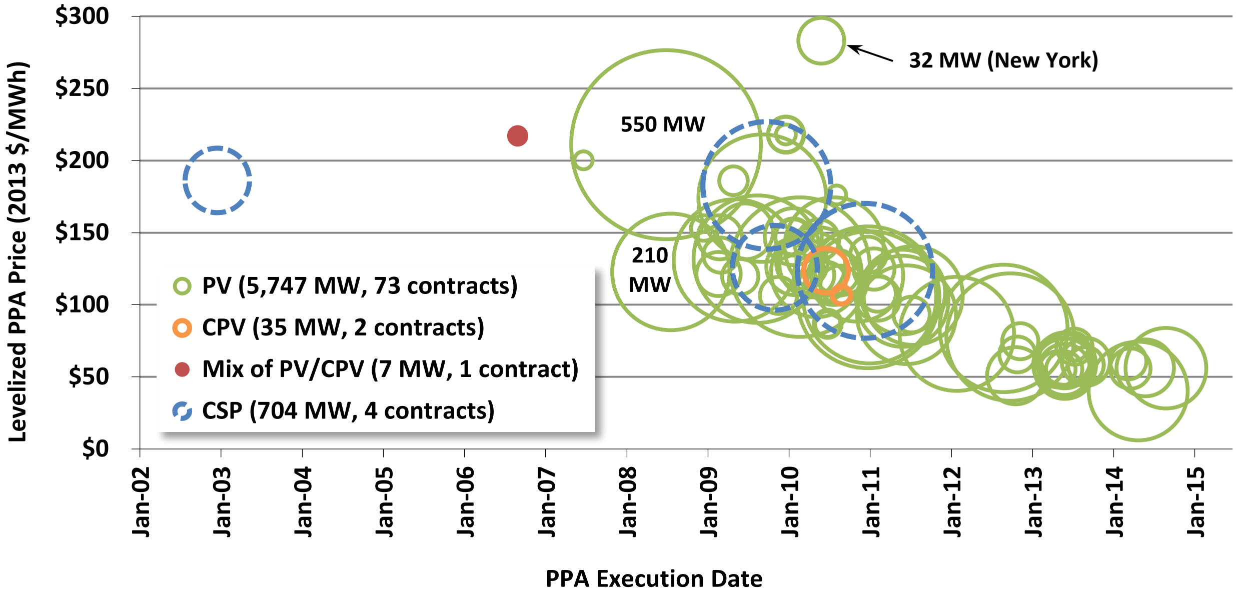

Figure 15. Levelized PPA Prices by Technology and PPA Execution Date

Figure 15 provides a number of insights:

- PPA pricing has, in general, declined over time, to the point where recent PPAs have been priced as aggressively as $50/MWh levelized (in 2013 dollars), or even lower. In the Southwest (where these low-priced projects are located), pricing this low is, in some cases, competitive with in-region wind power (see, for example, the text box in Bolinger and Weaver (2013) that compares the economics of the co-located Macho Springs wind and solar projects). This is particularly the case when considering solar's on-peak generation profile, which – as discussed in the text box on page 32, *Estimating PV's TOD Value* – can give solar a TOD pricing advantage of ~$25/MWh relative to wind.[51]
- Although at first glance there does not seem to be a significant difference in the PPA prices required by different solar technologies, it is notable that all of the recent PPAs in the sample employ PV technology. Back in 2002 when the Nevada Solar One (CSP) PPA was executed, PV was too expensive to compete at the wholesale level, but by 2009-2010 when the other three CSP PPAs in the sample were executed, PV pricing had closed the gap. Since then, virtually all new contracts have employed PV technology, while a number of previously-executed CSP contracts have either been canceled or converted to PV technology. CPV was seemingly competitive back in 2010 when the two contracts in the sample were executed, but lack of any new contracts since then (at least within the sample) prevents a more-recent comparison – and is perhaps telling in its own right.[52]

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[51] The levelized PPA prices shown in Figure 15 (and throughout this chapter) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, PV's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the buyer.

[52] That said, SunPower has been quietly rolling out its new low-concentration (i.e., 7 suns) C7 CPV technology, with a 1 MW_{AC} pilot project at Arizona State University (online in early 2013); a contract with Apple for the 20 MW_{AC} Fort Churchill Solar Project (partially constructed as of April 2014) to power its data center near Reno, NV; and a sale of technology to a project in China. At present, no cost or price information is available for these projects.

- Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects. Very large projects often face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as more interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from scale economies in terms of the impact on the PPA price. Perhaps in part as a result, with a few notable exceptions, most of the more-recent PPAs in the sample are for smaller projects, in the 20-50 MW range.[53]
- Not surprisingly, the highest-priced contract in the sample comes from Long Island, which does not enjoy the abundant sunshine of the Southwest (where most of our sample is located – 95% of the total capacity within the PPA sample is located in CA, NV, AZ, or NM), and where wholesale power prices are high due to transmission constraints.

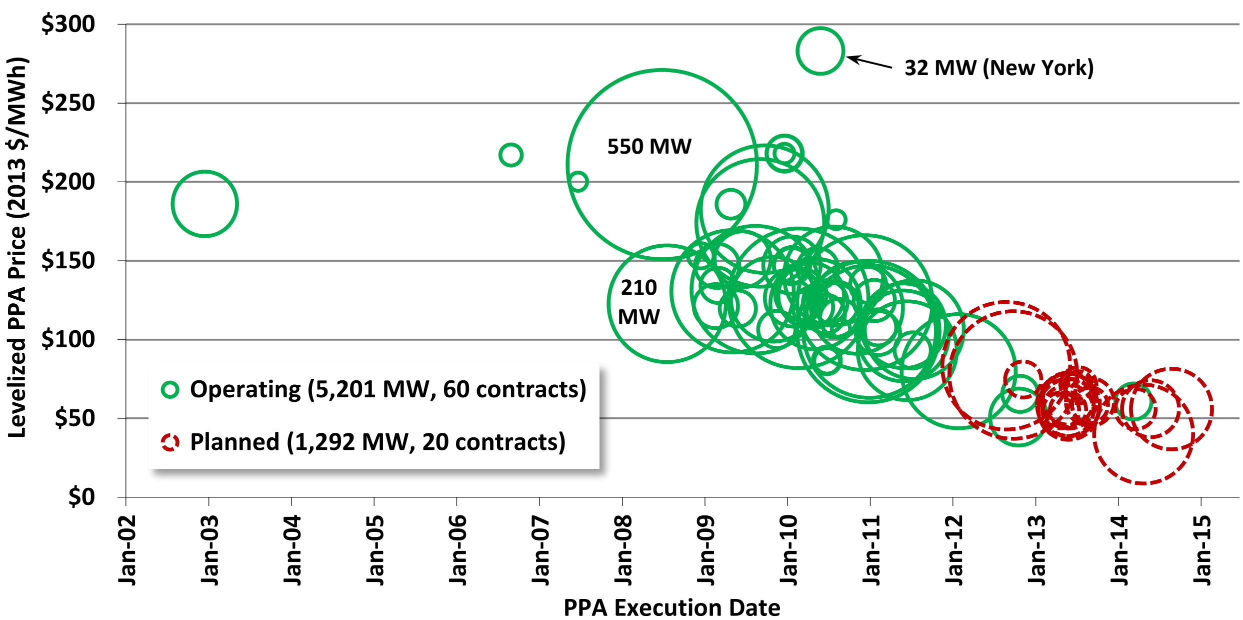

Figure 16. Levelized PPA Prices by Operational Status and PPA Execution Date

Not all of the projects behind the contracts shown in Figure 15 are fully (or even partially) operational, though all of them are still in play (i.e., the sample does not include PPAs that have been terminated). Figure 16 shows the same data as Figure 15, but broken out according to whether (80%) or not (20%) a project has begun to deliver power.[54] Understandably, most of the more-recently signed PPAs in the sample pertain to projects that are still in development or under construction, and have not yet begun to deliver electricity under the terms of the PPA. Given that many of these same PPAs are also the lowest-priced contracts in the sample, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown here (though the text box on page 33 – *Is $50/MWh Solar for*

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[53] This trend towards smaller utility-scale projects (as well as lower PPA prices) could also reflect the fact that many utilities in the Southwest (where 95% of the PPA sample projects are located) have largely met or exceeded state RPS requirements through 2020, and so are not eager to sign PPAs with large projects (if at all).

