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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION

Docket No. E-01345A-13-0248

Comments of First Solar

First Solar, Inc. ("First Solar") respectfully submits these comments to the Arizona Corporation Commission ("Commission") on the Utilities Division Staff ("Staff") report docketed on September 30, 2013 ("Staff Report").

First Solar agrees with Staff that increasing levels of distributed generation ("DG") penetration will result in greater cost-shifting to customers without DG systems. As discussed in more detail below, First Solar recommends that the Commission adopt the second alternative, "LFCR DG Premium for All New DG Customers" ("Staff Alternative 2"), set forth in the Staff Report for the following reasons:

- First, Staff Alternative 2 provides a fair method of addressing the cost shifting associated with net-metering ("NM") going forward.

- Second, by essentially using the avoided cost of utility scale solar as a proxy to determine the "DG Premium," Staff Alternative 2 ensures that Arizonans do not overpay for incremental rooftop solar capacity.

- Third, Staff Alternative 2 allows for regular and relatively straightforward updates of the utility-scale cost proxy to ensure that the "DG Premium" fairly reflects evolving market conditions and fluctuations in the cost of solar PV systems going forward.

- Finally, the proposal to grandfather existing rooftop installations under present NM rules ensures that the settled expectations of subscribing customers are acknowledged and protected.

Staff Alternative 2 provides a well-reasoned, market-based approach to addressing the cost-shift caused by NM and fairly balances the interests of all stakeholders.

As discussed in First Solar's comments submitted in this docket on September 18, 2013, First Solar recommends that the Commission's review of net metering should be completed expeditiously and not postponed until the next Arizona Public Service ("APS") rate case in 2015. First Solar continues to support near term resolution of this issue for the reasons elaborated in its earlier comments. (Attached hereto as Exhibit A.)

The Staff Report

The Staff Report leaves no doubt that net metering as it is currently configured results in inequitable cost-shifting that will only be exacerbated as DG employing NM increases.

Specifically, the Staff Report recognizes that "with increasing levels of DG penetration, the potential of shifting costs from customers with DG systems to those customers without such systems becomes apparent." (Staff Report, p. 4). Staff adds that "[t]he magnitude and significance of this cost shift increases as more and more DG systems are added to the utility's system." (Staff Report, p. 5).

Nevertheless, the Staff Report rejects the two alternatives advanced by APS to address this problem in its submission on July 12, 2013 and recommends that the Commission should postpone any action to address cost shift issues caused by NM until the next APS rate case in 2015. According to the Staff Report, "[d]evelopment of equitable rate structures that address the inherent disconnect between [net metering] and volumetric rates can best be accomplished in a general rate case." (Staff Report, p. 6).

Recognizing, however, that the Commission may prefer to address the cost shift associated with NM now, the Staff Report also advances two solutions which could be implemented on a revenue-neutral basis prior to the next APS rate case. Staff also recommends that existing installations benefiting from NM be grandfathered.

Timing of Commission Action on Net Metering

Staff has recommended that the Commission postpone its decision addressing NM until the next APS rate case in 2015. First Solar does not have a view on the legal merits of this issue (*i.e.*, the arguments advanced in SEIA's motion filed in this docket). However, to the extent that the Commission has the flexibility to address the NM issue in advance of APS' next rate case, it should do so now for the following reasons.

First, as the Staff Report recognizes, NM, as it is currently configured, results in a shift of costs to customers who do not benefit from NM. The Staff Report also recognizes that this inequity will only grow over time if it is not addressed. During that time, under business as usual circumstances, the number of rooftop PV installations are likely to increase at least at the current rate of 500 systems a month, as estimated by APS, further exacerbating the problem identified in the Staff Report.

Furthermore, deferring the decision to address these issues for two years may actually compound the problem exponentially. Experience in Germany and other countries shows that changes to solar policies that are signaled far in advance of when they actually take effect often result in the exact outcomes that the change in policy was intended to prevent. In Germany, scheduled feed-in-tariff ("FIT") reductions intended to moderate PV capacity over time actually produced significantly higher than expected volumes at higher rates as subscribers anticipated the future curtailment of subsidies. Because it is reasonable to assume that market participants in Arizona will behave rationally, one can anticipate a similar "run on the net metering bank" between now and 2015 if there is an expectation that NM policy will be revised to address the concerns raised in the Staff Report at that time. Moreover, fundamental fairness will likely require that customers subscribing under existing NM arrangements will be grandfathered, perpetuating the inequity described in the Staff Report at significantly higher levels of penetration.

It is simply more sensible to try to resolve the NM issues today—with an understanding that future, more moderate changes may be necessary—than to postpone taking action for two years in the hope that a perfect solution will be developed in the meantime.

Lost Fixed Cost Recovery

The Staff Report recommends two alternatives for modifying the existing NM rules. Both alternatives would require NM customers to make additional payments into APS' Lost Fixed Cost Recovery ("LFCR") adjustor mechanism with an offsetting reduction in LFCR payments by non- subscribing customers. First Solar supports using the LFCR mechanism as a revenue-neutral means of reducing the cost shift associated with NM identified in the Staff Report.

Staff Alternative 2: LFCR DG Premium for All New DG Customers

Staff Alternative 2 has considerable merit. Because the proposal links NM economics to the cost of utility-scale solar facilities, the price that APS would pay for electricity generated by rooftop PV should not exceed the cost that APS would incur in procuring significantly less expensive electricity from utility scale solar facilities. Essentially, this is an avoided cost analysis that simply compensates NM rates at the cost that APS avoids in procuring the alternative, i.e., utility scale solar. This approach ensures that Arizonans pay no more for solar capacity than the least cost solar alternative in the market. Additionally, because the price of utility scale solar acquired through Power Purchase Agreements ("PPA") is determined by the market, Staff's proposal ensures that NM compensation will be adjusted as PV prices decrease. Finally, linking compensation of DG solar to utility scale solar ensures that the non-fuel related benefits of solar are also taken into consideration implicitly.

Pricing of Utility-Scale Projects

Although First Solar agrees with the fundamental principal underlying Staff Alternative 2, Staff's estimated price for utility scale solar PPA's in Arizona of 10 cents/kWh is significantly higher than current market clearing prices for utility scale solar in the Western U.S. In fact, Staff recognizes that this price is conservative.

The Lawrence Berkeley National Laboratory ("LBNL") has recently issued a report, *Utility-Scale Solar 2012, An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*[1] (attached hereto as Exhibit B) (the "LBNL Report"), that provides data on utility-scale PPAs in the U.S. from 2006 through 2012. *Id.,* at pp. 19-27. Figure 13 in the LBNL Report shows the continuously falling prices of solar PPAs between 2006 and 2012 both by technology type and project size. The ten PPAs executed in 2012 and 2013, most of which were for small- to medium-sized projects, were all priced well below 10 cents/KWh, with all of the 2013 projects being much closer to 5 cents than 10 cents. *See also*, Figure 15.[2]

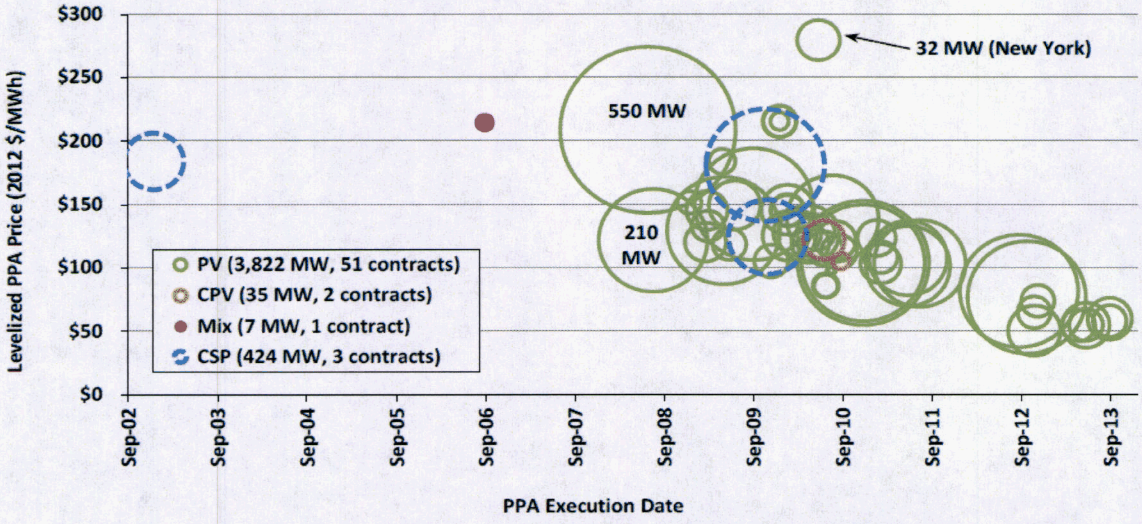

Figure 13. Levelized PPA Prices by Technology and PPA Execution Date

[1] Lawrence Berkeley National Laboratory, "Utility-Scale Solar 2012, An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States." September 2012. Authors: Mark Bolinger and Samantha Weaver.

[2] While the LBNL Report does not identify the location of the solar projects included in its analysis, Arizona has some of the best insolation in the United States and would certainly not be disadvantaged relative to projects in California or other Southwestern states where most of the identified projects are likely located.

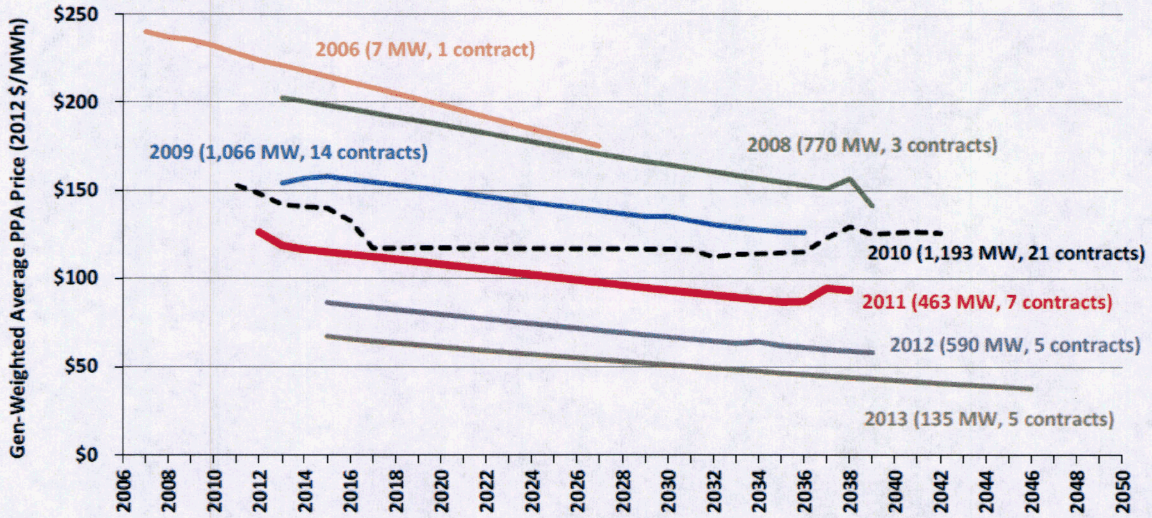

Figure 15. Generation-Weighted Average PPA Prices Over Time by Contract Vintage

The LBNL Report concludes:

> *Driven primarily by lower installed project prices (which, in turn, have been driven primarily by declining module prices), levelized PPA prices have fallen dramatically over time, by $25/MWh per year on average. Some of the most-recent PPAs in the West have levelized PPA prices as low as $50-60/MWh [in 2012]. . ..*

[citation (emphasis supplied)]. The data provided by the LBNL report suggest, and First Solar's market experience confirms, that PPA prices of 10 cents/KWh are outdated, and that current clearing prices are anywhere from 30 to 50% lower than the figure estimated in the Staff Report. Staff's proposal should be updated accordingly.

Regular Updating of the "DG Premium"

The market-based equation that the Staff has proposed to calculate the "DG Premium" in Staff Alternative 2 can be adjusted regularly with the latest pricing data for utility-scale projects. This allows for taking future PV price reductions into consideration and thus provides for greater accuracy when calculating the DG Premium. This is a considerable advantage over any other mechanism that locks in a premium for long periods of time and that would consequently result in larger adjustments over longer intervals.

In contrast to Staff Alternative 2, compensation for DG electricity as currently set under Arizona's NM policy *increases* over time—even as solar costs *decrease*—because it is determined by retail prices that have increased historically as the cost of fuel and overhead charges included in retail rates have risen. Thus, ratepayers will pay *more* for PV electricity generated from retail rooftops over time even though solar costs have decreased significantly and are projected to continue doing so.

Staff Alternative 1: LFCR Flat Charge for All New DG Customers

Staff Alternative 1 does not benefit from the attributes of Staff Alternative 2.

The requirement that all new APS DG customers be required to pay the monthly LFCR Flat Charge rather than the percentage of bill LFCR--both currently available to all APS customers--would address some of the cost shift of NM. However, it has considerable drawbacks compared to Staff Alternative 2 and consequently Staff Alternative 2 should be preferred.

First, the difference between the LFCR Flat Charge and the percentage of bill LFCR was not designed to represent the additional cost of DG and is not an appropriate proxy. It is an arbitrary figure.

Second, because the LFCR Flat Charge is in no way linked to the price of lower cost utility-scale PPAs, Staff Alternative 1 is not as likely to ensure that customers do not overpay for solar electricity.

Finally, any future changes to the LFCR Flat Charge would not reflect evolving market conditions.

Grandfathering

First Solar agrees with Staff's recommendation that PV projects currently benefitting from NM should be grandfathered and that the projects themselves, rather than APS customers who currently own or lease the projects, should be the beneficiaries of the grandfathering.

Conclusion

Utility customers should have the right to install PV systems on their roofs. Conversely, utility customers who do not have PV systems on their roofs should not have to pay more for the solar electricity generated from those rooftop systems than the lowest cost solar alternative in the market. Staff Alternative 2 fairly balances both expectations by lowering the cost of procuring solar energy for all APS customers while preserving choice for those customers who desire it.

