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Mark Bolinger, Samantha Weaver[1], Jarett Zuboy[2]

[1]Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Lab, Berkeley, CA

[2]Independent Consultant, Golden, CO

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Is $50/MWh Solar for Real? Falling Project Prices and Rising Capacity Factors Drive Utility-Scale PV Toward Economic Competitiveness

Mark Bolinger[1]*, Samantha Weaver[1], Jarett Zuboy[2]

[1]Lawrence Berkeley National Laboratory, Berkeley, CA, USA
[2]Independent Consultant, Golden, CO, USA

*Correspondence
Mark Bolinger, Lawrence Berkeley National Laboratory, 1 Cyclotron Road, MS 90-4000, Berkeley CA 94720
Email: MABolinger@lbl.gov

Recently announced low-priced power purchase agreements (PPAs) for U.S. utility-scale PV projects suggest $50/MWh solar might be viable under certain conditions. To explore this possibility, this paper draws on an increasing wealth of empirical data to analyze trends in three of the most important PPA price drivers: upfront installed project prices, operations and maintenance (O&M) costs, and capacity factors. Average installed prices among a sample of utility-scale PV projects declined by more than one third (from $5.8/W$_{AC}$ to $3.7/W$_{AC}$) from the 2007–2009 period through 2013, even as costlier systems with crystalline-silicon modules, sun tracking, and higher inverter loading ratios (ILRs) have constituted an increasing proportion of total utility-scale PV capacity (all values shown here are in 2013 dollars). Actual and projected O&M costs from a very small sample of projects appear to range from $20–$40/kW$_{AC}$-year. The average net capacity factor is 30% for projects installed in 2012, up from 24% for projects installed in 2010, owing to better solar resources, higher ILRs, and greater use of tracking among the more recent projects. Based on these trends, a pro-forma financial model suggests that $50/MWh utility-scale PV is achievable using a combination of aggressive-but-achievable technical and financial input parameters (including receipt of the 30% federal investment tax credit). Although the U.S. utility-scale PV market is still young, the rapid progress in the key metrics documented in this paper has made PV a viable competitor against other utility-scale renewable generators, and even conventional peaking generators, in certain regions of the country.

Keywords: utility-scale, capacity factor, power purchase agreement, price trends, O&M, economic competitiveness

Short title: Technical and Economic Improvements Drive Utility-Scale PV to $50/MWh

1. Introduction

Power purchase agreement (PPA) prices associated with U.S. utility-scale photovoltaic (PV) projects have declined precipitously over the past few years (Figure 1[1]), with some recently signed contracts averaging around $50/MWh – i.e., roughly half the level commonly seen just a few years ago. Most of these projects with ultra-low PPA prices, however, have not yet been built, and in many cases are not scheduled to achieve commercial operations until late 2016.[2] Others that are already operational (e.g., Macho Springs) or that are scheduled to come online in 2015 (e.g., Sandstone) benefit from state-level incentives that help to reduce PPA prices[3] (Table 1[4]).

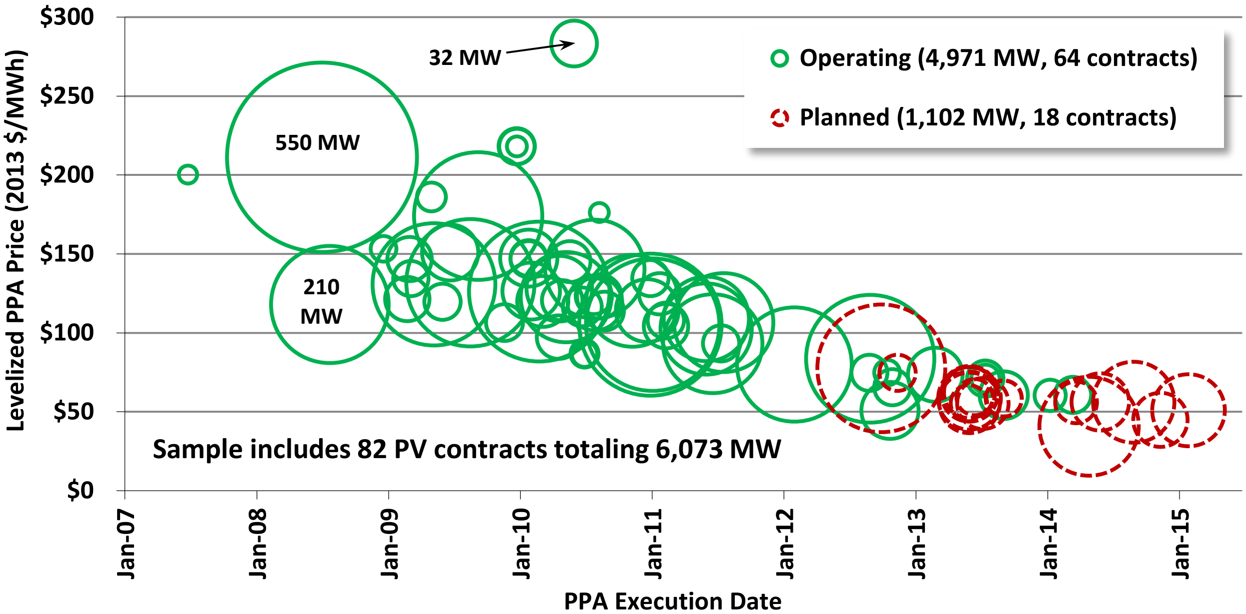

Figure 1. Levelized U.S. Utility-Scale PV PPA Prices by Operational Status and PPA Execution Date

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[1] The PPA prices shown in Figure 1 and Table 1 are levelized (using a 7% real discount rate) over the full term of each contract, after accounting for any escalation rates and time-of-delivery factors. The PPA price data are drawn from FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, and trade press articles.

[2] Of the capacity shown in Figure 1, 18%—the newer contracts denoted by the red dashed circles—was not yet online at the time of writing. All of these projects are scheduled to be built in 2015 or, more often, 2016.