[54] If a project had begun to deliver power as of June 2014– even if not yet fully operational or built out to its contractual size – it is characterized as "operating" in Figure 16. Only those projects that were still in development or were under construction but not yet delivering power are characterized as "planned."

Real? – suggests that even the lowest PPA prices in our sample can pencil out under the right conditions).[55]

Two-thirds of the contracts in the sample feature pricing that does not escalate (in nominal dollars) over the life of the contract – which means that pricing actually *declines* over time in real dollar terms.[56] Figure 17 illustrates this decline by plotting over time, in real 2013 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts). In addition to the declining real prices over time within each PPA vintage, the steady march downward across vintages is also evident, demonstrating substantial reductions in pricing by PPA execution date.

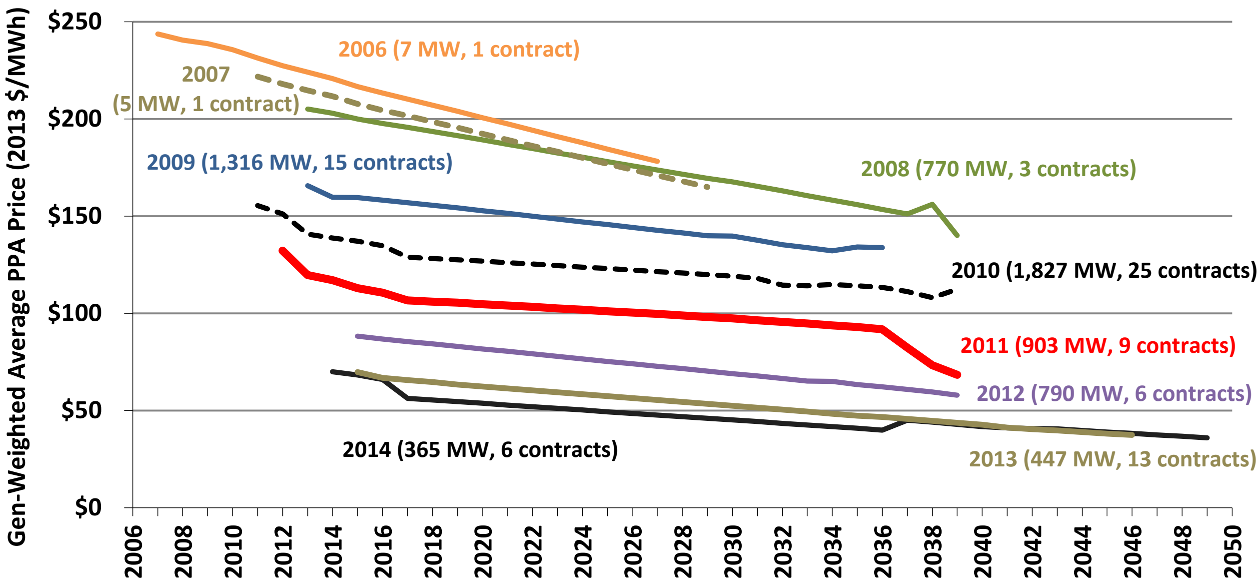


Figure 17. Generation-Weighted Average PPA Prices Over Time by Contract Vintage

To provide a clearer look at the time trend, the blue-shaded columns in Figure 18 simply levelize the price streams shown in Figure 17. Based on this sample, levelized PPA prices for utility-scale solar projects consistently fell by almost $25/MWh per year on average from 2006 through 2013, with a much smaller price decline of ~$5/MWh evident in the limited 2014 sample.[57]

[55] There is a history of solar project and PPA cancellations in California, though in many cases these have involved projects using less-mature technologies (e.g., stirling dish engines, compact linear Fresnel reflectors, and power towers). For PV projects, price revisions are perhaps a more likely risk – e.g., if the solar trade dispute with China were to harm existing module supply contracts.

[56] This compares to just over 50% of the contracts in LBNL's much larger wind PPA price sample (Wiser and Bolinger 2014). By offering prices that are flat or even decline in real dollar terms over long periods of time, wind and solar power can provide a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013).

