Utility-Scale Solar 2014

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

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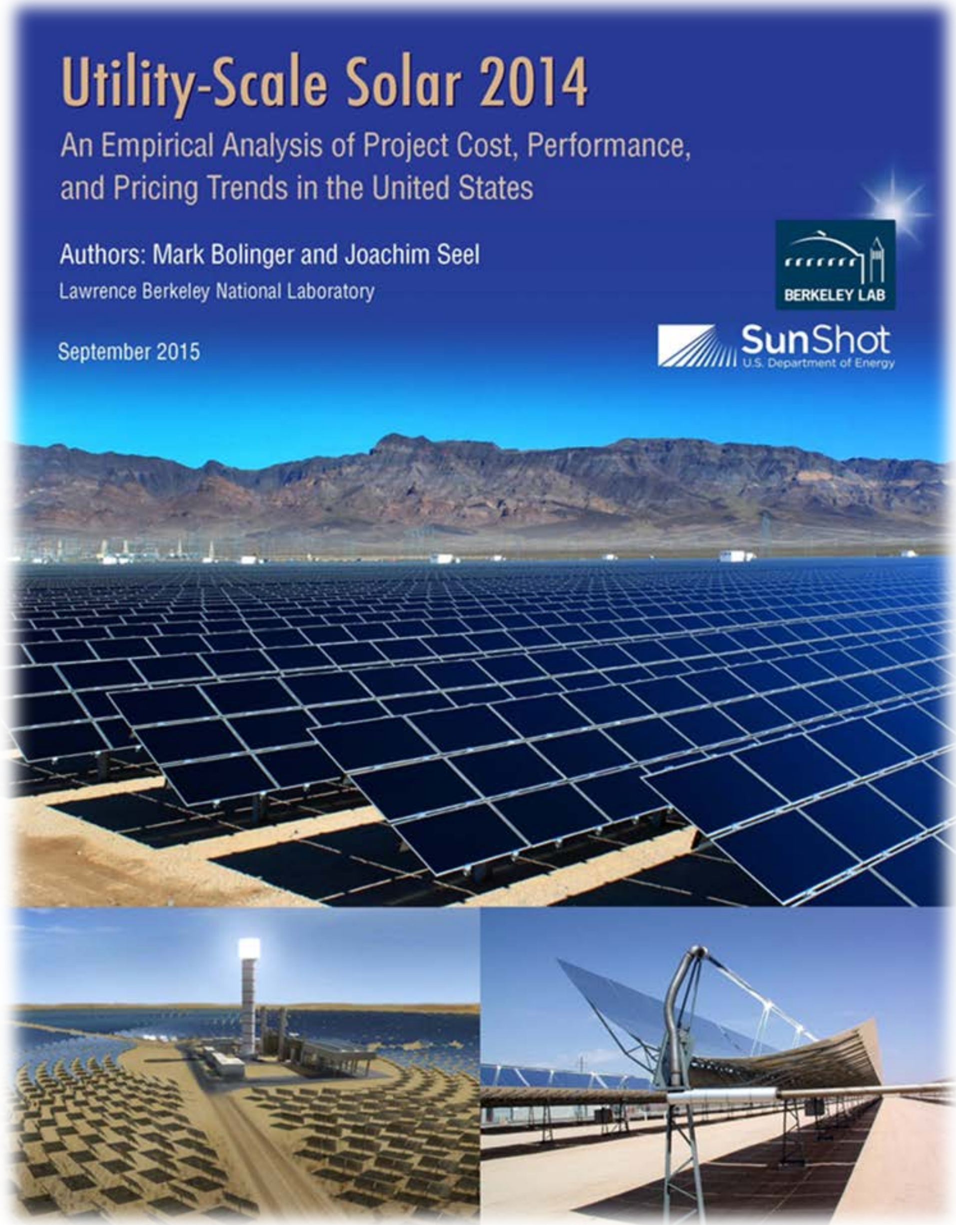


Presentation Outline

Strong growth of the utility-scale solar market offers increasing amounts of project-level data that are ripe for analysis.

1. Introduction to the project population and description of broader technology trends

Key findings from analysis of the data samples:

2. Installed project prices
3. Operation and maintenance (O&M) costs
4. Performance (capacity factors)
5. Power purchase agreement ("PPA") prices
6. Future outlook

We define "utility-scale" as **any ground-mounted project that is larger than 5 MW_{AC}**. Smaller systems are analyzed in LBNL's *"Tracking the Sun"* series.

Total utility-scale solar project universe is dominated by PV projects

PV project population: 192 projects totaling 6,201 MW_{AC}

- This population's characteristics are described in the next few slides

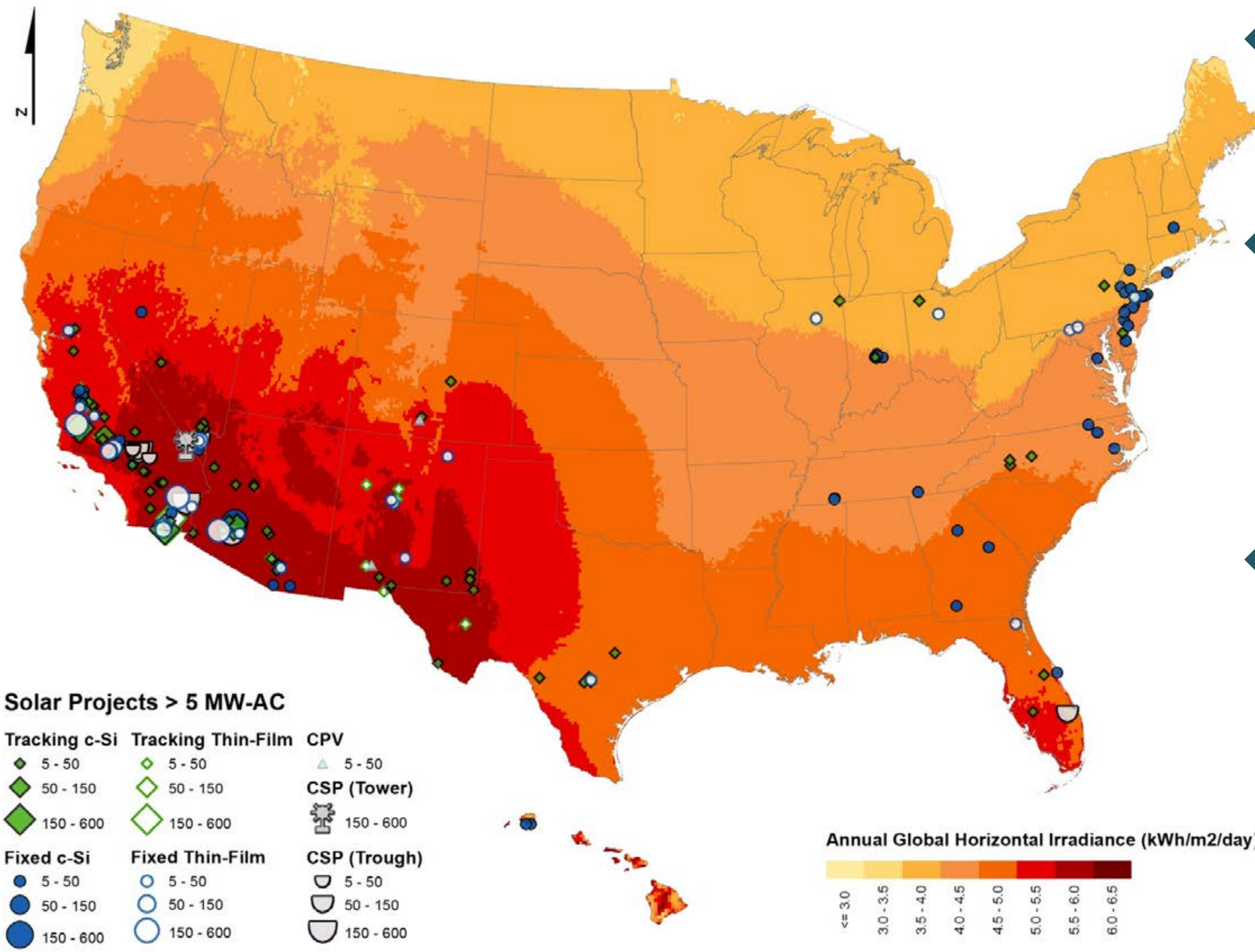
CPV project population: 2 projects totaling 35 MW_{AC}

- Both almost 4 years old, use Amonix high-concentration technology, are sited in similarly excellent solar resource areas, and have inverter loading ratios of ~1.17