Sincerely,

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EXHIBIT A

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IN THE MATTER OF THE APPLICATION)
OF ARIZONA PUBLIC SERVICE COMPANY) Docket No. E-01345A-13-0248
FOR APPROVAL OF NET METERING)
COST SHIFT SOLUTION)
)

Comments of First Solar

First Solar, Inc. ("First Solar") respectfully submits these Comments to the Arizona Corporation Commission ("ACC") to provide its perspective on the Arizona Public Service Company ("APS") net metering cost shift solution application.

On November 1, 2006, after a three-year review process, the ACC adopted a renewable energy standard ("RES"). The RES requires Arizona's regulated utilities to generate 15 percent of their energy from renewable resources by 2025 in order "to generate 'clean' energy to power Arizona's future."[1] Given Arizona's potential renewable generation resources, it was clear that this RES goal was likely to be met largely by solar electricity generation.

Adopting the RES was a forward-looking step. In 2006, the solar industry was still nascent. There was very little experience to guide predictions of solar cost reduction trajectories, solar's growth path, the capabilities of specific solar technologies, or solar applications that made the most sense to meet policy goals.

At the time, only 140 MW of solar photovoltaic ("PV") installations had been installed in the U.S. as a whole, of which 50 megawatts ("MW") was considered residential and 90 MW non-residential (including government buildings, retail stores, utility installations,

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[1] Arizona Corporation Commission (ACC). "Commissioners Approve Rules requiring 15 Percent of Energy from Renewables by 2025." Press Release. 1 Nov 2006.

and military installations)[2]. The largest PV systems in the U.S., all located in California, were no larger than 1 MW in size. Even Germany, which led the world in PV in 2006, had not yet reached 1,000 MW of total installations. In Arizona, just over 2 MW of PV capacity was installed in 2006, for a total of 19 MW of PV installed in Arizona by the end of that year.[3]

The cost of PV in 2006 was on the order of $8-9.00/ installed watt,[4] and "utility scale" PV systems effectively did not exist.

Given the relative inexperience with solar and its high cost both in general and in Arizona specifically, it made sense at the time to adopt policies and initiate a range of programs and generous subsidies to gain experience across a variety of solar options. These included a 30% distributed generation ("DG") carve-out as part of the RES, an upfront subsidy from APS of $3.00/ watt installed for rooftop systems, and net energy metering ("NEM"). Since 2006 the Commission has adopted new rate basing methods which have helped facilitate new solar resources.

The solar industry has matured significantly since 2006 and installations in Arizona have grown exponentially: 1,097 MW of solar-generating facilities were installed in Arizona by the end of 2012,[5] making Arizona second in the nation only to California. Even more significantly, the price of PV has fallen precipitously. Recently released data by the Solar Energy Industry Association and GTM Research show an average cost/installed watt for residential rooftop PV of $4.81 and the average cost/installed watt for utility scale systems as $2.10.[6] No one could have predicted these cost reductions two, much less seven, years ago. First Solar has consistently said that as the cost of solar comes down, so must solar subsidies. For the solar industry to be sustainable and maintain its public and political support, subsidies should be appropriate to the economic, environmental and societal value provided by solar energy. In locations where it is not yet possible to compete entirely without subsidies, we should aim to achieve solar policy goals at the lowest overall cost with the intent of creating a level playing field with other energy sources over time.

In light of the experience gained over the past seven years and the significant cost reductions during that time period, it is appropriate to review and revise the programs and

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[2] U.S. Department of Energy. Energy Efficiency & Renewable Energy (EERE) Network News. "Report: U.S. Solar Cell Market Increased 33 Percent in 2006". 28 March 2007. Web. 19 September 2013.
[3] Sherwood, Larry. "US Solar Market Trends 2007." Interstate Renewable Energy Council. August 2008: pp. 15 & 9. In 2006, a 1 MW solar thermal electric plant was constructed in Arizona. This was the first new U.S. solar thermal power plant to be constructed in 15 years. Nine solar thermal electric plants with a capacity of 354 MW were constructed in California from 1985 to 1991.
[4] Barbose, Dargouth, Weaver and Wiser. "Tracking the Sun IV, An Historical Summary of the Installed Price of Photovoltaics from 1998 to 2012." *Lawrence Berkeley National Laboratory*. July 2013.
[5] Solar Energy Industries Association (SEIA). "U.S. Solar Industry Year in Review 2009." 15 April 2010.
SEIA/GTM Research. "U.S. Solar Market Insight® Report: 2012 Year in Review: Executive Summary." 2013.
[6] SEIA/GTM Research. "U.S. Solar Market Insight® Report: Q2 2013: Executive Summary." 2013: pp. 14-15. It should be noted that these figures represent national averages based on data collected by SEIA and GTM Research, which likely does not include all price points in the market. Further, as noted in the report, actual pricing will vary by geography and jurisdiction.

subsidies put in place in 2006 in order to reflect current market realities and to provide both value and continued solar growth for Arizona, and it is reasonable for the ACC to conduct such a review.

For example, in 2006, when the ACC proposed a distributed generation carve-out, community solar programs that achieve most, if not all, of the DG policy goals were not even an option for consideration. While there are several models of community solar programs, in general they are smaller installations (<10MW) that are connected to the distribution or sub-transmission systems. Customers can either directly purchase energy from these facilities or customers can own a share of the installed capacity. These community solar programs allow all electricity consumers, not just those who actually own suitable rooftops, to participate in and take advantage of solar generation. In addition to being available to a broader range of ratepayers than physical rooftop PV installations, these "community" installations can be strategically sited in locations to address distribution and/or transmission constraints and also can take advantage of the benefits of scale typically associated with "utility-scale" systems. And yet, notwithstanding these benefits, community solar programs have not been as popular as rooftop solar options because, in most instances, they do not benefit from NEM. This asymmetric treatment of community solar and rooftop solar should be remedied—for example by revising rooftop NEM programs—so that they both compete on a level playing field. Only then will all solar resources be developed on a least-cost basis.

Both community solar and rooftop solar have enjoyed huge cost reductions during the past several years. Yet, in contrast to community solar development, the growth of the rooftop segment has far exceeded expectations. This difference in growth rates has been primarily due to new financing models and the generous embedded subsidies asymmetrically provided to rooftop solar in NEM, which has now become the principal policy driver of rooftop PV. As a result, the total cost of rooftop PV on the utility system has become much higher than could have been foreseen, placing an unanticipated burden on utilities and ratepayers.

Since 2006, we have also gained significant experience with utility-scale solar programs. Whereas in 2006 the largest ground mounted PV projects in the country were no larger than 1 MW in size, today First Solar alone has commissioned over 1600 MW of grid-connected PV systems in North America and is advancing a 3,000 MW pipeline of U.S. projects, including the 290 MW Agua Caliente project, in Yuma County, which will be completed this year. First Solar's systems range in size from relatively small, 10 MW facilities to two 550 MW facilities located in California. The utility-scale power plants that First Solar constructs today support grid stability and reliability through grid-friendly features such as voltage regulation, active power control, ramp-rate control, fault ride-through, frequency control and others—benefits that can also be provided by smaller-scale community power plants. A plant-level control system that controls a large number (in the hundreds) of individual inverters to affect plant output at the grid connection point is a key enabler. These grid benefits of larger scale solar were certainly not foreseen in 2006. In addition, increasingly reliable forecasting also makes solar from utility-scale systems a much more predictable generator of electricity. Furthermore, these larger scale systems can provide all of these attributes, as well as the environmental benefits associated with all solar applications, at a significantly lower cost per kilowatt hour due to the cost economies associated with large scale.

The 2006 RES and the policies adopted to achieve the RES mandate have successfully facilitated the growth and maturation of solar in Arizona. The past seven years have also provided valuable experience to help guide today's decisions about the next phase of RES-related policies. The ACC can now use real experience and data to evaluate the various solar options available and their costs and benefits, something that was not possible in 2006, and use that information to guide its decision about NEM.

The objective of this next phase of solar policy should be to maximize the solar benefit per dollar spent; fairly compensate for solar generation without discriminating among various solar applications; increase access to green electricity for all ratepayers; and reduce the cost of achieving Arizona's renewable energy goals. The current review and proposed revision of NEM have been criticized by some as anti-solar. We believe just the reverse to be true. Unless the regulatory structure is adjusted to incorporate current market realities, the unforeseen economic impact of NEM may result in an indiscriminate backlash against solar of all sizes and types. The issue is not *whether* Arizona should continue to develop large amounts of new solar generation but rather *how* Arizona should shape and fine-tune its policies to achieve this objective equitably and at lowest cost. The ACC needs to take the lead to develop a solar plan that will create a robust and sustainable solar industry by developing the appropriate solar regulatory structure for the future, not the past. This plan should consider all the salient operational, financial, market and resource planning factors in order to meet customers' solar needs at the lowest average cost for ALL customers. We believe that the ACC has the full range of information needed to make a decision now. It is important that this review of policy proceed expeditiously and not be deferred.

Sincerely,

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EXHIBIT B

LBNL-6408E

Utility-Scale Solar 2012

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

Authors: Mark Bolinger and Samantha Weaver

Lawrence Berkeley National Laboratory

September 2013

BERKELEY LAB

SunShot
U.S. Department of Energy

LBNL-6408

Utility-Scale Solar 2012

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

Authors: Mark Bolinger and Samantha Weaver
Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory

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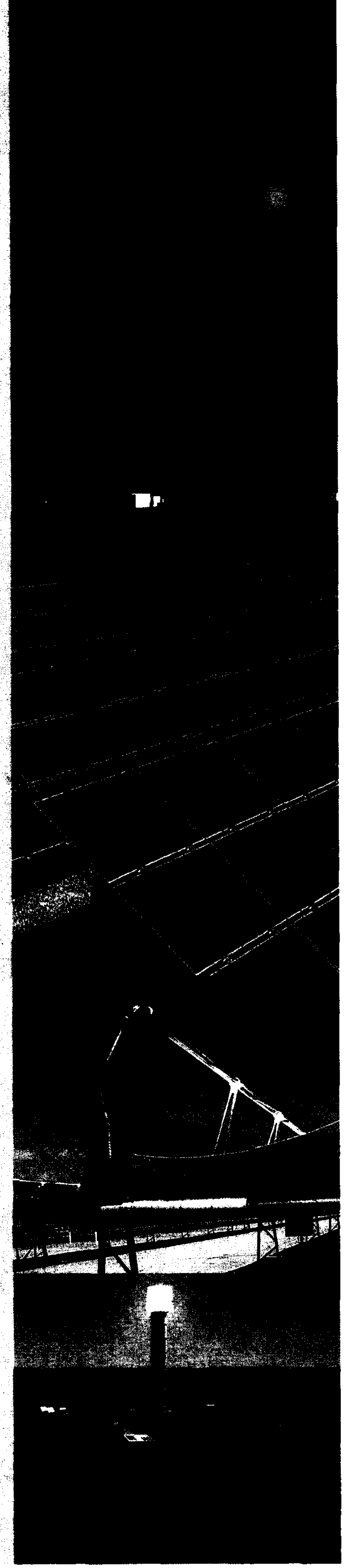


Executive Summary

With a critical mass of new large-scale or "utility-scale" solar projects (including PV, CPV, and CSP) now online and in some cases having operated for a number of years (generating data in addition to electricity), the utility-scale sector of the solar market is ripe for analysis. This report, which is envisioned to be the first in an ongoing annual series, meets this need through in-depth, 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 U.S. (where utility-scale is defined as any ground-mounted project larger than 2 MW_{AC}). As such, it provides a more-integrated and holistic view of the market than is commonly found.

Given the nascent state of the utility-scale solar market, data availability is still, in places, an issue in this inaugural edition. Moreover, 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, given that a number of large CSP projects are currently under construction. Despite these challenges, the report nevertheless paints a coherent picture that will be refined, enriched, and solidified over time as more data become available. Until then, some of the more-notable findings from this year's report include the following:

- ***Installed Prices:*** Installed PV project prices have fallen by nearly one-third since the 2007-2009 period, from around $5.6/$W_{AC}$ to $3.9/$W_{AC}$ on average for projects completed in 2012 (with some projects higher and others lower). Most of the decline has been concentrated among projects using c-Si modules, as the gap between c-Si and thin-film steadily eroded over this period. In response to falling c-Si module prices, there has been a marked increase in the proportion of projects using c-Si (rather than thin-film) modules.
- ***O&M Costs:*** Although O&M cost data are extremely limited at present, what little empirical data exist 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 (for parabolic trough) are higher, presumably due to the plumbing and thermal components, and come in around $60/$kW_{AC}$-year.
- ***Capacity Factors:*** Like insolation levels, PV capacity factors vary by region. They also vary depending on whether a project is installed at a fixed-tilt or uses a tracking device, with single-axis trackers able to achieve capacity factors in excess of 30% in some of the better locations (thus confirming the industry rule of thumb that single-axis tracking provides a 20% boost in output). In lieu of trackers, and enabled by the sharp decline in module prices, some projects have instead opted to oversize the PV array relative to the capacity rating of the inverters as a way to boost capacity factor. On the CSP side of the market, parabolic trough systems that have been operating in the U.S. for more than 20 years are still (in 2012) achieving capacity factors in excess of 20% (solar portion only, no storage), which is comparable to newer trough projects. Meanwhile, a pilot project for power tower technology has underperformed relative to expectations, but several much larger power tower projects under construction will soon test that technology on a truly commercial scale in the United States (several commercial power tower projects have been operating in the Mediterranean region for several years).

- ***PPA Prices:*** Driven primarily by lower installed PV project prices (which, in turn, have been driven primarily by declining module prices), as well as expectations for further cost reductions in future years, levelized PPA prices have fallen dramatically over time, by $25/MWh per year on average. Some of the most-recent PPAs (for PV projects) in the West have levelized PPA prices as low as $50-60/MWh (in 2012 dollars), which, in some cases, is competitive with wind power projects in that same region. Solar appears to be particularly competitive when considering its time-of-delivery pricing advantage over wind (roughly $25/MWh in California at current levels of penetration).