[3] New Mexico's and Arizona's 10-year production tax credit ("PTC") each averages $27/MWh over the full 10-year term (though Arizona's steadily declining credit is worth slightly more on a present value basis). In addition, Macho Springs' ability to share interconnection and other infrastructure with a co-located wind power project was also reportedly a significant enabler of its low PPA price.

[4] In addition to the four contracts detailed in Table 1, there are at least a dozen planned utility-scale PV projects in California with levelized PPA prices in the $55-$65/MWh range (real 2013 dollars), most of which will not be built until 2016. These projects benefit from the demand created by California's renewables portfolio standard ("RPS"), but not from direct state-level financial incentives. Another notable project not shown in Figure 1 or Table 1 is First Solar's 18 MW_{AC} Barilla project built in Texas in 2014; it is the first utility-scale PV project in the United States to be built on a merchant basis (i.e., without a long-term PPA) to compete directly with wholesale power prices. Finally, looking outside of the United States, the Dubai Electricity and Water Authority ("DEWA") recently awarded a 25-year PPA at an unsubsidized price of $58.4/MWh to Saudi Arabia's ACWA Power for a 200 MW PV project in Dubai. Unlike the U.S. projects analyzed in this paper, this Dubai project does not benefit from a 30% investment tax credit, and as such has been heralded by some to be the lowest-priced solar contract in the world [3].

Table 1. Details on the Four Lowest-Price PPAs in the Sample

Project Name	State	Project Capacity (MW_{AC})	Levelized PPA Price (2013 $/MWh)	PPA Execution Date & Term	Year Online	State Financial Incentives
Austin Energy/ Recurrent	TX	150	$41.0/MWh	5/2014 20 years	2016	None
Sandstone	AZ	45	$44.8/MWh	11/2014 21 years	2015	10-year PTC
Macho Springs	NM	50	$50.9/MWh	10/2012 20 years	2014	10-year PTC
River Bend	AL	80	$51.0/MWh	2/2015 20 years	2016	None

This apparent forward-bidding of low PPA prices for projects that are still very much in the planning stages begs the question of whether $50/MWh solar is, indeed, achievable (particularly without state incentives), or whether developers may have instead gotten ahead of themselves and bid too aggressively in "a race to the bottom"? This paper answers this question by drawing on the wealth of empirical data that has begun to accumulate in the utility-scale PV sector as this sector has grown rapidly in recent years. Specifically, it analyzes trends in three of the most important drivers of PPA prices: upfront installed project prices (the traditional realm of solar economics studies; see, for example, [1] and [2]), operations and maintenance (O&M) costs, and capacity factors. By analyzing these empirical trends and calculating what it takes to make $50/MWh PV a reality, this paper demonstrates that, under best-case conditions (including receipt of the 30% federal investment tax credit), $50/MWh PV is, indeed, currently achievable.

The paper proceeds as follows. Section 2 describes the total population of utility-scale PV projects from which installed price, O&M cost, and capacity factor data samples are drawn in subsequent sections. This brief characterization of the project population highlights how project development trends are influencing trends in the rest of the data (and the capacity factor data in particular). Section 3 updates and extends through 2013 the installed price trend for utility-scale PV projects that was recently presented within this same journal through 2012 [1]. Installed prices, however, tell only part of the story: Sections 4 and 5 present trends in the equally important O&M costs and capacity factors, respectively. Section 6 then uses the empirical data presented in Sections 3, 4, and 5 as inputs into a simple pro-forma financial model exploring whether a $50/MWh PPA is feasible based on benchmarks already being observed in the market. Section 7 briefly concludes.

2.0 Characterization of the Utility-Scale PV Sector

Although specific definitions vary,[5] "utility-scale PV" generally refers to large (multi-megawatt) PV projects that generate electricity for sale to utilities at wholesale prices rather than for onsite consumption. In the United States, utility-scale PV has been the fastest-growing sector of the overall PV market (which also includes the residential and commercial sectors) since 2007, and since 2012 it has accounted for the largest share of the overall PV market in terms of new capacity installed [5]. This dominance is projected to continue through 2016 [5], with subsequent prospects dependent on whether or not the 30% federal investment tax credit is extended beyond 2016 or reverts to 10% at the end of that year, as currently scheduled.

This paper defines utility-scale PV to include any ground-mounted project with a capacity rating larger than 5 MW_{AC}. Based on this definition, 126 utility-scale PV projects totaling 3,023 MW_{AC} were fully online and operating in the United States by the end of 2013.[6] The first of these projects came online in 2007, and—highlighting just how young this sector is—92% of this capacity was installed in the 3 years from 2011 through 2013 (Figure 2). Most of this capacity (86%) is installed in the southwestern United States (broadly defined here to include the five states of California, Nevada, Arizona, New Mexico, and Colorado)—a region with a strong solar resource and state-level policies (such as renewable portfolio standards and state-level tax credits) that encourage utility-scale solar deployment.[7]

Within this utility-scale PV project population, projects can be classified into four main categories, depending on the type of module used—crystalline-silicon (c-Si) or thin-film (primarily cadmium telluride)—and whether the modules are mounted at a fixed-tilt or on a system that tracks the sun.[8] Over time, there has been a trend towards projects using c-Si modules, often in conjunction with single-axis tracking (Figure 2). As a result, at the end of 2013, c-Si projects accounted for substantially more capacity than thin-film projects (69% versus 31%), while the overall proportions of fixed-tilt and tracking capacity were about even (after tracking accounted for 60% of the record amount of new utility-scale PV capacity installed in the United States in 2013). Specifically, the total project population of 3,023 MW_{AC} was dominated by tracking c-Si projects (1,489 MW_{AC}), followed by fixed-tilt thin-film (893 MW_{AC}) and fixed-tilt c-Si (595 MW_{AC}) projects, along with just two tracking thin-film projects (47 MW_{AC}).