CSP project population: 16 projects totaling 1,773 MW_{AC}

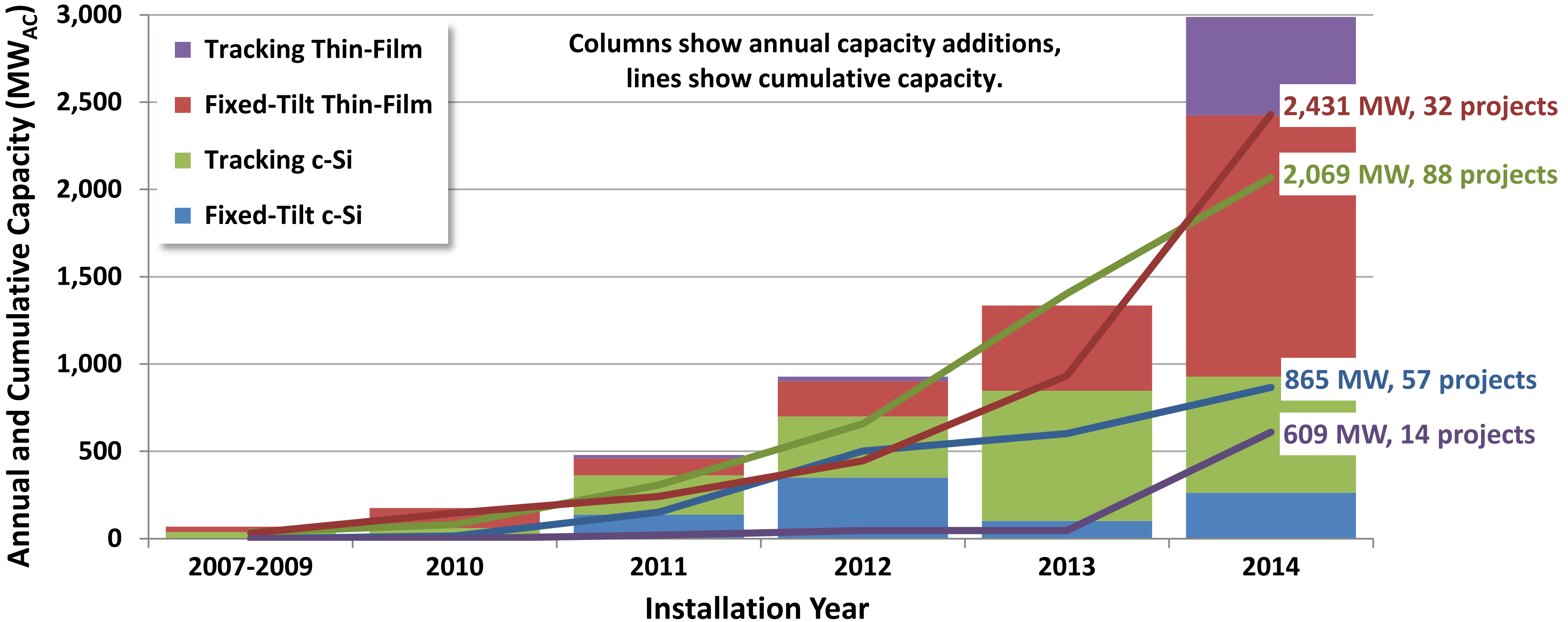
- After nearly 400 MW_{AC} built in the late-1980s (and early-1990s), no new CSP was built in the U.S. until 2007 (68 MW_{AC}), 2010 (75 MW_{AC}), and 2013-2015 (1,237 MW_{AC})
- Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors
- The five 2013-2015 projects include 3 parabolic troughs (one with 6 hours of storage) totaling 750 MW_{AC} (net) and two "power tower" projects (one with 10 hours of storage) totaling 487 MW_{AC} (net)

Historically heavy concentration in the Southwest and mid-Atlantic, but now spreading to Southeast



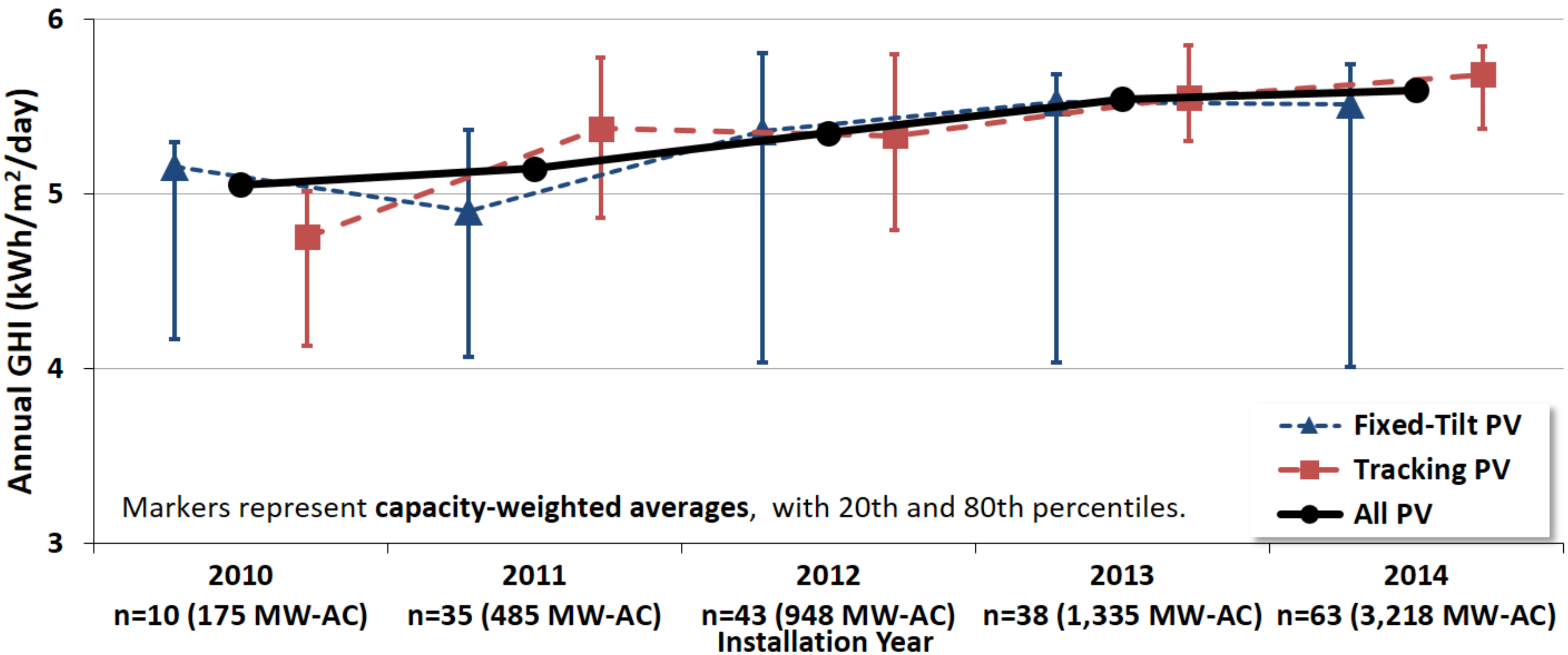
- Primarily fixed-tilt c-Si projects in the East
- Tracking (c-Si and, increasingly, thin-film) is more common in the Southwest
- Total MW share:
  1) CA – 59%
  2) AZ – 17%
  3) NV – 5%
  4) NM – 4%
  5) TX – 3%

PV project population broken out by tracking vs. fixed-tilt, module type, and installation year



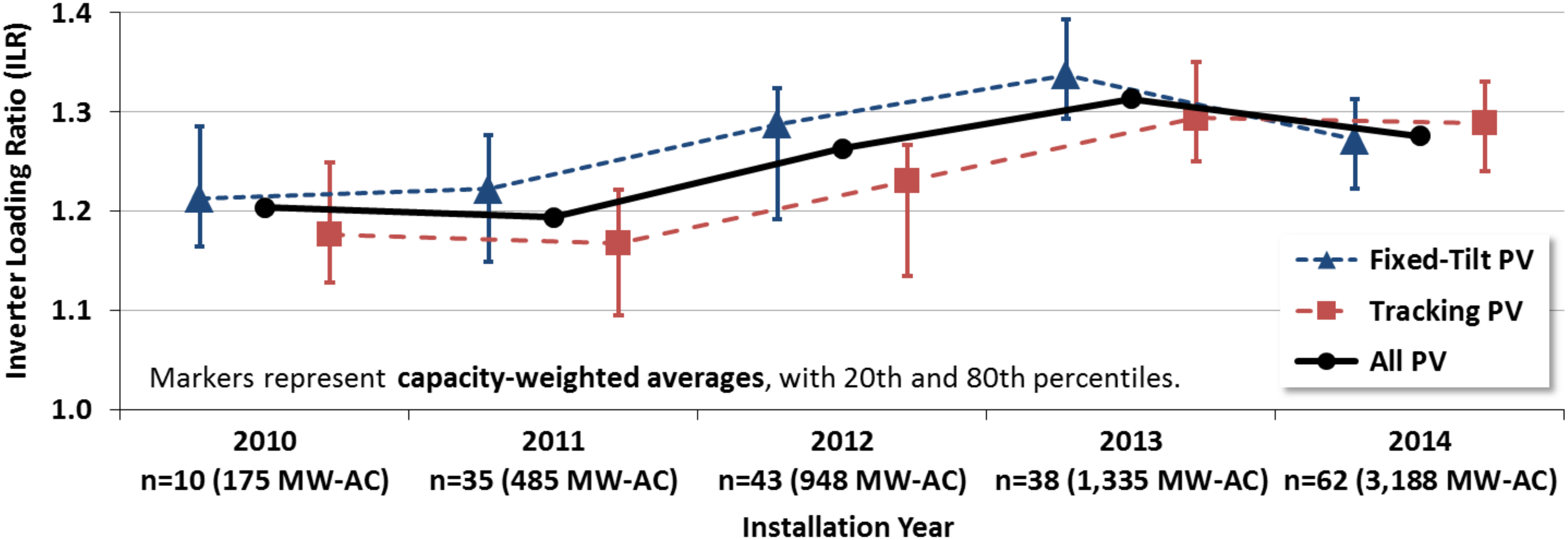
- 48% of cumulative PV capacity in population came online in 2014 (70% in 2013-2014)
- 50% of PV capacity that came online in 2014 was from ***just three*** large thin-film projects: Topaz (586 MW_{AC}), Desert Sunlight (563 MW_{AC}), Agua Caliente (348 MW_{AC})
- "Tracking c-Si" and "fixed-tilt thin-film" have been the predominant configurations over time, but this is changing: more tracking (12) than fixed-tilt (4) thin-film projects came online in 2014 (though fixed-tilt thin-film *capacity* far outweighed tracking thin-film)