1. Introduction

Until the mid-2000s, large-scale solar projects primarily consisted of (and the corresponding term "utility-scale solar" most often referred to) concentrating solar power ("CSP") projects using parabolic trough technology to produce steam and generate electricity; a number of such projects have been in operation in the United States since the 1980s. More recently, however, utility-scale solar increasingly refers to large, centralized photovoltaic ("PV") projects that sell wholesale electricity directly to utilities, rather than displacing on-site consumption (as has been the more-traditional application for PV). In the United States, utility-scale has been the fastest-growing sector of the PV market, and now dominates: 2012 marked the first year that it captured the largest share of the overall PV market in terms of new MW installed, a distinction that is projected to continue through at least 2016 (GTM/SEIA 2013). Moreover, although a number of new CSP projects – featuring not just parabolic troughs but also newer technologies including compact linear Fresnel reflectors and power towers – have been built in recent years or are currently under construction, PV has largely surpassed CSP as the preferred utility-scale solar technology, with nearly five times as much PV as CSP capacity either currently operating, under construction, or under development in utility-scale configurations (SEIA 2013).

This 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. 2013), 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 tend to be unavailable publicly, and also less meaningful,[1] within the residential and commercial sectors.

The operating history of utility-scale PV in the U.S. has been brief, however. According to GTM/SEIA (2013), more than 2.8 GW_{DC} of the 3 GW_{DC} of utility-scale PV online in the U.S. at the end of 2012 were built in 2010 (0.27 GW_{DC}), 2011 (0.76 GW_{DC}), and 2012 (1.78 GW_{DC}). The back-loaded nature of this progression, along with ongoing strong deployment in 2013 and

[1] 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 less useful, and often reflect the "price to beat" more so than the lowest possible price.

beyond, suggests that while there are currently useful data to analyze, data availability will grow rapidly in the coming years.

As such, this report is the first 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 inaugural edition, we define "utility-scale" as any ground-mounted project with a nameplate capacity of 2 MW_{AC} or larger. 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 concentrating photovoltaic ("CPV") and CSP projects are also included where data are available.

The report proceeds to analyze the data in a logical order, starting with up-front installed prices in Section 2, then moving on to operating costs and performance (i.e., capacity factor) in Sections 3 and 4, all of which influence the PPA prices that are reported and analyzed in Section 5. Data sources are diverse and vary 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 section, and at least in this first edition of the report, 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, 2012 dollars.[2]

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. 2013), 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* (and perhaps in the future, this report) along with modeled installed price benchmarks and projections of near-term system pricing developed through research efforts underway at NREL (Feldman et al. 2013).

[2] 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 2013*.

2. Installed Prices

Berkeley Lab has gathered installed price data for 202 utility-scale (i.e., ground-mounted and larger than 2 MW) solar projects totaling more than 2,000 MW_{DC} (1,735 MW_{AC}) and installed between 2007 and 2012. The sample consists largely of PV projects (194 projects totaling 1,544 MW_{AC}), but also includes five CSP projects totaling 149 MW_{AC}, two CPV projects totaling 35 MW_{AC}, and one 7 MW_{AC} project that employs a mix of PV and CPV technology. In general, only fully operational projects for which all individual phases were in operation at the end of 2012 are included in the sample.[3] These definitional choices obviously impact the sample boundaries, and may lead to differences between the average installed prices presented in this section and those reported elsewhere (e.g., GTM/SEIA 2013). Furthermore, by definition, our sample is backward-looking, and therefore may not reflect installed price levels in 2013 and beyond.[4]

This section analyzes installed price trends[5] among just the sample of PV projects described above (installed prices for the eight CSP, CPV, and mixed-technology projects are discussed separately in the text box on page 5). It begins with an overview of installed prices over time, and then examines utility-scale system prices by technology, system size, and geographic region. 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 2012 dollars.

Installed PV Prices Continued to Drop in 2012, but Less Than in Previous Years

Figure 1 shows installed price trends for PV projects installed since 2007 in both DC and AC terms. Because solar project capacity is commonly reported in DC terms (particularly for PV in the residential and commercial sectors), the installed cost or price of solar is most often reported in $\$/W_{DC}$ terms as well (see, for example, Barbose et al. 2013 and GTM/SEIA 2013). For utility-scale solar applications, however, $\$/W_{AC}$ is a more appropriate metric, 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 – both in terms of their capacity ratings and their per-unit costs. Second, as discussed later in Section 4, some utility-scale PV projects intentionally oversize the DC PV array relative to the AC capacity of the inverters as a way to maximize

[3] In contrast, later sections of this report do report data for individual phases of projects that are online, or (in the case of Section 5 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

[4] Anecdotal information suggests that installed prices have continued to move lower in 2013. For example, on July 1, 2013, the Public Service Company of New Mexico filed for regulatory approval of 23 MW_{AC} of thin-film PV projects to be built in 2014 at an installed price of just $\$2.03/W_{AC}$, compared to $\$2.29/W_{AC}$ for 20 MW_{AC} of PV currently under construction in 2013 and $\$4.15/W_{AC}$ for 22.5 MW_{AC} built in 2011 (O'Connell 2013).

[5] 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.

average inverter load and efficiency and thereby boost the AC capacity factor. 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, $/W_{AC}$ (where the AC rating equals the aggregate inverter capacity rating) is the more appropriate cost or price metric to use. Here (in Figure 1) we show 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. 2013). The remainder of this section, however, as well as the rest of this document, report data exclusively in AC terms.

As shown in Figure 1, installed prices among the sample of utility-scale PV projects have declined by nearly one-third on average from the 2007-2009 period through 2012, dropping from $5.6/W_{AC}$ to $3.9/W_{AC}$ over this period. Most of this decline occurred in 2010 and 2011, as capacity-weighted average prices fells by only $0.3/W_{AC}$ from 2011 to 2012.

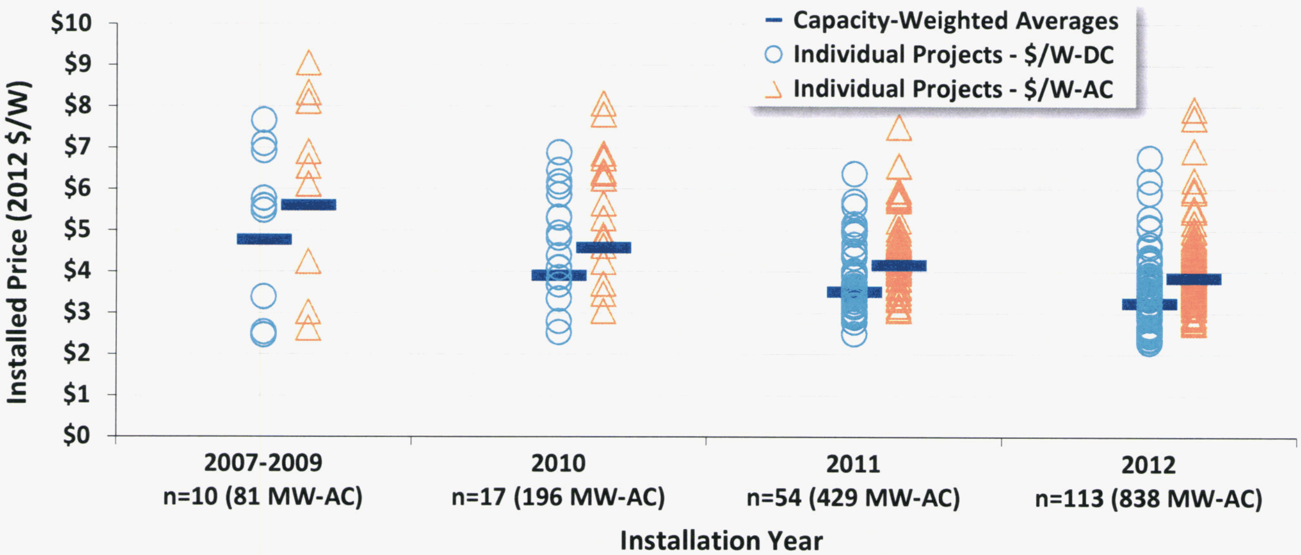


Figure 1. Installed Price of Utility-Scale PV, 2007-2012

Though capacity-weighted average prices have declined over time, there is nevertheless a considerable spread in individual project prices. Among the 113 projects in the sample completed in 2012, for example, installed prices range from $2.8/W_{AC}$ to $8.0/W_{AC}$, and preceding years show similar levels of variability. This price variation can be explained in part by differences in system configuration, project size, and geographic region, all of which are explored in greater detail below.[6]

[6] Other factors may also have an influence. For example, some of the higher-priced projects built in 2012 and shown in Figure 1 are not only small, but are also interconnected on the customer side of the meter, which presents a different value proposition (potentially subject to value-based pricing) than that offered by a truly wholesale project. In addition, some of these higher-priced projects are installed on top of capped landfills, which – much like roof-mounted projects – requires customized mounting and installation procedures that can drive up installed costs or prices.

CSP and CPV Installed Prices

The installed price sample includes five CSP projects (three parabolic troughs, one compact linear Fresnel reflector, and one power tower), two CPV projects, and one project using a mix of CPV and PV. The installed price estimates for these eight projects are *not* included in any of the Section 2 figures because two of these projects have high enough installed prices that it does not make sense to include them on the same graph with PV projects, yet there are simply too few of these "non-PV" projects at present to warrant separate graphs. Instead, the installed prices of these eight projects are discussed separately within this text box, and nowhere else in this report (though capacity factor and PPA price data for a subset of these projects are presented in Sections 4 and 5, respectively). All prices reported below are in 2012 $\$/W_{AC}$.

Among the CSP systems are a 3.2 MW_{AC} compact linear Fresnel reflector project (Ausra's Kimberlina project) and a 5 MW_{AC} power tower project (eSolar's Sierra SunTower), both online since 2009. Both are considered to be pilot projects, and based on Section 1603 grant data, have installed prices of roughly $\$15.3/W_{AC}$ and $\$13.7/W_{AC}$, respectively. The remaining three CSP projects in the sample all feature parabolic trough technology, and have installed price estimates of $\$8.4/W_{AC}$ (a 2 MW_{AC} Sopogy MicroCSP project in Hawaii, built in 2009), $\$6.6/W_{AC}$ (FPL's 75 MW_{AC} Martin Next Generation Solar Energy Center in Florida, built in 2010) and $\$4.5/W_{AC}$ (the 64 MW_{AC} Nevada Solar One project, built in 2007).

The two CPV projects are more recent. The 5.04 MW_{AC} Hatch Solar Center in New Mexico was built in 2011 at an installed price of $\$4.2/W_{AC}$, while the 30.24 MW_{AC} Cogentrix Alamosa project in Colorado was built in 2012 at an installed price of $\$3.8/W_{AC}$. Both projects feature Amonix technology and dual-axis tracking.

Finally, the 6.9 MW_{AC} SunE Alamosa project in Colorado – which features a mix of PV and CPV technology, as well as fixed-tilt, single-axis, and double-axis tracking – was built in 2007 with an installed price of $\$9.4/W_{AC}$.

Installed PV Prices Vary by Configuration, Project Size, and Region

The price variation noted in the previous section is partially attributable to project configuration – i.e., whether PV projects use crystalline silicon ("c-Si") or thin-film modules, and whether those modules are mounted at a fixed-tilt or on a tracking system. Figure 3 breaks out installed prices over time among these project configurations.

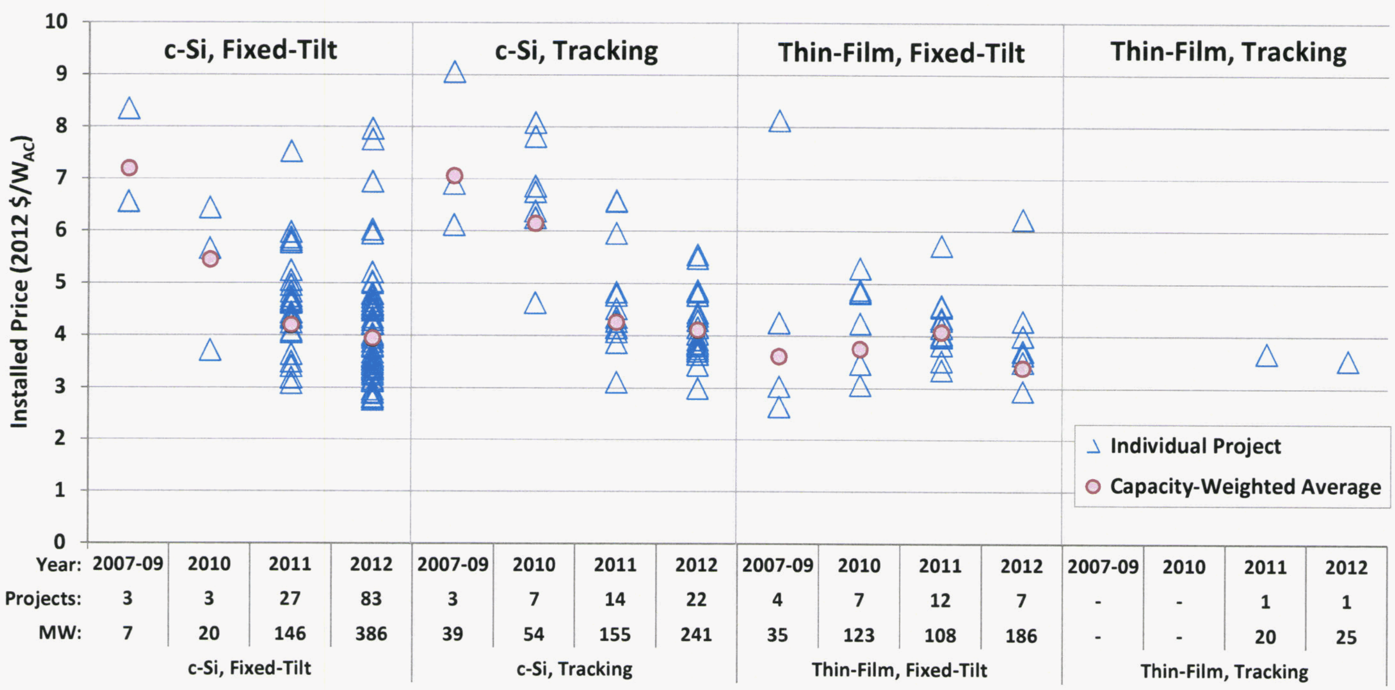


Figure 2. Installed Price of Utility-Scale PV by Configuration, 2007-2012

Note: Capacity-weighted average price not shown for system configurations with fewer than two data points.