[5] Bolinger and Weaver [4] describe some of the variations. For example, the U.S. Energy Information Administration (EIA) characterizes any project of 1 MW_{AC} or larger as utility-scale, while GTM Research and the Solar Energy Industries Association (SEIA) [5] base the distinction on the offtake arrangement (i.e., whether the solar electricity is primarily consumed on site or sold to a utility) rather than on project capacity.
[6] The utility-scale PV characteristics presented here are drawn from Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory (NREL), SEIA, Google Earth, and trade press articles.
[7] See [4] for a map of the United States that shows specific project locations in relation to solar resource strength.
[8] All of the PV projects in the population that use tracking systems use single-axis (as opposed to dual-axis) tracking. Dual-axis tracking is not yet seen as cost effective in the market.

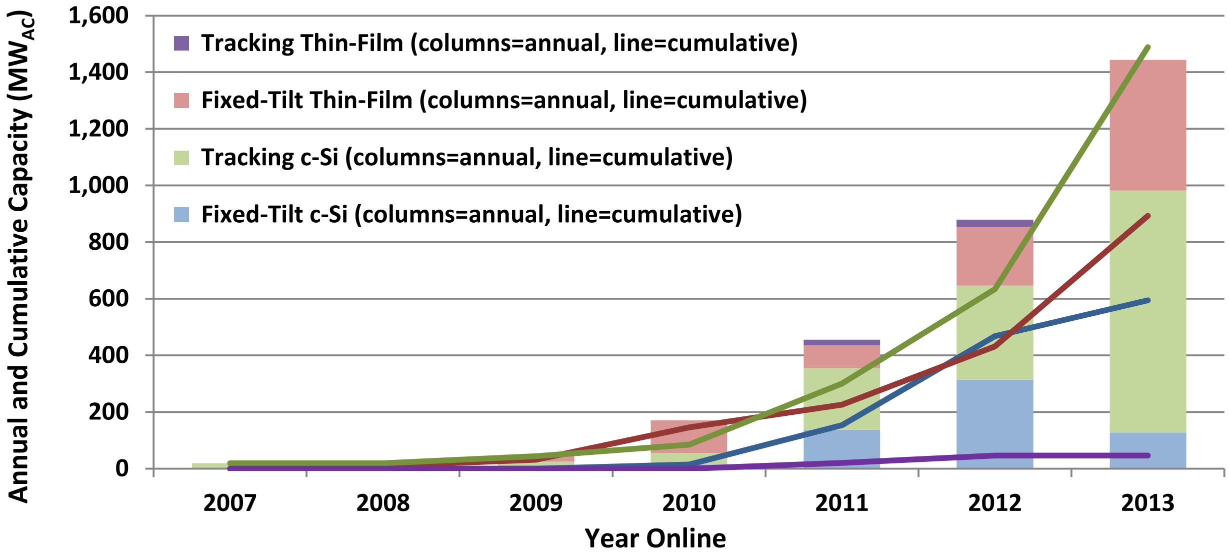

Figure 2. Historical U.S. Utility-Scale PV Capacity by Module Type and Project Configuration

Two development trends within this population are worth noting for the positive impact they have on project performance, as measured by capacity factor.[9] First, the average solar resource strength (defined in Figure 3 in terms of direct normal irradiance or DNI) across the project population has generally increased with project vintage. On average, more recent projects have been built at sites with a stronger solar resource (red line and left scale in Figure 3). All else equal, this trend boosts average capacity factors.

Second, as module costs have fallen more rapidly than inverter costs, developers have been increasing the capacity of the direct-current (DC) module array relative to the alternating-current (AC) inverter rating as a way to squeeze more electricity (e.g., during shoulder periods) out of the existing inverter(s) and thereby boost revenue—particularly under PPAs that use time-of-delivery pricing [6]. This DC/AC capacity ratio, known by a variety of names, is referred to here as the inverter loading ratio (ILR).[10] Figure 3 shows that the average ILR has increased from roughly 1.18 for 2010- and 2011-vintage projects to nearly 1.27 for 2013-vintage projects. All else equal, as the ILR increases, so will the amount of generation per unit of AC capacity, resulting in a higher capacity factor in AC terms (in DC terms, capacity factor will actually *decrease* as the ILR increases[11]).

[9] Capacity factor is a measure of the actual generation from a project as a percentage of the maximum possible generation from that project if it were operating at full capacity at all times. The specific formula for calculating cumulative capacity factor is provided later in footnote 26.
[10] The ILR is also referred to as DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, and DC load ratio [6,7].
[11] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an ILR of 1.20 and a 20% capacity factor in DC terms at an ILR of 1.50.

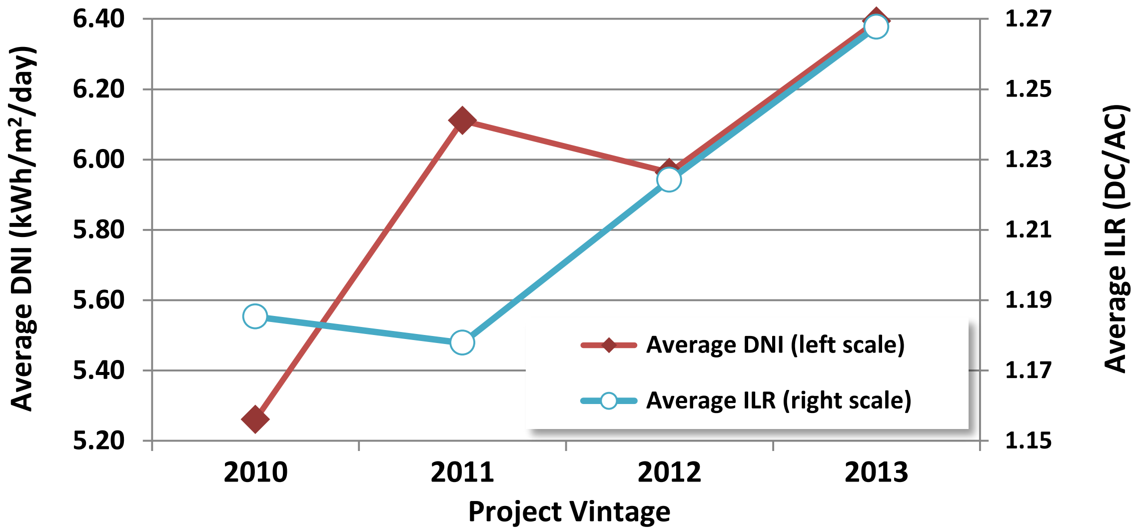

Figure 3. Trends in DNI and ILR by PV Project Vintage

3.0 Falling Installed System Prices

Figure 4 shows installed price data[12] for 98 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects, totaling 2,599 MW_{AC}, built between 2007 and 2013.[13] By definition, this sample is backward-looking, in the sense that only projects that were fully operational by the end of 2013 are included.[14] Moreover, installed prices within this backward-looking sample may reflect transactions (e.g., entering into an engineering, procurement, and construction—or EPC—contract) that occurred one or more years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporary costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent reductions in component costs or other changes in market conditions.[15] For these reasons, the data presented in this section may not correspond to other recent installed price benchmarks for utility-scale PV and may differ from the average installed prices reported elsewhere (e.g., in [5]).