On average, more recent project vintages have been built in higher-quality solar resource sites



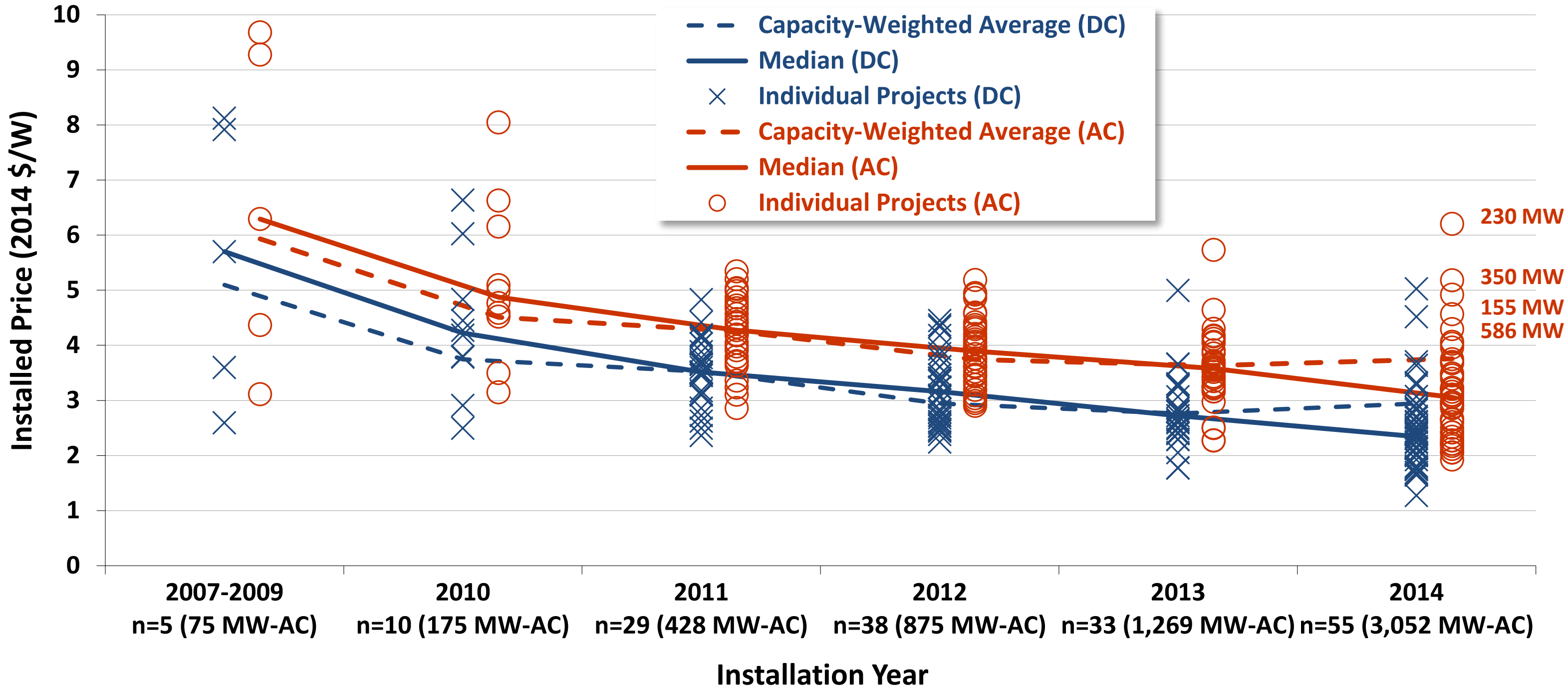
- An increase in the average GHI by project vintage simply reflects a relative shift in newer capacity towards the high-GHI Southwest
- The wide 80/20 distribution of fixed-tilt PV reflects deployment throughout the US, whereas tracking PV is concentrated more in the high-GHI Southwest
- All else equal, higher GHI should boost sample-wide capacity factors (reported later)

The average inverter loading ratio (ILR) has increased over time, to around 1.3 in 2013-14



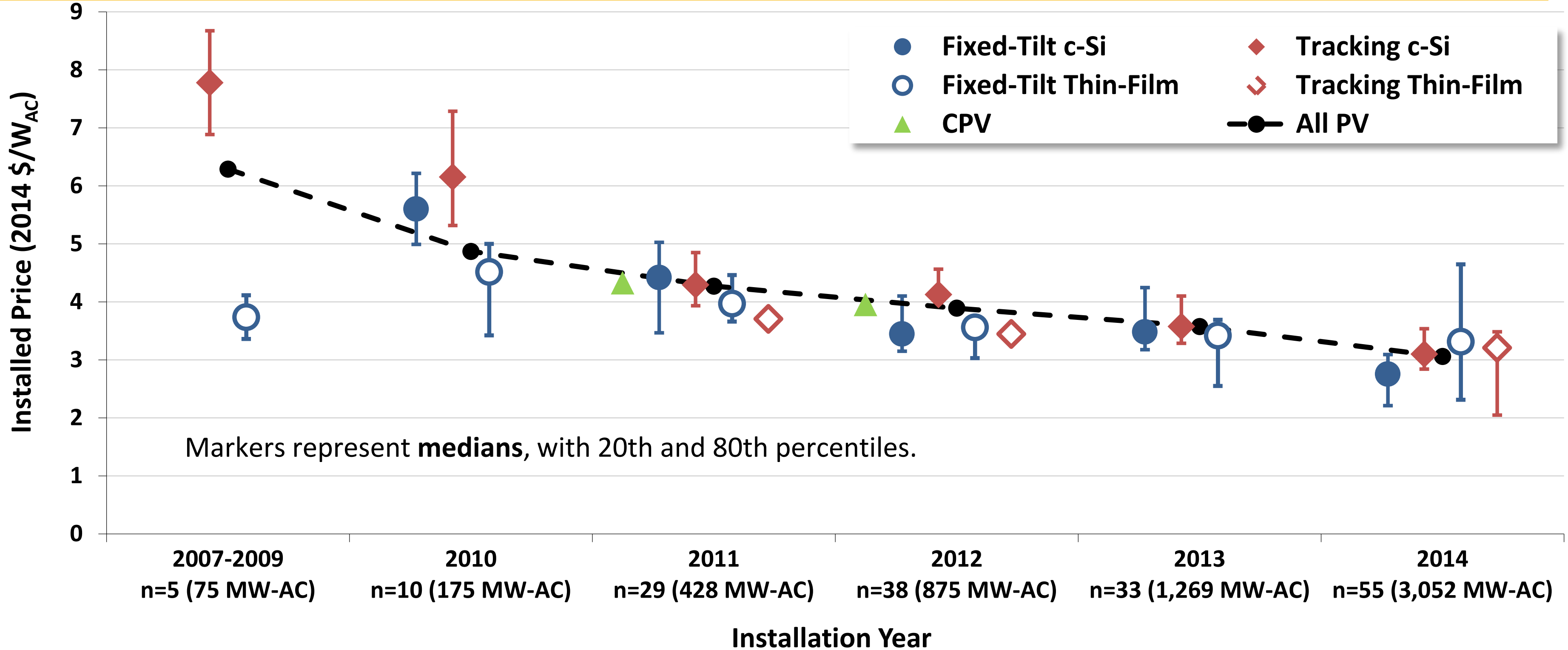
- As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity to enhance revenue
- The apparent decline in the capacity-weighted average ILR from 2013 to 2014 is related to several large projects – the median ILR (not shown) held constant in 2014 (was 1.29 in both years)
- Except in 2014 (skewed by several large projects), fixed-tilt PV generally has a higher average ILR than tracking PV (fixed-tilt has more to gain from boosting ILR)
- All else equal, a higher ILR should boost sample-wide capacity factors (reported later)