Trends of particular note include:

- There has been a convergence in the average installed price of c-Si and thin-film projects. Though projects using c-Si modules have historically been significantly more expensive than projects using thin-film modules, the price gap has eroded considerably over time. This convergence has been driven primarily by the price of c-Si modules falling more quickly than the price of thin-film modules, attributable to both a decline in the price of silicon as well as a global excess of c-Si module manufacturing capacity.
- Tracking systems remain only slightly more expensive than fixed-tilt systems within the sample – a difference of less than $\$0.2/W_{AC}$ in 2011 and 2012 among c-Si projects. The small size of this gap may be due in part to the previously mentioned higher DC/AC capacity ratio among fixed-tilt projects in general (this trend is explored further in Section 4), which boosts their installed prices in AC terms.
- As the price of c-Si projects has converged with thin-film, the number of c-Si projects in the sample (particularly fixed-tilt projects) has grown almost exponentially. Figure 2 shows that in 2011 and 2012 – coinciding with the timing of the convergence – c-Si projects overwhelmingly surpassed thin-film as the most frequently installed project type in the sample. This trend is mirrored in the broader market as well.

Project size may also explain some of the variation in installed prices, as PV projects in the sample range from 2 MW_{AC} to nearly 100 MW_{AC}. Figure 3 investigates whether scale economies potentially allow the larger projects in the sample to achieve lower costs, by focusing on just those PV projects in the sample that were installed in 2012 (recall from Figure 2 that average installed prices did not vary widely across system configurations in 2012, thereby making it a convenient year for this purpose). As might be expected, utility-scale PV projects do exhibit economies of scale, though the impact is most pronounced at the very low end of the size range. Out beyond 5-10 MW, scale economies appear to diminish considerably.

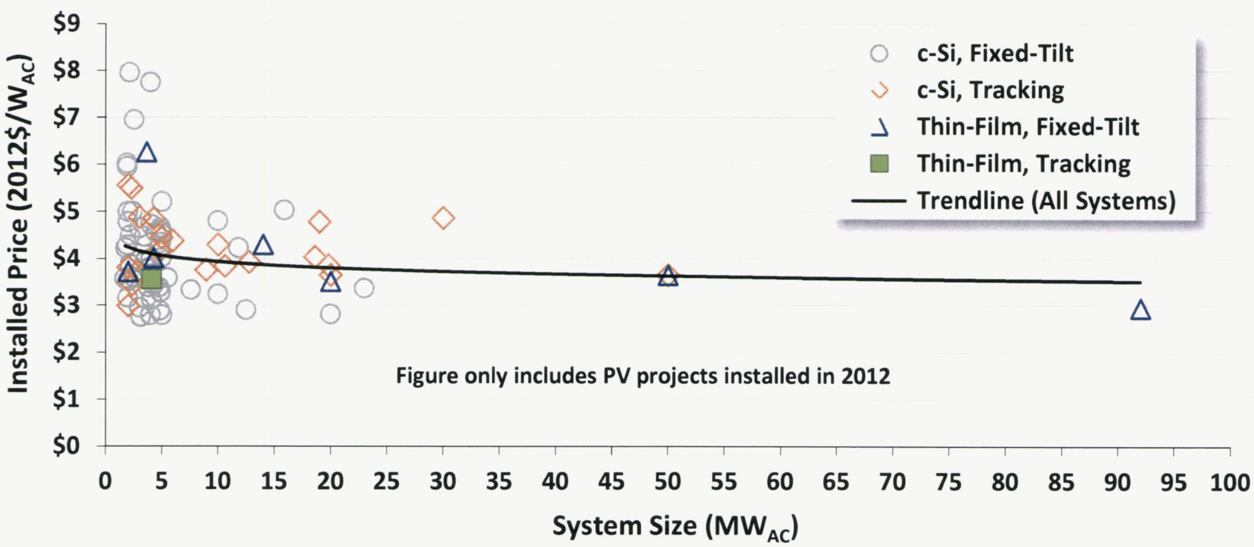


Figure 3. Installed Price by Configuration and Project Size for 2012 PV Projects

Finally, installed prices might also vary between geographic regions, due to variations in prevailing project sizes, land costs, labor costs, regulatory environments, landscape type, environmental conditions, number of active developers, and presence of industry infrastructure, among other factors. Figure 4 shows that solar projects in the West region (defined here to include Arizona, California, Colorado, Nevada, New Mexico, Oregon, and Texas) have historically had lower prices than projects elsewhere, but that this gap has narrowed over time as prices in other regions have fallen more significantly. The West's historical price advantage can perhaps be attributed to at least two factors: (1) larger projects have typically been built in western states due to relatively easy acquisition of land, potentially offering cost savings due to economies of scale, and (2) the region has more experience with utility-scale solar installations (with a number of projects in operation since 2007 or earlier), and thus likely more mature infrastructure and more competition within the solar market.

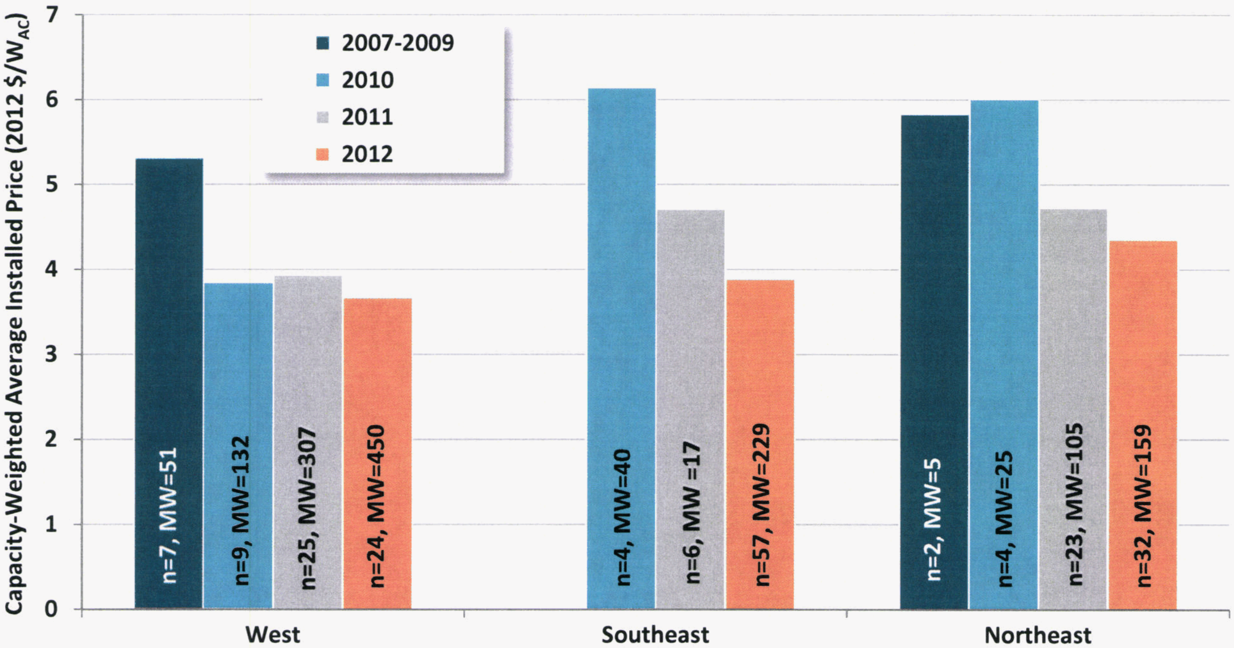


Figure 4. Capacity-Weighted Average Installed Price for PV by Geographic Region
Note: Capacity-weighted average prices not shown for years in which fewer than two installed price data points are available.

As other areas of the country have gained installation experience with utility-scale PV, their prices have converged with those in the West. In 2012, for example, the capacity-weighted average price in the West was \$3.7/W_{AC}, compared to \$3.9/W_{AC} in the Southeast (defined here to include Florida, Kentucky, North Carolina, and Tennessee) and \$4.4/W_{AC} in the Northeast (defined here to include Delaware, Illinois, Massachusetts, Maryland, New Jersey, Ohio, Pennsylvania, and Vermont). This \$0.7/W_{AC} range from lowest to highest compares favorably with the more-than-\$2.0/W_{AC} range experienced as recently as 2010.

3. Operations and Maintenance Costs

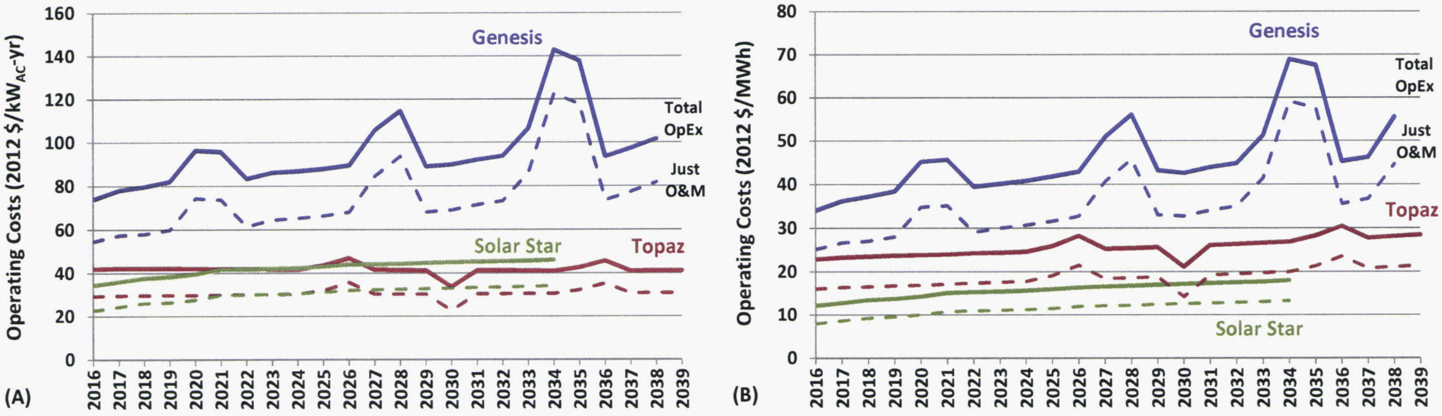
In addition to up-front installed project costs or prices, utility-scale solar projects also incur ongoing operations and maintenance ("O&M") costs. This section reviews and analyzes the limited data on O&M costs that are in the public domain. It starts with a review of *projected* O&M costs from three 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 operating expenses for those projects each year on FERC Form 1.

Projected Operating Costs Are Similar for Different PV Configurations, Higher for CSP

In the past two 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. None of these three projects – all of which are in California – was fully online at the time of writing, though all were under construction and Topaz had begun to deliver some energy from early phases of the project.

Though not empirical data, projected operating expenses for these three projects are nevertheless instructive, not only because the projects are all very large (i.e., truly 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 U.S. 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 may not be entirely representative of their respective technology configurations. For example, given that these projected operating expenses 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 operating expenses (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.

Figure 5 shows projected operating expenses 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),[7] $/kW$_{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 Section 5). For each project, Figure 5 shows not only total operating expenses ("OpEx" – shown by the solid lines), but also just those expenses allocated to actual O&M (the dashed lines, which make up 70%-80% of total OpEx).[8]



Source: FitchRatings 2013, 2012, 2011

Figure 5. 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 $20 to $30/kW$_{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. 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).

Limited Sample of Empirical Operating Costs Seems to Conform to Projections

Empirical data on the operating 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.[9] And even fewer of those

[7] 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.

[8] In addition to O&M costs, total operating expenses also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (FitchRatings 2013, 2011).

[9] 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

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.[10] Nevertheless, Figure 6 shows historical O&M costs for a very small sample of utility-scale solar projects – a total of nine projects totaling 137 MW – in both \$/kW-year and \$/MWh terms.[11] Only three of these projects (denoted by the three lines to represent project continuity over multiple years) have historical data for more than a single year; the other six only have data for 2012. Despite the extremely limited sample, reported costs are seemingly in line with the projected O&M costs in the early years of Figure 5 above – i.e., in the neighborhood of \$20-\$40/kW_{AC}-year or \$10-\$20/MWh for PV, and around \$60/kW_{AC}-year for the lone CSP parabolic trough project.

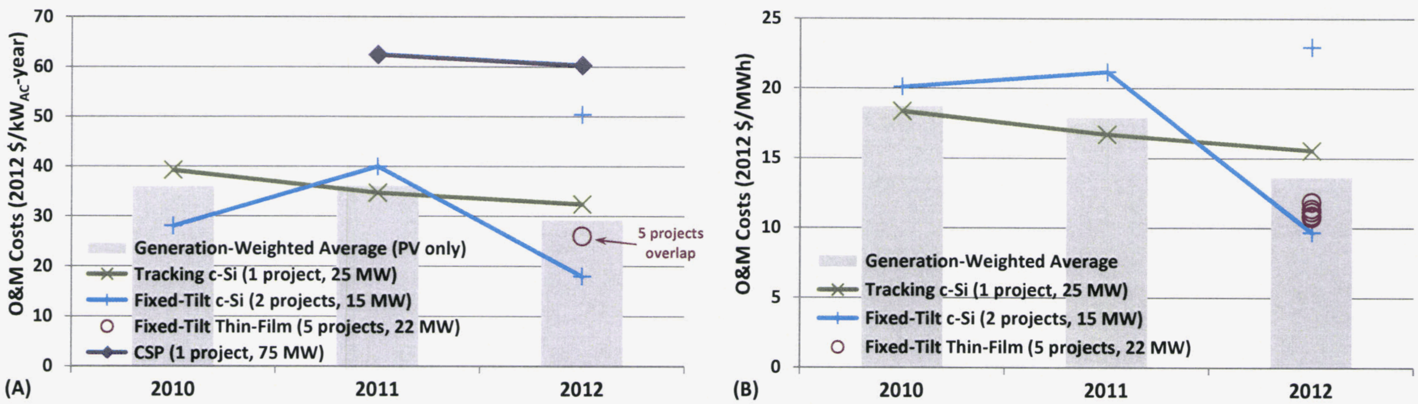


Figure 6. Empirical O&M Costs by Project Type

As utility ownership of operating solar projects increases in the years ahead, the sample of projects reporting O&M costs will grow, potentially allowing for more interesting analyses in future editions of this report.