[57] In Figures 17 and 18, the small sample size in 2011-2014 relative to the much larger sample of contracts signed in either 2009 or 2010 might lead some to conclude that the utility-scale solar market is cooling down. Although there has been some chatter in the trade press to this effect, Figures 17 and 18 should not necessarily be used to support that argument. Rather, the declining sample size in Figures 17 and 18 is likely more the result of two factors: (1) 2014 represents just a partial year, and (2) FERC Electronic Quarterly Reports, which are the principal data source for PPA price data, are only filed once projects are operational and delivering power. As a result, the 2011-2014 sample will likely grow in future years with the build-out of projects that signed PPAs in those earlier years. For example, the 2013 sample size of 13 projects totaling 447 MW has nearly tripled from the 5 projects totaling 135

With levelized PPA prices now hovering around $50/MWh on average (based on the combined 2013/2014 sample), future price declines are likely to be much smaller than in the past.

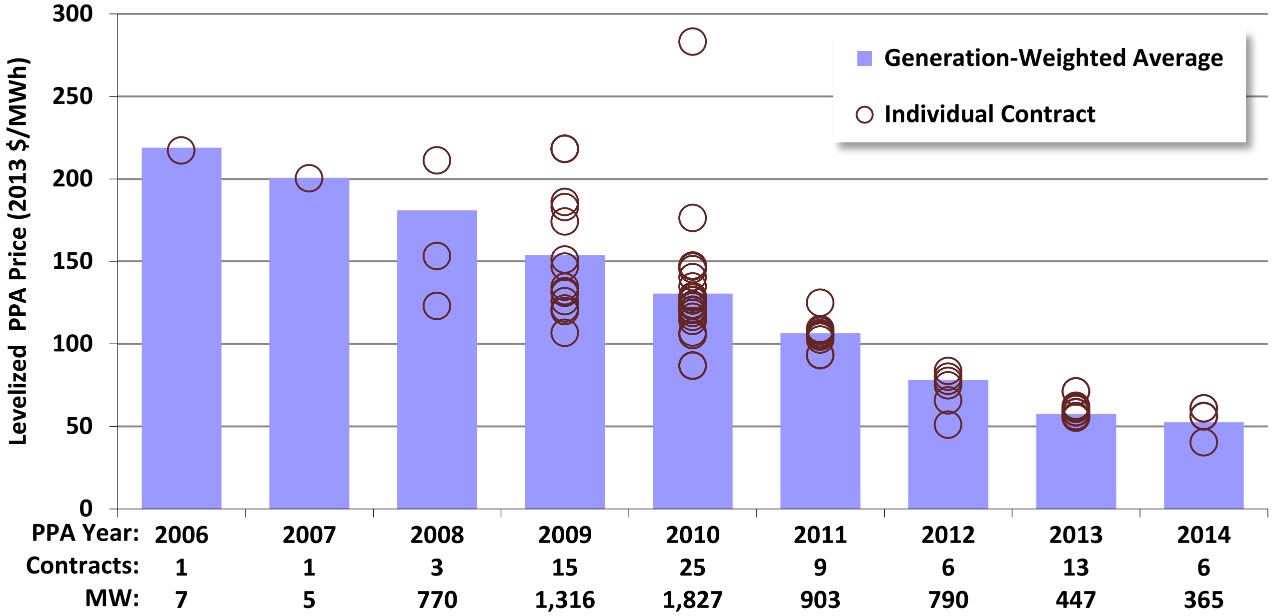


Figure 18. Levelized PPA Prices by Contract Vintage

This strong time trend, along with small sample size in the most-recent years, complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength (though again, 95% of the capacity in the sample is in the Southwest), tracking versus fixed-tilt, and c-Si versus thin-film. To try and control for the influence of time, one could potentially analyze these differences within a single year (e.g., 2009 or 2010, years in which the sample is largest), but doing so would divide the sample to the point where sample size is too small to reliably discern any differences (and any discernible differences would, by now, be four to five years old, calling into question their current relevance).

Furthermore, it is not clear that some of these variables should have much of an impact on PPA prices. For example, several of the most-recent PV contracts in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing.[58] Instead, the time trend – in large part reflecting falling module costs, as well as expectations for even further declines in module and projects costs in the future – has probably been the dominant influence on PPA prices in recent years.