Median installed price of PV has fallen steadily, by more than 50%, to around \$3/W_{AC} (\$2.3/W_{DC}) in 2014



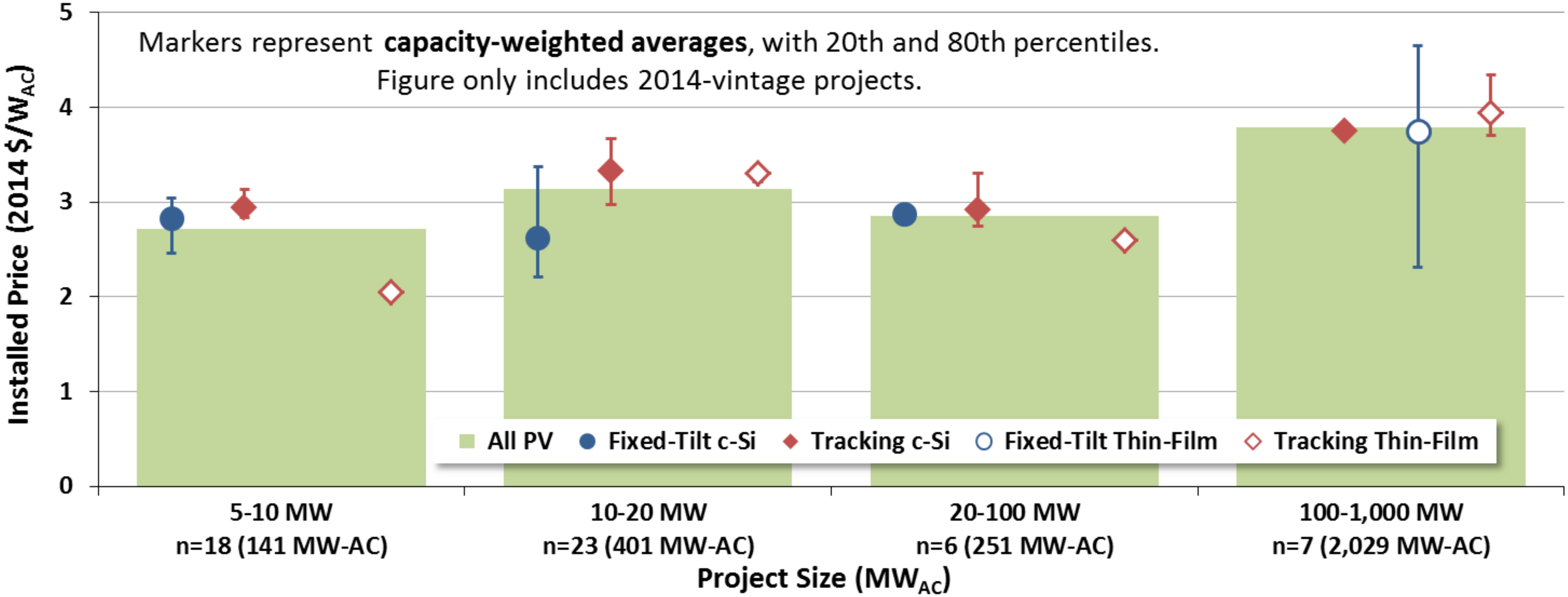
- Installed prices are shown here in both DC and AC terms, but because AC is more relevant to the utility sector, all metrics used in the rest of this slide deck are expressed solely in AC terms
- The lowest 20th percentile fell from \$3.2/W_{AC} in 2013 to \$2.3/W_{AC} in 2014
- Capacity-weighted average prices were pushed higher in 2014 by several very large projects that had been under construction for several years (but only entered our sample in 2014, once complete)
- This sample is backward-looking and may not reflect the price of projects built in 2015/2016

Installed price decline led primarily by c-Si



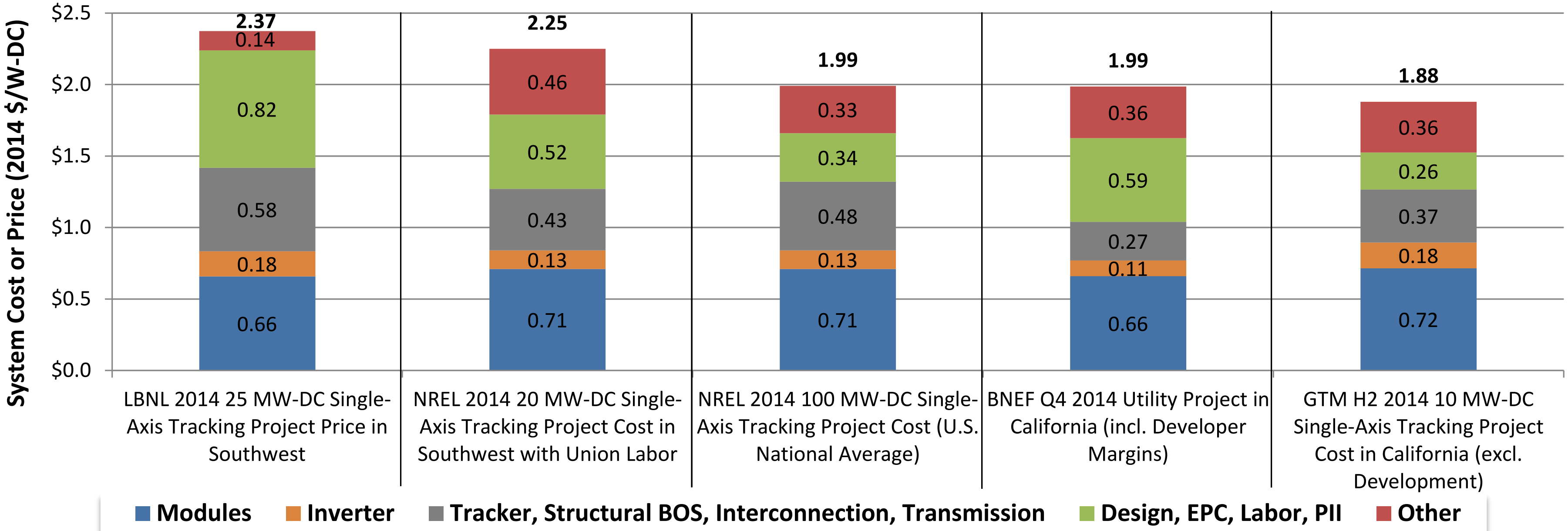
- Pricing has converged among the various mounting/module configurations over time
- Not surprisingly, tracking appears to be slightly more expensive than fixed-tilt (at least for c-Si)
- Large 80/20 range of fixed-tilt thin-film in 2014 reflects several mega-projects with high prices
- The two CPV projects built in 2011 and 2012 were priced similar to PV at the time

2014 project sample does not reflect economies of scale



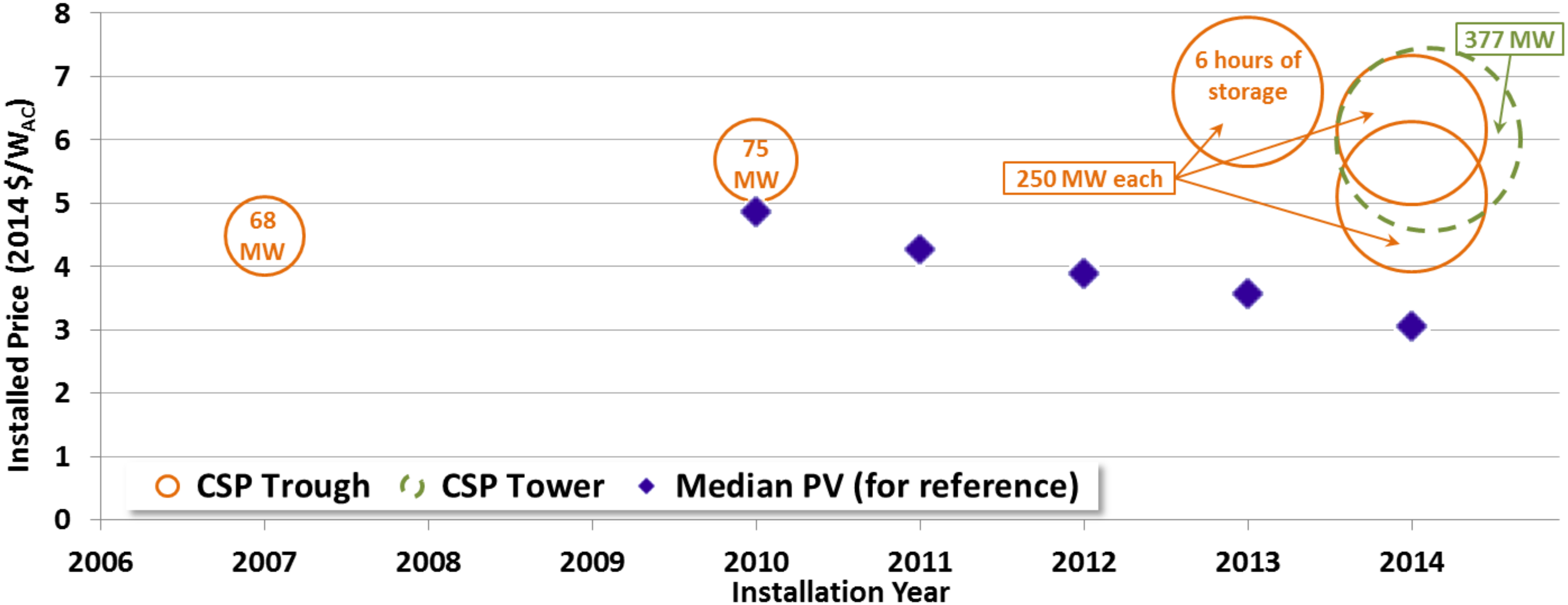
- Modular/scalable "power block" solutions from manufacturers like SunPower and First Solar may have already wrung out most of the cost savings otherwise available to larger projects
- Several of the 100+ MW projects have been under construction for several years, possibly reflecting a higher-cost past
- In general, larger projects may face greater development, regulatory, interconnection costs that outweigh any economies of scale