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 5.

[10] For example, a number of investor-owned utilities in California and the Southwest that own large solar projects either do not report operating costs for their solar projects on Form 1 at all, or else report them in an aggregated manner that does not readily lend itself to analysis.

[11] 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.

4. Capacity Factors

At the close of 2012, a number of utility-scale solar projects 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.[12] Sourcing net generation data from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and state regulatory filings, this section presents net capacity factor data for 73 PV projects totaling 743 MW_{AC} (including one 5 MW_{AC} dedicated CPV project and one 7 MW_{AC} project that uses both PV and CPV technology) and eleven CSP projects (ten parabolic trough and one power tower, none with storage) totaling 423 MW_{AC} (and for which only the solar generation is reported here – no gas or oil augmentation is included). This sample size will increase significantly in next year's edition, as the large amount of new utility-scale solar capacity that came online in 2012 will have its first full operating year in 2013. As sample size increases, so too will the information content of this section in future editions of this report.

Unless otherwise noted, the capacity factors presented here represent *cumulative* capacity factors – i.e., calculated over as many years of data as are available for each individual project (going back to 2007), rather than for just a single year. In all cases, capacity factors are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[13] which results in higher capacity factors than if reported in DC terms, 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. All capacity factors reported herein are also expressed in *net*, rather than *gross*, terms – i.e., they represent the output of the project net of its own use.

PV Capacity Factors Vary Considerably by Project, but Time Trend Proves Elusive

Figure 7 presents the cumulative capacity factors for all 73 PV projects, broken out by commercial operation date. As many as five years of net generation data go into the cumulative capacity factor calculations for the three projects that achieved commercial operations in late 2007, while the 45 projects in the sample that came online in 2011 have just a single year (2012) impacting their capacity factors.

As shown, there is a wide spread of capacity factors across the entire period. For example, projects built in 2010 feature capacity factors ranging from 13.8% up to 30.2%, and other years have spreads that are almost as wide. A number of factors could be responsible for this wide range, including: whether the project is mounted at a fixed-tilt or uses tracking technology (this distinction is already noted in Figure 7, where projects with trackers generally, though not always, yield a higher capacity factor);[14] in what part of the country the project is located (as

[12] 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.

[13] 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]

[14] The overwhelming majority of PV projects in the sample that use tracking systems use single-axis trackers. Dual-axis trackers are limited to just one PV project in the sample, plus the two projects that use CPV technology (either exclusively or in combination with PV). For PV, where direct focus is not as important as it is for CPV or CSP,

average insolation levels vary across the U.S.); what type of solar technology is used (e.g., c-Si versus thin-film versus CPV); the size of the PV array relative to the inverter capacity; inter-year resource variability; and finally, when the project was built.[15]

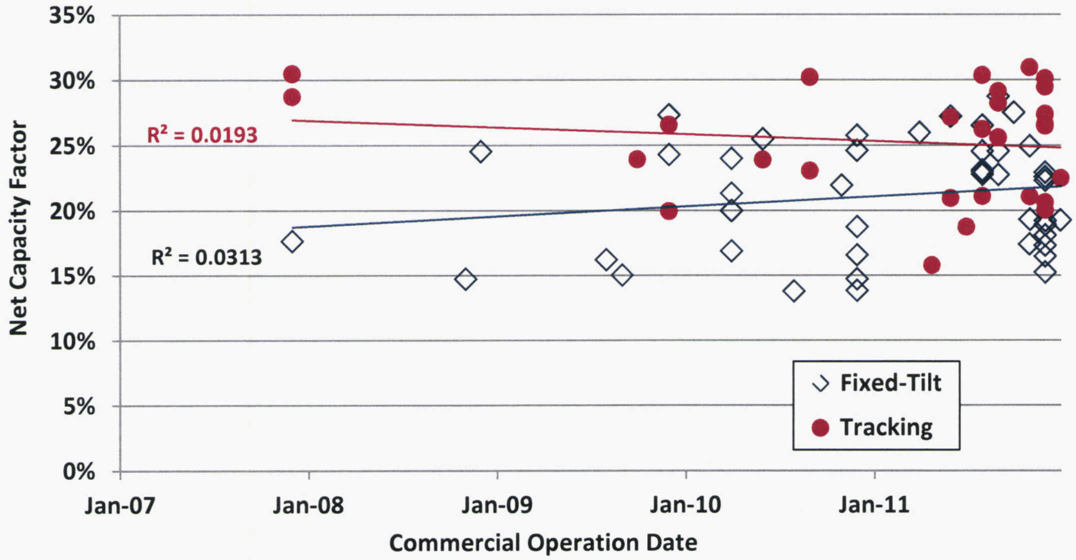


Figure 7. Cumulative Capacity Factor by Commercial Operation Date (PV Only)

Regarding the last variable, there does not seem to be much of a time trend evident in Figure 7: the best-fit line for fixed-tilt systems does slope slightly upward over time, but with a very low R^2, while the best-fit line for tracking systems slopes slightly *downward* (and with an even lower R^2). Any time trend could be obscured by other influences, however – for example, regional differences in the solar resource or use of different technology. Figure 8 attempts to control for these influences by focusing only on those projects located in the West region (defined rather liberally here to include Colorado, Texas, New Mexico, Arizona, Nevada, and California, and where 69% of the capacity in the sample resides), and breaking them out by both technology type (c-Si vs. thin-film) and whether or not tracking is used. The capacity factors shown in each year represent the generation-weighted average of the cumulative capacity factor from all projects that achieved commercial operations in that particular year.

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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, depending on the PPA price.

[15] Other factors such as tilt and azimuth will also play a role, though since we are focusing only on ground-mounted utility-scale projects, our operating assumption is that these fundamental parameters will be optimized to maximize energy production.

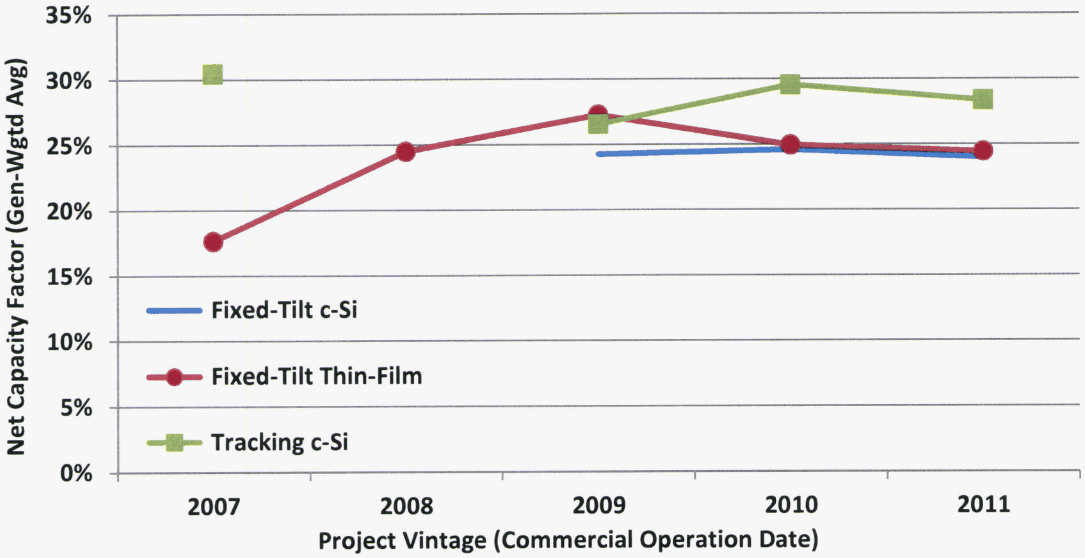

Figure 8. Generation-Weighted Capacity Factor by Project Vintage (West Region)

Even after controlling for these other influences, Figure 8 does not suggest much of a time trend – i.e., with the possible exception of fixed-tilt thin-film systems (though that trend is skewed by a single 2007 project), there is no indication that projects built more recently have higher capacity factors. This lack of a time trend is somewhat notable given that: (A) PV project performance degrades slightly over time, which – all else equal – would lead one to expect that older projects would have slightly lower cumulative capacity factors than newer projects, and (B) falling module prices have led some projects to oversize the DC solar array relative to the AC inverter capacity rating as a way to boost capacity factor.[16] We explore each of these variables below.

Performance Degradation Not Observable Within Limited Timeframe of PV Project Sample

Although performance degradation is commonly accounted for in power purchase agreements,[17] it does not appear to be a strong influence in the sub-sample of eleven projects (totaling 96 MW_{AC}) for which three or more years of data are available (each of these eleven projects is shown as an individual line in Figure 9).[18] To be fair, the impact of degradation would be

[16] One might also expect that newer projects would 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 so than for other technologies like wind power, efficiency improvements over time show up more as cost savings rather than as higher capacity factors.

[17] For example, among a sample of power purchase agreements for fifteen projects (not all of which are yet online) totaling 2,138 MW_{AC}, the projected decline in contracted generation ranges from 0.5%/year to 0.9%/year, with a capacity-weighted average of 0.65%/year (the mean and median are also 0.65%/year). These contractual degradation rates are likely somewhat conservative or over-stated, since they are typically tied to performance thresholds (which the developer presumably does not want to breach) within the PPA.

[18] Figure 9 is not on a cumulative basis. Instead, it shows individual project capacity factors in each individual calendar year, as a means of checking for signs of performance degradation.

difficult to perceive after just three to five years – e.g., all else equal, a degradation rate of 0.65%/year would reduce a 30% capacity factor in year one to 29.6% in year three and 29.2% in year five, leaving the cumulative three-year capacity factor at 29.8% (or 29.6% over five years). In other words, over this short time frame, degradation of capacity factors would be barely perceptible, particularly with other variables (e.g., inter-year variability in the solar resource) influencing the trend as well.

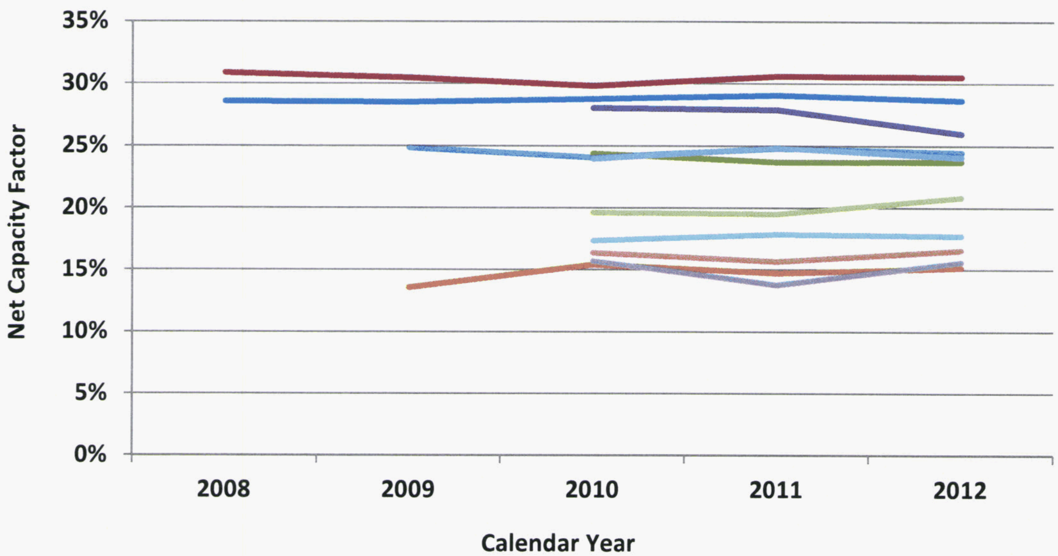

Figure 9. Capacity Factor Over Time For Projects With At Least 3 Years of History

Oversizing of PV Array Relative to Inverter Capacity Boosts Capacity Factor

One design element that varies considerably among utility-scale PV projects is the ratio of the project's DC capacity rating – determined by the size of PV array – to the aggregate AC capacity of the inverters. Adding module capacity beyond what is considered optimal (in terms of maximizing solar generation) given the inverters' capacity rating will increase the amount of DC power flowing to the inverters at any given time (except during peak production times, when the inverters will be maxed out and excess power will be spilled), thereby boosting the average inverter load and efficiency and leading to a higher capacity factor.[19] With the cost of modules having dropped precipitously in recent years, this strategy is now more cost-effective than it once was, and can be a viable alternative to a tracking system as a means of maximizing production during on-peak periods and boosting capacity factor. This strategy may also contribute to the small difference in installed prices between fixed-tilt and tracking systems detected earlier in Figure 2.

Figure 10(A) plots the DC/AC nameplate capacity ratio against cumulative net capacity factor for the 73 PV projects in the sample. The relationship appears to be fairly strong for fixed-tilt systems (high R^2 best-fit line) – the higher the DC/AC ratio, the higher the capacity factor – but

[19] 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.

not for tracking systems (much flatter best-fit line with low R^2),[20] which have not pushed the DC/AC envelope in the way that fixed-tilt systems have. This is not surprising: tracking systems are already operating at or near peak capacity for a significant proportion of each day (by virtue of the fact that they follow the sun), and therefore have less to gain from oversizing – particularly given the incremental expense of oversizing the tracking system itself (not just the modules).