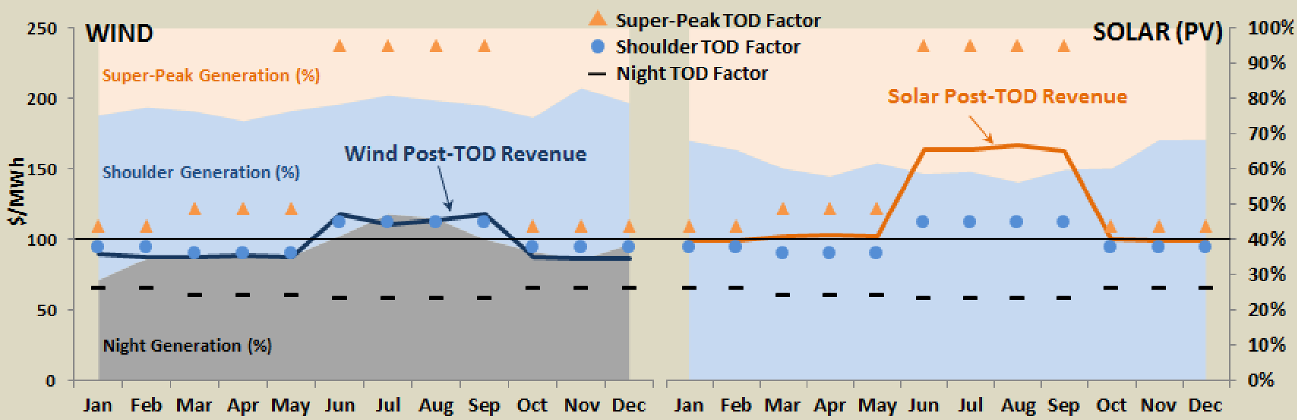
MW that were reported for 2013 in last year's edition (Bolinger and Weaver 2013); similarly, the earlier years of 2009-2012 each also saw their sample size increase from last year (though by relatively smaller amounts than 2013).

[58] This could be because tracking systems add up-front costs to the system (see Figure 6 in Chapter 3) that are recouped over time through greater energy yield (see Figure 12 in Chapter 5), thereby leaving the net impact on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico estimated (based on a review of 216 solar responses to its 2012 Renewable RFP) that the average PPA price benefit of single-axis tracking is just $3/MWh, or less than 4% of a levelized PPA price in the mid-$70/MWh range (O'Connell 2013).

Estimating PV's TOD Value

Two-thirds of the more-than 6,300 MW in the solar PPA price sample presented in Chapter 6 feature prices that vary by time of delivery (both diurnally and seasonally – there are no solar PPAs in the sample that vary prices diurnally but not seasonally or vice versa). This stands in stark contrast to Berkeley Lab's much larger sample of wind project PPAs (>29 GW), where only 13% (of MW) vary prices diurnally, only 8% vary prices seasonally, and only 7% vary prices *both* diurnally *and* seasonally (Wiser and Bolinger 2014). This disparity is partly attributable to geography – a large number of solar projects in the sample are located in the Southwest and sell power within or into California, where time-of-delivery ("TOD") pricing is relatively common, while the wind PPA sample is more-evenly distributed throughout the country. It also potentially reflects, however, the fact that solar tends to benefit from TOD pricing, while wind is often indifferent to or even hurt by it.

The figure below explores the potential TOD value that solar provides relative to wind power, by comparing an actual wind (left graph) and PV (right graph) project, each of which sells energy to PG&E under a PPA with TOD pricing. The shaded background of each graph shows the percentage of generation in each month that falls into one of PG&E's three TOD periods (super-peak, shoulder, or night). Overlaid on top are PG&E's most recent TOD factors (denoted by the triangles, circles, and dashes) applied to a hypothetical base (i.e., pre-TOD) PPA price of $100/MWh for both projects. These TOD factors always penalize (i.e., with a price less than the $100/MWh base price) night-time generation and reward (with a price above the $100/MWh base price) super-peak generation (particularly during summer months), while either penalizing or rewarding (though only minimally in either case) shoulder-period generation depending on the month. The solid lines labeled wind and solar "Post-TOD Revenue" represent the $100/MWh base PPA price as modified by the TOD factors given the underlying generation profile of each project. In other words, these lines represent the revenue that each project would actually earn over the course of the year.