[12] 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 the fair market value of a given project (the price at which it would be sold through an arms-length transaction in a competitive market).
[13] This sample for which installed price data are available represents 78% of the total number of projects (86% of the total capacity) in the project population described in Section 2. The installed price information presented here is drawn from Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state and federal regulatory filings, company financial filings, trade press articles, and NREL.
[14] This contrasts with the PPA prices shown in Figure 1, where 18% of the capacity in that sample is not yet operational.
[15] This may partially explain why the decline in installed prices presented in this section seemingly has not kept pace with the decline in PPA prices shown in Figure 1.

Although utility-scale PV capacity is more appropriately reported in AC (rather than DC) terms,[16] Figure 4 shows installed prices in both $/W$_{AC}$ and $/W$_{DC}$ terms to provide continuity between this paper and others (e.g., [1], [2] and [5]) that have expressed installed prices only in $/W$_{DC}$ terms. Apart from Figure 4, the remainder of this paper reports data exclusively in AC terms.

As shown in Figure 4, average installed prices among the sample of utility-scale PV projects have declined by more than one third from the 2007–2009 period through 2013, as capacity-weighted average prices dropped from $5.8/W$_{AC}$ to $3.7/W$_{AC}$ over that timeframe. Most of this decline occurred through 2012, however, as capacity-weighted average prices within the sample were little changed from 2012 ($3.8/W$_{AC}$) to 2013 ($3.7/W$_{AC}$).

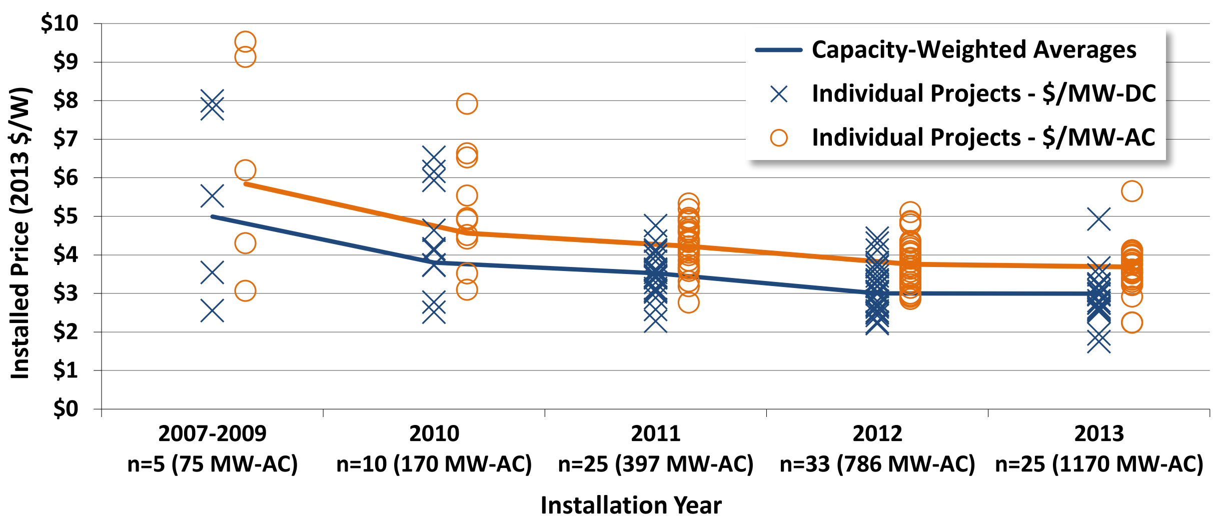

Figure 4. Installed Price of U.S. Utility-Scale PV, 2007–2013

Anecdotally, a similar pattern of slowing price declines even among forward-looking prices is evident in a recent Public Service Company of New Mexico (PNM) filing for regulatory approval of 40 MW$_{AC}$ of utility-scale PV scheduled to be built in 2015 (as two separate 20-MW$_{AC}$ projects). The company expects this new turnkey capacity to cost $1.98/W$_{AC}$, which is down only slightly from the $2.03/W$_{AC}$ it is currently paying for another 23-MW$_{AC}$ project built in 2014.[17]

Though capacity-weighted average prices in the sample have declined over time (at least through 2012), there remains a considerable spread in individual project prices. Among the 25 PV projects in the sample that were completed in 2013, for example, installed prices range from

[16] AC capacity is more appropriate for utility-scale PV because all other utility-scale generation sources to which utility-scale PV is compared—including concentrating solar power projects—are described in AC capacity terms. In addition, as described in Section 2, ILRs have increased over time, making the DC capacity of a project less meaningful (given that output is increasingly constrained by the AC inverter rating).

[17] Both of these prices (of ~$2/W$_{AC}$) are down more substantially from the $2.25/W$_{AC}$ that PNM paid for another 20 MW$_{AC}$ built in 2013 and the $3.99/W$_{AC}$ that it paid for an initial 22.5 MW$_{AC}$ built in 2011 [8]. PNM's 2011 price point of roughly $4/W$_{AC}$ is consistent with the capacity-weighted average price for 2011 shown in Figure 4, while PNM's 2013 price point of $2.25/W$_{AC}$ is at the low end of the overall range for 2013.

$2.2/W_{AC}$ to $5.6/W_{AC}$, and prior years also show substantial variability. This price variation is partially attributable to differences in module type and project configuration (Figure 5).