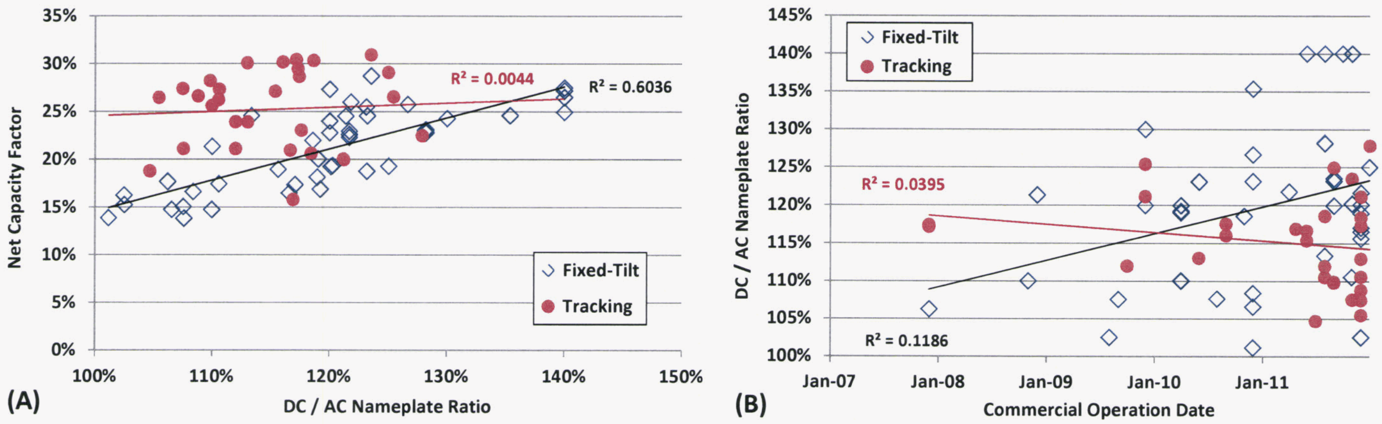

Figure 10. DC/AC Nameplate Ratio vs. Capacity Factor and Commercial Operation Date

If the oversizing of fixed-tilt systems has been a recent development (e.g., as module costs have decreased), then this might be another reason to expect a time trend in capacity factor. Figure 10(B) suggests that there is, in fact, a positive relationship between commercial operation date and the DC/AC ratio among fixed-tilt (but not tracking) systems, but it is very weak (i.e., low R^2). Hence, based on Figures 7-10, we conclude that while there may be a bit of a positive time trend influencing the capacity factors of fixed-tilt (but not tracking) systems, that relationship is weak. To the extent that it does exist, it is likely driven by a general increase in the DC/AC ratio among newer projects.

PV Capacity Factors Influenced More by Location and Tracking, Less by Module Type

Without a strong time trend to complicate the analysis, we can analyze the remaining influences on capacity factor with just a single graph. Figure 11 parses the sample (excluding the one CPV and one mixed-technology project, neither of which fits neatly into any of these buckets[21]) in three different ways: by region, by fixed-tilt versus tracking, and by c-Si versus thin-film.

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[20] Most of the tracking projects with capacity factors around 20% or less are in northern climates – Vermont, Illinois, Delaware, New Jersey, and Ohio – which presumably explains their lower capacity factors relative to other tracking systems in the sample.

[21] The 5.04 MW_{AC} Hatch CPV project in New Mexico had a 20.9% capacity factor in 2012, while the mixed-technology 7 MW_{AC} SunE Alamosa project in Colorado has had a 29.1% cumulative capacity factor (with very little annual variation) over the 5-year period from 2008-2012. Finally, though technically not included in this year's capacity factor sample because it came online in early 2012, the 30.24 MW_{AC} Cogentrix Alamosa CPV project in Colorado had a 24.8% capacity factor in the twelve-month period from July 2012 through June 2013.

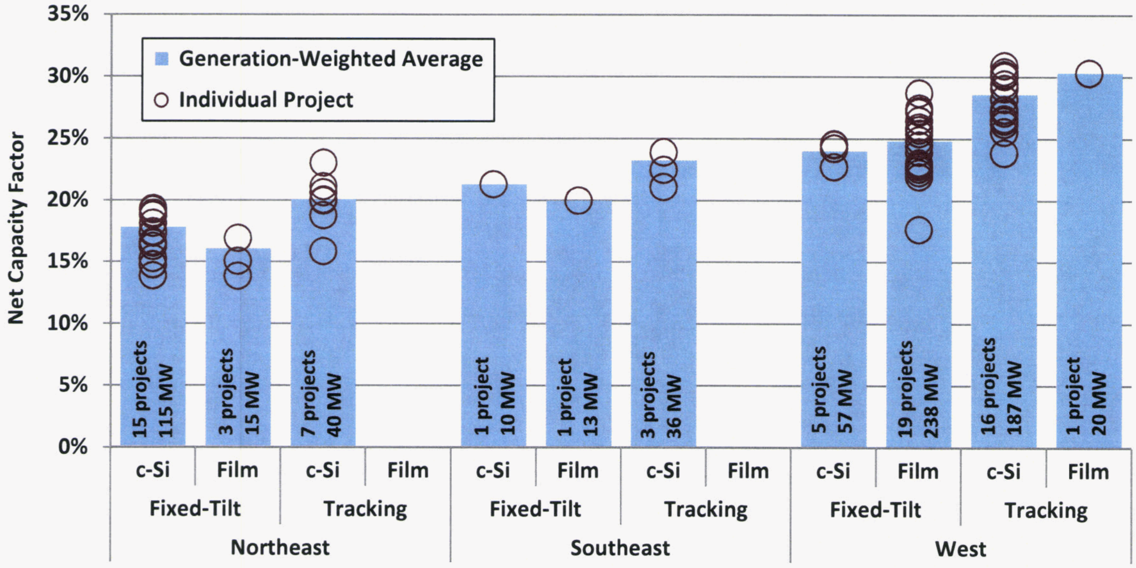

Figure 11. Cumulative PV Capacity Factor by Region and Project Configuration

Although sample size can become an issue when sub-dividing the sample this narrowly, the results are nevertheless largely as expected. Projects located in the Northeast region (broadly defined here to include Delaware, Illinois, Ohio, Pennsylvania, New Jersey, New York, Massachusetts, and Vermont) feature the lowest capacity factors, followed by the Southeast (which includes just Florida and North Carolina at this time), while the West (Texas, Colorado, Arizona, New Mexico, Nevada, and California) features the highest capacity factors. Within each region, projects using trackers (overwhelmingly single-axis) feature higher capacity factors than fixed-tilt systems.[22] And finally, thin film technology appears to have a slight edge over c-Si in the West region, where ambient temperatures are highest, while c-Si wins out in the other two regions.[23]

Parabolic Troughs Have a Long and Reliable Performance Record (Power Towers Less So)

There are thirteen CSP projects in the U.S. that are larger than 2 MW and that have been operating for one or more years. Two of these projects, however, do not have reliable net

[22] A rule of thumb in the industry is that single-axis trackers will boost energy yield (i.e., capacity factor) by 20%, and this is roughly borne out by the sample of projects in the West. The c-Si trackers in the West sample have a 19% higher generation-weighted average capacity factor than the fixed-tilt c-Si systems, while the lone thin-film tracker in the sample has a 22% higher capacity factor than the fixed-tilt thin-film systems. The use of trackers is not as common among thin-film systems because the lower efficiency of thin-film relative to c-Si 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.

[23] The vast majority of thin film systems in the sample (82% of all thin-film capacity in the sample) use CdTe panels from First Solar. On its web site (http://www.firstsolar.com/en/Innovation/Advanced-Thin-Film-Modules), 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 Southwest region.

generation data, because one of them (the Kimberlina compact linear Fresnel lens project in California) primarily produces steam for industrial uses, while the other (the Martin parabolic trough project in Florida) feeds steam to a co-located combined cycle gas plant, with the resulting generation attributed to the gas plant. That leaves eleven CSP plants in the sample: the nine parabolic trough SEGS plants (totaling 354 MW) that have been operating in California for more than twenty years, the 64 MW Nevada Solar One parabolic trough project that has been operating in Nevada since mid-2007, and the 5 MW Sierra SunTower project that has been online in California since mid-2009.

Figure 12 shows the net annual capacity factors from just the solar portion of these projects (i.e. no augmentation with natural gas or fuel oil is included in Figure 12), going back to 2001. The eleven projects fall roughly into three groupings: SEGS III-IX, along with Nevada Solar One (represented by the dashed black line), have the highest capacity factors; SEGS I and II are grouped in the middle; and the Sierra SunTower has by far the lowest capacity factor.

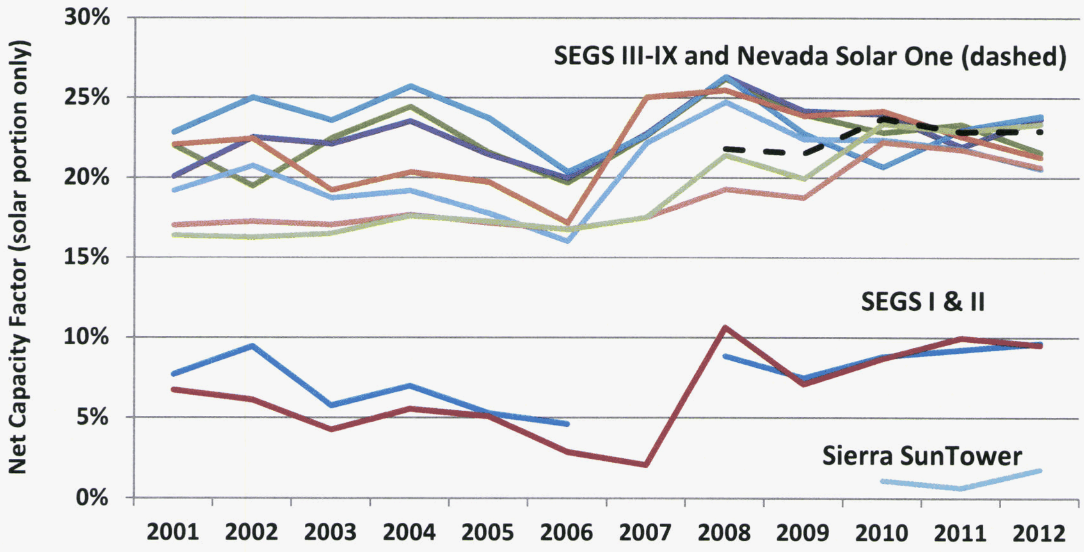

Figure 12. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

Figure 12 provides several insights:

- Capacity factors among the uppermost grouping, which includes SEGS III-IX and Nevada Solar One, have converged in the past three years, 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. Nevada Solar One also took advantage of the Section 1603 grant program in late-2009 to expand the size of its solar field by 5%; the resulting step-up in capacity factor from 2010-2012 (relative to 2008-2009) is also evident in Figure 12.
- One likely reason for the consistently lower capacity factors of the SEGS I and II projects is that they feature smaller solar fields (relative to nameplate capacity) than the other seven SEGS projects. Just as oversizing a PV array relative to inverter capacity can boost

capacity factor, so too can increasing the number of parabolic trough collectors relative to the nameplate rating of the steam turbine. Another potential factor is that 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.

- Though considered a pilot project, the Sierra SunTower has, nevertheless, not lived up to performance expectations, and appears to be operating only a portion of the time (Gunther 2013).[24]
- Finally, Figure 12 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 22.9% solar-only to 23.2% gas-included in 2012), with gas usage most often peaking in the spring and fall (shoulder months).

With a handful of major CSP projects – including two large power tower facilities (Ivanpah and Crescent Dunes) and three large parabolic trough projects (Genesis, Mojave, Solana) – currently under construction in the U.S., the availability of CSP performance data will improve in future years.

[24] In response to a query regarding this project's low capacity factor, eSolar (the project sponsor) described this project as a "multipurpose facility" that "operates and produces power on a part time basis" and is "also used for product development, research, and technology demonstration," and later clarified that "Sierra SunTower is an operating full-scale facility where power generation is blended with product development on heliostats, control software and O&M areas" (Huibregtse, 2013). More recently, Greentech Media (Wesoff 2013) reported that "eSolar is now pursuing enhanced oil recovery applications, rather than power generation in the U.S."

5. 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 sample of utility-scale solar projects in the U.S. The sample includes a total of 57 contracts totaling 4,289 MW_{AC} and broken out as follows: 51 PV PPAs totaling 3,822 MW_{AC}, two CPV PPAs totaling 35 MW_{AC}, one 7 MW_{AC} PPA that is a mix of PV and CPV, and 3 CSP PPAs (two parabolic trough, one power tower) totaling 424 MW_{AC}.

The universe 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 – although the prices paid by FIT programs are discussed in a text box on page 27. In short, the goal of this section is to learn how much post-incentive revenue a utility-scale solar project requires to be viable, 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.[25]

[25] 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.

Time-of-Delivery Pricing: Delivering Electricity When It Is Most Valuable

55% of the nearly 4,300 MW in the solar PPA price sample 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 (>25 GW), where only 15% (of MW) vary prices diurnally, only 10% vary prices seasonally, and only 8% vary prices *both* diurnally *and* seasonally. This disparity is partly attributable to geography – a large number of solar projects in the sample are located in the West 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.

For example, based on actual diurnal and seasonal production profiles of both a PV and a wind project that have PPAs with PG&E, TOD pricing (using PG&E's 2011 TOD factors) benefits PV over wind by $23/MWh on a levelized basis (in real 2012 dollars). Similarly, for a different pair of projects that have PPAs with Southern California Edison (which uses its own TOD factors, different from PG&E's), PV has a $26/MWh TOD advantage over wind. In other words, if these PV and wind PPAs all had the same "base price" (i.e., pre-TOD adjustment), the PV projects would earn $23-$26/MWh more revenue than the wind projects over the full terms of the contracts once the TOD factors had been applied to that base price. Or, stated another way, the PV projects could offer a base price that is at least $20/MWh lower than the wind projects' base price and still earn roughly the same amount of post-TOD revenue (levelized $/MWh) as those wind projects over the full contract terms.