In this real-life example, the PV project fares pretty well, particularly in the summer months, while the wind project tends to more or less hug the $100/MWh base price throughout the year. Over the course of the full year, PV's TOD advantage over wind in this example comes to around $24/MWh on average. In other words, if these PV and wind PPAs both had the same base price of $100/MWh, the PV project would earn $24/MWh more revenue than the wind project each year once the TOD factors had been applied to that base price. Conversely, the PV project could offer a base price that is at least $20/MWh lower than the wind project's base price and still earn roughly the same amount of post-TOD revenue (levelized $/MWh) as the wind project over the course of the year. Although this is a PG&E example, the results are similar for California's other two major utilities (each of which has its own unique TOD periods and factors), and provide at least some indication of the TOD value that solar provides to utilities (at least relative to wind – compared to a constant 24/7 flat block of power, solar's TOD advantage is slightly lower, around $20/MWh).

Of course, PV's TOD advantage is heavily dependent on the TOD factors currently in use, and so should not be considered generalizable or static. For example, Mills and Wiser (2012) use a capacity expansion model to demonstrate that at progressively higher solar penetrations in California, solar's TOD advantage will decrease as the net peak load (i.e., peak load net of solar generation) shifts progressively later into the afternoon and eventually evening, when solar production starts to fade (absent storage). Presumably in such a potential future scenario, TOD factors would no longer favor mid-day generation as much as they currently do, which would, in turn, erode solar's TOD advantage.

Is $50/MWh Solar for Real?

As utility-scale solar PPA prices have dropped over the past few years, seemingly each successive news story on the latest "lowest-price contract ever" has been met with some combination of awe (that solar could really be that cheap), wonder (how it could possibly pencil out), and skepticism (that the project will ever be built at that price). This was the case, for example, in early 2013, when it first came to light that the 50 MW_{AC} Macho Springs project (now operating) would sell electricity at a fixed price of $57.90/MWh for twenty years (this low price was chalked up to New Mexico's 10-year production tax credit). The reaction was similar earlier this year on news that Austin Energy had signed a 20-year contract with a 150 MW_{AC} project in West Texas (where there are no state-level solar incentives) for just under $50/MWh, and likewise when First Solar announced that it was building the first-ever merchant solar project, also in West Texas (where wholesale power prices averaged just $35/MWh in 2013).

Rather than simply rely on the fact that experienced developers are the ones bidding these prices, and that there seems to be considerable depth of field as well – e.g., Austin Energy reportedly received "a substantial number of bids" totaling 1 GW under $55/MWh (Wilder 2014) – this appendix turns to financial modeling to show how $50/MWh solar (without state incentives) might pencil out. The relatively simple pro forma model assumes that the project is financed with a combination of sponsor equity and long-term project-level debt, and that the sponsor has sufficient tax appetite to fully use tax losses and credits in the years in which they are generated. Drawing upon empirical data presented elsewhere in this report, as well as representative financing parameters pulled from other studies (Bolinger 2014), the most important model inputs are shown in the table below for three hypothetical projects labeled "good," "better," and "best" to emphasize the aggressive nature of all three projects relative to our empirical project sample.

	Best	**Better**	**Good**
Installed Cost ($/$W_{AC}$)	1.80	1.85	1.90
Capacity Factor (AC)	35%	33%	30%
Annual Degradation	0.5%	0.5%	0.5%
Total Operating Expenses ($/$kW_{AC}$-year)	20	27	35
Sponsor After-Tax Internal Rate of Return (IRR)	8%	10%	12%
Term Debt Interest Rate	5.0%	5.5%	6.0%
Debt Term (years)	20	17	15
Debt Service Coverage Ratio (P50)	1.30	1.35	1.35
Resulting 20-Year PPA Price (flat, no escalation)	**$38.6/MWh**	**$49.8/MWh**	**$65.0/MWh**

For example, the modeled range of installed costs ($1.80-$1.90/W_{AC}) falls entirely outside of the range of backward-looking empirical data presented in Chapter 3, but is not too far below the low end of the range presented in Figure 5, nor from PNM's assertion that it will build two 20 MW_{AC} projects in 2015 for $1.98/$W_{AC}$. The capacity factor range is consistent with projects located in the highest resource bin of Figure 12 and using single-axis tracking. The degradation rate of 0.5%/year is a fairly standard assumption, while the operating expense range (intended to encompass *all* operating costs – not just O&M – and assumed to escalate in nominal dollars at 2%/year) is feasible in light of data presented in Chapter 4. The four financing parameters come from Bolinger (2014).