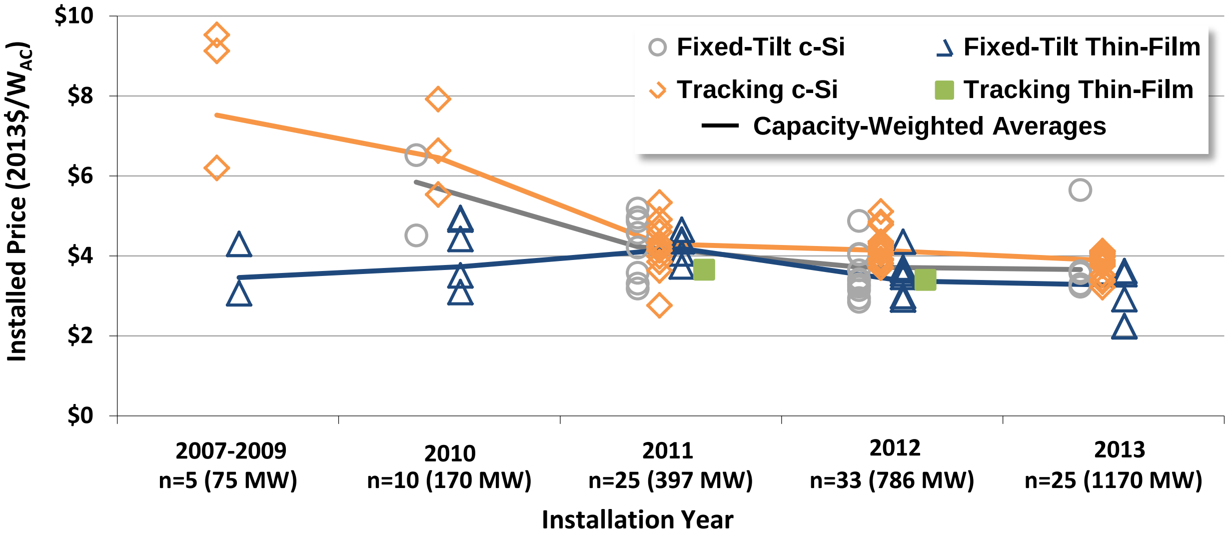

Figure 5. Installed Price of U.S. Utility-Scale PV by Module Type and Project Configuration, 2007–2013

For example, although projects using c-Si modules historically have been significantly more expensive than projects using thin-film modules (e.g., by $2.1/W_{AC}$ on average in 2010, though based on a very small sample), the average installed price of c-Si and thin-film projects largely converged in 2011, precipitating the start of a significant increase in the number of c-Si projects in both the installed price sample and the broader population (see Figure 2).[18] Since 2011, there have been only minor differences in installed prices across these categories, with c-Si projects being slightly more expensive than thin-film (just $0.4/W_{AC}$ on average in 2013 among fixed-tilt projects) and with tracking projects only slightly more expensive than fixed-tilt (just $0.20/W on average in 2013 among c-Si projects). As discussed in Section 5, however, the higher upfront cost of single-axis tracking provides a benefit in terms of greater energy production and hence likely lower $/MWh costs over a project's life.[19]

4.0 O&M Costs

In addition to upfront installed project prices, utility-scale PV projects incur ongoing O&M costs. Publicly available empirical data on the O&M costs of utility-scale PV projects are hard to obtain. Relatively few utility-scale PV projects have been operating for more than a full year, and even fewer of those projects are owned by investor-owned utilities, which are required by the Federal Energy Regulatory Commission (FERC) to report on Form 1 the O&M costs of the

[18] This shift towards c-Si can be illustrated anecdotally by the Copper Mountain projects in Nevada: the first three phases (built from 2008–2012) use thin-film modules, while the fourth phase (planned for 2015) will use c-Si modules. In a similar nod to the increasing cost competitiveness of c-Si, PNM's 40 MW_{AC} slated for 2015 will use c-Si modules, in contrast to its previous projects (built in 2011, 2013, and 2014), all of which use thin-film modules. In its recent regulatory filing, PNM attributes the switch to c-Si solely to cost considerations [8].

[19] For example, based on its review of offers received in response to a renewable energy request for proposals, PNM estimated that the average PPA price benefit of single-axis tracking was $3/MWh, or about 4% of a levelized PPA price in the mid-$70/MWh range [9].

power plants they own.[20] Finally, even fewer of those investor-owned utilities that own utility-scale PV projects actually report operating cost data in FERC Form 1 as they are required to.

Because of these limitations, the sample of utility-scale PV projects for which O&M cost data are publicly available is very small: just seven projects totaling 60 MW_{AC} (see the left graph in Figure 6).[21] Two of these projects have historical data for more than 2 years; the other five have data for only 2012 and 2013. Despite the extremely limited sample (and the considerable range of costs within it), reported empirical O&M costs seem to fall largely within the neighborhood of \$20–\$40/kW_{AC}-year. The sample is too small to discern any sort of time trend, however, and the data are included here primarily to help benchmark the operating cost input assumption to the pro forma financial model later in Section 6.