Not surprisingly, most (>90%) of the relative benefit comes from diurnal variation in the TOD factors. PV generates the bulk of its daily output mid-day when prices are highest, and does not produce at night, thereby avoiding the lowest-priced period of each day. Wind production profiles vary from site to site and by region, but tend to be more evenly distributed throughout the day – i.e., not as concentrated as PV in the high-priced on-peak periods, and instead generating some portion of daily output during the low-priced off-peak periods. Seasonal differences in production between wind and PV tend not to be as large as the diurnal difference; nor are the seasonal TOD adjustments as stark as the diurnal.

Of course, PV's TOD advantage over wind 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, likely erode solar's TOD advantage over wind.

For each of the contracts in the sample,[26] we have collected the contractually locked-in PPA price data over the full term of the PPA,[27] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed (see the text box on this page).[28] 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[29]) these projects over the life of the contract – at least on a post-incentive basis. In other words, these PPA prices do reflect the

[26] 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.

[27] The minimum PPA term in the sample is 15 years, the maximum is 30 years, the average (both simple and capacity-weighted) is 23.4 years, and the median is 25 years.

[28] 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 2013* 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.

[29] 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.

receipt of federal (e.g., the 30% ITC or cash grant, accelerated tax depreciation)[30] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[31] As such, the levelized PPA prices presented in this section should *not* be equated with a project's levelized cost of energy ("LCOE").

Figure 13 shows trends in the levelized PPA prices from the entire sample (not all of which is yet operational) over time. Each bubble in Figure 13 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).[32] Different solar technologies (e.g., PV versus CPV versus CSP) are denoted by different colors and patterns.

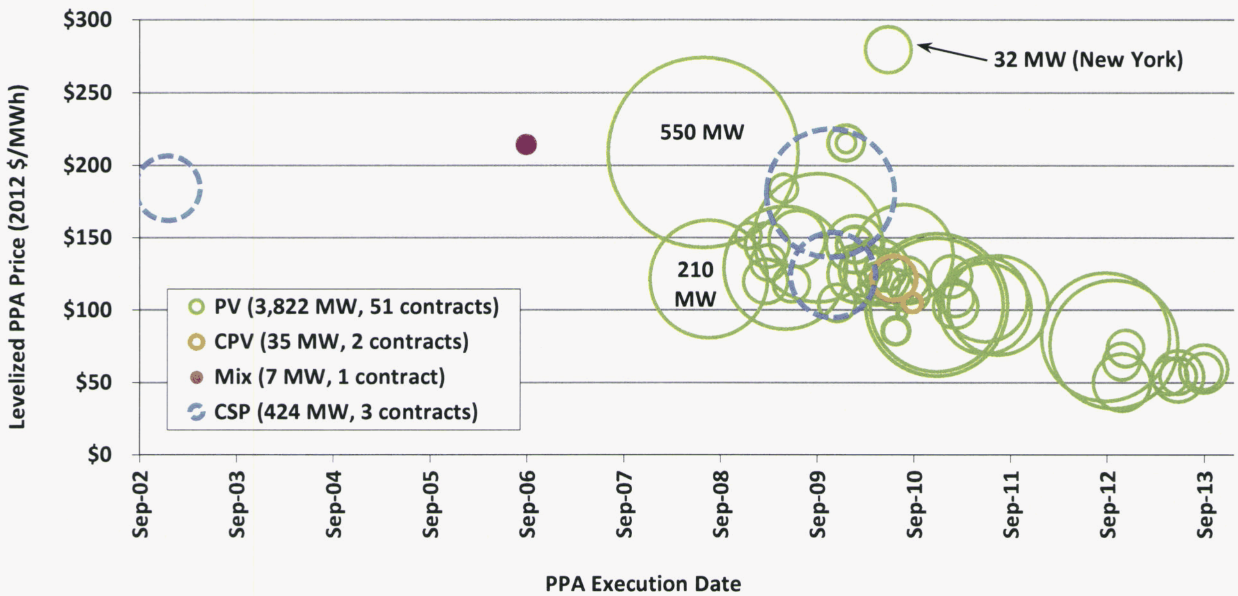

Figure 13. Levelized PPA Prices by Technology and PPA Execution Date

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[30] In addition to the other federal incentives listed, seven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all seven 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.

[31] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher if there were no federal ITC (i.e., 30%/(1-federal tax rate)). Though there is too much variety in state-level incentives to try and systematically quantify their impact here, one example is New Mexico's refundable Production Tax Credit, which pays 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 (and federal) incentives can reduce PPA prices.

[32] Because PPA prices reflect market conditions at the time a PPA is executed – which could be a year 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 sections.

Figure 13 provides a number of insights:

- The utility-scale solar market is relatively young, particularly for PV. Utility-scale CSP projects have been around since the 1980's, and one PPA in the sample for a new CSP project was executed back in late 2002, but with a few limited exceptions (e.g., the PVUSA facility in California from the 1980s), utility-scale PV has only been a reality in the U.S. since 2006/2007.
- Not surprisingly, the highest-priced contract in the sample comes from the Northeast (Long Island), which does not enjoy the abundant sunshine of the West (where 96% of the PPAs in the sample, and 99% of the capacity represented by those PPAs, are located).
- PPA pricing has, in general, declined over time, to the point where recent PPAs have been priced as aggressively as \$50-\$60/MWh levelized (in 2012 dollars). In the West/Southwest (where these low-priced projects are located), pricing this low is, in some cases, competitive with wind power (Wiser and Bolinger 2013), as illustrated in the Macho Springs text box on the next page. This is particularly the case when considering solar's on-peak generation profile, which – as discussed in the time-of-delivery text box on page 20 – can give solar a TOD pricing advantage relative to wind.[33]
- 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 virtually 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 when the other two CSP PPAs in the sample were executed, PV had caught up in terms of pricing. 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.
- Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects (>200 MW). Though scale economies are present in PV projects (at least at the low end of the size range, per Figure 3 earlier), very large projects often face greater development challenges than smaller projects, including greater 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.

[33] The levelized PPA prices shown in Figure 13 (and throughout this section) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, solar's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the utility purchaser.

Macho Springs: Solar Co-Located With – *And Competitive With* – Wind

In November 2012, El Paso Electric filed for approval of 20-year PPA with the 50 MW_{AC} Macho Springs PV project, developed by Element Power (and later sold to First Solar). This project has at least two notable features: (1) it is co-located with the existing 50.4 MW Macho Springs wind project (also developed by Element Power and selling electricity to El Paso Electric), which began commercial operations in late 2011, and (2) it has the lowest PPA price of any solar project in the sample, at roughly $50/MWh levelized (real 2012 dollars). In fact, the solar project is priced lower than the co-located wind project (though the wind PPA was signed more than two years earlier, in 2010), which sells electricity at a levelized price of just below $80/MWh (real 2012 dollars).

The solar project benefits from some of the infrastructure that had already been built for the wind project, such as the substation, which no doubt helps to support its lower price. Another factor is New Mexico's 10-year refundable Production Tax Credit, which provides an average of $27/MWh to solar (though actual amounts vary by year over the 10-year period), compared to just $10/MWh (flat) for wind. Otherwise, the two projects are essentially the same size, were developed by the same developer, have the same PPA term (20 years) and off-taker, and receive essentially the same federal benefits (accelerated depreciation and either the 30% ITC or the 30% Section 1603 cash grant – the wind project chose the grant).

To date, the wind project has generated a 29% net capacity factor, while the solar project expects to reach almost 26%. But these annual averages mask likely seasonal synergies: so far, the wind project's lowest monthly output has been in July, August, and September – three summer months in which the solar project will presumably generate its highest output. This natural complementarity allows the two projects to more fully utilize their interconnection agreement and transmission rights.

Macho Springs is the latest in a growing number of solar projects that are co-located with either wind (Catalina, Grand Ridge, Wild Horse, Kingman, Atlantic County Utilities Authority) or geothermal (Stillwater) projects – though so far none of these hybrid projects have been truly envisioned or developed as integrated projects (rather, solar has been added later in each case, and is sold under a separate PPA). As such, there are presumably still as-yet-untapped synergies to be realized in the future for hybrid projects that are envisioned, planned and developed as such right from the start.

Not all of the projects behind the contracts shown in Figure 13 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 14 shows the same data as Figure 13, but broken out according to whether or not a project has begun to deliver power.[34] 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 some of these projects can be profitably built and operated under the aggressive PPA price terms shown here.[35]

[34] If a project had begun to deliver power as of June 2013– even if not yet fully operational or built out to its contractual size – it is characterized as "operating" in Figure 14. Only those projects that were still in development or were under construction but not yet delivering power are characterized as "planned."

[35] 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; for example, one of the lowest-priced PPAs in the sample would have had an even lower price (by $5/MWh) if not for an upward price revision stemming from import duties placed on Chinese-made modules (Palo Alto 2012).

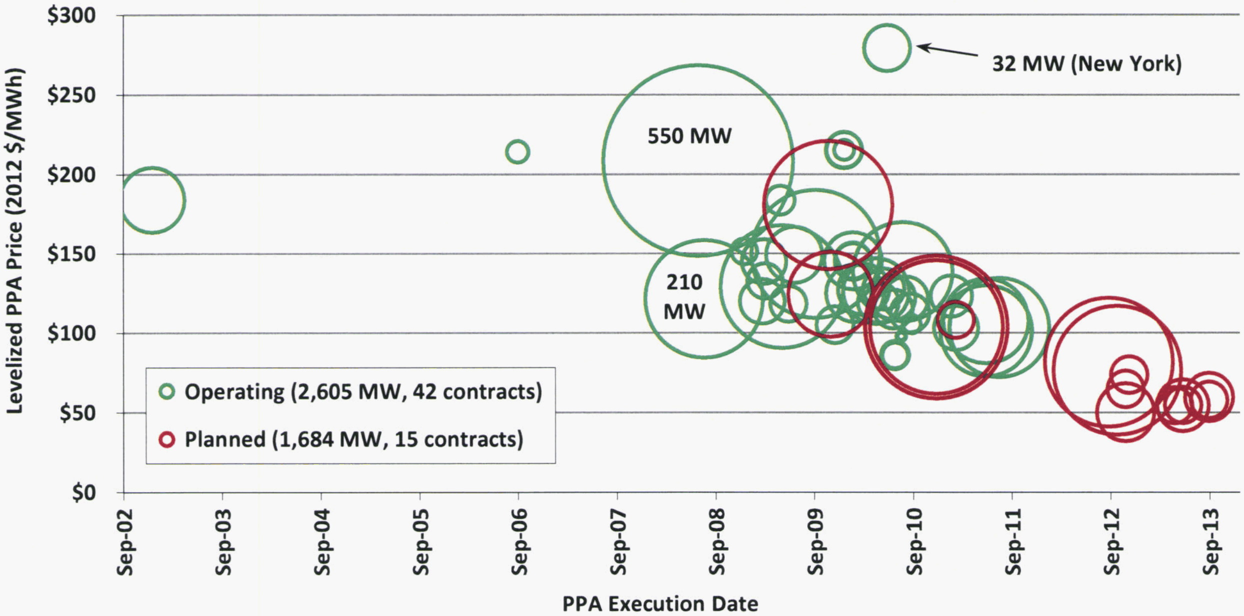

Figure 14. Levelized PPA Prices by Operational Status and PPA Execution Date

Roughly 60% 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. Figure 15 illustrates this decline by plotting over time, in real 2012 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. All technology types – PV, CPV, and CSP – are included in Figure 15.

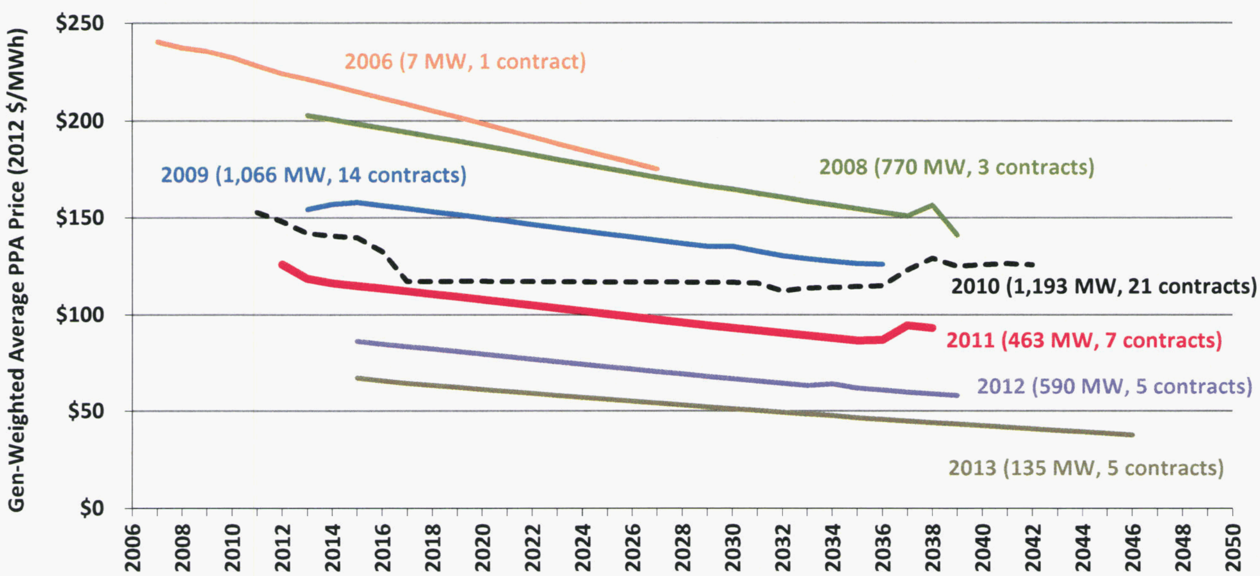

Figure 15. Generation-Weighted Average PPA Prices Over Time by Contract Vintage

To provide a clearer look at the time trend, Figure 16 simply levelizes the price streams shown in Figure 15. Based on this sample, levelized PPA prices for utility-scale solar projects have fallen by roughly \$25/MWh per year on average over this period.[36]