Bottom-up modeled installed prices are lower than our empirical data



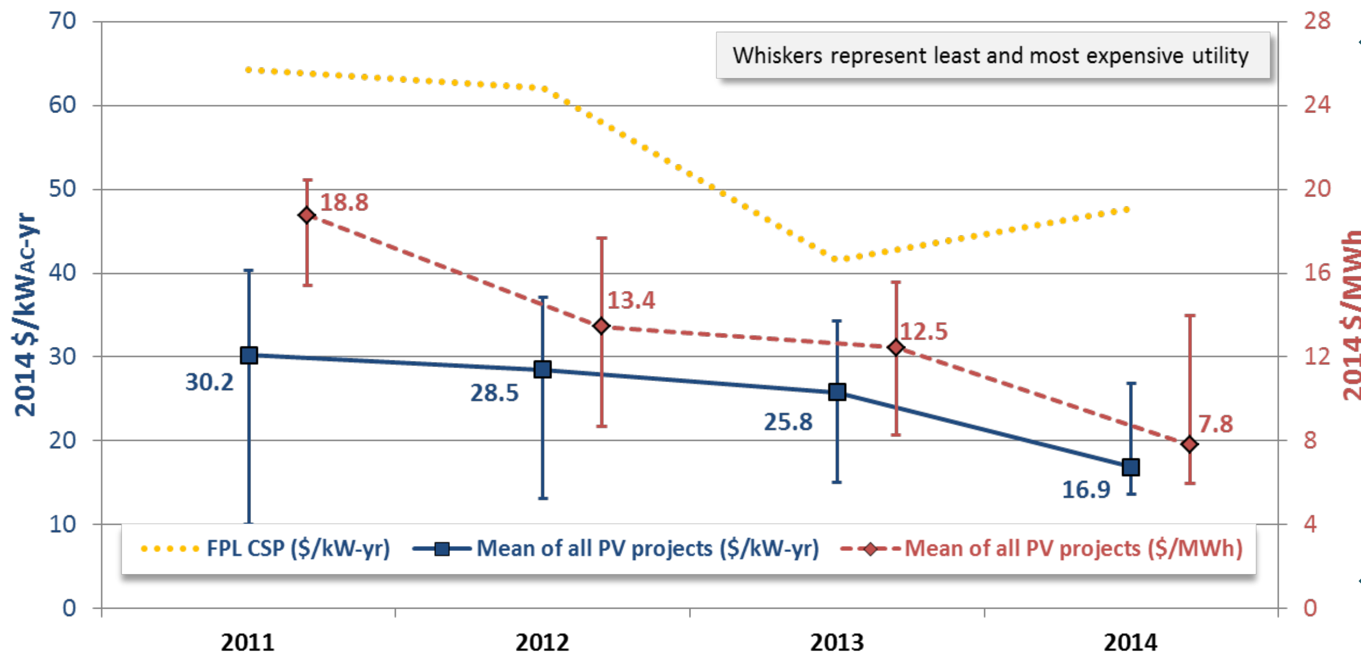
- Prices presented here in DC terms, to be consistent with how presented by NREL, BNEF, GTM
- Empirical LBNL project (far left) is most-expensive at $2.37/$W_{DC}$, despite reporting among the lowest module costs ($0.66/$W_{DC}$)
- Largest discrepancy is in EPC category – perhaps reflecting forward-looking modeling vs. backward-looking empirical data (sample LBNL project achieved commercial operation in 2014)
- There are also discrepancies in terms of what costs are captured by the various modeled estimates relative to the empirical data (e.g., development costs, financing costs)
- There is fairly substantial variation even among the various bottom-up modeled estimates

Not much movement in the installed price of CSP



- Small sample of 6 projects (4 built in 2013-14) makes it hard to identify trends
- That said, there does not appear to be much of a trend – CSP prices seem to be moving sideways (in contrast to PV's downward trend)
- To be fair, newest projects are much larger, and include storage and/or new technology (power tower) in some cases, making comparisons difficult

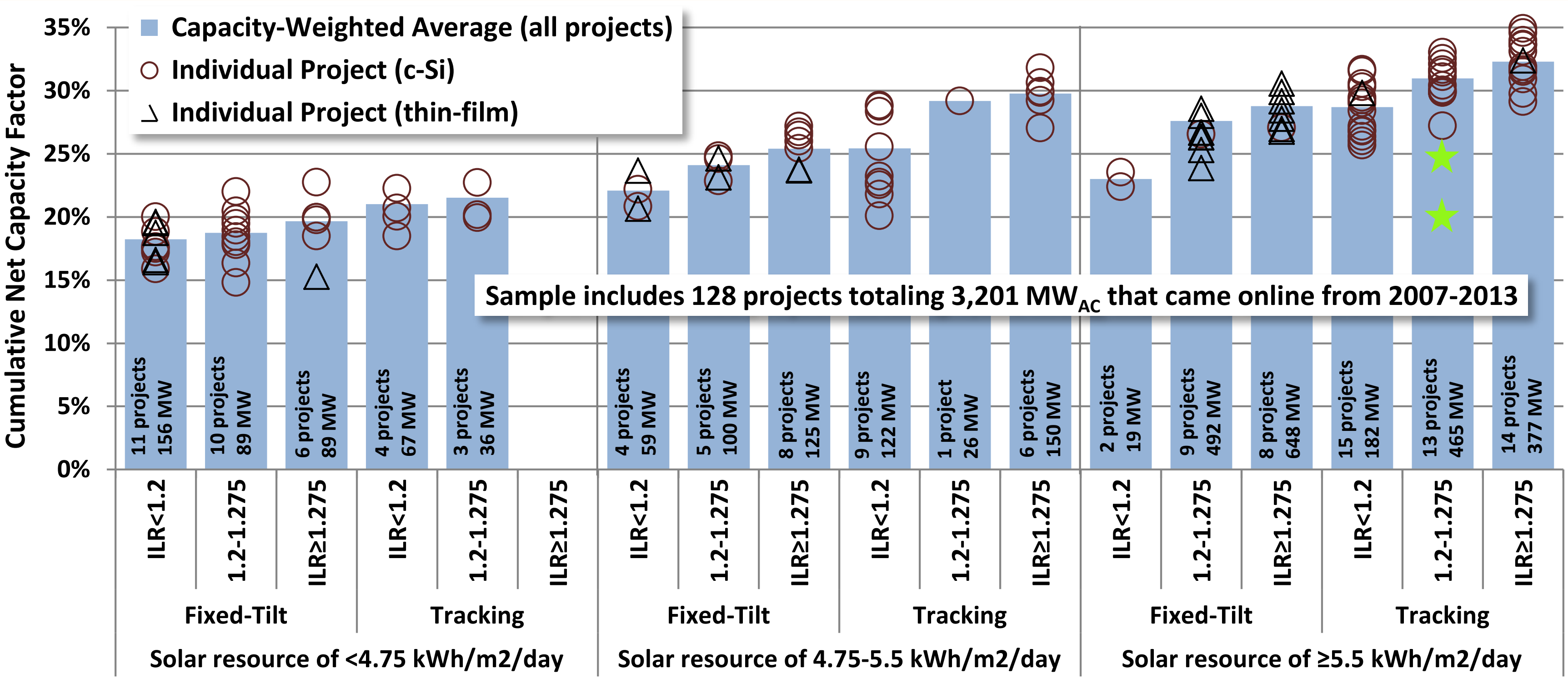
O&M cost data still very thin, but largely consistent with early years of cost projections



Year	PG&E		PNM		APS		FP&L	
	MW_{AC}	# projects	MW_{AC}	# projects	MW_{AC}	# projects	MW_{AC}	# projects
2011	N/A	N/A	N/A	N/A	51	3	110	3
2012	50	3	20	4	96	4	110	3
2013	100	6	42	4	136	6	110	3
2014	N/A	N/A	65	6	168	7	110	3
predominant technology	fixed-tilt c-Si		fixed-tilt thin-film		primarily tracking c-Si		mix of c-Si and CSP	