While certain assumptions for the "best" project are no doubt aggressive (e.g., $1.80/$W_{AC}$, 8% IRR, $20/kW-year total OpEx), the less-aggressive "better" project still shows that if a project can be built for $1.85/$W_{AC}$ before 2017 (still aggressive), then it should be able to achieve a 20-year PPA price (flat in nominal dollars) of less than $50/MWh based on project parameters that are already being achieved today (e.g., 33% net capacity factor, 5.5% 17-year debt), all the while earning a sponsor with tax appetite a 10% after-tax IRR (the IRR quickly reaches 8.6% at the end of year six, and then remains above 8% until the debt is fully retired in year 17, after which it increases to 10% by the end of year 20). Mixing and matching various assumptions from the three projects could similarly break the $50/MWh threshold in certain combinations (e.g., the "good" installed cost and "best" capacity factor assumptions combined with "better" assumptions for everything else yields $47.9/MWh). In other words, a project need not excel in every aspect in order to hit $50/MWh. In addition, state-level incentives (not modeled here) could help to sweeten the deal.

In short, although $50/MWh solar may not generate as much of a return as sponsors might like, financial modeling – not to mention the recent spate of market announcements – suggests that it is indeed feasible under the right conditions (including access to the 30% federal investment tax credit).

7. Conclusions and Future Outlook

Other than the SEGS I-IX parabolic trough CSP projects built in the 1980s, virtually no utility-scale PV, CPV, or CSP projects existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in 2013 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including storage – either achieving commercial operations or entering the commissioning phase. Although the operating history of many these newer PV, CPV, and CSP projects is still very limited, a critical mass of data nevertheless enables empirical analysis of this rapidly growing sector of the market.

This second edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since the 2007-2009 period (but perhaps showing signs of slowing), relatively modest O&M costs, solid performance with improving capacity factors, and record-low PPA prices of around $50/MWh in some cases (again, with the steady decline over the years perhaps showing signs of slowing). Meanwhile, the other two utility-scale solar technologies – CPV and CSP – have also made solid strides in recent years, but are nevertheless finding it difficult to compete with increasingly low-cost PV.[59]

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry over the next few years. Specifically, Figure 19 shows the amount of solar power (and, in the inset, other resources) currently working its way through 37 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country.[60]

These data should be interpreted with caution: although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built.[61] That said, efforts have been made by the FERC, ISOs, RTOs,

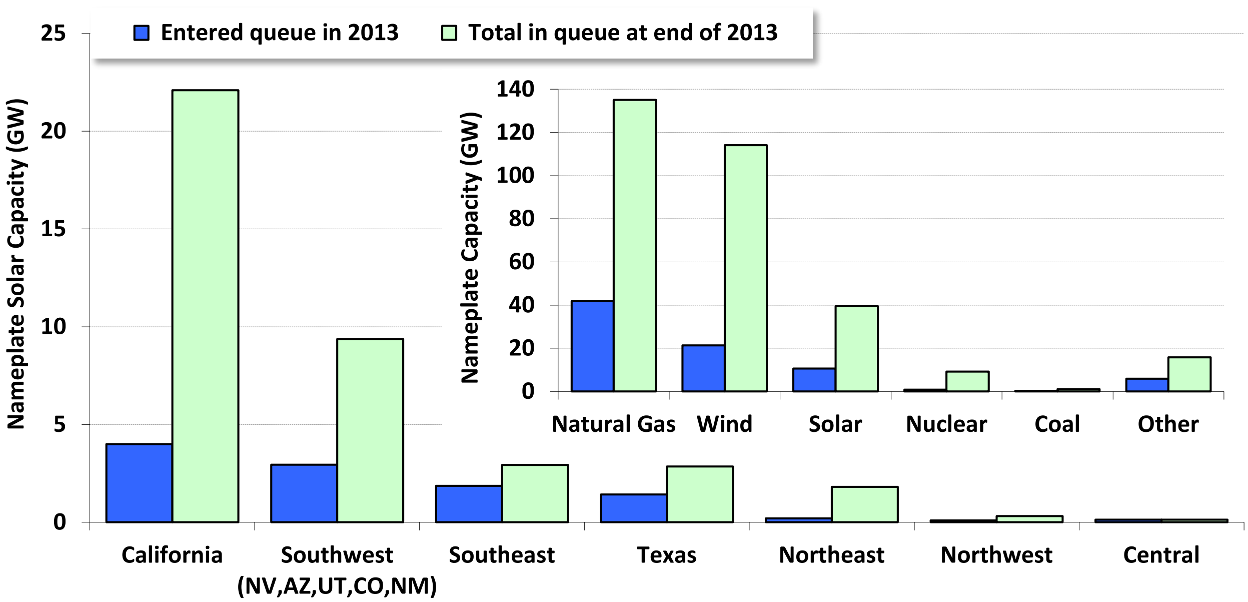
[59] Avian mortality has also emerged as an unexpected potential threat to power tower technology in particular.