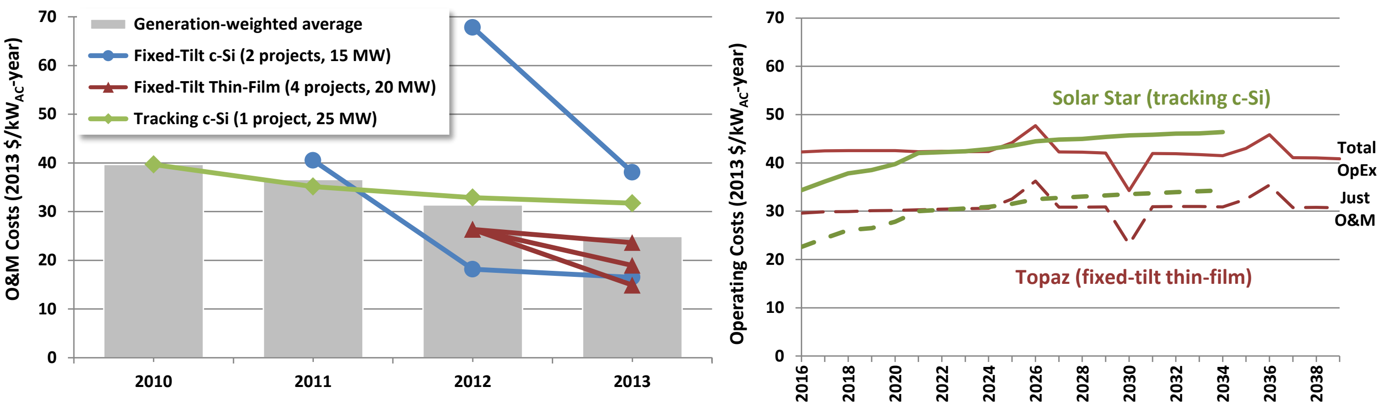

Figure 6. Operating and O&M Costs for U.S. Utility-Scale PV Projects from Empirical Data (left) and Bond Rating Agency Research (right)

To supplement the limited empirical data, the graph on the right of Figure 6 presents *projected* O&M (dashed lines) as well as total operating (OpEx, solid lines[22]) costs from two large projects that have financed a portion of their capital costs through public bond offerings, thereby necessitating the disclosure of detailed project information [10,11]. The 550-MW Topaz project is a fixed-tilt thin-film project, while the 579-MW Solar Star project uses c-Si with single-axis tracking. Both projects are located in California and, at the time of writing, were either fully online (Topaz) or under construction and delivering electricity from early phases (Solar Star).

Though not empirical data, and perhaps tending to be conservative in nature,[23] projected O&M and operating costs for these two projects are instructive. As shown, the two PV projects have

[20] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses," namely those operational costs associated with supervision and engineering, maintenance, rents, and training. Though definitions may vary, FERC Form 1's "operating expenses" are largely consistent with what most industry participants would consider to be O&M costs, rather than total operating expenses.
[21] The O&M cost information presented in this section is drawn from FERC Form 1 and FitchRatings.
[22] In addition to O&M costs—i.e., those costs incurred directly to operate and maintain the generating plant itself—total operating expenses include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead [10,11].
[23] Given that these projected O&M costs are obtained from documentation intended to support a credit rating, they may be conservatively high 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

very similar O&M and total operating cost projections, with O&M costs in the \$22 to \$36/kW$_{AC}$-year range over time—i.e., largely consistent with the limited empirical sample shown in the left graph.[24] For both projects, projected O&M costs account for about 75% of total projected operating costs.

5.0 Rising Capacity Factors

At the close of 2013, at least 64 utility-scale PV projects totaling 1,532 MW$_{AC}$ had been operating for at least 1 full year (and for as many as 6 full years), thereby enabling the calculation of capacity factors.[25,26] Although the capacity-weighted average cumulative capacity factor across this sample is 27.5%,[27] Figure 7 shows a considerable variation in individual project-level capacity factors (from 16.6% to 32.8%) around this central tendency. This variation can be explained by a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site (measured in DNI with units of kWh/m^2/day), whether the array is mounted at a fixed-tilt or on a tracking mechanism, the DC capacity of the array relative to the AC inverter rating (the ILR), and the type of modules used (c-Si versus thin-film).[28]

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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 [10,11]. For this reason, actual O&M costs for these projects might tend to be lower than shown in Figure 6. On the other hand, these are both very large projects, and smaller projects might experience higher per-unit O&M costs if economies of scale are present.

[24] The projected O&M costs for Solar Star are also consistent with PNM's \$21/kW$_{AC}$-year estimate of annual O&M costs (which, in addition to O&M contract costs, also include costs associated with vegetation and animal management, vandalism, and other property damage) for 40 MW$_{AC}$ (split into two 20-MW$_{AC}$ projects) of tracking c-Si projects that it plans to build in 2015 [8].

[25] The capacity factor information presented here is drawn from FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings.

[26] The capacity factor 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]. As such, the capacity factors presented in this section represent *cumulative* capacity factors—i.e., they are calculated over as many full years of data as are available for each individual project, ranging from just 1 year (2013) for projects built in 2012 to a maximum of 6 years (2008–2013) for projects built in 2007. In addition, the capacity factors are expressed in *net*, rather than *gross*, terms (i.e., they represent the output of the project net of its own use). They are also calculated in AC terms (i.e., using the MW$_{AC}$ rather than MW$_{DC}$ capacity rating), which results in higher capacity factors than if reported in DC terms (see footnote 11) 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.

[27] The median is 26.9%, and the simple average is 25.9%.

[28] Other factors such as tilt and azimuth also play a role; however, since this paper focuses only on ground-mounted utility-scale projects, we assume these fundamental parameters will be optimized equally across projects to maximize energy production.