- Only a few utilities report solar O&M costs (see table), and tend to report fleet-wide averages rather than project-level costs (which limits the usefulness of the data)
- O&M costs appear to be declining over time as fleet size increases, but hard to tell (e.g., missing PG&E data for 2014 could be skewing sample)

27.5% average sample-wide PV net capacity factor, but with large project-level range (from 15%-35%)

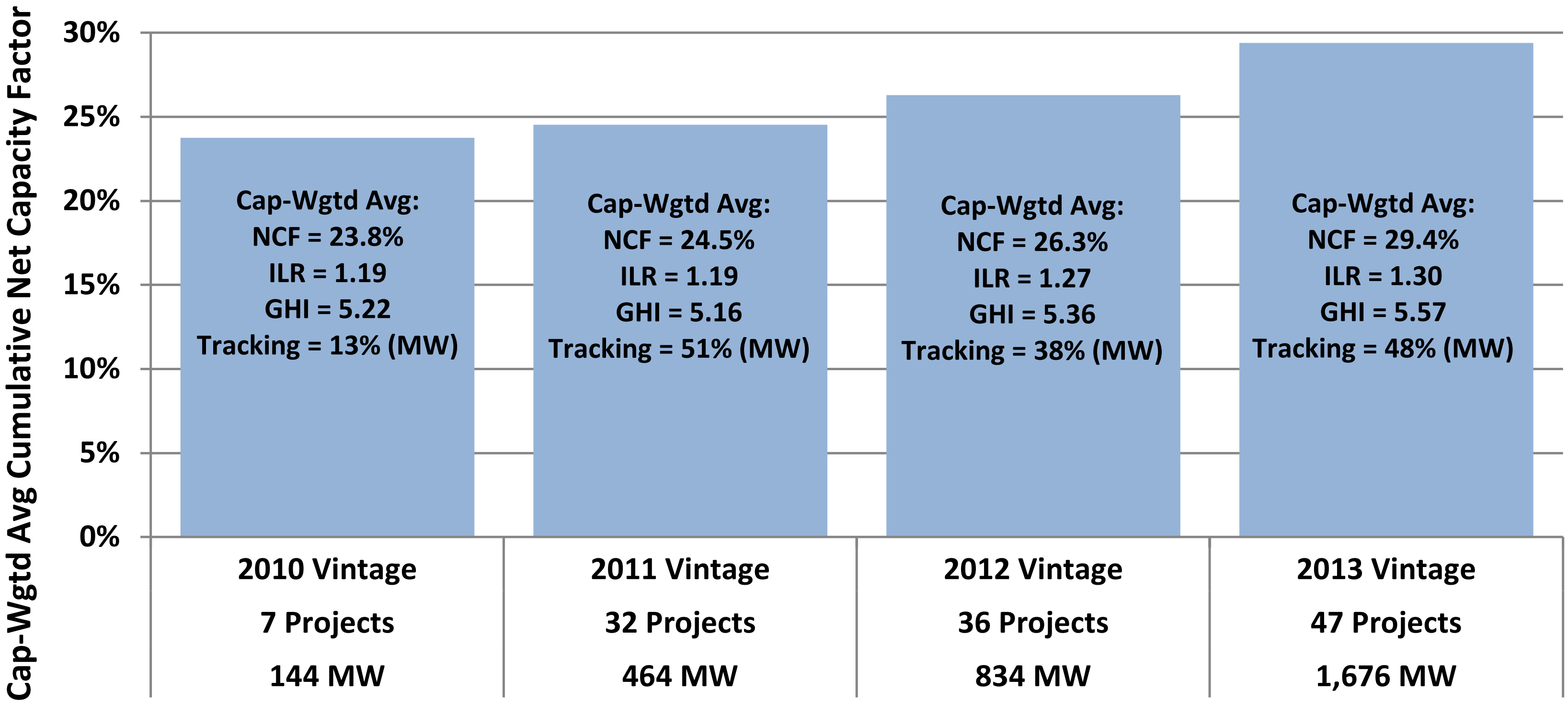


Project-level variation in PV capacity factor is driven by:

- **Solar Resource (GHI):** Highest resource bin has ~8% higher capacity factor than lowest
- **Tracking:** Adds ~4% to capacity factor on average across all three resource bins
- **Inverter Loading Ratio (ILR):** Highest ILR bins have ~4% higher capacity factor than lowest
- **Module type:** No discernible pattern between c-Si and thin-film

The two CPV projects (see green stars) have underperformed relative to similarly configured PV projects

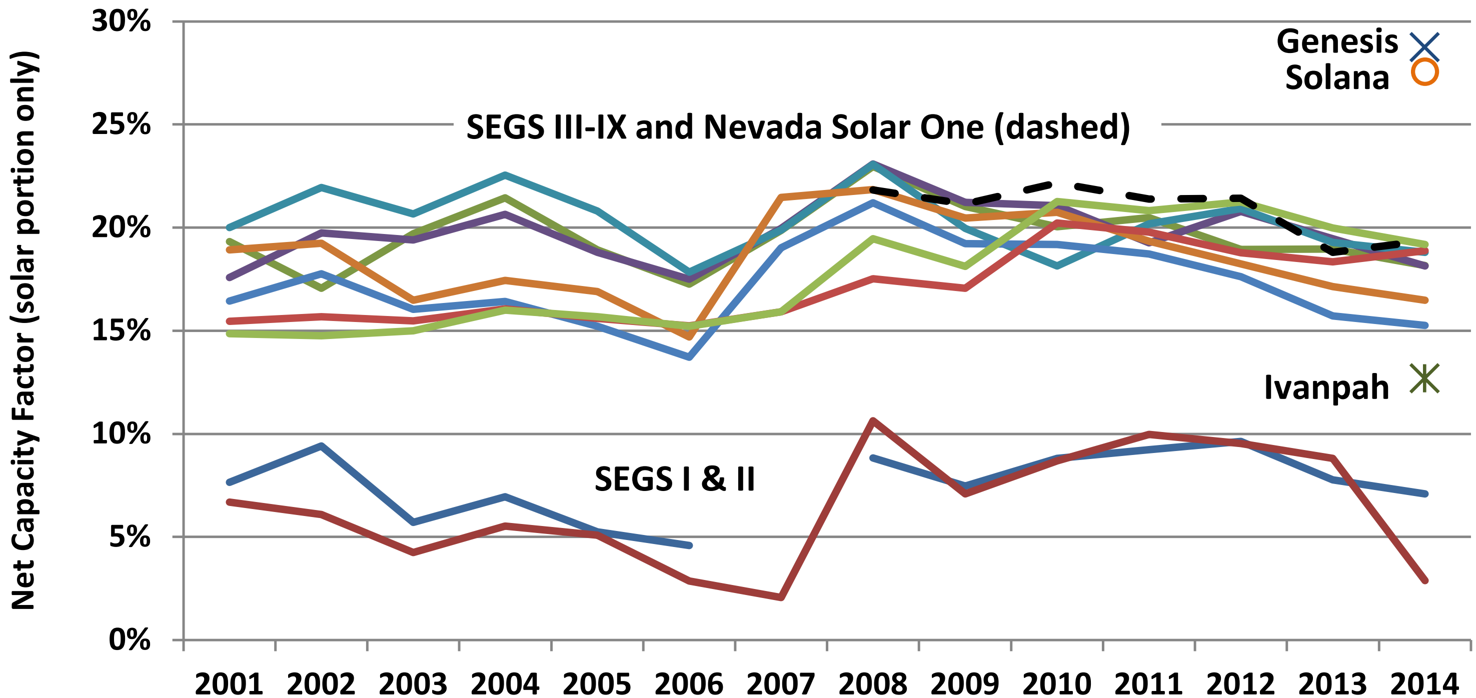
More recent PV project vintages have higher capacity factors on average



Higher capacity factors by vintage driven by an increase in:

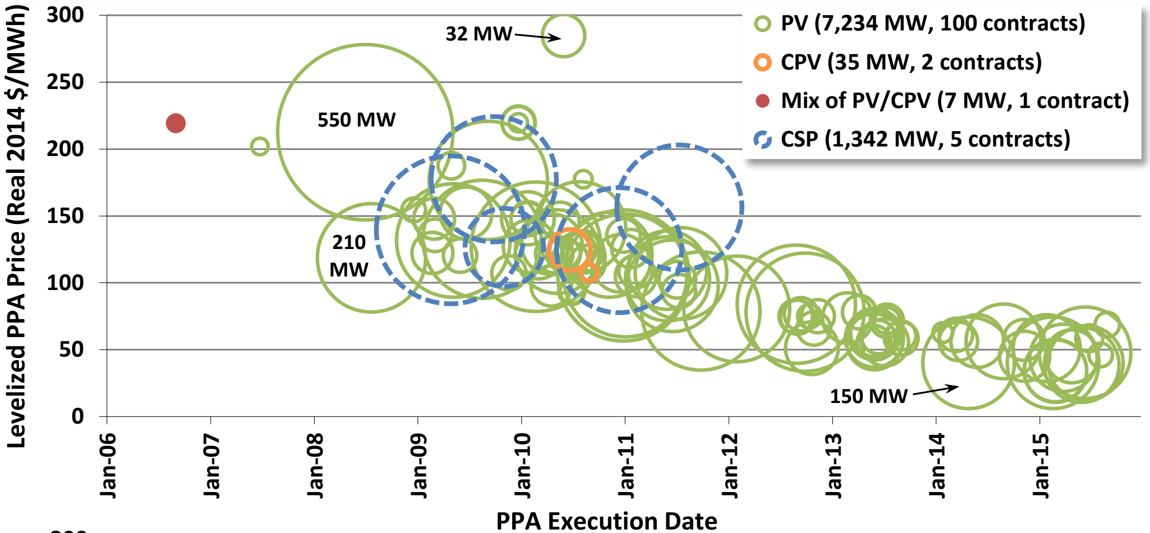
- Tracking in 2011
- Inverter loading ratio (ILR) in 2012 and 2013
- Strength of the solar resource (GHI) in 2012 and 2013