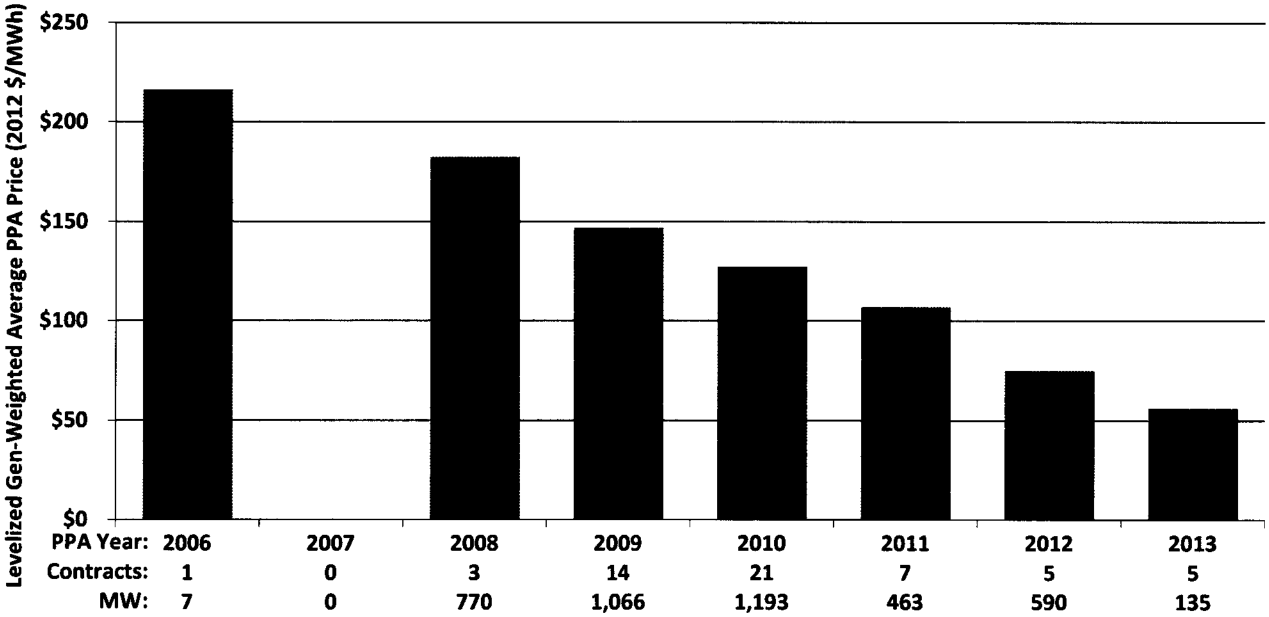

Figure 16. Levelized Generation-Weighted Average PPA Prices by Contract Vintage

This strong time trend, along with small sample size in the most-recent years, complicates more-refined analysis of other variables examined in earlier sections, such as regional differences (though again, nearly the entire sample is in the West), 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 three to four years old, calling into question their current relevance).

Furthermore, it is not clear that some of these variables should even 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 even 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

[36] In Figures 15 and 16, the small sample size in 2011, 2012, and 2013 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 (Caley 2013), Figures 15 and 16 should not necessarily be used to support that argument. Rather, the declining sample size in Figures 15 and 16 is likely more the result of two factors: (1) 2013 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, 2012, and 2013 sample will likely grow in future years with the build-out of projects that signed PPAs in those earlier years.

(at least in these cases) not a critical determinant of PPA pricing.[37] 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[38] – has likely been the dominant influence on PPA prices in recent years, as illustrated by the somewhat-controlled case study presented in the Copper Mountain text box below.

Copper Mountain Projects Illustrate Strong Time Trend in PPA Prices

Boulder City, Nevada is home to a variety of utility-scale solar projects, including the 64 MW_{AC} Nevada Solar One CSP project as well as four phases (each successively larger than the previous) of the Copper Mountain PV projects, which, when fully operational, will total 458 MW_{AC}. The four Copper Mountain projects provide a somewhat-controlled example of the strong trend of falling PPA prices over time, in the sense that they are all located in the same contiguous area, are all owned and operated by the same independent power producer (Sempra Generation U.S. Gas & Power), and the first three phases all use First Solar's CdTe thin-film modules in a fixed-tilt configuration (and therefore have similar actual or expected capacity factors in the mid-20% range) and have long-term PPAs with the same counterparty (PG&E). Notably, in a high-profile nod to the increasing cost-competitiveness of c-Si technology relative to thin film, Sempra announced in August 2013 that the fourth phase (which has a 20-year PPA with the Southern California Public Power Authority) would use c-Si modules made by Trina Solar.

The PPA for the initial 10 MW phase (called El Dorado, though often considered part of Copper Mountain 1) was executed in December 2008 at a levelized price of roughly $150/MWh (in real 2012 dollars). Six months later (June 2009), an additional 48 MW PPA (Copper Mountain 1) was executed at the same price as El Dorado (both of these were 20-year PPAs). Roughly two years later (July 2011), a 25-year PPA for another 150 MW (Copper Mountain 2) was executed at a levelized price of about $103/MWh (real 2012 dollars). And finally, in August 2012 (a full year before Trina Solar was selected as the module supplier), a 20-year PPA for another 250 MW (Copper Mountain 3) was executed at a levelized price of roughly $82/MWh (real 2012 dollars).

Given the underlying similarities among these four projects, the ~$70/MWh decrease in levelized PPA prices over this roughly 3-year period (the magnitude of which is consistent with the decline seen across the full sample in Figure 16) can presumably be attributed primarily to the declining cost of solar modules (and, to a lesser extent, other balance-of-system costs) over this period. Other possible contributors include the realization of greater scale economies with each successively larger phase (though Figure 3 suggests that scale economies may diminish beyond 5-10 MW), as well as improvements in operating costs as Sempra gains greater experience with these projects. Whatever the true combination of drivers, the controlled nature of this case study supports the notion that an analysis of the other variables not examined in this section – tracking vs. fixed-tilt, thin-film vs. c-Si – is not strictly necessary in order to explain the strong time trend shown in Figure 16.

[37] This could be because tracking systems add up-front costs to the system (see Figure 2 in Section 2) that are recouped over time through greater energy yield (see Figure 11 in Section 4), thereby leaving the net impact on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico recently 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).

[38] The steady decline in levelized PPA prices in recent years is not fully consistent with the moderating decline in installed project prices shown earlier in Section 2. A primary reason is that PPA prices are often negotiated on a forward-looking basis – i.e., based on what developers think that modules and projects will cost a year or two in the future when the project is actually built (recall from Figure 14 that nearly 40% of the PPA price sample in capacity terms comes from projects not yet built). The declining cost environment of recent years has, no doubt, influenced expectations for future project costs and, in turn, achievable PPA prices. A second potential explanation is that the installed project prices presented in Section 2 may be conservative in the sense that they are backward-looking, focusing on projects installed through 2012 only.

Price Comparison With Feed-In Tariff ("FIT") Programs That Support Utility-Scale Projects

At least three feed-in tariff ("FIT") programs in the U.S. support projects that fall under the definition of utility-scale used in this report (i.e., ground-mounted projects larger than 2 MW). The Sacramento Municipal Utility District ("SMUD") allows projects up to 5 MW to participate (though larger projects have been subdivided into 5 MW parcels in order to qualify), Vermont's Sustainably Priced Energy Enterprise Development ("VT SPEED") program allows projects up to 2.2 MW, and the Los Angeles Department of Water and Power ("LADWP") allows projects up to 3 MW. Although projects participating in these three programs are ***NOT*** included in the PPA price sample analyzed in this report, it is, nevertheless, interesting to review the prices paid by these FIT programs and compare them to the prevailing PPA prices in the sample.

SMUD's FIT prices are split into nine different time-of-delivery periods, and are fixed for the 20-year duration of the contract. Based on a typical PV production profile in SMUD's service territory, SMUD estimates the PV-production-weighted average annual nominal dollar price to be around $148/MWh (which equates to a levelized 20-year price of roughly $130/MWh in real 2012 dollars) for projects commencing commercial operations in 2012 (i.e., when most of the participating projects came online). SMUD's program was fully subscribed within a week, suggesting that developers considered the pricing to be attractive. Based on where utility-scale solar PPA prices in the West were in early 2010 when the program was launched (see Figure 13), however, SMUD's price does not seem to be too out of line with the market.

The VT SPEED program originally offered a price of $300/MWh flat for 25 years (around $260/MWh levelized in real 2012 dollars), and was quickly over-subscribed. The price was subsequently reduced to $240/MWh ($210/MWh levelized in real 2012 dollars), and in early 2013, the program switched to a competitive reverse-auction format, whereby developers compete for contracts by offering the lowest price (below a pre-established price cap of $257/MWh) at which they are willing to sign a contract. The two winning bids under that Spring 2013 auction came in at $134-$144/MWh flat for 25 years ($114-$122/MWh levelized in 2012 dollars) – substantially lower than what earlier participants are being paid (and comparable to what SMUD is paying in the sunny Central Valley of California). Until these projects are built and operating, however, it remains to be seen whether $134/MWh is sufficient to support solar in sun-challenged New England.

LADWP's program is divided into five 20 MW blocks, with the base price (to be adjusted by TOD factors) starting at $170/MWh in the first block and declining by $10/MWh in each subsequent block (i.e., to $130/MWh for the last 20 MW block). The first 20 MW block was offered (and oversubscribed) in early 2013, and allocation of the second block was underway in July 2013. Although the local ratepayer advocate has criticized this program as paying too much for solar based on the low market prices available elsewhere (and evident in Figure 13), LADWP counters that it can cost up to $30/MWh to wheel that cheap desert solar power into Los Angeles – a cost it can avoid by developing smaller projects closer to home. In addition to this 100 MW fixed-price program, LADWP plans to launch a related program in the near future that – like Vermont – will use competitive bidding to allocate an additional 50 MW.

6. Conclusions

Though parabolic trough CSP projects have been operating in the U.S. since the late 1980s, there were virtually no commercial utility-scale PV projects in operation prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the U.S. Over this same five-year period, CSP also experienced a bit of a renaissance, with new parabolic trough systems operating and under construction, and several large power tower projects also nearing completion in the United States.

With a critical mass of new projects now online and in some cases having operated for several years (generating data in addition to electricity), the utility-scale sector is ripe for analysis. This report, which is envisioned to be the first in an ongoing annual series, meets this need through in-depth, 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 PPA prices. As such, it provides a more-integrated and holistic view of the market than is commonly found.

Given the nascent state of the market, data availability is still, in places, an issue in this inaugural edition. The report nevertheless paints a coherent picture that will be refined, enriched, and solidified over time as more data become available. Until then, some of the more-notable findings from this year's report include the following:

- ***Installed Prices:*** Installed project prices have fallen by nearly one-third since the 2007-2009 period, from around $5.6/W$_{AC}$ to $3.9/W$_{AC}$ on average for projects completed in 2012 (with some projects higher and others lower). Most of the decline has been concentrated among projects using c-Si modules, as the gap between c-Si and thin-film steadily eroded over this period. In response to falling c-Si module prices, there has been a marked increase in the proportion of projects using c-Si (rather than thin-film) modules.
- ***O&M Costs:*** Although O&M cost data are extremely limited at present, what little empirical data exist 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, presumably due to the plumbing and thermal components, and come in around $60/kW$_{AC}$-year.
- ***Capacity Factors:*** Like insolation levels, PV capacity factors vary by region. They also vary depending on whether a project is installed at a fixed-tilt or uses a tracking device, with single-axis trackers able to achieve capacity factors in excess of 30% in some of the better locations (thus confirming the industry rule of thumb that single-axis tracking provides a 20% boost in output). In lieu of trackers, and enabled by the sharp decline in module prices, some projects have instead opted to oversize the PV array relative to the capacity rating of the inverters as a way to boost capacity factor. On the CSP side of the market, parabolic trough systems that have been operating in the U.S. for more than 20 years are still (in 2012) achieving capacity factors in excess of 20% (solar portion only, no storage), which is comparable to newer trough projects. Meanwhile, a pilot project for power tower technology has underperformed relative to expectations, but several much

larger power tower projects under construction will soon test that technology on a truly commercial scale in the United States (several commercial power tower projects have been operating in the Mediterranean region for several years).

- ***PPA Prices:*** Driven primarily by lower installed project prices (which, in turn, have been driven primarily by declining module prices), levelized PPA prices have fallen dramatically over time, by \$25/MWh per year on average. Some of the most-recent PPAs in the West have levelized PPA prices as low as \$50-60/MWh (in 2012 dollars), which, in some cases, is competitive with wind power projects in that same region. Solar appears to be particularly competitive when considering its time-of-delivery pricing advantage over wind (roughly \$25/MWh in California at current levels of penetration).

Utility-scale project developers (as well as utilities) can use these findings and data to refine their views of the market and/or to inform the various tradeoffs that they must regularly make, for example regarding choice of technology. Policymakers and the general public will presumably come away from this report with a newfound understanding of just how competitive utility-scale solar has become in a very short time-period. Consultants, modelers, and financiers, meanwhile, can use these empirical data from actual operating experience to either validate or improve their modeling assumptions, thereby leading to better representation of this sector in future studies.

Although the insights in this first edition are compelling, they are nevertheless still constrained by limited data availability. As the market itself continues to grow in future years, so too will the sample of data available for analysis, highlighting the importance of maintaining and updating these fledgling data sets in the coming years so that future editions of this report can continue to track this rapidly growing market.

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:

- ***Nameplate Capacity:*** Form EIA-860, FERC Form 556, state regulatory filings, trade press articles
- ***Installed Prices (Section 2):*** 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 the National Renewable Energy Laboratory (NREL)
- ***O&M Costs (Section 3):*** FitchRatings (projections only) and FERC Form 1 (actual/empirical data)
- ***Capacity Factors (Section 4):*** FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings
- ***PPA Prices (Section 5):*** 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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