[60] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas, Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Imperial Irrigation District, Southern Company, Nevada Power, PacifiCorp (Mountain region), and 26 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 90% of the U.S. total. Figure 19 only includes projects that were active in the queue at the end of 2013 but that had not yet been built; suspended projects are not included.

[61] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences balance out on net.

and utilities to reduce the number of speculative projects that have, in recent years, clogged these queues.

Even with this important caveat, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2013, there were 39.5 GW of solar power capacity (of any type – e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report – ***roughly eight times the installed utility-scale solar power capacity in our entire project population at that time.*** This 39.5 GW (10.7 GW of which first entered the queues in 2013) represented nearly 13% of all generating capacity within these selected queues at the time, in third place behind natural gas at 43% and wind at 36% (see Figure 19 inset).



Source: Exeter Associates review of interconnection queue data

Figure 19. Solar and Other Resource Capacity in 37 Selected Interconnection Queues

The larger graph in Figure 19 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides. Perhaps not surprisingly (given the map of solar resource and project location shown in Figure 3, earlier), 80% of the total solar capacity in the queues at the end of 2013 is within California (56%) and the Southwest region (24%), followed by 7% each in the Southeast and Texas (ERCOT), and 5% in the Northeast.

Though not all of the planned projects represented within Figure 19 will ultimately be built, presumably many of those that are built will most likely come online prior to 2017, given the scheduled reversion of the 30% investment tax credit ("ITC") to 10% at the end of 2016. Even if *only half* of the solar capacity in these queues meets that deadline, it will still mean an unprecedented amount of new construction in 2014, 2015, and 2016 – as well as a massive amount of new data to collect and analyze in future editions of this report.

A note on the sources of data used in this report:

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources), broken out by data set:

- ***Technology Trends (Chapter 2):*** Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), Google Earth, trade press articles
- ***Installed Prices (Chapter 3):*** Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, trade press articles, and data previously gathered by NREL
- ***O&M Costs (Chapter 4):*** FitchRatings (projections only); FERC Form 1 and state regulatory filings (actual/empirical data)
- ***Capacity Factors (Chapter 5):*** FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings
- ***PPA Prices (Chapter 6):*** FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

In addition, the individual reference documents listed below provided additional data and/or helped to inform the analysis.

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Acknowledgments

The authors thank Minh Le, Elaine Ulrich, Christina Nichols, and Ammar Qusaibaty of the U.S. Department of Energy's Solar Energy Technologies Office for their support of this work. The authors would also like to thank Justin Baca and Aaron Holm of the Solar Energy Industries Association (SEIA) for maintaining and sharing SEIA's list of major solar projects in the U.S. Thanks also to the following individuals for reviewing earlier drafts of this report: Amory Lovins (Rocky Mountain Institute), Daniel Boff and Adam Cohen (U.S. Department of Energy), Michael Rogol (PHOTON Consulting), and Ryan Wiser (LBNL). Of course, any remaining errors or omissions are the sole responsibility of the authors.

Cover photos courtesy of Sempra U.S. Gas & Power, NREL, and BrightSource Limitless.

The work described in this report was funded by the U.S. Department of Energy's Solar Energy Technologies Office, within the Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

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