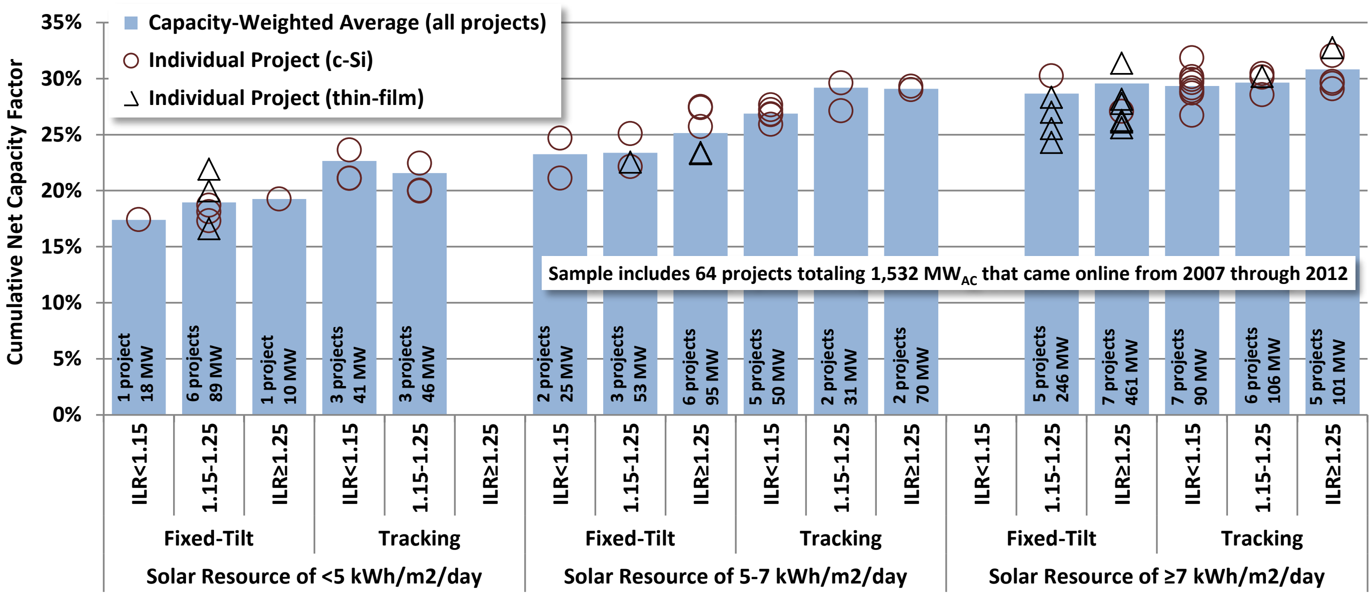

Figure 7. Cumulative U.S. Utility-Scale PV Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, ILR, and Module Type

Project vintage might also be expected to play a role, with newer projects having 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 modules to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well), or they use the same number of them to boost the amount of capacity installed on a fixed amount of land (which directly reduces at least $/W$_{DC}$ costs, if not also $/W$_{AC}$ costs). In other words, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is therefore most likely attributable to a time trend in one of the other variables noted above, e.g., towards higher ILRs, a higher DNI, or greater use of tracking.

Figure 8 supports this hypothesis by breaking out the average cumulative net capacity factor by project vintage across the sample of projects built in 2010, 2011, or 2012 (and by noting the relevant average project parameters within each vintage). As shown, the average capacity factor does not differ much on average between 2010- and 2011-vintage projects, which makes sense given the lack of significant change in average ILR across vintages, in conjunction with the opposing influences of a lower DNI and a higher proportion (in capacity terms) of projects using tracking among 2011-vintage projects. Projects built in 2012, however, have a notably higher capacity factor on average (almost 30%), driven by a significant increase in both the average ILR and the average DNI.[29] Because average DNI and ILR increased among the fleet of projects built

[29] The sharp increase in the average capacity factor among 2012-vintage projects comes in spite of reports that the insolation in the southwestern United States (where many of these projects are located) was below normal in 2013 [12]. With just a single year—2013—contributing to the capacity factor calculation, the 2012-vintage projects presumably would be impacted more negatively than the 2010- and 2011-vintage projects by sub-par 2013 insolation.

in 2013 (Figure 3), additional increases in capacity factors might be expected among 2013-vintage projects.

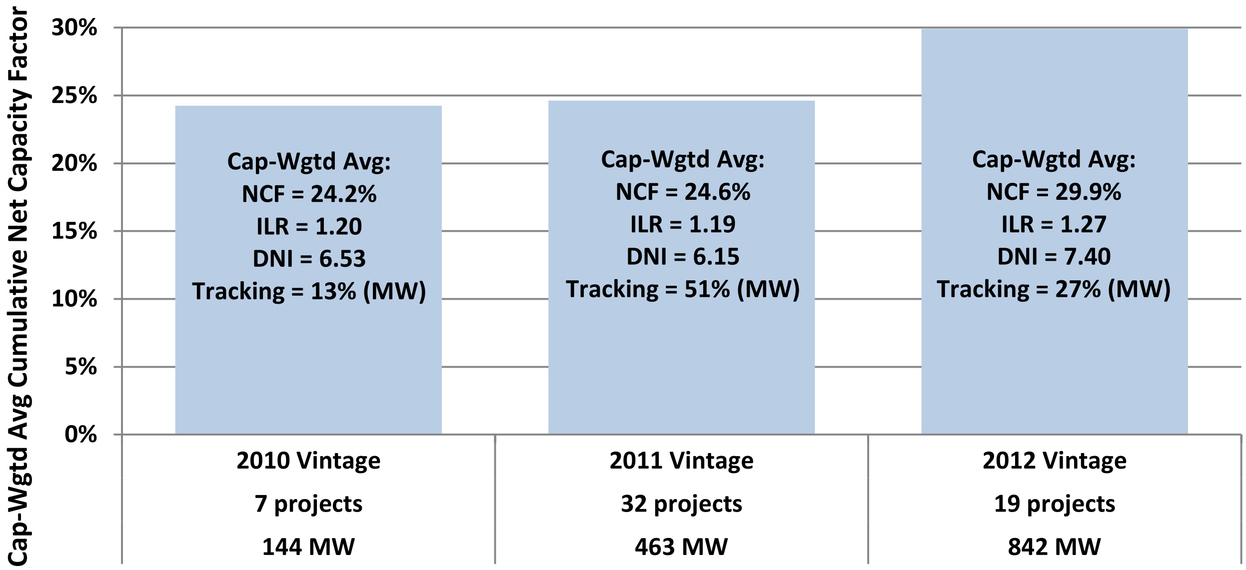

Figure 8. Cumulative U.S. Utility-Scale PV Net Capacity Factor (NCF) by Project Vintage: 2010-2012 Projects Only

6.0 Achieving $50/MWh PV

This paper so far portrays an increasingly competitive utility-scale PV sector, with installed prices falling even as developers shift towards more-expensive project configurations involving single-axis tracking and/or higher ILRs to boost production and, hence, AC capacity factors. But is this progress enough to justify the $50/MWh PPAs that have been signed recently (as shown in Figure 1 and Table 1)? This section addresses this question by using a pro-forma financial model to see whether input assumptions drawn from the empirical data presented in previous sections, in conjunction with current market-based financing parameters, yield a PPA price close to $50/MWh (without state-level incentives).