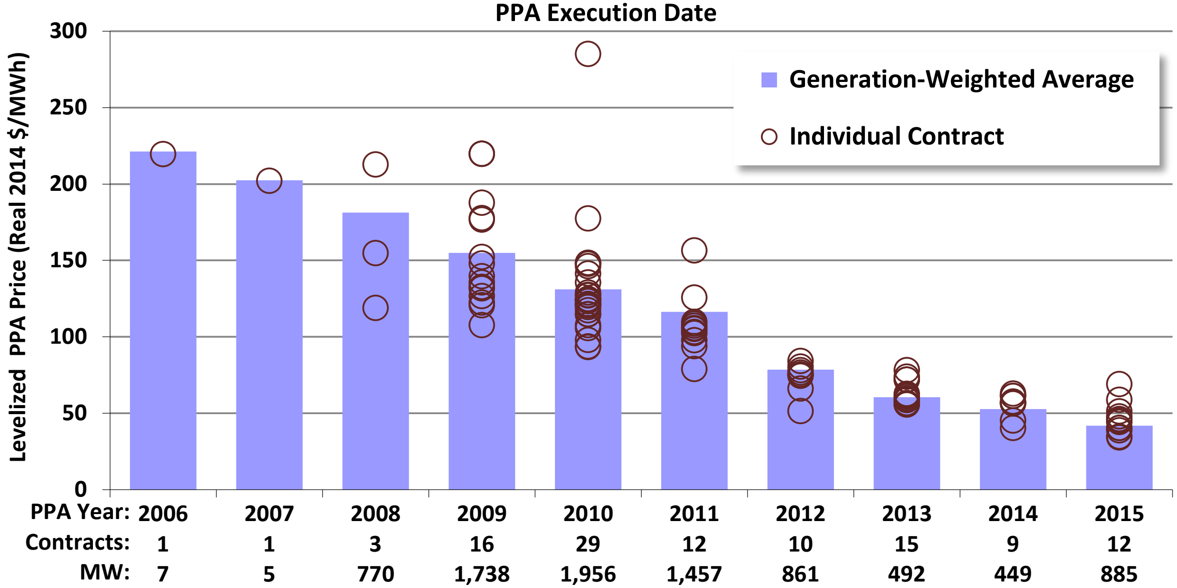
Two of three new CSP projects struggled with teething issues in 2014 (but improving in 2015)



- SEGS III-IX from the 1980s still chugging along (not far below 2007's Nevada Solar One), while SEGS I-II have lower NCFs (due to a variety of factors)
- Among newer projects: Genesis matched expectations, but Solana (expecting ~41%) and Ivanpah (expecting ~27%) fell short – *but improving so far in 2015*

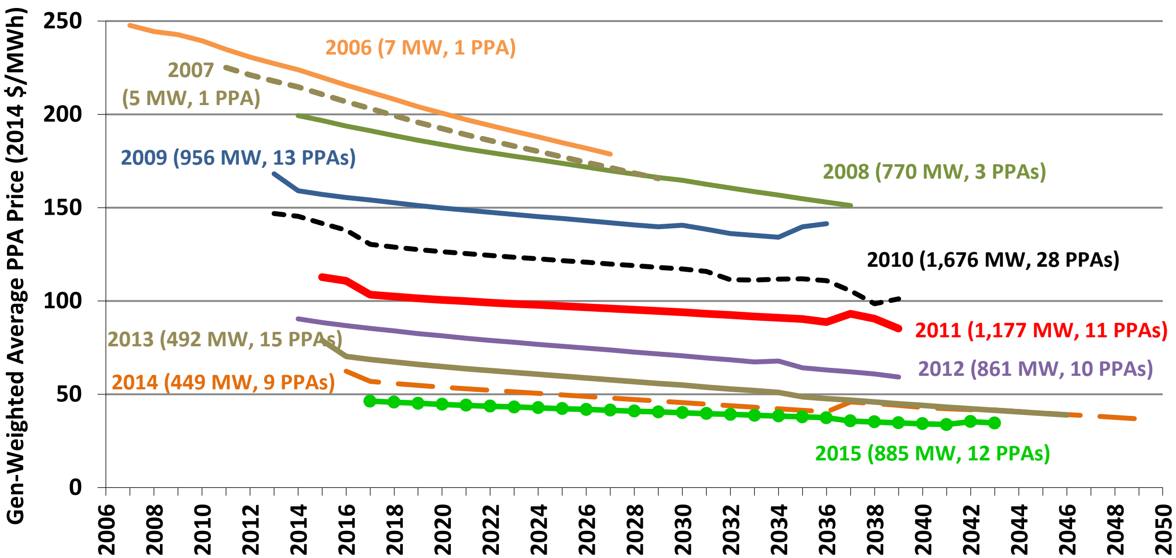
Levelized PPA prices have fallen by more than two-thirds since 2009

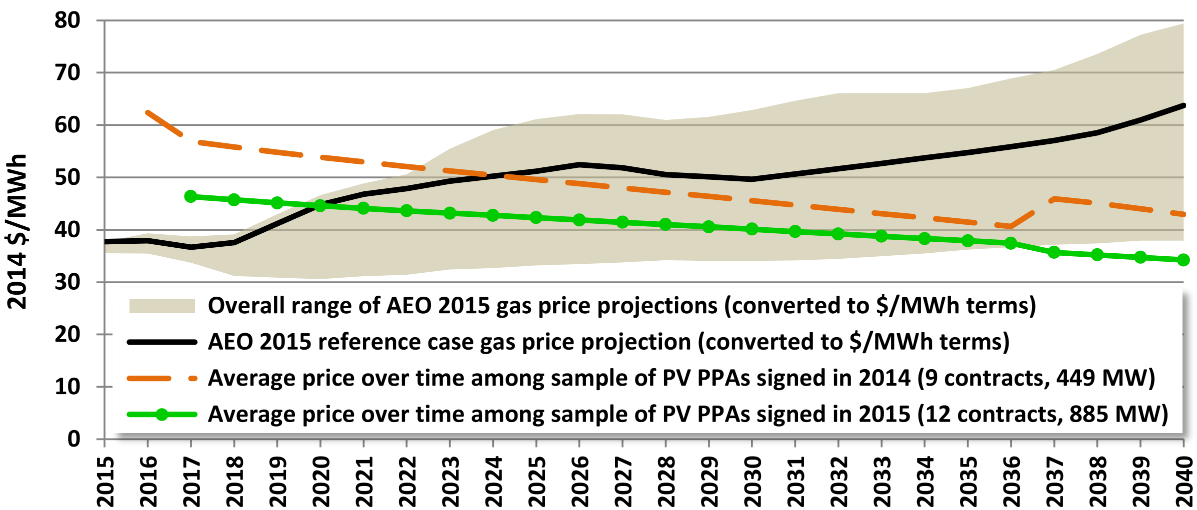




- PPA prices are levelized over the full term of the contract, after accounting for any escalation rates and/or time-of-delivery factors
- Strong/steady downward price trend since 2006
- Smaller projects (e.g., 20 MW) no less competitive
- CPV and CSP largely competitive ***at the time***, but little visibility recently
- >75% of the sample is currently operational
- Broadening of the market in 2015 (AR, AL, FL)

PV PPA prices generally decline over time in real dollar terms, in contrast to fuel cost projections





- ~70% of PV sample has flat annual PPA pricing (in nominal dollars), while the rest escalate at low rates
- Thus, average PPA prices ***decline*** over time in real dollar terms (top graph)
- Bottom graph compares 2014- and 2015-vintage PPA prices to range of gas price projections from AEO 2015, showing that…
- …PV can compete with *even just the fuel costs* of gas-fired generation, and also provides a long-term hedge against potential fuel cost increases

Apparent deep market at these low PPA prices

Austin Energy:

- 600 MW solar RFP received 7,976 MW response (33 bidders, 149 proposals)
- Almost 1,300 MW were offered at levelized prices of $45/MWh or less.

Southwestern Public Service:

- 200 MW solar RFP received 5,250 MW response
- ~3,000 MW priced at $40-50/MWh, ~1,800 MW priced at $50-60/MWh (levelized)

NV Energy:

- 200 MW renewable RFP received 2,537 MW response (90% of which was PV)
- Two 100 MW winners ~$40/MWh levelized; others reportedly at similar prices

Idaho Power and Rocky Mountain Power:

- These two Idaho and Utah utilities have been inundated with >2,000 MW of requests for "avoided cost" PURPA contracts at prices of ~$50-70/MWh

Across the South:

- Recently announced PPAs in Alabama ($61/MWh), Arkansas (~$50/MWh), Georgia (~$65/MWh), Florida ($70/MWh)

Financial modeling also supports low PPA prices – and suggests modest set-back in 2017

Now:

Using aggressive-but-achievable empirical data drawn from this slide deck, along with basic finance assumptions, yields a real levelized PPA price of $43.5/MWh – *consistent with the data sample*

- **Empirical project assumptions:** $2/W$_{AC}$ CapEx, 33% net capacity factor (with 0.5% annual degradation), $30/kW-year total OpEx
- **Financing assumptions:** 30% ITC, 5-year MACRS depreciation, 40.2% combined tax rate, 25-year PPA term, 10% after-tax equity IRR, 17-year debt at 5.5% interest and 1.35 DSCR

Post-2016:

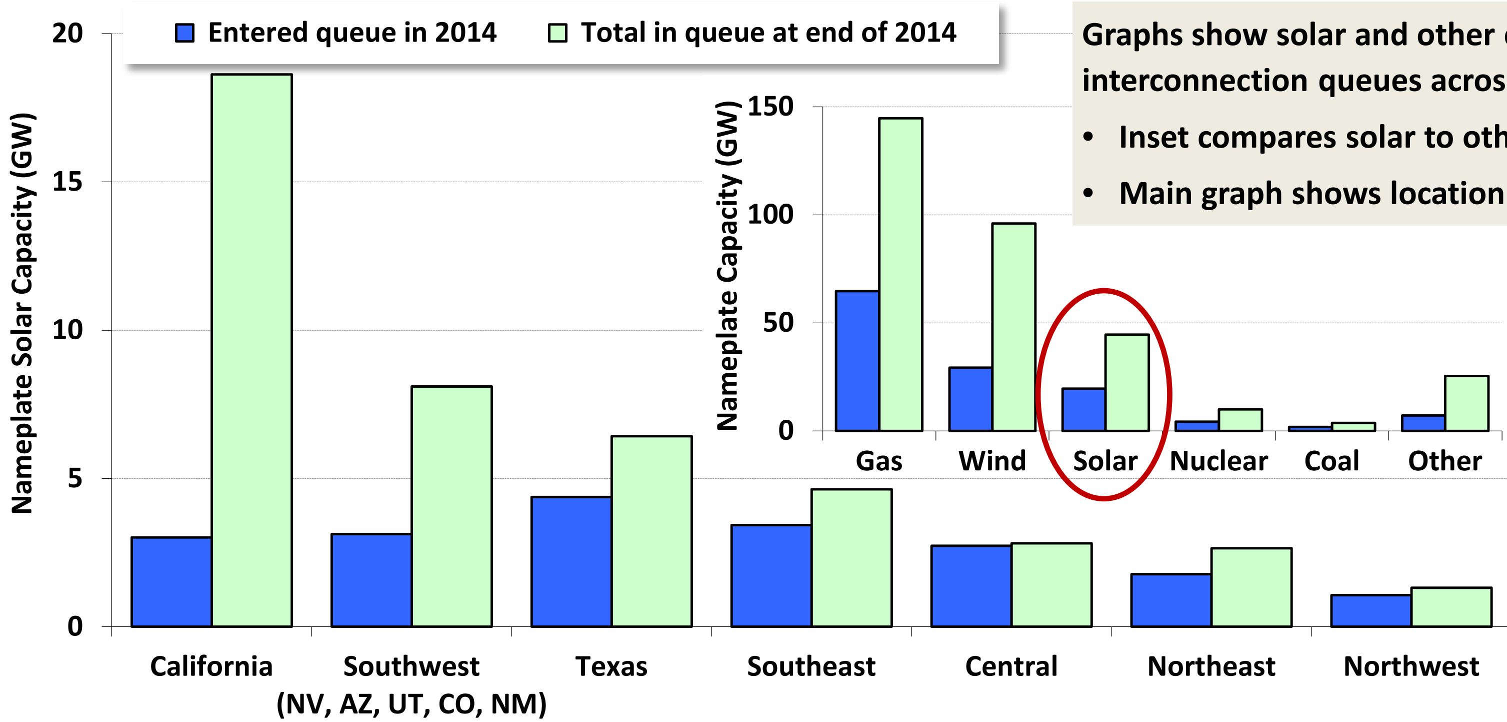
If 30% ITC reverts to 10% in 2017, this very same project would need a PPA price of $54.2/MWh, all else equal

- PPA price increase is limited to $10.7/MWh by a boost in leverage from 44.3% to 58.6%, which reduces the WACC from ~7% to ~6%, thereby partially mitigating the reduction in the ITC
- Though certainly not $43.5/MWh, $54.2/MWh is still not too shabby (think back a few years…)

To get back to $43.5/MWh under a 10% ITC through CapEx reductions alone, installed cost would need to drop by $0.50/W$_{AC}$, to $1.5/W$_{AC}$

- Some 2015/16 projects may already be at or close to $1.5/W$_{AC}$ (recent financing announcements)
- First Solar’s CEO recently promised “fully installed” costs of less than $1/W in 2017 (even if he was thinking in DC terms, this is still at or below $1.5/W$_{AC}$)

Looking ahead: utility-scale pipeline has grown, driven by an expanding market outside of the Southwest



Graphs show solar and other capacity in 35 interconnection queues across the US:

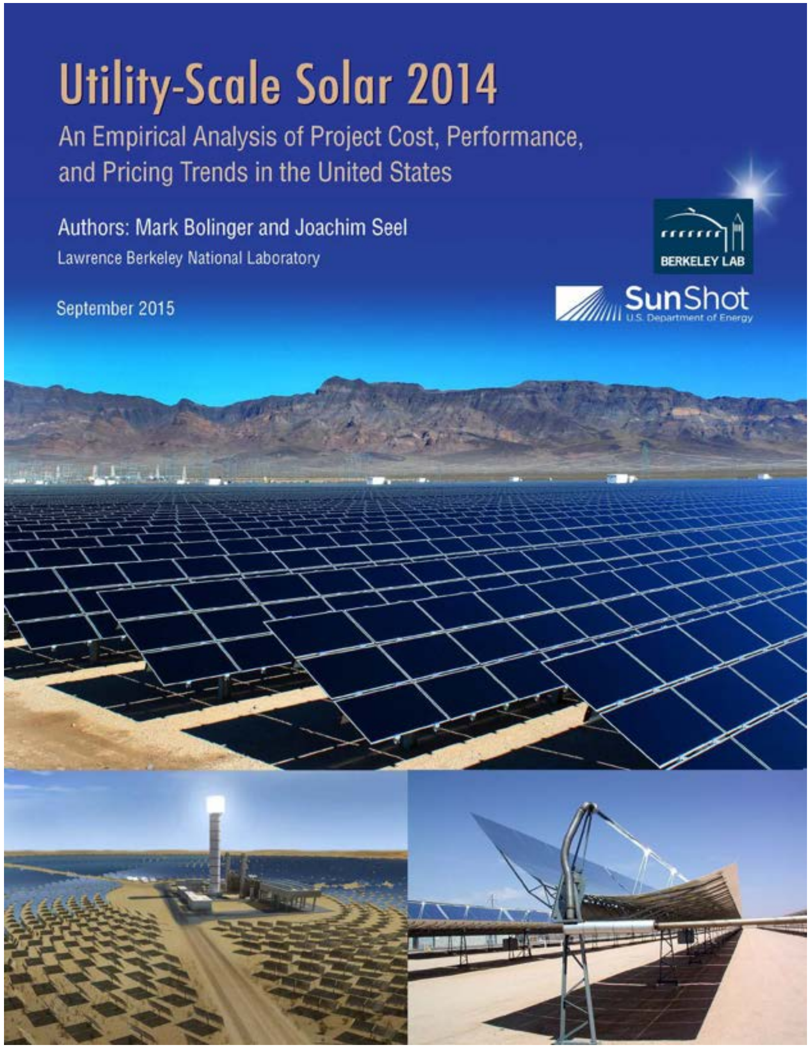
- **Inset compares solar to other resources**
- **Main graph shows location of solar**

- 44.6 GW of solar was in the queues at the end of 2014 (up from 39.5 GW at end of 2013): ***more than 5 times*** *the installed solar capacity in our project population at the end of 2014*
- Solar was in third place in the queues, behind natural gas and wind
- **Expanding market:** Texas and Southeast had more new entrants than California or Southwest in 2014; other three regions saw an unprecedented influx of new solar capacity in 2014 as well
- ***Not all of this capacity will be built!*** (but much of what is will likely be built prior to 2017)

Questions?

Download this report and all of our other solar and wind work at:

http://emp.lbl.gov/reports/re



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