The simple pro-forma financial model—developed for and detailed within [13]—assumes that the project is financed solely by a combination of sponsor equity and long-term project-level debt (i.e., no third-party tax equity) and that the sponsor has sufficient "tax appetite" to make efficient use of tax losses (5-year MACRS depreciation[30]) and credits (the 30% federal investment tax credit) in the years in which they are generated. This simple financing structure, involving such a tax-efficient sponsor, will yield a lower overall weighted-average cost of capital than complicated partnership flip or sale-leaseback structures involving third-party tax equity [13]; hence this should be considered a best-case financing scenario.

Similarly, to reach $50/MWh, the inputs drawn from the empirical data in Sections 3–5 presumably also must reflect best-case conditions. The column titled "Case 1" in Table 2 reflects these assumptions: $2.25/W$_{AC}$ is the low end of the installed price range among 2013-vintage projects from Figures 4 and 5, total operating expenses of $30/kW$_{AC}$-year (assumed to escalate in

[30] MACRS stands for Modified Accelerated Cost Recovery System.

nominal dollars at the assumed inflation rate of 2%/year) seem feasible based on Figure 6, and a 33% capacity factor (in AC terms) matches the best projects shown in Figure 7. The assumed output degradation rate of 0.5%/year is an industry standard that is commonly used within utility-scale PV PPAs to reduce expected/promised generation over time [14]. Recent financing parameters come from [13] and include a 10% after-tax internal rate of return (IRR) for the project sponsor and a 5.5% all-in interest rate on 17-year term debt with a debt service coverage ratio (DSCR) of 1.35[31]—all of which enables a capital structure (determined endogenously by the model) of 54% equity and 46% debt.

The bottom row of Table 2 shows that this particular combination of aggressive-but-achievable input parameters breaks the $50/MWh threshold on a real dollar basis. Since Figure 1 and Table 1 are also expressed in real 2013 $/MWh, we can conclude that the scenario laid out in Table 2/Case 1 is largely consistent with recent PPA prices shown in Figure 1 and Table 1.

Table 2. Key Inputs for Pro-Forma PPA Modeling

Modeling Parameter	Case 1	Case 2	Source
Installed Cost ($/$W_{AC}$)	2.25	1.55	Section 3 (for Case 1)
Net Capacity Factor (AC)	33%	25%	Section 5
Total Operating Expenses ($/$kW_{AC}$-year)	30		Section 4
Annual Degradation	0.5%		[14]
Sponsor After-Tax Internal Rate of Return (IRR)	10%		Recent market-based financing terms from [13]
Term Debt Interest Rate	5.5%		
Debt Term (years)	17		
Debt Service Coverage Ratio (P50)	1.35		
Capital Structure (%Equity/%Debt)	54%/46%		Determined by model
Levelized 20-Year PPA Price (2013 $/MWh)	**$49.9/MWh**	**$49.8/MWh**	**Model Output**

Absent even higher inverter loading ratios, dual-axis tracking, and/or project-level storage becoming economical, however, the applicability of the 33% net capacity factor (in AC terms) assumed in Case 1 will be limited to projects located in the best resource areas (e.g., in the southwestern United States). To examine what it takes to achieve $50/MWh solar in other parts of the United States, Case 2 of Table 2 assumes a more modest capacity factor of 25% – shown earlier to be nearly achievable (with tracking) in even the lowest resource bin of Figure 7. All other inputs except installed price are held constant in Case 2, given that operating costs, degradation, and financing terms should not differ materially by location. As shown, in order for Case 2 to break $50/MWh in real dollar terms, the installed price must fall to $1.55/$W_{AC}$ – i.e., well below the range of installed prices seen in Figures 4 and 5 among the sample 2013-vintage projects, but perhaps achievable within the next few years, given analyst projections [2] and lower installed price benchmarks in Germany [15,16].

Finally, the results in Table 2 assume access to the 30% federal investment tax credit in Section 48 of the tax code. This 30% credit is scheduled to revert to 10% for any project placed in service after December 31, 2016. Rerunning Case 1 and Case 2 with the same input assumptions except for a 10%, instead of 30%, investment tax credit yields real levelized PPA prices of

[31] The DSCR of 1.35 is based on a P50 (i.e., median) generation estimate.

$62.6/MWh and $61.3/MWh, respectively.[32] Hence, if the investment tax credit reverts to 10% as currently scheduled, project sponsors will need to find additional cost or performance improvements to achieve $50/MWh PPA prices.[33]

7.0 Conclusion

Although the U.S. utility-scale PV market is young and the operating history of many projects (particularly the record amount of new capacity built in 2013) is still very limited, a critical mass of project-level data now enables empirical analysis of this rapidly growing sector of the market. This paper draws on the increasing wealth of data to illuminate progress in PPA prices, installed project prices, operating costs, and capacity factors. Using a pro-forma financial model, it also demonstrates that the recent remarkable decline of PPA prices to $50/MWh appears to be justified by the combined progress in installed prices and capacity factors. This progress has helped make PV the dominant utility-scale solar technology in the United States and a viable competitor against other renewable generators, and even conventional peaking generators, in certain regions of the United States.

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[32] This $12-$13/MWh (in real 2013 dollars) increase in levelized PPA prices resulting from the reversion of the 30% investment tax credit back to 10% is perhaps more modest of an impact than one might expect, in large part due to a corresponding shift in the project's capital structure. Specifically, as the size of the credit decreases to 10%, the amount of leverage the project can support increases from 46% (see Table 2) to 61%. Because debt is cheaper than equity, the greater amount of leverage possible under the 10% credit partially mitigates the negative impact of the declining credit [13].

[33] If federal tax incentives were eliminated altogether (e.g., no investment tax credit at all, and a 12-year straight-line rather than a 5-year accelerated depreciation schedule), the corresponding real levelized PPA prices for Case 1 and Case 2 would be $76.8/MWh and $74.2/MWh, respectively. In this light, the aforementioned $58.4/MWh unsubsidized PPA price between ACWA Power and DEWA for a planned 200 MW project in Dubai does indeed seem unprecedented [3].

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